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memorandum

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subject **Greenhouse Gas Mitigation Measure 3.7-1 in the Environmental Impact Report for the Proposed Inglewood Basketball and Entertainment Center (IBEC) Project**

1. Introduction

The following analysis is provided in order to help inform the City of Inglewood's evaluation of, and recommended response to, an issue raised in a comment letter submitted on June 15, 2020 from David Pettit, Senior Attorney at the Natural Resources Defense Council (NRDC) relating to the City's Draft EIR (Draft EIR) and Final EIR for the Proposed Inglewood Basketball and Entertainment Center (IBEC) Project (Proposed Project).

Specifically, the June 15 NRDC letter referred to the Fourth District Court of Appeal decision in *Golden Door Properties, LLC v. County of San Diego* (Cal. Ct. App., June 12, 2020, No. D075328) 2020 WL 3119041. While the June 15, 2020 letter did not identify any specific concerns about the greenhouse gas (GHG) mitigation measures included in the Proposed Project Draft EIR or Final EIR, the letter indicated that the County of San Diego's use of "standardless GHG offset protocols" was rejected by the Fourth District Court of Appeal. The comment then urged the City of Inglewood (City) to ensure that the Proposed Project GHG mitigation measures are "additional and enforceable – which San Diego's were not."

2. Background on the Challenged San Diego County Mitigation Measure

The rejected component of the GHG mitigation at issue in *Golden Door Properties,* namely GHG-1 (referred to below as the San Diego Mitigation Measure) allowed carbon offset credits to be used as mitigation for a project's GHG emissions if the offset credits were:

> *purchased through any of the following: (i) a CARB-approved registry, such as the Climate Action Reserve, the American Carbon Registry, and the Verified Carbon Standard, (ii) any registry approved by CARB to act as a registry under the state's cap and trade program, (iii) through the CAPCOA GHG Rx and the SDAPCD, or (iv) if no registry is in existence as identified in options (i), (ii), or (iii) above, then*

any other reputable registry or entity that issues carbon offsets consistent with Cal Health & Safety Code section 38562(d)(1)), to the satisfaction of the Director of PDS.

(Id., at *56)

The San Diego Mitigation Measure thus allowed project applicants to purchase credits from one of three categories of carbon registries or, if those registries were not available, any other registry approved by the County's Planning Director. The San Diego Mitigation Measure placed no limitation on which protocols or standards issued by those registries could be selected by a project applicant. Additionally, the only criteria for approving a different (that is, a non-California Air Resources Board (CARB)-approved registry) was that the different registry must sell carbon offsets that were "consistent with Section 38562(d)(1)" of the California Health and Safety Code.[1] Of note, the San Diego Mitigation Measure omitted the requirement set forth in Health and Safety Code §38562(d)(2), namely that GHG emission "reduction is in addition to any GHG emission reduction otherwise required by law or regulation, and any other GHG emission reduction that otherwise would occur."

In other words, the San Diego Mitigation Measure would have allowed an applicant for a general plan amendment in San Diego County to mitigate 100 percent of its GHG impacts by utilizing carbon offset credits from a non-CARB-approved registry, using an unidentified offset credit with unknown and unidentified standards, including from projects located outside the United States, so long as the measure satisfied some- but not all-of the basic "environmental integrity" standards established by the State Legislature for CARB Cap-and-Trade credits. Additionally, the San Diego Mitigation Measure provided no objective criteria for determining that the GHG emission reduction goals were met.

On these facts, the Court of Appeal held that the San Diego Mitigation Measure did not comply with the California Environmental Quality Act (CEQA) because it contained unenforceable performance standards and improperly deferred and delegated mitigation. *(Id.,* at *1.) At the same time, the opinion indicated that the holdings were "limited to the facts of [that] case" and were "not intended to be, and should not be construed as a blanket prohibition on using carbon offsets-even those originating outside of California- to mitigate greenhouse gas emissions under CEQA." *(Id.,* at *2.)

While refinements to the Draft EIR mitigation measure may not be legally necessary, in view of the *Golden Door Properties* decision, and the City's receipt of the June 15 letter referencing this decision, the following analysis reviews the GHG mitigation measure recommended in the Draft EIR, and identifies ways that it can be refined or clarified to further ensure that the mitigation measure will provide the City with clear standards to enforce the requirement that the Proposed Project achieve no net additional GHG emissions, and thereby reduce the Proposed Project's GHG impact to a less-than-significant level.[2] Although issued in light of the specific holding of *Golden Door Properties,* we wish to emphasize that this memorandum does not indicate (and should not be construed to indicate) that GHG mitigation measures used to satisfy CEQA requirements must meet all CARB statutory or regulatory requirements. ESA is aware of no statutory or regulatory requirement that would indicate such a conclusion. Equally important, it is ESA's professional opinion that CARB Offset Credits (as defined in Section

1 California Health and Safety Code §38562(d)(1) requires that GHG emission reductions achieved in CARB's Cap-and-Trade program are "real, permanent, quantifiable, verifiable, and enforceable by the state board." A full discussion of the applicable statutory and regulatory scheme establishing the CARB Cap-and-Trade program is included in Section 3.7.3 of the Draft EIR.

2 The "no net additional" standard is at times referred to in the EIR as "no net new," or "net zero." In all cases, the applicable threshold is defined on page 3.7-30 of the Draft EIR to mean "that if the Proposed Project would not emit any additional greenhouse gas emissions beyond the baseline over its estimated 30-year life, the impact would be less than significant."

3, below) offer no automatic scientific or technical advantages beyond properly developed registry offset credits,[3] and that carbon offset credits issued by qualified registries through projects that comply with properly developed protocols and standards achieve the degree of reliability and enforceability required under CEQA.

3. Background on the State's Cap-and-Trade Program

Assembly Bill 32 (AB 32) requires statewide emissions of GHGs to return to 1990 levels of by 2020. Senate Bill 32 (SB 32) mandates that the State achieve GHG levels of at least 40 percent below 1990 levels no later than December 31, 2030. A key element of California's climate plan is the Cap-and-Trade Program, which, according to CARB which oversees the program, "sets a statewide limit on sources responsible for 85 percent of California's greenhouse gas emissions…".[4] There are approximately 450 covered entities, including electricity importers and large industrial facilities emitting 25,000 $MTCO_2e$ or more annually in specified sectors including but not limited to manufacturers of cement, iron, glass, or pulp and paper, petroleum refiners, electrical generators, and distributors of transportation, natural gas, and other fuels. Each covered entity was granted a starting allocation, essentially an annual allowable GHG emission level, tied to their 2012 levels and these emission limits (caps) decrease 3 percent annually through 2020. Covered entities are to achieve emission reductions through technology, engineering, and process improvements, and are able to purchase CARB Offset Credits for no more than 8 percent of a facility's compliance obligation. These CARB Offset Credits are limited to emissions-reduction projects generated in the United States, and verified in accordance with one of six CARB-approved protocols.

CARB allowed for an entity which is not a covered entity to voluntarily participate in the Cap-and-Trade Program. There are three manners in which non-covered entities may participate:

(1) Opt-in covered entities,

(2) Voluntarily Associated Entities, and

(3) Other registered participants.

Opt-in covered entities are limited by CARB[5] to entities within a sector subject to the Cap-and-Trade Program, with annual GHG emissions below the inclusion threshold, for example, a glass manufacturer with emissions less than 25,000 $MTCO_2e$. Other registered participants are those which do not intend to hold allowances or CARB Offset Credits, such as third party verifiers. Voluntarily Associated Entities (VAEs) are those entities or individuals not classified as a covered entity or an opt-in covered entity, which, according to CARB[6] "intends to purchase, hold, sell, retire or clear allowances or CARB offset credits". Examples of VAEs given by CARB include registered offset project operators and derivatives clearing organizations.

How Trades are Conducted under the Cap-and-Trade Program

The Compliance Instrument Tracking System Service (CITSS) was created to implement market transactions under California's Cap-and-Trade program. Market participants must hold specified accounts to hold and retire

3 Although not proposed for the IBEC Project for reasons identified below, it is also possible, and indeed likely, that other GHG reduction offset credits generated outside of CARB-approved registries could satisfy the requirements for enforceability and environmental integrity for adequate mitigation under CEQA.

4 https://ww2.arb.ca.gov/sites/default/files/classic//cc/capandtrade/guidance/cap_trade_overview.pdf; Accessed July 11, 2020.

5 https://ww2.arb.ca.gov/sites/default/files/classic//cc/capandtrade/guidance/chapter4.pdf; Accessed July 11, 2020.

6 https://ww2.arb.ca.gov/sites/default/files/classic//cc/capandtrade/guidance/chapter4.pdf; Accessed July 11, 2020.

compliance instruments (i.e. credits) and to participate in transactions of compliance instruments with other account holders.[7] While CARB's September 2012 guidance[8] and the California Code of Regulations (CCR §95814)[9] may suggest that a VAE may procure and voluntarily retire CARB Offset Credits through the State's Cap-and-Trade Program, to retire CARB Offset Credits, an entity must have, in addition to a General Account, a Compliance Account within CITSS[10]. Further, CCR §95830 states clearly that "[a]n entity cannot hold a compliance instrument until the Executive Officer approves the entity's registration with CARB and the accounts administrator creates an account in the tracking system."[11] VAEs are not allowed to register Compliance Accounts; only Covered and Opt-In Entities are allowed to register Compliance Accounts. ESA made inquiries to CARB staff,[12] who confirmed that VAEs are not allowed to retire CARB Offset Credits at this time. Thus, at this time it is infeasible for a entity to become a VAE and retire CARB Offset Credits for purposes outside the Cap-and-Trade Program.

4. IBEC Project Mitigation Measure

The component of the Proposed Project GHG mitigation requirement that addresses the use of carbon offset credits is Measure 3.7-1, paragraph (a)(2)(B)(b)(i). As recommended in the Draft EIR, this measure requires as follows:

> *Carbon offset credits. The project applicant may purchase carbon offset credits that meet the requirements of this paragraph. Carbon offset credits must be verified by an approved registry. An approved registry is an entity approved by CARB to act as an "offset project registry " to help administer parts of the Compliance Offset Program under CARB 's Cap and Trade Regulation. Carbon offset credits shall be permanent, additional, quantifiable, and enforceable.*[13]

The Proposed Project GHG mitigation measure is substantially different than the San Diego Mitigation Measure. Though a full description of the differences between the measures is beyond the scope of this analysis, there are several key distinctions between the Draft EIR mitigation measure and the San Diego measure, which provide the IBEC Project mitigation measure with materially greater certainty and enforceability.

First, the Proposed Project cannot utilize carbon offset credits to mitigate all of the project's GHG emissions. Instead, the Proposed Project must first utilize a set of specifically enumerated local / onsite measures intended to reduce the Project's GHG emissions by minimizing energy demand, including both electricity and natural gas, through implementation of LEED Gold certification. (MM-3.7-1(2)(A)(a)) No analogous provision is provided in the San Diego Mitigation Measure.

7 When CARB Offset Credits are used to meet any portion of an entity's compliance obligation, the credits are transferred to the ARB Retirement Account, which ensures the credits are permanently retired from the Cap and Trade Program, and cannot be retrieved, transferred, or otherwise returned to the market or used for other purposes.

8 California Air Resources Board, Cap and Trade Guidance, September 2012; https://ww2.arb.ca.gov/sites/default/files/classic//cc/capandtrade/guidance/chapter4.pdf ; Accessed July 08, 2020

9 17 CCR § 95814. *Voluntarily Associated Entities and Other Registered Participants.*

10 https://ww2.arb.ca.gov/sites/default/files/classic//cc/capandtrade/guidance/chapter5.pdf; page 42; Accessed July 17, 2020.

11 17 CCR § 95830. Registration with ARB.

12 Personal communication between Heidi Rous, Director at ESA, and Virginia Odom, Air Pollution Specialist, CARB; July 8, 2020.

13 The text of this paragraph from the Draft EIR mitigation measure reflects the commitment by the IBEC project applicant to purchase offset credits as part of its obligations to meet the requirements of AB 987 (codified at California Public Resources Code §21168.6.8), which was developed in consultation with the CARB and determined by the CARB to meet the no net new greenhouse gas emissions requirement set forth in AB 987 as calculated pursuant to the methodology approved by the CARB.

Second, the Proposed Project must implement a detailed set of transportation demand management measures, which will be refined during the life of the project. These include, in brief summary, measures which (1) encourage alternative modes of transportation (such as rail, public transit, and vanpool); (2) provide event-day dedicated shuttle service that meets specific quantitative and qualitative criteria; (3) encourage the use of carpools and zero-emission vehicles by providing parking and pricing incentives for such vehicles, as well as a minimum of 330 electric vehicle charging stations; (4) encourage active transportation; (5) provide an employee vanpool program; (6) provide a "Park-n-Ride" Program; and (7) establish a public information/education program to promote the use of transit and other means of reducing transportation sources of GHG emissions. (MM-3.7-(a)1(2)(A)(b)). No analogous provision is provided in the San Diego Mitigation Measure.

Third, the Proposed Project must utilize and quantify project design features that result in localized reductions of NOx and PM2.5 emissions, to the extent those features result in quantifiable GHG emission reduction co-benefits. (MM-3.7- l(a)(2)). No such localized requirements were applicable in the San Diego Mitigation Measure.

Fourth, the Proposed Project is subject to the specific commitments (not applicable to San Diego) that the Proposed Project has made pursuant to AB 987, which include local direct GHG reduction measures that, as required by AB 987, would be made binding conditions of project approval by the City. The determination by CARB, dated November 27, 2019, that these commitments meet the requirements of AB 987 is included in the Administrative Record for the Proposed Project.

Fifth, Draft EIR Mitigation Measure 3. 7-l(a), paragraph (2)(B)(b)(i) expressly includes the requirement (missing from the San Diego Mitigation Measure) set forth in California Health and Safety Code §38562(d)(2) that GHG reduction measures must be '"additional" (that is, that emission reductions provided by the project must be in addition to those otherwise required by law or regulation, and that otherwise would occur in the absence of that measure).

Finally, unlike the San Diego Mitigation Measure, the emissions reductions in Proposed Project Mitigation Measure 3.7-1 must be verified pursuant to Mitigation Measure 3. 7-1 (b) through an Annual GHG Verification Report prepared by the project operator, which shall be submitted to the City, with a copy provided to CARB, each year following the commencement of project operations. The GHG Verification Report would be reviewed by a qualified expert retained by the City (at the project applicant's expense).

ln short, there are important distinctions between the San Diego Mitigation Measure and Proposed Project Mitigation Measure 3.7-1, which help ensure materially greater enforceability and verification of the Proposed Project measure.

Nevertheless, to further enhance the measure's verification and enforceability, ESA recommends for the City's consideration the following refinements to Draft EIR Mitigation Measure 3.7- l(a), paragraph (2)(B)(b)(i):

- Carbon offset credits used to meet this provision of Mitigation Measure 3.7-1(a) should be expressly required to substantively satisfy all six of the statutory "environmental integrity" requirements applicable to the CARB Cap-and-Trade Program, generally as set forth in both subdivisions (d)(1) and (d)(2) of California Health and Safety Code §38562. Accordingly, the measure should require all offset credits to be permanent, additional, quantifiable, verifiable, real, and enforceable. The applicability of these environmental integrity standards to the Proposed Project is discussed in detail below in section 6 of this memorandum.[14] In the Draft EIR, the requirement that offset credits be verifiable and real was not explicitly included in the mitigation measure.

- The project applicant should be limited to utilizing only carbon offset credits generated by projects that have been implemented, independently verified, and enforced in accordance with objective criteria set forth in any one of the following nine sets of adopted protocols/standards issued by an offset project registry approved by the CARB (including specific methodologies that comply with these standards, and allowing for substitution of demonstrated equivalent standards and protocols over time as technology changes): (1) U.S. Forestry (Climate Action Reserve (CAR) Version 5.0; American Climate Registry (ACR Version 6.0 and all Methodologies authorized thereby), (2) Urban Tree Planting (CAR Version 2.0), (3) Livestock Digesters (CAR Version 4.0), (4) Ozone Depleting Substances (CAR Version 2.0), (5) Mine Methane Capture (CAR Version 1.1), (6) Rice Cultivation (CAR Version 1.1), (7) U.S. Landfill (CAR Version 5.0; Verified Carbon Standard/Verra (VCS) Version 4 and Methodologies authorized thereby), (8) Grasslands (CAR Version 2.1; ACR Version 6.0 and Methodologies authorized thereby), and (9) Green Energy (ACR Version 6.0 and VCS Version 4, and Methodologies authorized thereby). Copies of each Protocol and Standard are enclosed as **Exhibit A** to this memorandum, together with copies of the CAR Reserve Offset Program Manual and the CAR Verification Program Manual.

- Express provisions should be made to ensure that, in the unlikely event that an approved registry becomes no longer approved by the CARB and the offset credits cannot be transferred to another approved registry, the project applicant shall comply with the rules and procedures for retiring and/or replacing offset credits in the manner specified by the applicable Protocol, Standard or Methodology, including (to the extent required) by purchasing an equivalent number of credits to recoup the loss.

- The project applicant should be limited to utilizing only carbon offset credits generated by projects within the United States or its territories.[15]

Finally, in order to further verify that the emission reduction measures (including but not limited to offset credits) are achieved and enforced, ESA recommends in Mitigation Measure 3.7- l(b) that the City ensure the availability of an expert who meets or exceeds the following level of experience and qualifications to assist with the City's annual review of the GHG Verification Report: an expert GHG emissions verifier accredited by the ANSI National Accreditation Board (ANAB) Accreditation Program for Greenhouse Gas Validation/Verification Bodies or a Greenhouse Gas Emissions Lead Verifier accredited by CARB.

These refinements would not materially alter the pre-existing requirements of Measure 3.7- l(a) and (b), nor would these refinements alter the GHG emissions analysis included as part of the EIR. Instead, these refinements would enhance the City's ability to clearly enforce objective, quasi-regulatory standards issued by the approved registry for all carbon offset credits acquired by the project applicant in satisfaction of Measure 3.7-1 (a), paragraph (2)(B)(b)(i) by constraining the project applicant's options for the use of carbon offsets within the somewhat broader range of options previously provided by the Draft EIR version of Measure 3.7- 1. As such, these refinements would not cause any new or greater significant environmental impacts, and thus no recirculation of the EIR would be required under CEQA Guidelines §15088.5. Further, it is possible – and indeed

14 This and all further references to these environmental integrity standards in this memorandum should be understood consistent with this paragraph.

15 While consistency with regulations implementing the CARB Cap-and-Trade requirement is not required for CEQA-compliance GHG mitigation offset credits, this provision would ensure consistency with the requirements applied to CARB Offset Protocols set forth in CCR, Title 17, §95972(c).

likely – that other, equally enforceable and reliable Protocols and Standards exist. However, by limiting the universe of Protocols and Standards, the City would be able to ensure that all of the Standards and Protocols that could be used by the project applicant under this provision of Mitigation Measure 3.7-1 have been specifically reviewed and approved prior to the City's consideration of certification of the EIR and approval of the Proposed Project; and, with this proposed refinement, the project applicant would be prevented from selecting a "standardless" or otherwise less enforceable means of securing carbon offset credits.

5. Discussion of Recommended Mitigation Measure Refinements

As authorized by CEQA Guidelines §15126.4(c)(3)-(4), mitigation measures for a project's GHG emissions may include the use of offsite measures, "including offsets that are not otherwise required," as well as measures that sequester GHGs.

CARB administers CARB Offset Credits for use in California's Cap-and-Trade Program. Initially authorized by the California legislature in 2006 (AB 32, the Global Warming Solutions Act of 2006), California's Cap-and-Trade Program applies only to specified "covered entities" in certain industries. For these specified sectors of the economy, CARB establishes an overall limit on GHG emissions, which cap declines over time. Entities subject to the Cap-and-Trade Program are issued allowances for GHG emissions by CARB. If an entity produces GHG emissions in excess of its allowances, it may elect to meet its compliance obligations under the Cap-and-Trade Program through emissions credits known as CARB Offset Credits.

As noted above, CARB Offset Credits are highly regulated by the CARB, and must meet six statutory environmental "integrity standards" (that is, credits must be real, verifiable, quantifiable, enforceable, permanent, and additional) set forth in California Health and Safety Code §38652(d)(1) and (d)(2). These integrity standards are further interpreted by California Code of Regulations (CCR), Title 17, §95802. To ensure these integrity standards are achieved, detailed measures for monitoring, reporting, and verifying CARB Offset Credits are specified in CCR §§95976-95988.

The Cap-and-Trade Program is implemented by CARB in partnership with each of three specifically accredited Offset Project Registries (the Climate Action Reserve, American Carbon Registry, and Verra) that have been approved by the CARB Executive Officer as satisfying the requirements set forth in CCR, Title 17, §95986(a)-(j). The approved Registries list and review projects, and issue registry offset credits, which may later be submitted to CARB for final evaluation and issuance of CARB Offset Credits.

CARB Offset Credits are considered highly reliable, and were credited by the *Golden Door Properties* court as such, because they must:

1. use defined, previously approved protocols (i.e., standards) that have been determined to satisfy the environmental integrity standards of Health and Safety Code §38562(d)(1),(2);
2. be verified by independent, non-profit registries approved by CARB; and
3. be subject to further review by CARB staff.

However as discussed above in section 3 of this memorandum, CARB Offset Credits are utilized only by a selected set of capped sectors and only for their participation in the California Cap-and-Trade program. The Proposed Project does not qualify as a Covered Entity or Opt-In Entity. Accordingly, it would not be feasible under the current regulatory scheme to equate the CEQA Guidelines §15126.4(c)(3) authorization for a project such as the Proposed Project to use "offsets" as a means of mitigating its GHG emissions under CEQA with the use of CARB Offset Credits. Accordingly, the gold standard in the context of carbon offset credits used to mitigate GHG emissions under CEQA are credits that substantively meet the environmental integrity standards set forth in California Health and Safety Code §38562(d)(1)-(2) (i.e., real, verifiable, quantifiable, enforceable, permanent, and additional), without reference to those requirements that apply only to facilitate CARB's statutory obligations to implement and enforce California's Cap-and-Trade Program.

To that end, ESA's recommended refinements to Mitigation Measure 3.7-1 achieve a substantially equivalent degree of enforceability and environmental integrity by requiring that any carbon offset credits used by the project applicant must:

1. use defined, previously approved protocols / standards that have been determined to substantively satisfy the environmental integrity standards of California Health and Safety Code §38562(d)(1),(2);
2. be verified by independent, non-profit registries approved by CARB; and
3. be subject to further review by independent verifiers employed by a government agency (here, the City) who meet stringent levels of professional qualification (i.e., ANAB Accreditation Program for Greenhouse Gas Validation/Verification Bodies or a Greenhouse Gas Emissions Lead Verifier accredited by CARB) as part of the required review of GHG Annual Verification Report to be submitted to the City and provided to CARB.

This would represent a highly enforceable and clearly defined mitigation measure because the project applicant would now be limited to the use of offset credits issued pursuant to a defined set of protocols (using the terminology of CAR) or standards (using the terminology of Verra or ACS), if it elects to purchase and retire offset credits pursuant to Proposed Project EIR Mitigation Measure 3.7- l(a), paragraph (2)(B)(b)(i). As summarized below, and set forth with in each of the expressly listed Protocols and Standards (and Methodologies developed pursuant to those Standards), each of these Protocols and Standards substantively satisfy the six environmental integrity standards enumerated in California Health and Safety Code §38562(d)(1),(2). They do so by setting forth comprehensive, detailed, and objective standards that ensure offset credits meet the detailed regulatory requirements of each Protocol and Standard.

ln addition, feasibility of this mitigation measure would be assured by including a range of Protocols and Standards across a diversity of sectors for which there is a well-developed carbon market. Thus, even if credits are not readily available within any one of the approved Standards or Protocols, the project applicant would have a sufficient degree of flexibility to ensure that enforceable credits can be obtained through another of the expressly listed and evaluated Standards and Protocols.

6. Summary Regarding Each Approved Standard’s / Protocol's Method of Achieving the AB32 Environmental Integrity Standards

As enunciated by the California Air Pollution Control Officers Association (CAPCOA), the environmental value of a carbon offset credit is its assurance that an emission reduction has occurred. Different than "evaluating produce at the farmer's market, it is not possible to examine the [GHG offset] product to determine its value. Not only are emission reductions invisible, they actually *didn't happen*. So to have confidence in their value, we need a reliable and accurate picture of what *would have happe*ned, as well as *what actually happened*." (CAPCOA, Quantifying Greenhouse Gas Mitigation Measures (2010), p. 22 (*CAPCOA Quantifying*), italics in original.)

The overarching standards for reliably and accurately quantifying the inherently intangible nature of a carbon offset is codified in the AB 32 environmental integrity measures enunciated in Health and Safety Code §38562(d)(1) and (d)(2), which provide that offset credits be "real, permanent, quantifiable, verifiable, enforceable, and additional." These terms have been further implemented through protocols and standards developed by the CARB-approved registries in accordance with the standards set forth in CCR, Title 17, §§95802 and 95972.

The following evaluation is intended to summarize ESA's professional opinion that the recommended set of approved Registry Protocols and Standards would substantively achieve the equivalent standards of CARB Offset Credits. To focus analysis on this point, where necessary, the definitions below have been slightly modified in order to substantively address the environmental integrity standards of §38562(d)(1) and (d)(2), as further informed by CCR §§95802 and 95972, while omitting procedural requirements or assumptions unique to the CARB-implemented Cap-and-Trade Program.[16]

1. ***"Real"** means that GHG reductions result from a demonstrable action or set of actions, and are quantified using appropriate, accurate, and conservative methodologies that account for all GHG emissions sources, GHG sinks, and GHG reservoirs within the offset project boundary and account for uncertainty and the potential for activity-shifting leakage and market-shifting leakage*.

   Each of the approved standards and protocols contains provisions to ensure that offset measures result in real GHG reductions that result from a demonstrated set of actions. For example:

   – ACR implements this requirement, in part, through the ACR Standard Version 6.0[17] requirement that no ex-ante credits will be issued; instead all ACR credits issued must be based on emission mitigation activities that have actually occurred, and are quantifiable and verifiable. (ACR Standard, p. 15). This requirement is further implemented through Section 2.A of the ACR Standard which requires that the International Organization for Standardization (ISO) 14064 Part 2 (2006) GHG accounting specifications are followed, which include provisions for ensuring that conservative assumptions, values and procedures are utilized to ensure that GHG emissions reductions or removals are not overestimated. Similarly, Chapter 10 of the ACR Standard details requirements for ensuring that emissions credits are not double-counted (ACR Standard, p. 59.)

   – Similar to the ACR Standard summarized above, Section 2.2.1 of Verra Standard 4[18] expressly requires that Verra offset projects approved under the Verra Standard must utilize conservative assumptions, values and procedures to ensure that net GHG emission reductions or removals are not overestimated, consistent with the principles set forth in ISO 14064 Part 2 (2006). ESA agrees that this standard provides assurance that GHG emissions are "real" within the meaning of Health and Safety Code §38562(d)(1) and implementing regulations thereto.

   – The Climate Action Reserve (CAR) Reserve Offset Program Manual enunciates that its procedures are intended to ensure that its programs are not an "artifact of incomplete or inaccurate emissions accounting." Methods for quantifying emission reductions should be conservative to avoid overstating a project's effects. The effects of a project on GHG emissions must be comprehensively accounted for, including unintended

16 Separate from the statutory environmental integrity criteria, the requirement contained in CCR, Title 17, §95972(b) of the Regulations that a crediting period be established for each protocol approved by CARB has similarly been achieved by each of the protocols recommended for inclusion in Mitigation Measure 3.7-l(a) (for example, Verra Standard 4, Section 2.3.2(1), p. 5).

17 All further references the ACR Standard are to Version 6, unless otherwise noted.

18 All further references the Verra Standard are to Version 4, unless otherwise noted.

effects (often referred to as "leakage").[19] Among other factors, the CAR ensures that all offset credit issues are "real" by requiring that all material sources, sinks, and reservoirs – regardless of where they are physically located – are accounted for in CAR protocols (for a source to be immaterial, it must account for less than 5 percent of GHG reductions). Where such exclusions are used, formulae must be adjusted to conservatively ensure that there is no overestimation of GHG reductions. A general discussion of the quantitative methods required by this measure are set forth in Section 2.5.1 of the CAR Reserve Offset Program Manual, and detailed requirements are contained in applicable Protocols.

2. *"**Permanent**" means that GHG reductions are not reversible, or when GHG reductions may be reversible, that mechanisms are in place to replace any reversed GHG emission reductions to ensure that all credited reductions endure for at least 100 years.*

   Each of the approved standards and protocols contains provisions to ensure permanence of offset measures. For example:

   – The ACR Standard ensures permanence by using quantified methods for assessing the risk of reversal (i.e., the risk that avoided GHG emissions do not meet longevity requirements due to intentional or unintentional acts of the project proponent). To address this risk, project proponents must enter into legally binding Reversal Risk Mitigation Agreements with ACR that detail the risk mitigation option selected, and the requirement for reporting and compensating reversals.

   – The Verra Standard requires application of a quantification mechanism for applicable protocols (that it has termed the AFOLU Non-Permanence Risk Tool) that multiplies the applicable non-permanence risk rating identified in a particular Methodology authorized by the Standard as determined by the AFOLU Non-Performance Risk Tool, by the change in carbon stocks. The detailed requirements for ensuring the provision of buffer credits by project applicants to address the risk of reversal are detailed in Section 3.19.4 (p. 45) of the Verra Standard.

   – Consistent with the principles set forth for ACS and Verra, the CAR similarly requires that GHG emissions reductions to be "effectively permanent," using the CARB standard of being the equivalence of removing carbon dioxide from the atmosphere for 100 years. As explained generally in Section 2.8 of the Reserve Offset Program Manual and detailed in applicable Protocols (including Forest and Grassland Protocols) where there is a risk that that carbon may be re-emitted, the CAR requires that reversals be compensated to ensure the integrity of credits issued, and to ensure their effectiveness at offsetting GHG emissions

3. *"**Quantifiable**" means the ability to accurately measure and calculate GHG reductions relative to a project baseline in a reliable and replicable manner for all GHG emission sources.*

   Each of the approved standards and protocols contains provisions for accurate quantification and objective calculation of offset measures, which account for all of the factors indicated above. For example:

   – ACR implements the quantifiable requirements through myriad procedures. These are summarized in Appendix C to the ACR Standard, which expressly builds on the ISO technical specifications for GHG accounting set forth in ISO 14064 Parts 1-3:2006 and ISO 14065:2013. (ACR Standard, p. 102.)

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19 The Climate Action Reserve provides general policies, applicable to each of the individual protocols approved under Mitigation Measure 3.7•1, through its Reserve Offset Program Manual and Verification Manual. For purposes of brevity, this summary focuses on these general provisions as these are sufficient to illustrate the clear standards utilized by the Climate Action Reserve to ensure the six environmental integrity standards are required. Detailed quantification calculations, methodologies, and additional rules are further provided within each approved Protocol.

- The ISO 140604 Part 2 standard, in addition to the World Resources Institute/World Business Council for Sustainable Development (WRI/WBCSD) Greenhouse Gas Protocol for Project Accounting guidance, is used by the CAR (see, e.g., CAR Reserve Offset Program Manual, p. 4 which is required by the listed CAR Protocols.)

- Verra specifies the standards and requirements for quantifying an accurate baseline and project accounting in Sections 3.12 and 3.14 for its Standard 4 (Verra Standard, pp. 33, 34.)

4. *"**Verifiable**" means that reports prepared by project operators or their designees are well documented and transparent such that the reports lend themselves to an objective review by a qualified verification body.*

   Each or the approved standards and protocols contains provisions for transparent and well-documented verification of emissions credits, which account for all of the factors indicated above. For example:

   - ACR details its validation and verification requirements in Chapter 9.C, using objective measures that ensure clear documentation and transparency, and allow for objective third-party review of documentation. (ACR Standard, pp. 54-58.)

   - Verification requirements are addressed throughout the Verra Standard, including without limitation, in Section 4.1.24, which provides that projects shall document and explain the sampling methods employed by the validation/verification body for the verification of GHG emission reductions or removals generated by the project. Such verification methods are required to be statistically sound. Any subsequent changes to the sampling method(s) required as a result of the verification findings must be documented in accordance with Verra requirements. (Verra Standard, p. 54.)

   - As more fully set forth in Section 2 of the CAR Reserve Offset Program Manual, the CAR protocols detail the steps and formulae to estimate, monitor, and verify GHG reductions achieved by specific types of projects. While each project protocol contains guidance specific to individual project types, all CAR protocols also adhere to general project accounting principles, including the ISO 14064 Part 2 requirement utilized by ACR and Verra. The CAR Reserve Offset Program Manual details implementation of the general accounting principles set forth therein, including without limitation the requirements of (a) relevance; (b) completeness; (c) consistency; (d) transparency; (e) accuracy; and (f) conservativeness. In all cases, trained verifiers are utilized by the CAR, to provide further assurance that promised project activities have occurred pursuant to CAR requirements.

5. *"**Enforceable**" means the authority to hold a particular party liable and to take appropriate action if any of the requirements of the applicable protocol or standard are violated. Each of the approved standards and protocols contains provisions for contractual enforcement of offset measures.*[20]

   For example:

   - The ACR implements this requirement, in part, through Section 8.B of the Standard, which provides that ACR has the right to refuse to list or issue credits for violations of ACR requirements. Additionally, where applicable (e.g., for forest or grassland protocols where ownership and/or control of land is critical to maintaining reliable GHG sinks), a project proponent must provide evidence that the applicable land is eligible, that the project proponent holds clear land title and title to the GHG offsets, and that the offsets contract is enforceable. (ACR Standard, p. 82.)

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20 In addition to enforceability contemplated by the Health and Safety Code environmental integrity standards, the City maintains ultimate enforcement authority over the project applicant through the use of the annual submittal of the GHG Verification Report, qualified review by the City, and obligation for the project applicant to pursue additional or replacement measures in the event of a shortfall of GHG emissions reductions in a prior year.

- Verra implements this requirement through Section 3.6. 1 of the Verra Standard, which requires that all projects provide one or more of seven enumerated types of evidence demonstrating that the project proponent maintains the legal right to control and operate project and program activities.
- Similar to the principles enunciated in the ACR Standard, where applicable (e.g., for forest or grassland protocols where ownership and/or control of land is critical to maintaining reliable GHG sinks), a CAR project proponent must provide evidence that the applicable land is eligible for the project, that the project proponent holds clear land title and title to the GHG offsets, and that the offsets contract is enforceable. This is further assured through the CAR's verification that an account holder can only hold or retire offset credits in its account for which it is the sole holder of legal or equitable title. Additional assurance is provided by requiring attestation of title, and ensuring that a legally binding and enforceable contract (typically referred to as Project Implementation Agreement) is entered into between project proponents and the CAR.

6. *“**Additional**" means that GHG emission reductions or removals exceed any GHG reduction or removals otherwise required by law, regulation or legally binding mandate, and exceed any GHG reductions or removals that would otherwise occur in a conservative business-as-usual scenario.*

   Each of the approved standards and protocols contains provisions for additionality. For example:

- ACR ensures that the additionality standard is satisfied by verifying that credited offsets exceed the GHG reductions and removals that would have occurred under current laws and regulations, current industry practices, and without carbon market incentives. Project proponents must demonstrate that the GHG emission reductions and removals from an offset project are above and beyond the "business as usual" scenario, using conservative assumptions set forth in ISO 14064 Part 2 (2006). (ACR Standard 6, pp. 28-32.)
- Verra ensures additionality through, among others, the provisions and requirements of Section 3.13 of the Verra Standard. Consistent with statutory and regulatory requirements, in order to qualify for offsets, a carbon offset project must demonstrate that the activity results in emissions reductions or removals that are in excess of what would be achieved under a business as usual scenario, and the activity would not have occurred in the absence of the incentive provided by the program activity. Detailed other requirements apply depending on the type and sector of the offset project utilized. (Verra Standard, p. 33.)
- To ensure additionality, the CAR employs objective criteria designed to distinguish additional projects from those that would have happened anyway (i.e., in the absence of an offset market). These criteria fall into two categories: (1) a legal requirement test, and (2) a performance standard test. These tests are explained and described in detail in Section 2.4 of the CAR Reserve Offset Program Manual and are further detailed within each approved Protocol.

7. Conclusion

ESA has reviewed each of the specific Protocols and Standards enumerated above, which have been recommended for express inclusion in Proposed Project EIR Mitigation Measure 3.7- 1. Based on this review, and particularly with inclusion of the refinements suggested above, Mitigation Measure 3.7-1 would constitute a clear, feasible, verifiable and enforceable mitigation measure to offset Proposed Project GHG emissions.

Exhibits

Exhibit A

Carbon Offset Credit Standards and Protocols

A.1 American Carbon Registry Standards

A.1.1 Afforestation and Reforestation of Degraded Land

METHODOLOGY FOR THE QUANTIFICATION, MONITORING, REPORTING AND VERIFICATION OF GREENHOUSE GAS EMISSIONS REDUCTIONS AND REMOVALS FROM

AFFORESTATION AND REFORESTATION OF DEGRADED LAND

VERSION 1.2

May 2017

METHODOLOGY FOR THE QUANTIFICATION, MONITORING, REPORTING AND VERIFICATION OF GREENHOUSE GAS EMISSIONS REDUCTIONS AND REMOVALS FROM

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May 2017

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ABOUT AMERICAN CARBON REGISTRY® (ACR)

A leading carbon offset program founded in 1996 as the first private voluntary GHG registry in the world, ACR operates in the voluntary and regulated carbon markets. ACR has unparalleled experience in the development of environmentally rigorous, science-based offset methodologies as well as operational experience in the oversight of offset project verification, registration, offset issuance and retirement reporting through its online registry system.

ACRONYMS

ACR	American Carbon Registry
AFOLU	Agriculture, forestry and other land uses
A/R	Afforestation/Reforestation
BEF	Biomass expansion factor
CAI	Current annual increment
CDM	Clean Development Mechanism
CO2	Carbon dioxide
DBH	Diameter at breast height
ERT	Emission reductions tons
FAO	Food and Agriculture Organization (United Nations)
FFE	Fire and Fuels Extension Guide
FVS	Forest Vegetation Simulator
GHG	Greenhouse gas
GIS	Geographical Information System
GPG-LULUCF	Good Practice Guidance for Land Use, Land Use Change and Forestry (IPCC)
GPS	Global Positioning System
IPCC	Intergovernmental Panel on Climate Change
OF	Oxidized fraction
QA/QC	Quality assurance / Quality control
PP	Project proponent
SLF	Short lived fraction

SOC	Soil organic carbon
SOP	Standard operating procedure
UNFCCC	United Nations Framework Convention on Climate Change
USFS	United State Forest Service
VCS	Verified Carbon Standard
VVB	Validation and verification body
WWF	Wood waste

CONTENTS

TABLES

EQUATIONS

INTRODUCTION

The American Carbon Registry (ACR) in 2010 approved the use of the Clean Development Mechanism (CDM)-approved consolidated afforestation and reforestation baseline and monitoring methodology AR-ACM0001 Version 5.0.0, "Afforestation and Reforestation of Degraded Land," for developing an afforestation/reforestation (A/R) project for registration on ACR. See http://americancarbonregistry.org/carbon-accounting/carbon-accounting/other-accepted-methodologies. (AR-ACM0001 has since been retired by CDM and replaced by AR-ACM0003.)

In March 2011, ACR published its Methodology for Afforestation and Reforestation of Degraded Land, v1.0, which represented a modification to the CDM methodology with clarifications for project registration on ACR as well as the addition of harvested wood products accounting. This methodology modification was drafted by TREES Forest Carbon Consulting, using wood products accounting methods drawn from a "Methodology for Improved Forest Management through Extension of Rotation Age" developed by Winrock International for Ecotrust and approved under the Verified Carbon Standard (VCS) as VM0003. ACR wishes to thank TREES Forest Carbon Consulting for its assistance in making the first modification.

In a second modification, the U.S. Forest Service proposed adding its Forest Vegetation Simulator (FVS) as an approved tool to estimate carbon stock changes. This modification was reviewed by the ACR AFOLU Technical Committee and is published by ACR as the Methodology for Afforestation and Reforestation of Degraded Land, v 1.1. ACR wishes to thank the U.S. Forest Service for its assistance in making the second modification.

While new methodologies are approved through a process of public consultation and scientific peer review, methodology modifications such as these are reviewed by an independent ACR Agriculture, Forestry and Other Land Use (AFOLU) Technical Committee (see http://www.americancarbonregistry.org/carbon-accounting/acr-afolu-technical-committee). Both of the above modifications were considered by this Committee and recommended for approval. Version 1.1 was posted for public comment in June 2013.

1 SOURCE, DEFINITIONS AND APPLICABILITY

1.1 SOURCE

This methodology is a revision of CDM Methodology AR-ACM0001 to include accounting for harvested wood products, as well as the incorporation of Forest Vegetation Simulator (FVS) as an approved tool to estimate carbon stock changes. The methodology structure and text is directly adapted from these methodologies:

- AR-ACM0001, Version 5.0.0, “Afforestation and reforestation of degraded land”, consolidated and published by the UNFCCC CDM Executive Board;
- VM0003 “Methodology for Improved Forest Management through Extension of Rotation Age”, developed by Winrock International for Ecotrust, and approved under the Verified Carbon Standard (VCS).
- Additional text on the use of FVS, drafted by the U.S. Forest Service.

For more information regarding the source methodologies and their consideration by the CDM Executive Board (the Board) please refer to http://cdm.unfccc.int/goto/ARappmeth (note that AR-ACM0001 has since been retired by CDM and replaced by AR-ACM0003). For VM0003, please refer to http://database.v-c-s.org/methodologies/methodology-improved-forest-management-through-extension-rotation-age-v12. . For Forest Vegetation Simulator, see http://www.fs.fed.us/fmsc/fvs/.

This methodology also refers to the latest approved versions of the following CDM tools, procedures, guidelines and guidances:

- Procedures to demonstrate the eligibility of lands for afforestation and reforestation CDM project activities;
- Guidance on application of the definition of the project boundary to A/R CDM project activities;
- Tool for the identification of degraded or degrading lands for consideration in implementing CDM A/R project activities;
- Combined tool to identify the baseline scenario and demonstrate the additionality in A/R CDM project activities;
- Calculation of the number of sample plots for measurements within A/R CDM project activities;
- Tool for testing significance of GHG emissions in A/R CDM project activities;

- Estimation of GHG emissions due to clearing, burning and decay of existing vegetation attributable to a CDM A/R project activity;
- Estimation of the increase in GHG emissions attributable to displacement of pre-project agricultural activities in A/R CDM project activity;
- Tool for estimation of change in soil organic carbon stocks due to the implementation of A/R CDM project activities.

All the above-mentioned tools, procedures, guidelines and guidance are available at: http://cdm.unfccc.int/Reference/tools and http://cdm.unfccc.int/Reference/Procedures/index.html.

Some sections of this methodology refer to the Forest Vegetation Simulator (FVS) as a tool to estimate carbon stock changes. FVS is the U.S. Forest Service's national forest growth model. The FVS software package is free and available on the internet. Please note that:

- The additional guidelines on using FVS in conjunction with this methodology, included in section 4, must be followed.
- When following this methodology, the latest version of the FVS software should always be used.
- FVS may only be used for projects located within the United States.

1.2 SELECTED BASELINE APPROACH

"Existing or historical, as applicable, changes in carbon stocks in the carbon pools within the project boundary"

1.3 DEFINITIONS

All definitions, eligibility requirements, and other criteria of the ACR Standard shall apply. This includes the definitions of "forest" and "Afforestation / Reforestation".

1.4 APPLICABILITY

This methodology is applicable to afforestation and reforestation ACR project activities that are implemented on degraded lands.

The conditions under which the methodology is applicable are:

I. The A/R ACR project activity is implemented on degraded lands, which are expected to remain degraded or to continue to degrade in the absence of the project, hence the land cannot be expected to revert to a non-degraded state without human intervention.
II. If at least a part of the project activity is implemented on organic soils or wetlands[1], intentional manipulation of the water table is not allowed (i.e. the project activity shall not involve manipulation of hydrology or otherwise affect hydrology), not more than 10% of their area may be disturbed as result of soil preparation for planting and species planted are restricted to those likely to have occurred under historic natural forest conditions in the project area, per best available knowledge (relevant literature and/or consultation with local experts).
III. Litter shall remain on site and not be removed in the A/R ACR project activity.
IV. Ploughing/ripping/scarification attributable to the A/R ACR project activity, if any, is:
    A. Done in accordance with appropriate soil conservation practices, e.g. follows the land contour; and
    B. Limited to the first five years from the year of initial site preparation; and
    C. Not repeated, if at all, within a period of 20 years.

The latest version of the “Tool for the identification of degraded or degrading lands for consideration in implementing CDM A/R project activities” shall be applied for demonstrating that lands are degraded or degrading.

Applicability condition I and the requirement to use the CDM tool for identification of degraded or degrading lands do not imply that there may be no remnant trees as of the project start date, or no natural regeneration in the baseline scenario. However, note the following:

- Remnant trees must be either excluded from the project boundary, if in patches large enough to exclude; or if individual remnant trees are present within the project boundary, these must be either included in both the baseline and project scenarios (using the guidance in 2.4 and 2.5) or tagged and excluded in both the baseline and project scenarios.
- Natural regeneration in the baseline scenario is expected to be minimal, such that the project lands continue to be classified as degraded or degrading. To ensure that this assumption remains valid over the Crediting Period, this methodology requires the establishment of Regeneration Monitoring Areas, outside the project boundary in areas similar to the project area but unplanted, in which baseline natural regeneration must be assessed at intervals not to exceed 10 years. See details in section 3.3.

[1] “Wetlands”, “settlements”, “cropland” and “grassland” are land categories as defined in the Good Practice Guidance for Land Use, Land-use Change and Forestry (IPCC, 2003)

2 BASELINE METHODOLOGY PROCEDURE

2.1 PROJECT BOUNDARY AND ELIGIBILITY OF LAND

The "project boundary" geographically delineates the afforestation or reforestation project activity under the control of the Project Proponent (PP). The A/R ACR project activity may contain more than one discrete area of land. Each discrete area of land shall have a unique geographical identification.

It shall be demonstrated that each discrete area of land to be included in the boundary is eligible for an A/R ACR project activity. PPs shall apply the "Procedures to demonstrate the eligibility of lands for afforestation and reforestation CDM project activities" as approved by the Board.

The latest version of "Guidance on application of the definition of the project boundary to A/R CDM project activities" (available at: http://cdm.unfccc.int/Reference/Guidclarif) may be applied in identification of areas of land planned for an A/R ACR project activity.

Tables 1 and 2 shall be followed in determining the GHG assessment boundary, along with the guidance in the ACR Standard. Exclusion of carbon pools and emission sources is allowed, subject to considerations of conservativeness and significance testing. Pools or sources may always be excluded if conservative, i.e. exclusion will tend to underestimate net GHG emission reductions/removal enhancements. Pools or sources may also be excluded if application of the most recent version of the CDM "Tool for testing significance of GHG emissions in A/R CDM project activities" leads to the conclusion that a particular pool or source is insignificant. Pools and sources deemed significant and/or selected for accounting in the baseline scenario shall also be accounted in the project scenario.

The carbon pools included in or excluded from accounting are shown in Table 1.

Table 1: Carbon Pools Accounted for in the Project Boundary

CARBON POOLS	ACCOUNTED FOR	JUSTIFICATION / EXPLANATION
Above-ground biomass	Yes	Major carbon pool subjected to project activity.

CARBON POOLS	ACCOUNTED FOR	JUSTIFICATION / EXPLANATION
Below-ground biomass	Yes	Below-ground biomass stock is expected to increase due to the implementation of the A/R ACR project activity.
Dead wood	Yes (alternatively No)	This stock may change (when compared to baseline) due to implementation of the project activity. The methodology provides an approach for accounting for this pool, but it also allows for exclusion of the dead wood carbon pool if transparent and verifiable information can be provided that carbon stocks in dead wood in the baseline scenario can be expected to decrease more or increase less, relative to the project scenario.
Litter	Yes (alternatively No)[2]	This stock may change (when compared to baseline) due to implementation of the project activity. The methodology provides an approach for accounting for this pool, but it also allows for exclusion of the litter carbon pool if transparent and verifiable information can be provided that carbon stocks in litter in the baseline scenario can be expected to decrease more or increase less, relative to the project scenario.
Soil organic carbon (SOC)	Yes (alternatively No if project implemented on wetlands or organic soils)	Soil disturbance resulting from site preparation, if applied on more than 10% of the project area, may cause a temporary emission from soil carbon and therefore accounting of C stock changes in this pool is required, otherwise it is optional.
Wood products	Optional	This stock may increase (when compared to baseline) due to implementation of the project activity. The methodology provides an approach for accounting for this pool, but it allows also for exclusion of the wood products pool.

The emission sources and associated GHGs included in or excluded from accounting are shown in Table 2.

[2] Note that per the ACR Standard , litter is considered a priori insignificant and thus may be excluded (or optionally included).

Table 2: Emission Sources and GHGs Included in or Excluded from Accounting

SOURCES	GAS	INCLUDED / EXCLUDED	JUSTIFICATION / EXPLANATION
Burning of woody biomass	CO_2	Excluded	Carbon stock decreases due to burning are accounted as a change in carbon stock.
	CH_4	Included	Burning of woody biomass for the purpose of site preparation or as part of forest management can lead to significant levels of emissions of methane.
	N_2O	Excluded	Potential emissions are negligibly small.

2.2 IDENTIFICATION OF THE BASELINE SCENARIO AND DEMONSTRATION OF ADDITIONALITY

Project Proponents shall demonstrate additionality through the ACR three-prong test. The CDM "Combined tool to identify the baseline scenario and demonstrate additionality in A/R CDM project activities," required by ACM0001, is required; this amplifies but does not conflict with ACR's three-prong test.

2.3 STRATIFICATION

If the project activity area is not homogeneous, stratification should be carried out to improve the accuracy and precision of biomass estimates. Different stratifications may be required for the baseline and project scenarios in order to achieve optimal accuracy of the estimates of net GHG removal by sinks. For estimation of baseline net GHG removals by sinks, or estimation of actual net GHG removals by sinks, strata should be defined on the basis of parameters that are key entry variables in any method (e.g. growth models or yield curves/tables) used to estimate changes in biomass stocks. Thus:

- **FOR BASELINE NET GHG REMOVALS BY SINKS.** It will usually be sufficient to stratify according to area of major vegetation types because baseline removals for degraded (or degrading) land are expected to be small in comparison to project removals;
- **FOR ACTUAL NET GHG REMOVALS BY SINKS.** The stratification for ex ante estimations shall be based on the project planting/management plan. The stratification for *ex post* estimations shall be based on the actual implementation of the project planting/management plan. If

natural or anthropogenic impacts (e.g. local fires) or other factors (e.g. soil type) add variability to the growth pattern of the biomass in the project area, then the ex post stratification shall be revised accordingly.

PPs may use remotely sensed data acquired close to the time of project commencement and/or the occurrence of natural or anthropogenic impacts for ex ante and ex post stratification.

PPs should treat the part of the project area which contains organic soils, if any, as a separate stratum and ensure that applicability condition II of this methodology is met in this stratum.

2.4 BASELINE NET GHG REMOVALS BY SINKS

The baseline net GHG removals by sinks is the sum of the changes in carbon stocks in the selected carbon pools within the project boundary that would have occurred in the absence of the A/R ACR project activity.

Under the applicability conditions of this methodology:

- Changes in carbon stock of above-ground and below-ground biomass of non-tree vegetation may be conservatively assumed to be zero for all strata in the baseline scenario;
- If values for carbon stocks of dead wood and litter carbon pools are readily available (for example, from the Forest Vegetation Simulator) those values may be used to estimate changes in carbon stocks in the baseline scenario. If values are not readily available, it may conservatively be assumed that the sum of the changes in the carbon stocks of dead wood and litter carbon pools is zero for all strata in the baseline scenario;
- Since carbon stock in soil organic carbon (SOC) is unlikely to increase in the baseline, the change in carbon stock in SOC may be conservatively assumed to be zero for all strata in the baseline scenario.

Therefore the baseline net GHG removals by sinks will be determined as:

Equation 1

$$\Delta C_{BSL} = \Delta C_{TREE\_BSL} + \Delta C_{WP\_BSL}$$

WHERE

ΔC_{BSL}	Baseline net GHG removals by sinks; MT CO_2e
ΔC_{TREE_BSL}	Sum of the carbon stock changes in above-ground and below-ground biomass of trees in the baseline; MT CO_2e

ΔC_{WP_BSL}	Carbon stock changes in wood products in the baseline; MT CO_2e

2.4.1 Carbon Stock Changes in Above-ground and Below-ground Tree Biomass (ΔC_{TREE_BSL})

The estimation of carbon stock changes in above-ground and below-ground tree biomass in the baseline (ΔC_{TREE_BSL}) will be carried out using the equations below. These equations provide for the calculations to be performed for each stratum. If there is more than one stratum in the baseline scenario, the outcome will be summed over all the strata to obtain the value for the whole project.

The carbon stock changes in above-ground and below-ground tree biomass in the baseline is estimated by one of the following methods:

Equation 2

$$\Delta C_{TREE\_BSL} = \frac{44}{12} \times \Delta B_{TREE\_BSL} \times CF_{TREE\_BSL}$$

AND

Equation 3

$$\Delta C_{TREE\_BSL} = \Delta C_{TREE\_BSL\_FVS} \times \frac{44}{12} \times A_{BSL}$$

WHERE

ΔC_{TREE_BSL}	Change in carbon stock in living tree biomass in baseline; MT CO_2e
$\frac{44}{12}$	Ratio of molecular weights of CO_2 and carbon; dimensionless
ΔB_{TREE_BSL}	Change in biomass of living trees in baseline; MT d.m.
CF_{TREE_BSL}	Carbon fraction of dry matter for tree biomass in baseline; MT C MT^{-1} d.m.
$\Delta C_{TREE\_BSL\_FVS}$	Change in carbon stock in living tree biomass in the baseline scenario from FVS. This is estimated by summing the Aboveground Live Total Carbon and the Belowground Live Carbon in the FVS stand carbon report and subtracting this value for the year at the start of the A/R ACR project activity from

	the value for a future year. Units must be changed to metric tons per hectare; MT C/ha
A_{BSL}	Area; ha

Change in biomass of living trees (ΔB_{TREE_BSL}) is estimated as follows:

Equation 4

$$\Delta B_{TREE\_BSL,t} = \sum_{j} A_{BSL,j} \times I_{V,j,t} \times D_j \times BEF_{1,j} \times (1 + R_{1,j}) - \sum_{j} B_{LOSS\_BSL,j,t}$$

WHERE

$\Delta B_{TREE\_BSL,t}$	Change in biomass of living trees in baseline, in year t; MT d.m.
$A_{BSL,j}$	Area under trees of species or group of species j; ha
$I_{V,j,t}$	Current annual increment in stem volume of trees of species or group of species j, in year t; m^3 ha^{-1} yr^{-1}
D_j	Basic wood density for species or group of species j; MT d.m. m^{-3}
$BEF_{1,j}$	Biomass expansion factor for conversion of annual net increment (including bark) in stem biomass to increment in total above-ground tree biomass for species or group of species j; MT d.m. $(MT\ d.m.)^{-1}$
$R_{1,jj}$	Root-shoot ratio appropriate for biomass increment for species or group of species j; MT d.m. MT^{-1} d.m
$B_{LOSS\_BSL,j,t}$	Loss of tree biomass of species or group of species j in year t; MT d.m.
j	1, 2, 3, … tree species or group of species in the given stratum in the baseline scenario
t	1, 2, 3, … t* years elapsed since the start of the A/R ACR project activity

If biomass increment tables are available and applicable to the species used in the project activity, these can directly be used in equation 4. Note that available data on average annual increment in the stem volume of trees ($I_{V,j,t}$) may be expressed as a net average annual increment (i.e. biomass loss is already allowed for) and in such a case biomass loss ($B_{LOSS\_BSL,j,t}$) shall be set to zero in equation 4 in order to avoid double counting.

On the other hand, the average annual increment in the stem volume of trees ($I_{V,j,t}$) may be the gross average annual increment, in which case biomass loss ($B_{LOSS\_BSL,j,t}$) may either be conservatively assumed as zero or must be estimated on the basis of transparent and verifiable information on the rate at which pre-project activities (such as collection fuelwood or fodder, selection harvesting, mortality of trees, etc.) are reducing biomass stocks in existing live trees.

If species or group of species specific volume/biomass increment tables are not available then the product of the terms $I_{V,j,t} \times D_j \times BEF_{1,j}$ in equation 4 may be estimated by multiplying the relevant data from Table 3A.1.5 of IPCC GPG-LULUCF 2003 by the fractional value of the crown cover of the trees in the baseline. For example, if the crown cover of trees in the baseline is estimated as 10%, the project is located in Africa, the age class of the trees is >20 years, and the climate/forest type is “Moist with Short Dry Season”, then the value of $I_{V,j,t} \times D_j \times BEF_{1,j}$ may be estimated as 0.10×1.3 = 0.13 MT d.m. ha^{-1} yr^{-1}.

2.4.2 Carbon Stock in Living Trees at the Start of the Project Activity

Carbon stock in living trees at the start of the project activity is calculated as follows:

Equation 5

$$C_{TREE\_BSL} = \frac{44}{12} \times B_{TREE\_BSL} \times CF_{TREE\_BSL}$$

WHERE

C_{TREE_BSL}	Carbon stock in living trees in the baseline at the start of the project activity; MT CO_2e
$\frac{44}{12}$	Ratio of molecular weights of CO_2 and carbon; dimensionless
B_{TREE_BSL}	Biomass of living trees in the baseline at the start of the project; MT d.m.
CF_{TREE_BSL}	Carbon fraction of dry matter for tree biomass in baseline; MT C MT^{-1} d.m.

The biomass of living trees in the baseline at the start of the project activity is estimated using any one of the following methods:

2.4.2.1 ESTIMATION BASED ON EXISTING DATA

If published data is available from which biomass density per unit area for the project area can be estimated, the data may be used provided that the estimated value of biomass density per unit area does not underestimate biomass in the project area. In this case, the biomass of living trees in the baseline at the start of the project activity is calculated as:

Equation 6

$$\mathbf{B_{TREE\_BSL} = BD_{TREE\_BSL} \times A_{TREE\_BSL}}$$

WHERE

B_{TREE_BSL}	Biomass of living trees in the baseline at the start of the project activity; MT d.m.
BD_{TREE_BSL}	Tree biomass density per unit area of the project area (obtained from published literature); MT d.m. ha^{-1}
A_{TREE_BSL}	Area of land within the project boundary where living trees are standing at the start of the project activity; ha

2.4.2.2 DEFAULT ESTIMATION USING PARAMETER RATIO

Under this method one of the following parameters of the existing trees in baseline is estimated (denoted by P_{BSL} in the equation below): (a) Crown cover; (b) Basal area per hectare; and (c) Stand density index. Project area may be stratified on the basis of the variability of the parameter selected.

The biomass of living trees in the baseline at the start of the project activity is then calculated as:

Equation 7

$$\mathbf{B_{TREE\_BSL} = \frac{P_{BSL}}{P_{FOREST}} \times B_{FOREST} \times A_{TREE\_BSL} \times (1 + R_{TREE\_BSL})}$$

WHERE

B_{TREE_BSL}	Biomass of living trees in the baseline at the start of the project activity; MT d.m.
P_{BSL}	Parameter for living trees in the baseline at start of the project activity

P_{FOREST}	The same parameter for a fully stocked forest in the region/country where the project activity is located
B_{FOREST}	Biomass density of a fully stocked forest in the region/country where the project activity is located; MT d.m. ha^{-1}
A_{TREE_BSL}	Area of land within the project boundary where living trees are standing at start of the project activity; ha
R_{TREE_BSL}	Root-shoot ratio of trees in the baseline; dimensionless

Value of B_{FOREST} is obtained according to guidance provided in the relevant table in Section 2.8.

2.4.2.3 COMPLETE INVENTORY OF TREES

If the trees in the baseline are few and scattered, all the trees may be inventoried and dimensional measurements (diameter or height or both) may be carried out on them. One of the methods explained in section 2.5.1.1 of this methodology is then used for estimating the biomass of each tree. Biomass of living trees in the baseline at the start of the project is then calculated as:

Equation 8

$$B_{TREE\_BSL} = \sum_{i=1}^{n} B_{TREE,i}$$

WHERE

B_{TREE_BSL}	Biomass of living trees in the baseline at the start of the project activity; MT d.m.
$B_{TREE,i}$	Biomass of the i^{th} tree as estimated from dimensional measurements; MT d.m.
n	Total number of living trees in the baseline at start of the project activity

2.4.2.4 INVENTORY OF TREES IN SAMPLE PLOTS

If the number of trees in the baseline scenario is too large for a complete inventory to be carried out, sample plots are laid out and dimensional measurements are carried out on the trees in these sample plots. One of the methods explained in section 2.5.1.1 of this methodology is then used for estimating the biomass of each tree. The biomass of living trees in the baseline at the start of the project activity is then calculated as:

Equation 9

$$B_{TREE\_BSL} = \frac{A_{TREE}}{A_{TREE,p}} \sum_{p} B_{TREE,p}$$

WHERE

B_{TREE_BSL}	Biomass of living trees in the baseline at the start of the project activity; MT d.m.
A_{TREE}	Area of land within the project boundary where living trees are standing at start of the project activity; ha
$A_{TREE,p}$	Area of sample plots where dimensional measurements are carried out on the trees; ha
$B_{TREE,p}$	Biomass of living trees in plot p as estimated from dimensional measurements; MT d.m.

2.4.2.5 ESTIMATION USING THE FOREST VEGETATION SIMULATOR (FVS)

Under this method, the Forest Vegetation Simulator is used to estimate the carbon stock in living trees at the start of the project activity. Because carbon (rather than biomass) is estimated, the equation below is used in place of equation 5.

Equation 10

$$C_{TREE\_BSL} = \frac{44}{12} \times C_{TREE\_BSL\_FVS} \times A_{BSL}$$

WHERE

C_{TREE_BSL}	Carbon stock in living trees in the baseline at the start of the project activity; MT CO_2e
$C_{TREE\_BSL\_FVS}$	The carbon stock in living tree biomass in the baseline scenario from FVS. This is estimated by summing the Aboveground Live Total Carbon and the Belowground Live Carbon in the FVS stand carbon report for the year at the start of the A/R ACR project. Units must be changed to metric tons per hectare; MT C/ha

A_{BSL}	Area; ha
$\frac{44}{12}$	Ratio of molecular weights of CO_2 and carbon; dimensionless

2.4.3 Carbon Stock in Long-term Wood Products (ΔC_{WP_BSL})

Under the applicability conditions of this methodology, it can be assumed that there is no commercial timber produced on the degraded lands in the absence of the project activities. Carbon stock in long-term wood products can be assumed to be zero for the baseline scenario. Alternatively, the Forest Vegetation Simulator (FVS) may be used to produce a baseline stock.

Carbon stock change in wood products for commercial timber produced on degraded lands is estimated by one of the following methods:

Equation 11

$$\Delta C_{WP\_BSL} = 0$$

AND

Equation 12

$$\Delta C_{WP\_BSL} = \frac{44}{12} \times \Delta C_{WP\_BSL\_FVS} \times A_{BSL}$$

WHERE

ΔC_{WP_BSL}	Carbon stock changes in wood products in the baseline; MT CO_2e
$\Delta C_{WP\_BSL\_FVS}$	The change in carbon in wood products in the baseline scenario as estimated by FVS. This is obtained from the Merchantable Carbon Stored column of the FVS harvested products carbon report and includes both the carbon still in use and sequestered in a landfill. Units must be changed to metric tons per hectare; MT C/ha
A_{BSL}	Area; ha
$\frac{44}{12}$	Ratio of molecular weights of CO_2 and carbon; dimensionless

2.4.4 Steady State Under the Baseline Conditions

The baseline net GHG removals by sinks, if greater than zero, shall be estimated using the approach provided in section 2.4.1 until steady state is reached under the baseline conditions. Under steady state:

Equation 13

$$\Delta C_{BSL} = 0$$

WHERE

ΔC_{BSL}	Baseline net GHG removals by sinks

PPs may, on a project specific basis, assess when a steady state is reached during the crediting period. This shall be estimated on the basis of transparent and verifiable information originating as appropriate from available literature, data from comparable areas, from field measurements in the planned project area, or from other sources relevant to the baseline circumstances. If no data is available, a default period of 20 years since commencement of the ACR project activity will be applied.

2.5 ACTUAL NET GHG REMOVALS BY SINKS

Under the applicability conditions of this methodology:

- Changes in carbon stock of above-ground and below-ground biomass of non-tree vegetation may be conservatively assumed to be zero for all strata in the project scenario. This includes changes in carbon stock of above-ground and below-ground biomass of herbaceous vegetation throughout the Crediting Period, and changes in carbon stock of above-ground and below-ground woody shrub biomass following planting.
- However, some afforestation/reforestation projects involve removal of a significant volume of shrub biomass during site preparation in order to create conditions favorable to the seedling establishment and survival. In such cases, changes in carbon stock of above-ground and below-ground biomass of woody shrub biomass must be accounted at the first verification following site preparation. PPs shall use the guidance on estimation of carbon stock and change in carbon stock in shrubs from the CDM tool "Estimation of carbon stocks and change in carbon stocks of trees and shrubs in A/R CDM project activities."[3]

[3] http://cdm.unfccc.int/methodologies/ARmethodologies/tools/ar-am-tool-14-v3.0.0.pdf.

The actual net GHG removals by sinks shall be estimated using the equations in this section. When applying these equations for the ex ante calculation of actual net GHG removals by sinks, PPs shall provide estimates of the values of those parameters that are not available before the start of the project. PPs should retain a conservative approach in making these estimates.

The actual net GHG removals by sinks shall be calculated as:

Equation 14

$$\Delta C_{ACTUAL} = \Delta C_P - GHG_E$$

WHERE

ΔC_{ACTUAL}	Actual net GHG removals by sinks; MT CO_2e
ΔC_P	Sum of the changes the carbon stock in the selected carbon pools within the project boundary; MT CO_2e
GHG_E	Increase in non-CO_2 GHG emissions within the project boundary as a result of the implementation of the A/R ACR project activity; MT CO_2e

2.5.1 Estimation of Changes in the Carbon Stocks

The verifiable changes in the carbon stock in the selected carbon pools within the project boundary are estimated using the following equation:[4]

Equation 15

$$\Delta C_P = \frac{44}{12} \times \sum_{t=1}^{t^*} \Delta C_t$$

WHERE

ΔC_P	Sum of the changes in carbon stock in all selected carbon pools in stratum i, since start of the project; MT CO_2e
ΔC_t	Change in carbon stock in all selected carbon pools, in year t; MT C
t	1, 2, 3, … t^* years elapsed since the start of the A/R project activity; yr

[4] IPCC GPG-LULUCF 2003, Equation 3.2.3.

$\frac{44}{12}$	Ratio of molecular weights of CO_2 and carbon; dimensionless

Change in carbon stock in all selected carbon pools, in year t, is calculated as:

Equation 16

$$\Delta C_t = \sum_{i=1}^{M_{PS}} (\Delta C_{TREE,i,t} + \Delta C_{SHRUB,i,t} + \Delta C_{DW,i,t} + \Delta C_{LI,i,t} + \Delta C_{SOC,i,t} + \Delta C_{WP,i,t})$$

WHERE

ΔC_t	Change in carbon stock in all selected carbon pools, in year t; MT C
$\Delta C_{TREE,i,t}$	Change in carbon stock in above-ground and below-ground biomass of trees in stratum i, in year t; MT C
$\Delta C_{SHRUB,i,t}$	Change in carbon stock in shrub biomass within the project boundary in stratum i, in year t, calculated using the CDM tool "Estimation of carbon stocks and change in carbon stocks of trees and shrubs in A/R CDM project activities"; MT C
$\Delta C_{DW,i,t}$	Change in carbon stock in the dead wood carbon pool in stratum i, in year t; MT C
$\Delta C_{LI,i,t}$	Change in carbon stock in the litter carbon pool in stratum i, in year t; MT C
$\Delta C_{SOC,i,t}$	Change in carbon stock in the soil organic carbon pool in stratum i, in year t; MT C
$\Delta C_{WP,i,t}$	Change in the wood products carbon pool for stratum i, in year t (possibly average over a monitoring period); MT C
i	1, 2, 3, … M_{PS} strata in the project scenario
t	1, 2, 3, … t^* years elapsed since the start of the A/R ACR project activity

2.5.1.1 ESTIMATING CHANGE IN CARBON STOCK IN TREE BIOMASS ($\Delta C_{TREE,i,t}$)

The change in carbon stock in tree biomass is estimated on the basis of field measurements in permanent sample plots at a point of time in year t_1 and again at a point of time in year t_2. The rate of change of carbon stock in trees is calculated as:

Equation 17

$$dC_{TREE,i,(t_1,t_2)} = \frac{C_{TREE,i,t_2} - C_{TREE,i,t_1}}{T}$$

WHERE

$dC_{TREE,i,(t_1,t_2)}$	Rate of change in carbon stock in above-ground and below-ground biomass of trees in stratum i, for the period between year t_1 and year t_2; MT C yr^{-1}
C_{TREE,i,t_2}	Carbon stock in trees in stratum i, at a point of time in year t_2; MT C
C_{TREE,i,t_1}	Carbon stock in trees in stratum i, at a point of time in year t_1; MT C
T	Time elapsed between two successive estimations ($T = t_2 - t_1$); yr
i	1, 2, 3, … M_{PS} strata in the project scenario

Change in carbon stock in tree biomass in year t ($t_1 \leq t \leq t_2$) is then calculated as:

Equation 18

$$\Delta C_{TREE,i,t} = dC_{TREE,i,(t_1,t_2)} \times 1 \text{ year}$$

WHERE

$\Delta C_{TREE,i,t}$	Change in carbon stock in above-ground and below-ground biomass of trees in stratum i, in year t; MT C
$dC_{TREE,i,(t_1,t_2)}$	Rate of change in carbon stock in tree biomass within the project boundary during the period between a point of time in year t_1 and a point of time in year t_2; MT C yr^{-1}

Carbon stock in above-ground and below-ground tree biomass ($dC_{TREE,i,t}$) is estimated by one of the following methods as applied in year t:

- The biomass expansion factor (BEF) method;
- The allometric equation method; and
- The FVS method.

2.5.1.1.1 BEF Method

In this method, first the stem volume (the commercial volume) of standing trees is estimated. Ex ante estimations of stem volume are based on tree growth models and ex post estimations are based on field measurements. The stem volume is expanded to the above-ground tree biomass using biomass expansion factor (BEF) and basic wood density (D). Total tree biomass is then obtained by multiplying the above-ground tree biomass by ($1+\mathrm{R}$) where R is the root-shoot ratio.

The following step-by-step procedure shows practical application of this method:

Step 1 This step is applied differently for ex ante and ex post estimations.

Step 1 (a) Ex ante estimation

I. For each tree species or group of species under the project scenario, select a tree growth model from existing data or literature. Available growth models could be in form of yield tables, growth curves/equations, or growth simulation models. See section 2.8 for exact guidance on selecting the growth model applicable;
II. From the growth model selected, calculate the stem volume of trees per unit area according to the project planting/management plan.

Step 1 (b) Ex post estimation

Ex post estimation of tree biomass must be based on actual measurements carried out on all trees in the permanent sample plots. The permanent sample plots are laid out according to the approved methodological tool “Calculation of the number of sample plots for measurements within A/R CDM project activities”.

The following sub-steps apply for ex post estimation:

I. Select the volume tables (these could be in form of equations or curves) applicable to the tree species or group of species planted under the project. See section 2.8 for exact guidance on selecting the volume tables applicable;
II. Depending on the volume tables selected in the sub-step above, measure the diameter at breast height (DBH) and/or tree height (H) of all trees in the permanent sample plots;

III. Insert the above field measurements into the selected volume tables and calculate the stem volume of all trees in each sample plot.

NOTE. It is also possible to combine the sub-steps (I) and (II) if a suitable field instrument (such as a Spiegel relascope) is used.

Step 2 Convert the stem volume to total carbon stock in tree biomass using the following equation:

Equation 19

$$C_{TREE,j,p,i} = V_{TREE,j,p,i} \times D_j \times BEF_{2,j} \times (1 + R_j) \times CF_j$$

WHERE

$C_{TREE,j,p,i}$	Total carbon stock in trees of species or group of species j in sample plot p in stratum i; MT C
$V_{TREE,j,p,i}$	Stem volume of trees of species or group of species j in plot p in stratum i estimated by using the diameter at breast height (DBH) and/or tree height (H) as entry data into a volume table; m^3
D_j	Basic wood density of species or group of species j; MT d.m. m^{-3}
$BEF_{2,j}$	Biomass expansion factor for conversion of stem biomass to above-ground tree biomass for species or group of species j; dimensionless
R_j	Root-shoot ratio for tree species or group of species j; dimensionless
CF_j	Carbon fraction of biomass for tree species or group of species j; MT C t^{-1} d.m.
j	1, 2, 3, … tree species or group of species in the project scenario
p	1, 2, 3, … sample plots in stratum i
i	1, 2, 3, … strata in the project scenario

2.5.1.1.2 Allometric Method

The allometric method directly calculates above-ground tree biomass without relating it to tree stem volume. The method depends upon availability of allometric equations which express above-ground tree biomass as a function of diameter at breast height (DBH) and/or tree height (H). Total tree biomass is then obtained by multiplying the above-ground tree biomass by ($1+\mathrm{R}$) where R is the root-shoot ratio.

The following step-by-step procedure shows how this method is practically applied:

Step 1 This step is applied differently for ex ante and ex post estimations.

Step 1 (a) Ex ante estimation

I. For each tree species or group of species, select an allometric equation from existing data or literature. See section 2.8 for exact guidance on selecting the allometric equation applicable;
II. For each tree species or group of species, select a tree growth model from existing data and literature, as explained in sub-step 1(a)(i) of the BEF method above;
III. Obtain the diameter at breast height (DBH) and/or tree height (H) corresponding to the age of tree at a given time from the tree growth model selected above;
IV. Insert the diameter at breast height (DBH) and/or tree height (H) into the allometric equation and calculate the total above-ground tree biomass per unit area according to the project planting/management plan.

Step 1 (b) Ex post estimation

Ex post estimation of tree biomass must be based on actual measurements carried out on all trees in the permanent sample plots. The permanent sample plots are laid out according to the approved methodological tool "Calculation of the number of sample plots for measurements within A/R CDM project activities".

The following sub-steps apply for ex post estimation.

I. Select an allometric equation for the tree species or group of species as described in sub-step 1(a)(i) above;
II. Depending on the allometric equation, measure the diameter at breast height (DBH) and/or tree height (H) of all trees in the permanent sample plots;
III. Insert the above measurements into the allometric equation and calculate the total above-ground tree biomass for each sample plot.

Step 2 Convert the above-ground tree biomass to total carbon stock in tree biomass using the following equation:

Equation 20

$$C_{TREE,j,p,i} = f_j(DBH, H) \times (1 + R_j) \times CF_j$$

WHERE

$C_{TREE,j,p,i}$	Total carbon stock in trees of species or group of species j in sample plot p in stratum i; MT C
CF_j	Carbon fraction of biomass for tree species or group of species j; MT C (MT d.m.)$^{-1}$
$f_j(DBH, H)$	Above-ground biomass of trees of species or group of species j in sample plot p calculated using allometric function returning total above-ground tree biomass on the basis of breast height (DBH) and/or height of the tree (H); MT d.m.
R_j	Root-shoot ratio for tree species or group of species j; dimensionless
j	1, 2, 3, … tree species or group of species in the project scenario
p	1, 2, 3, … sample plots in stratum i
i	1, 2, 3, … strata in the project scenario

FOR BOTH THE BEF METHOD AND THE ALLOMETRIC EQUATION METHOD, the total carbon stock in tree biomass for each stratum is calculated as follows:

Equation 21

$$C_{TREE,i} = \frac{A_i}{A_{p,i}} \sum_{p=1}^{P_i} \sum_{j=1}^{J_i} C_{TREE,j,p,i}$$

WHERE

$C_{TREE,i}$	Carbon stock in trees in stratum i; MT C

$C_{TREE,j,p,i}$	Carbon stock in trees of species or group of species j in plot *p* of stratum i; MT C
$A_{p,i}$	Total area of sample plots in stratum i; ha
A_i	Total area of stratum i; ha
j	1, 2, 3, … J_i species or group of species of trees in stratum i
p	1, 2, 3, … P_i sample plots in stratum i in the project scenario
i	1, 2, 3, … M_{PS} strata in the project scenario

Equation 18 when applied at two consecutive years t_1 and t_2 (e.g. two consecutive verification years) provides two values C_{TREE,i,t_1} and C_{TREE,i,t_2} which are then inserted in equation 14.

2.5.1.1.3 FVS Method

The FVS method uses the Forest Vegetation Simulator (FVS) to calculate aboveground and belowground tree biomass. For ex ante estimation, carbon estimates for initial and future years can be obtained from an FVS simulation done for each stratum. For ex post estimation, measurements from permanent sample plots can be entered into FVS and carbon estimates obtained for the year the plot data was collected with an FVS simulation for each stratum. The permanent sample plots are laid out according to the approved methodological tool “Calculation of the number of sample plots for measurements within A/R CDM project activities”. In both cases, the units for the FVS stand carbon report must be changed to metric tons per hectare.

The total carbon stock in tree biomass for each stratum is calculated as follows:

Equation 22

$$C_{TREE,i} = A_i \times C_{TREE,i\_FVS}$$

WHERE

$C_{TREE,i}$	Carbon stock in trees in stratum i; MT C
C_{TREE,i_FVS}	Carbon stock in trees for stratum i using FVS. This is estimated by summing the Aboveground Live Total Carbon and the Belowground Live Carbon in the FVS stand carbon report for a particular year. Units must be changed to metric tons per hectare; MT C/ha

A_i	Total area of stratum i; ha
i	1, 2, 3, … M_{PS} strata in the project scenario

Equation 22 when applied at two consecutive years t_1 and t_2 provides two values C_{TREE,i,t_1} and C_{TREE,i,t_2} which are then inserted in equation 17.

NOTE. At start of the project activity (that is for t_1=1) the baseline tree biomass is equal to initial biomass under the project, that is, the value of C_{TREE,i,t_1} in equation 17 is set equal to the baseline C stock as calculated in equation 5.

2.5.1.2 DEAD WOOD (IF SELECTED IN TABLE 1)

For ex ante estimates, if values for carbon stocks of dead wood are readily available (for example, from the Forest Vegetation Simulator) those values may be used. If values are not readily available, the changes in carbon stocks of dead wood shall be conservatively neglected.

Dead wood included in the methodology comprises two components only—standing dead wood and lying dead wood (that is, below-ground dead wood is conservatively neglected). Considering the differences in the two components, different sampling and estimation procedures shall be used to calculate the changes in dead wood biomass of the two components.

For the ex post situation, the rate of change in C stock in dead wood is estimated as follows:

Equation 23

$$dC_{DW,i,t} = \frac{C_{DW,i,t_2} - C_{DW,i,t_1}}{T}$$

WHERE

$dC_{DW,i,t}$	Rate of change in carbon stock in dead wood in stratum i, for the period between year t_1 and year t_2; MT C yr^{-1}
$C_{DW,i,t}$	Carbon stock of dead wood in stratum i, at time t; MT C
T	Number of years between monitoring time t_2 and t_1 ($T = t_2 - t_1$); yr
i	1, 2, 3, … M_{PS} strata in the project scenario
t	1, 2, 3, … t^* years elapsed since the start of the A/R ACR project activity

Change in carbon stock in dead wood in year t ($t_1 \le t \le t_2$) is then calculated as:

Equation 24

$$\Delta C_{DW,i,t} = dC_{DW,i,(t_1,t_2)} \times 1\ year$$

WHERE

$\Delta C_{DW,i,t}$	Change in carbon stock in dead wood in stratum i, in year t; MT C
$dC_{DW,i,(t_1,t_2)}$	Rate of change in carbon stock in dead wood in stratum i, for the period between year t_1 and year t_2; MT C yr^{-1}

Carbon stock of dead wood in stratum i, at time t is estimated by one of the following methods:

Equation 25

$$C_{DW,i,t} = \left(B_{SDW,i,t} + B_{LDW,i,t}\right) \times CF_{DW}$$

AND

Equation 26

$$C_{DW,i,t} = C_{SDW,i,t,FVS} \times A_i + \left(B_{LDW,i,t}\right) \times CF_{DW}$$

WHERE

$C_{DW,i,t}$	Carbon stock of dead wood biomass in stratum i, at a point of time in year t; MT C
$B_{SDW,i,t}$	Biomass of standing dead wood in stratum i, at a point of time in year t; MT d.m.
$B_{LDW,i,t}$	Biomass of lying dead wood in stratum i, at a point of time in year t; MT d.m.
CF_{DW}	Carbon fraction of dead wood biomass; dimensionless
i	1, 2, 3, … MPS strata in the project scenario
t	1, 2, 3, … t^* years elapsed since the start of the A/R ACR project activity

$C_{SDW,i,t,FVS}$	Carbon of standing dead wood in stratum i, in year t from FVS. This is from the Standing Dead Carbon column in the FVS stand carbon report. Units must be changed to metric tons per hectare; MT C/ha
A_i	Total area of stratum i; ha

The methods to be followed in the measurement of the standing dead wood and the lying dead wood biomass are outlined below.

2.5.1.2.1 Standing Dead Wood

Step 1 Standing dead trees shall be measured on permanent sample plots (established for estimating tree biomass - see 2.5.1.1 above) using the same criteria and monitoring frequency used for measuring living trees. The decomposed portion that corresponds to the original above-ground and below-ground biomass is discounted.

Step 2 The decomposition class of the dead tree and the diameter at breast height shall be recorded and the standing dead wood is categorized under the following four decomposition classes:

CLASS 1. Tree with branches and twigs that resembles a live tree (except for leaves);
CLASS 2. Tree with no twigs, but with persistent small and large branches;
CLASS 3. Tree with large branches only;
CLASS 4. Bole only, no branches.

Step 3a For tree in the decomposition class 1 biomass should be estimated using the allometric equation for living trees.

Step 3b When the bole is in decomposition classes 2, 3 or 4, it is recommended to limit the estimate of the biomass to the main trunk of the tree. Usually, there are no allometric equations applicable for such boles and their biomass is estimated based on volume assessment. The volume of dead wood is converted to biomass using the dead wood density appropriate for the decomposition class.

2.5.1.2.2 Lying Dead Wood

The lying dead wood pool is highly variable, and stocks increase as the stands grow; hence its monitoring may be taken up in the first, second or subsequent monitoring periods. The volume of lying dead wood can be assessed from the following survey.

Step 1 Lying dead wood should be sampled using the line intersect method (Harmon and Sexton, 1996).[5] Two 50-m lines bisecting each plot are established and the diameters of the lying dead wood (≥5 cm diameter) intersecting the lines are measured.

Step 2 The dead wood is assigned to one of the three density states $ds=1$ (sound), $ds=2$ (intermediate), and $ds=3$ (rotten) using the 'machete test', as recommended by IPCC Good Practice Guidance for LULUCF (2003), Section 4.3.3.5.3.

Step 3 The volume of lying dead wood per unit area is calculated using the equation (Warren and Olsen, 1964)[6] as modified by van Wagner (1968)[7] separately for each density state:

Equation 27

$$V_{LDW,i,t} = \frac{\pi^2 \times \left(\sum_{n=1}^{N} D_{n,i,t}^{\ 2}\right)}{8 \times L}$$

WHERE

$V_{LDW,i,t}$	Volume of lying dead wood per unit area in stratum i, at time t; m^3 ha^{-1}
$D_{n,i,t}$	Diameter of piece n of dead wood along the transect in stratum i, at time t; cm
N	Total number of wood pieces intersecting the transect; dimensionless
L	Length of the transect; m

[5] Harmon, M. E. and J. Sexton. (1996) Guidelines for Measurements of Woody Detritus in Forest Ecosystems. US LTER Publication No. 20. US LTER Network Office, University of Washington, Seattle, WA, USA.

[6] Warren, W.G. and Olsen, P.F. (1964) A line transect technique for assessing logging waste, Forest Science 10: 267-276.

[7] Van Wagner, C. E. (1968): The line intersect method in forest fuel sampling. Forest Science 14: 20-26.

i	1, 2, 3, … M_{PS} strata in the project scenario
t	1, 2, 3, … t^* years elapsed since the start of the A/R ACR project activity

Step 4 Volume of lying dead wood shall be converted into biomass using the following relationship.

Equation 28

$$B_{LDW,i,t} = A_i \times \sum_{ds=1}^{3} V_{LDW,i,t} \times D_{DW,ds}$$

WHERE

$B_{LDW,i,t}$	Biomass of lying dead wood in stratum i at time t; t d.m.
$V_{LDW,i,t}$	Volume of lying dead wood in stratum i, at time t; $m^3\ ha^{-1}$
$D_{DW,ds}$	Basic wood density of dead wood in the density class ds; t d.m. m^{-3} **NOTE:** To estimate density of each class, follow the procedure described in IPCC Good Practice Guidance for LULUCF (2003), Section 4.3.3.5.3.
A_i	Area of stratum i; ha
ds	Index for density state: 1 (sound), 2 (intermediate) or 3 (rotten)
i	1, 2, 3, … M_{PS} strata in the project scenario
t	1, 2, 3, … t^* years elapsed since the start of the A/R ACR project activity

2.5.1.3 LITTER
(IF SELECTED IN TABLE 1)

For ex ante estimates, if values for carbon stocks of litter are readily available (for example, from the Forest Vegetation Simulator) those values may be used. If values are not readily available, the changes in carbon stocks of litter shall be conservatively neglected.

For ex post estimates, four litter samples shall be collected per sample plot and well mixed into one composite sample. Samples shall be taken at the same time of the year in order to account for natural and anthropogenic influences on the litter accumulation and to eliminate seasonal effects.

A sub-sample from the composite sample of litter is taken, oven dried and weighed to determine the dry weight. The dry to wet weight ratio of the sub-sample is calculated and used for estimations of the litter dry weight.

To estimate the dry litter biomass in metric tons per hectare, the wet litter biomass for the sample plots is multiplied by the dry to wet weight ratio and an expansion factor for the plot size to calculate the litter biomass in metric tons per hectare (10,000 m^2/4 × area of sampling frame in m^2):

Equation 29

$$\mathbf{B_{LI,i,p} = 2.5 \times B_{LI\_WET,i,p} \times \frac{MP_{LI}}{a_{i,p}}}$$

WHERE

$B_{LI,i,p}$	Biomass of dry litter for plot p in stratum i; MT d.m. ha^{-1}
$B_{LI\_WET,i,p}$	Wet weight (field) of the litter in plot p of stratum i; kg
MP_{LI}	Dry-to-wet weight ratio of the litter (dry weight/wet weight); dimensionless
$a_{i,p}$	Area of sampling frame for plot p in stratum i; m^2
i	1, 2, 3, … M_{PS} strata in the project scenario
p	Index for sample plots

The average annual rate of change in the carbon stock of litter from the data at two monitoring intervals shall be calculated. As recommended in the Good Practice Guidance on LULUCF (Chapter 3.2, p 3.35), the dry mass of litter is converted into carbon using 0.370 MT C MT^{-1} d.m. as a default value for the carbon fraction.8 Thus:

[8] Smith and Heath, 2002.

Equation 30

$$dC_{LI,i,t} = \frac{B_{LI,i,t_2} - B_{LI,i,t_1}}{T} \times CF_{LI}$$

WHERE

$dC_{LI,i,t}$	Rate of change in the litter carbon pool in stratum i (averaged over a monitoring period); MT C yr^{-1}
$B_{LI,i,t}$	Biomass of litter in stratum i at time t; MT d.m.
T	Number of years between monitoring time t_2 and t_1 $(T = t_2 - t_1)$; yr
CF_{LI}	Carbon fraction of litter (default value 0.370 MT C MT^{-1} d.m.); MT C MT^{-1} d.m.
i	1, 2, 3, … M_{PS} strata in the project scenario
t	1, 2, 3, … t^* years elapsed since the start of the A/R ACR project activity

Change in carbon stock in litter in year t $(t_1 \le t \le t_2)$ is then calculated as:

Equation 31

$$\Delta C_{LI,i,t} = dC_{LI,i,(t_1,t_2)} \times 1 \text{ year}$$

WHERE

$\Delta C_{LI,i,t}$	Change in carbon stock in litter in stratum i, in year t; MT C
$dC_{LI,i,(t_1,t_2)}$	Rate of change in carbon stock in litter in stratum i, for the period between year t_1 and year t_2; MT C yr^{-1}

2.5.1.4 SOIL ORGANIC CARBON (IF SELECTED IN TABLE 1)

For ex ante estimations, the changes in stocks of soil organic carbon may be assessed using the default method or the changes may be conservatively neglected.

For ex post estimations, the changes in stocks of soil organic carbon are estimated using the approved methodological tool "Tool for estimation of change in soil organic carbon stocks due to the implementation of A/R CDM project activities". That is:

Equation 32

$$\Delta C_{SOC,i,t} = \Delta SOC_{AL,t}$$

WHERE

$\Delta C_{SOC,i,t}$	Change in carbon stock in the SOC pool in stratum i, in year t; MT C
$\Delta SOC_{AL,t}$	Change in carbon stock in the SOC pool as estimated in the tool "Tool for estimation of change in soil organic carbon stocks due to the implementation of A/R ACR project activities" applied to stratum i; MT C

2.5.1.5 WOOD PRODUCTS (IF SELECTED IN TABLE 1)

Wood products may be excluded from the project as this carbon stock is considered to be zero in the baseline scenario (see Section 2.4.3) and omission is thus always conservative. However, if included in the project scenario, wood products (if any) must also be included in accounting for the baseline scenario.

The change in carbon stock in wood products is estimated on the basis of harvested volume and ratios of long-term wood products of time in year t_1 and again at a point of time in year t_2 for each stratum. If harvesting boundaries extend across stratum boundaries, harvest volumes should be allocated to each stratum proportionally to the area harvested in each stratum and documentation thereof presented for verification. The rate of change of carbon stock in wood products is calculated as:

Equation 33

$$\Delta C_{WP,i,t} = \frac{C_{WP,i,t_2} - C_{WP,i,t_1}}{T}$$

WHERE

$\Delta C_{WP,i,t}$	Rate of change in long-term wood products from stratum *i*, averaged for the period between year t_1 and year t_2; MT C yr^{-1}
C_{WP,i,t_2}	Carbon stock in wood products from stratum i, up to year t_2; MT C
C_{WP,i,t_1}	Carbon stock in wood products from stratum i, up to year t_1; MT C
T	Time elapsed between two successive estimations $(T=t_2-t_1)$; yr

i	1, 2, 3, … M_{PS} strata in the project scenario
t	1, 2, 3, … t^* years elapsed since the start of the A/R ACR project activity

To calculate wood products two methodologies are available. The direct (1605b) method is only applicable within the 48 contiguous United States and for limited vegetation types. The less direct (Winjum et al.) method can be applied to any vegetation types throughout the world.

2.5.1.5.1 The 1605b Method

This method calculates the carbon extracted from the start of the project to date and then calculates the proportion of that carbon sequestered long term in wood products.

Step 1 Calculate the biomass of the total volume extracted from the start of the project to date from within the project boundary with extracted timber differentiated into sawnwood and pulpwood classes (if necessary convert volumes in ft^3 to m^3 by multiplying by 0.0283). When using the Forest Vegetation Simulator to estimate the change in carbon stock in wood products, this step can be skipped since these calculations are built into FVS.

Equation 34

$$\mathbf{EXC_{WP,i,t,s/p} = \sum_{h=1}^{H_{PS}} \sum_{j=1}^{S_{PS}} (V_{ex,i,h,s/p,j} \times D_j \times CF_j}$$

WHERE

$EXC_{WP,i,t,s/p}$	The summed stock of extracted biomass carbon from stratum i up to year t by wood product disposition (sawnwood/pulpwood) s/p; MT C
$V_{ex,i,h,s/p,j}$	The volume of timber extracted from stratum i during harvest h by species j and wood product disposition (sawnwood/pulpwood) s/p; m^3
D_j	Basic wood density of species j; MT d.m. m^{-3}
CF_j	Carbon fraction of biomass for tree species j; MT C MT^{-1} d.m. (IPCC default value = 0.5 MT C MT^{-1} d.m.)

h	1, 2, 3, …H_{PS} number of harvests since the start of the A/R ACR project activity up to year t
j	1, 2, 3, … S_{PS} tree species in the baseline scenario
s/p	Wood product disposition – defined here as sawnwood or pulp-wood
i	1, 2, 3, … M_{PS} strata in the project scenario
t	1, 2, 3, … t^* years elapsed since the start of the A/R ACR project activity

Step 2 Calculate the carbon in extracted timber that remains sequestered after 100 years. This can be done in one of two ways. Equation 35 uses Table 1.6 from the Forestry Appendix of the Technical Guidelines of the US Department of Energy's Voluntary Reporting of Greenhouse Gases Program (known as Section 1605b)[9]. PPs will determine the region the project is located in (using Figure 1.1 of the same document) and whether the timber is softwood or hardwood. Instead of tracking annual emissions through retirement, burning and decomposition, the methodology calculates the proportion of wood products that have not been emitted to the atmosphere 100 years after harvest and assumes that this proportion is permanently sequestered. The proportions defined as "In Use" and "Landfill" 100 years after production will be used here.

Equation 36 uses the Forest Vegetation Simulator to estimate the carbon sequestered over time in extracted timber.

Equation 35

$$C_{WP,i,t} = \sum_{s,p}^{s/p} EXC_{WP,i,t,s/p} \times 1605b$$

AND

Equation 36

$$C_{WP,i,t} = C_{WP,i,t,FVS} \times A_i$$

[9] http://www.eia.doe.gov/oiaf/1605/Forestryappendix[1].pdf; also available as a US Forest Service General Technical Report at: http://www.fs.fed.us/ne/durham/4104/papers/ne_gtr343.pdf

WHERE

$C_{WP,i,t}$	Carbon stock in wood products from stratum i up to year t; MT C
$EXC_{WP,i,t,s/p}$	The summed stock of extracted biomass carbon from stratum i up to year t by wood product disposition (sawnwood/pulpwood) s/p; MT C
$1605b$	The proportions of extracted timber still "in use" or sequestered in a "landfill" as wood products 100 years after production from Table 1.6 of the Forestry Appendix to the Technical Guidelines; MT C in products permanently sequestered MT C^{-1} extracted biomass carbon
s/p	Wood product disposition – defined here as sawnwood (s) or pulpwood (p)
i	1, 2, 3, … M_{PS} strata in the project scenario
t	1, 2, 3, … t^* years elapsed since the start of the A/R ACR project activity
$C_{WP,i,t,FVS}$	The carbon in wood products from stratum i up to year t as estimated by FVS. This is obtained from the Merchantable Carbon Stored column of the FVS harvested products carbon report and includes the carbon in wood products still in use and sequestered in a landfill. Because FVS is estimating the amount of carbon currently stored for a given year, and not necessarily the amount that is permanently sequestered, values used from the FVS report should be for the year 100 years after the harvest immediately preceding year t and the simulation should not include any harvests or thinnings that are planned to occur after year t. Units must be changed to metric tons per hectare; MT C/ha
A_i	Total area of stratum i; ha

2.5.1.5.2 The Winjum et al. Method

Step 1 Calculate the biomass of the total volume extracted from the start of the project to date from within the project boundary (if necessary convert volumes in ft^3 to m^3 by multiplying by 0.0283):

Equation 37

$$EXC_{WP,i,t,ty} = \sum_{h=1}^{H_{PS}} \sum_{j=1}^{S_{PS}} (V_{ex,i,h,ty,j} \times D_j \times CF_j$$

WHERE

$EXC_{WP,i,t,ty}$	The summed stock of extracted biomass carbon from stratum i up to year t by class of wood product *ty*; MT C
$V_{ex,i,h,ty,j}$	The volume of timber extracted from stratum i during harvest h by species j and wood product class ty; m^3
D_j	Basic wood density of species j; MT d.m. m^{-3}
CF_j	Carbon fraction of biomass for tree species j; MT C MT^{-1} d.m. (IPCC default value = 0.5 MT C MT^{-1} d.m.)
h	1, 2, 3, … H_{PS} number of harvests since the start of the A/R ACR project activity up to year t.
j	1, 2, 3, … S_{PS} tree species in the baseline scenario
ty	Wood product class – defined here as sawnwood, wood-based panels, other industrial roundwood, paper and paper board, and other
i	1, 2, 3, … M_{PS} strata in the project scenario
t	1, 2, 3, … t^* years elapsed since the start of the A/R ACR project activity

Step 2 Calculate the proportion of extracted timber that remains sequestered after 100 years. Instead of tracking annual emissions through retirement, burning and decomposition, the methodology calculates the proportion of wood products that have not been emitted to the atmosphere 100 years after harvest and assumes that this proportion is permanently sequestered. Default factors listed below are derived from Winjum et al.1998[10]. Alternatively, Project Proponents may use

[10] Winjum, J.K., Brown, S. and Schlamadinger, B. 1998. Forest harvests and wood products: sources and sinks of atmospheric carbon dioxide. Forest Science 44: 272-284

specific factors in equations 38 to 41 from local, regional or national sources that can be validated by peer-reviewed literature.

Equation 38

$$C_{WP,i,t} = \sum_{s,w,oir,p,o}^{ty} (((EXC_{WP,i,t,ty} - WW_{i,t}) - SLF_{i,t}) - OF_{i,t}$$

WHERE

$C_{WP,i,t}$	Carbon stock in wood products from stratum i up to year t; MT C
$EXC_{WP,i,t,ty}$	The summed stock of extracted biomass carbon from stratum i up to year t by class of wood product ty; MT C
$WW_{i,t}$	Wood waste. The fraction of biomass extracted from stratum i up to year t immediately emitted through mill inefficiency; MT C
$SLF_{i,t}$	Fraction of wood products up to year t that will be emitted to the atmosphere within 5 years of timber harvest; MT C
$OF_{i,t}$	Fraction of wood products up to year t that will be emitted to the atmosphere between 5 and 100 years of timber harvest; MT C
ty	Wood product class – defined here as sawnwood (s), wood-based panels (w), other industrial roundwood (oir), paper and paper board (p), and other (o)
i	1, 2, 3, … M_{PS} strata in the project scenario
t	1, 2, 3, … t^* years elapsed since the start of the A/R ACR project activity

WOOD WASTE FRACTION (WW)

Winjum et al 1998 indicate that the proportion of extracted biomass that is oxidized (burning or decaying) from the production of commodities to be equal to 19% for developed countries, 24% for developing countries.

WW is therefore equal to:

Equation 39

$$\mathbf{WW_{i,t} = EXC_{WP,i,t,ty} \times wf}$$

WHERE

$WW_{i,t}$	Wood waste. The fraction of biomass extracted from stratum i up to year t immediately emitted through mill inefficiency; MT C
$EXC_{WP,i,t,ty}$	The summed stock of extracted biomass carbon from stratum i up to year t by class of wood product ty; MT C
ty	Wood product class – defined here as sawnwood (s), wood-based panels (w), other industrial roundwood (oir), paper and paper board (p), and other (o)
wf	Wood waste fraction – 0.19 for developed countries, 0.24 for developing countries; MT C MT C^{-1}
i	1, 2, 3, … M_{PS} strata in the project scenario
t	1, 2, 3, … t^* years elapsed since the start of the A/R ACR project activity

SHORT-LIVED FRACTION (SLF)

Winjum et al 1998 give the following proportions for wood products with short-term (<5 yr) uses (applicable internationally):

Sawnwood	0.2
Woodbase panels	0.1
Other industrial roundwood	0.3
Paper and Paperboard	0.4

The methodology makes the assumption that all other classes of wood products are 100% oxidized within 5 years.

SLF is therefore equal to:

Equation 40

$$\mathbf{SLF_{i,t} = \left(EXC_{WP,i,t,ty} - WW_{i,t}\right) \times slp}$$

WHERE

$SLF_{i,t}$	Fraction of wood products extracted from stratum i up to year t that will be emitted to the atmosphere within 5 years of timber harvest; MT C
$EXC_{WP,i,t,ty}$	The summed stock of extracted biomass carbon from stratum i up to year t by class of wood product ty; MT C
$WW_{i,t}$	Wood waste. The fraction of biomass extracted from stratum i up to year t immediately emitted through mill inefficiency; MT C
slp	Short-lived proportion - 0.2 for sawnwood, 0.1 for woodbase panels, 0.3 for other industrial roundwood, 0.4 for paper and paperboard and 1 for other; MT C MT C^{-1}
ty	Wood product class – defined here as sawnwood (s), wood-based panels (w), other industrial roundwood (oir), paper and paper board (p), and other (o)
i	1, 2, 3, … M_{PS} strata in the project scenario
t	1, 2, 3, … t^* years elapsed since the start of the A/R ACR project activity

ADDITIONAL OXIDIZED FRACTION (OF)

Winjum et al 1998 gives annual oxidation fractions for each class of wood products split by forest region (boreal, temperate and tropical). This methodology projects these fractions over 95 years to give the additional proportion that is oxidized between the 5th and 100th years after initial harvest (Table 3):

Table 3: Proportion of Remaining Wood Products

Oxidized between 5 and 100 years after initial harvest by wood product class and forest region Wood Product Class.

WOOD PRODUCT CLASS	BOREAL	TEMPERATE	TROPICAL
Sawnwood	0.36	0.60	0.84
Woodbase panels	0.60	0.84	0.97
Other industrial roundwood	0.84	0.97	0.99
Paper and paperboard	0.36	0.60	0.99

OF is therefore equal to:

Equation 41

$$OF_{i,t} = \left((EXC_{WP,i,t,ty} - WW_{i,t}) - SLF_{i,t}\right) \times fo$$

WHERE

$OF_{i,t}$	Fraction of wood products extracted from stratum i up to year t that will be emitted to the atmosphere between 5 and 100 years of timber harvest; MT C
$EXC_{WP,i,t,ty}$	The summed stock of extracted biomass carbon from stratum i up to year t by class of wood product ty; MT C
$WW_{i,t}$	Wood waste. The fraction of biomass extracted from stratum i up to year t immediately emitted through mill inefficiency; MT C
$SLF_{i,t}$	Fraction of wood products extracted from stratum i up to year t that will be emitted to the atmosphere within 5 years of timber harvest; MT C
fo	Fraction oxidized – see Table 3 for defaults; MT C MT C^{-1}
ty	Wood product class – defined here as sawnwood (s), wood-based panels (w), other industrial roundwood (oir), paper and paper board (p), and other (o)
i	1, 2, 3, … M_{PS} strata in the project scenario
t	1, 2, 3, … t^* years elapsed since the start of the A/R ACR project activity

2.5.2 Estimation of GHG Emissions within the Project Boundary

The increase in GHG emissions as a result of the implementation of the proposed A/R ACR project activity within the project boundary can be estimated as:

Equation 42

$$GHG_E = \sum_{t=1}^{t^*} E_{BIOMASS\_BURN,t}$$

WHERE

GHG_E	Increase in GHG emissions as a result of the implementation of the proposed A/R ACR project activity within the project boundary; MT CO_2e
$E_{BIOMASS\_BURN,t}$	Non-CO_2 emissions due to burning of biomass of existing woody vegetation as part of site preparation during the year t, as estimated in the tool "Estimation of GHG emissions due to clearing, burning and decay of existing vegetation attributable to a CDM A/R project activity"; MT CO_2e
t	1, 2, 3, … t^* years elapsed since the start of the A/R ACR project activity

2.6 LEAKAGE

Under applicability conditions of this methodology the following types of leakage emissions can occur: GHG emissions due to activity displacement, the activity displaced being agricultural activities. Therefore, leakage is estimated as follows:

Equation 43

$$LK = \sum_{t=1}^{t^*} LK_{AGRIC,t}$$

WHERE

LK	Total GHG emissions due to leakage; MT CO_2e
$LK_{AGRIC,t}$	Leakage due to the displacement of agricultural activities in year t, as calculated in the tool "Estimation of the increase in GHG emissions attributable to

	displacement of pre-project agricultural activities in A/R CDM project activity"; MT CO_2e

2.7 NET ANTHROPOGENIC GHG REMOVALS BY SINKS

The net anthropogenic GHG removals by sinks is the actual net GHG removals by sinks minus the baseline net GHG removals by sinks minus leakage, therefore, the following general formula can be used to calculate the net anthropogenic GHG removals by sinks of an A/R ACR project activity ($C_{AR\text{-}ACR}$), in t CO_2e.

Equation 44

$$\mathbf{C_{AR-ACR} = \Delta C_{ACTUAL} - \Delta C_{BSL} - LK}$$

WHERE

C_{AR-ACR}	Net anthropogenic GHG removals by sinks; MT CO_2e
ΔC_{ACTUAL}	Actual net GHG removals by sinks; MT CO_2e
ΔC_{BSL}	Baseline net GHG removals by sinks; MT CO_2e
LK	Total GHG emissions due to leakage; MT CO_2e

In addition an uncertainty deduction, if required per the ACR Standard (i.e. if the precision target of ±10% of the mean at 90% confidence, applied to the final calculation of emission reductions/removal enhancements, is not achieved), must be applied to the result from equation 44 to give an adjusted value of $C_{AR\text{-}ACR}$ accounting for uncertainty.

2.7.1 Calculation of ERTs

To estimate the ERTs at time $t^* = t_2$ (the date of verification) for the monitoring period $T = t_2 - t_1$, this methodology uses the equation provided by ACR[11], which uses a buffer pool and other approved mechanisms to mitigate the risk of reversals. ACR does not award temporary credits.

[11] ACR clarifications for AR-ACM0001 v5, available at http://www.americancarbonregistry.org/carbon-accounting/AR-ACM0001%20v5%20clarificaitons%20for%20use%20on%20ACR.pdf

ERTs shall be calculated by applying the buffer deduction, if applicable:

Equation 45

$$ERT_t = \left(C_{AR-ACR,t_2} - C_{AR-ACR,t_1}\right) \times (1 - BUF)$$

WHERE

ERT_t	Number of Emission Reduction Tonnes at time $t=t_2-t_1$
C_{AR-ACR,t_2}	Cumulative total net GHG emission reductions up to time t_2; MT CO_2e
C_{AR-ACR,t_1}	Cumulative total net GHG emission reductions up to time t_1; MT CO_2e
BUF	Percentage of project ERTs contributed to the ACR buffer pool, if applicable

Per the ACR Standard, BUF is determined using an ACR-approved risk assessment tool.[12] If the Project Proponent elects to make the buffer contribution in non-project ERTs, or elects to mitigate the assessed reversal risk using an alternate risk mitigation mechanism approved by ACR, BUF shall be set equal to zero.

2.8 DATA AND PARAMETERS NOT MONITORED

(DEFAULT OR POSSIBLY MEASURED ONE TIME)

In addition to the parameters listed in the tables below, the provisions on data and parameters in the tools referred to in this methodology apply.

In choosing key parameters or making important assumptions based on information that is not specific to the project circumstances, such as in use of existing published data, PPs should retain a conservative approach: that is, if different values for a parameter are equally plausible, a value that does not lead to over-estimation of net anthropogenic GHG removals by sinks should be selected.

DATA / PARAMETER	$BEF_{2,j}$
DATA UNIT	Dimensionless

[12] As described in the ACR Standard, unless/until ACR publishes its own Tool for Risk Analysis and Buffer Determination, the Project Proponent shall use the latest version of the VCS AFOLU Non-Permanence Risk Tool, available at http://v-c-s.org/program-documents.

USED IN EQUATIONS	19
DESCRIPTION	Biomass expansion factor for conversion of stem biomass to above-ground biomass for tree species or group of species j
SOURCE OF DATA	The source of data shall be selected, in order of preference, from the following: • Local sources of species or group of species-specific data; • National sources of species or group of species-specific data (e.g. national forest inventory or national GHG inventory); • Species or group of species-specific data from neighbouring countries with similar conditions; • Globally available data applicable to species or group of species; • IPCC default values (e.g. Table 3A.1.10 of IPCC GPG-LULUCF 2003)[13]
MEASUREMENT PROCEDURES	N/A
COMMENTS	BEFs in IPCC literature and national forest inventories are usually applicable to closed canopy forests. If applied to individual trees growing in open field, it is recommended that the selected BEF_2 be increased by 30%

DATA / PARAMETER	$BEF_{1,j}$
DATA UNIT	Dimensionless
USED IN EQUATIONS	4
DESCRIPTION	Biomass expansion factor for conversion of annual net increment (including bark) in stem biomass to total above-ground tree biomass increment for species j
SOURCE OF DATA	• Local sources of species or group of species-specific data;

[13] Although the BEFs in Table 3A.1.10 apply to biomass, the dimensionless factors can be equally applied for wood volume expansions.

	• National sources of species or group of species-specific data (e.g. national forest inventory or national GHG inventory); • Species or group of species-specific data from neighbouring countries with similar conditions; • Globally available data applicable to species or group of species • IPCC default values (e.g. Table 3A.1.10 of IPCC GPG-LULUCF 2003)[14]
MEASUREMENT PROCEDURES	N/A
COMMENTS	BEFs in IPCC literature and national inventory data are usually applicable to closed canopy forest. If applied to individual trees growing in open field it is recommended that the selected BEF be increased by a further 30%

DATA / PARAMETER	$B_{LOSS\_BSL,j,t}$
DATA UNIT	MT d.m.
USED IN EQUATIONS	4
DESCRIPTION	Loss of tree biomass of species j in year t
SOURCE OF DATA	Existing data from the records relating to the project area. The source data could be the basis for estimating the rate at which pre-project activities (such as collection fuelwood or fodder, selection harvesting, mortality of trees, etc.) are reducing biomass stocks in existing live trees
MEASUREMENT PROCEDURES	N/A

DATA / PARAMETER	BD_{TREE_BSL}
DATA UNIT	MT d.m. ha^{-1}

[14] Although the BEFs in Table 3A.1.10 apply to biomass, the dimensionless factors can be equally applied for wood volume expansions.

USED IN EQUATIONS	6
DESCRIPTION	Tree biomass density per unit area of the project area (obtained from published literature)
SOURCE OF DATA	Published data may relate to the project area or to another area similar to the project area. If published data is in terms of volume and not in terms of biomass, or the biomass data does not include the below-ground biomass, then transparent and verifiable method using suitable parameters may be used for calculating the tree biomass per unit area from the available data
MEASUREMENT PROCEDURES	N/A

DATA / PARAMETER	B_{FOREST}
DATA UNIT	MT d.m. ha^{-1}
USED IN EQUATIONS	7
DESCRIPTION	Default above-ground biomass content in forest in the region/country where the A/R ACR project activity is located
SOURCE OF DATA	The source of data shall be selected, in order of preference, from the following: • Regional/national inventories e.g. national forest inventory, national GHG inventory; • Inventory from neighbouring countries with similar conditions; • Globally available data applicable to the project site or to the region/country where the site is located (e.g. latest data from FAO); • IPCC default values from Table 3A.1.4 of IPCC GPG-LULUCF 2003
MEASUREMENT PROCEDURES	N/A

DATA / PARAMETER	CF_j
DATA UNIT	MT C MT^{-1} d.m.
USED IN EQUATIONS	19, 20
DESCRIPTION	Carbon fraction of tree biomass for species or group of species j
SOURCE OF DATA	The source of data, in order of preference, shall be the following: • National level species or group of species-specific data (e.g. from national GHG inventory); • Species or group of species-specific data from neighbouring countries with similar conditions; • Globally available data (e.g. IPCC GPG-LULUCF 2003); • The IPCC default value of 0.5 MT C MT^{-1} d.m.
MEASUREMENT PROCEDURES	N/A

DATA / PARAMETER	CF_{DW}
DATA UNIT	MT C MT^{-1} d.m.
USED IN EQUATIONS	25, 26
DESCRIPTION	Carbon fraction of dry matter in dead wood biomass
SOURCE OF DATA	Default value 0.5 MT C MT^{-1} d.m. shall be used
MEASUREMENT PROCEDURES	N/A

DATA / PARAMETER	CF_{LI}
DATA UNIT	MT C MT^{-1} d.m.
USED IN EQUATIONS	30

DESCRIPTION	Carbon fraction of dry matter in litter biomass
SOURCE OF DATA	Default value 0.37 MT C MT^{-1} d.m. shall be used
MEASUREMENT PROCEDURES	N/A

DATA / PARAMETER	CF_{TREE_BSL}
DATA UNIT	MT C MT^{-1} d.m.
USED IN EQUATIONS	2
DESCRIPTION	Carbon fraction of dry matter for tree biomass in baseline
SOURCE OF DATA	Default value 0.50 MT C MT^{-1} d.m. may be used
MEASUREMENT PROCEDURES	N/A

DATA / PARAMETER	D_j
DATA UNIT	MT d.m. m^{-3}
USED IN EQUATIONS	4, 19
DESCRIPTION	Basic wood density for species or group of species j
SOURCE OF DATA	The source of data, in order of preference, shall be any of the following: • National and species or group of species-specific data (e.g. from national forest inventory or national GHG inventory); • Species or group of species-specific data from neighbouring countries with similar conditions; • Globally available species or group of species-specific data (e.g. Table 3A.1.9 IPCC GPG-LULUCF 2003)
MEASUREMENT PROCEDURES	N/A

DATA / PARAMETER	$D_{DW,ds}$
DATA UNIT	MT d.m. m^{-3}
USED IN EQUATIONS	28
DESCRIPTION	Basic wood density of dead wood in the density state: 1 (sound), 2 (intermediate) or 3 (rotten)
SOURCE OF DATA	The source of data, in order of preference, shall be any of the following: I. National and species-specific or group of species-specific data (e.g. from national GHG inventory); II. Species-specific or group of species-specific data from neighbouring countries with similar conditions. Sometimes (II) might be preferable to (I); III. Globally species-specific or group of species-specific (e.g. IPCC GPG-LULUCF 2003)
MEASUREMENT PROCEDURES	Project specific determination of the density is allowed

DATA / PARAMETER	$f_j(DBH, H)$
DATA UNIT	MT d.m. $tree^{-1}$
USED IN EQUATIONS	20
DESCRIPTION	Allometric function for species or group of species j linking tree diameter (diameter at breast height or other diameter), and possibly tree height (H), to above-ground biomass of living trees
SOURCE OF DATA	The source of data, in order of preference, shall be any of the following: • Existing local and species or group of species-specific data; • National and species or group of species-specific data (e.g. national forest inventory or national GHG inventory);

	• Species or group of species-specific data from neighbouring countries with similar conditions; • Globally available data applicable to species or group of species (e.g. Tables 4.A.1–4.A.3 of IPCC GPG-LULUCF 2003)
MEASUREMENT PROCEDURES	N/A

DATA / PARAMETER	$I_{V,j,t}$
DATA UNIT	m^3 ha^{-1} yr^{-1}
USED IN EQUATIONS	4
DESCRIPTION	Average annual increment in stem volume of species j, in year t
SOURCE OF DATA	The source of data, in order of preference, shall be the following: • Existing local and species or group of species-specific tree growth data or local volume tables; • National and species or group of species-specific tree growth data or standard volume tables (e.g. from national forest inventory or national GHG inventory); • Species or group of species-specific tree growth data or volume tables from neighbouring countries with similar conditions; • Globally available data applicable to species or group of species
MEASUREMENT PROCEDURES	N/A
COMMENTS	$I_{V,j,t}$ is estimated as the “current annual increment – CAI”. The “mean annual increment” – often abbreviated as MAI in the forestry inventories– can only be used if its use leads to conservative estimates. The values read from tables if expressed on the per unit of area basis will usually apply to fully stocked forest. Thus, they should be corrected to be applicable in the baseline conditions, e.g. by multiplication by the fraction of tree crown cover or fraction of number of stems in the baseline stratum of interest (other ways of correction may be proposed by project proponents)

DATA / PARAMETER	$OF_{i,t}$, $SLF_{i,t}$, $WW_{i,t}$
DATA UNIT	MT C
USED IN EQUATIONS	38-41
DESCRIPTION	$OF_{i,t}$ = Fraction of wood products extracted from stratum i up to year t that will be emitted to the atmosphere between 5 and 100 years after production; $SLF_{i,t}$ = Fraction of wood products extracted from stratum i up to year t that will be emitted to the atmosphere within 5 years of production; $WW_{i,t}$ = Fraction of biomass extracted from stratum i up to year t effectively emitted to the atmosphere during production.
SOURCE OF DATA	The source of the data is the published paper of Winjum et al. 1998: Winjum, J.K., Brown, S. and Schlamadinger, B. 1998. Forest harvests and wood products: sources and sinks of atmospheric carbon dioxide. Forest Science 44: 272-284
MEASUREMENT PROCEDURES	N/A

DATA / PARAMETER	R_j
DATA UNIT	Dimensionless
USED IN EQUATIONS	19, 20
DESCRIPTION	Root-shoot ratio for species or group of species j
SOURCE OF DATA	The source of data, in order of preference, shall be any of the following: • Existing local and species or group of species-specific data; • National and species or group of species-specific data (e.g. national forest inventory or national GHG inventory); • Species or group of species-specific data from neighbouring countries with similar conditions;

	- Globally available data applicable to species or group of species growing under similar conditions or similar forest type. If none of the above sources are available, then the value of R_j may be calculated as B/A where $B = \exp[-1.085 + 0.9256 \text{ x} \ln(A)]$, where A is above-ground biomass (t d.m. ha^{-1}) and B is below-ground biomass (t d.m. ha^{-1}) [Source: Table 4.A.4 of IPCC GPG-LULUCF 2003]
MEASUREMENT PROCEDURES	N/A

DATA / PARAMETER	R_{1j}
DATA UNIT	kg d.m.yr^{-1} (kg d.m.yr^{-1})$^{-1}$
USED IN EQUATIONS	4
DESCRIPTION	Root-shoot ratio appropriate for biomass increment for species j
SOURCE OF DATA	The source of data, in order of preference, shall be any of the following: I. National and species-specific or group of species-specific (e.g. from national GHG inventory); II. Species-specific or group of species-specific from neighbouring countries with similar conditions. Sometimes (II) might be preferable to (I); III. Species-specific or group of species-specific from global studies
MEASUREMENT PROCEDURES	N/A
COMMENTS	If none of the above sources are available, then the value of R_{1j} may be calculated as B/A where $B = \exp[-1.085 + 0.9256 \text{ x} \ln(A)]$, where A is above-ground biomass (t d.m. ha^{-1}) and B is below-ground biomass (t d.m. ha^{-1}) [Source: Table 4.A.4 of IPCC GPG-LULUCF 2003]

DATA / PARAMETER	R_{TREE_BSL}
DATA UNIT	Dimensionless

USED IN EQUATIONS	7
DESCRIPTION	Root-shoot ratio for the trees in the baseline
SOURCE OF DATA	The source of data, in order of preference, shall be any of the following: • Existing local and species or group of species-specific data; • National and species or group of species-specific data (e.g. national forest inventory or national GHG inventory); • Species or group of species-specific data from neighbouring countries with similar conditions; • Globally available data applicable to species or group of species growing under similar conditions or similar forest type. If none of the above sources are available, then the value of R_{TREE_BSL} may be calculated as B/A where $B = \exp[-1.085 + 0.9256 \text{ x } \ln(A)]$, where A is above-ground biomass (t d.m. ha^{-1}) and B is below-ground biomass (t d.m. ha^{-1}) [Source: Table 4.A.4 of IPCC GPG-LULUCF 2003]
MEASUREMENT PROCEDURES	N/A

DATA / PARAMETER	$V_{TREE,j,p,i}$
DATA UNIT	m^3
USED IN EQUATIONS	19
DESCRIPTION	Stem volume of trees of species or group of species j in plot p in stratum i
SOURCE OF DATA	The source of data, in order of preference, shall be the following: • Existing local and species or group of species-specific tree growth data or local volume tables; • National and species or group of species-specific tree growth data or standard volume tables (e.g. from national forest inventory or national GHG inventory);

	• Species or group of species-specific tree growth data or volume tables from neighbouring countries with similar conditions; • Globally available data applicable to species or group of species
MEASUREMENT PROCEDURES	N/A
COMMENTS	In case of ex ante estimation, it would not be possible to measure diameter of trees to be used in volume tables. In such cases, species-specific or group of species-specific age-diameter curves from local/national sources may be used to estimate the diameter at a given point of time. Age of trees in baseline may be estimated from historical records, participatory appraisal, or tree dendrometry methods. If such age-diameter curves are not available then average growing stock values from Table 3A.1.4 of IPCC GPG-LULUCF 2003 may be multiplied by the fractional value of estimated crown cover of trees. For example, if crown cover of trees is estimated as 10% and the project is located in Cameroon (growing stock volume of 135 m3/ha), then the stem volume of trees may be estimated as 0.10 × 135 = 13.50 m^3/ha

DATA / PARAMETER	1605b
DATA UNIT	Dimensionless
USED IN EQUATIONS	35
DESCRIPTION	Proportion of wood products still "in use" 100 years after production
SOURCE OF DATA	The source is the Forestry Appendix of US Department of Energy's Technical Guidelines for The Voluntary Reporting of Greenhouse Gas Program (Section 1605b): http://www.eia.doe.gov/oiaf/1605/Forestryappendix[1].pdf; also available as a US Forest Service General Technical Report at: http://www.fs.fed.us/ne/durham/4104/papers/ne_gtr343.pdf
MEASUREMENT PROCEDURES	N/A

3 MONITORING METHODOLOGY

All data collected as part of monitoring should be archived electronically and be kept at least for two years after the end of the last crediting period. One hundred percent of the data should be monitored if not indicated otherwise in the tables below. All measurements should be conducted according to relevant standards. In addition, the monitoring provisions in the tools referred to in this methodology apply.

3.1 MONITORING OF PROJECT IMPLEMENTATION

Information shall be provided, and recorded in the GHG Project Plan, to establish that:

I. The geographic coordinates of the project boundary (and any stratification inside the boundary) are established, recorded and archived;
II. Commonly accepted principles of forest inventory and management in the host country are implemented. In absence of these, standard operating procedures (SOPs) and quality control/quality assurance (QA/QC) procedures for inventory operations, including field data collection and data management, shall be identified, recorded and applied. Use or adaptation of SOPs available from published handbooks, or from the IPCC GPG LULUCF 2003, is recommended;
III. The forest planting and management plan, together with a record of the plan as actually implemented during the project, shall be available for validation and/or verification.

3.2 SAMPLING DESIGN AND STRATIFICATION

Stratification of the project area into relatively homogeneous units can either increase the measuring precision without increasing the cost unduly, or reduce the cost without reducing measuring precision because of the lower variance within each homogeneous unit. PPs should present in the GHG Project Plan an ex ante stratification of the project area or justify the lack of it. The number and boundaries of the strata defined ex ante may change during the crediting period (ex post).

3.2.1 Updating of Strata

The ex post stratification shall be updated because of the following reasons:

- Unexpected disturbances occurring during the crediting period (e.g. due to fire, pests or disease outbreaks), affecting differently various parts of an originally homogeneous stratum;

- Forest management activities (cleaning, planting, thinning, harvesting, coppicing, re-replanting) that are implemented in a way that affects the existing stratification.

Established strata may be merged if reasons for their establishing have disappeared.

3.2.2 Precision Requirements

The targeted precision level for biomass estimation shall be ±10% of the mean at a 90% confidence level. Given the correlation between biomass and volume, assessing the precision level with a confidence interval for cubic foot volume is sufficient. PPs may use the latest version of the approved tool for “Calculation of the number of sample plots for measurements within A/R CDM project activities” to determine the sample size and allocation of sample plots among strata.

3.3 REGENERATION MONITORING AREAS

To ensure that the natural (without planting) regeneration rates assumed in the baseline scenario remain valid over the Crediting Period, the Project Proponent shall establish a Regeneration Monitoring Area for each of the strata in the project. Each Regeneration Monitoring Area must be at least 1/4 hectare in size and must be designated outside the project boundary in an area similar to the project area in soil type, slope, aspect, and distance to seed sources. Regeneration Monitoring Areas should be near the project area, but it is suggested they be located far enough away to avoid regeneration due to seeds from the trees planted in the project area.

Each Regeneration Monitoring Area must be examined close to the project start date to determine initial regeneration values. Each Regeneration Monitoring Area must then be re-assessed at intervals not to exceed ten (10) years for the duration of the Crediting Period.

At each re-assessment, regeneration (number of seedlings per hectare) in the Regeneration Monitoring Areas shall be compared to the regeneration assumptions used for the baseline to determine whether the number of seedlings per hectare varies significantly from assumptions. If the observed number of seedlings per hectare exceeds the baseline estimate by more than 10% and by more than 10 trees per hectare, the baseline scenario (including the baseline scenario simulated by FVS, if used) must be modified to better reflect the observed values.

Note that although the required reassessment of natural regeneration based on Regeneration Monitoring Areas may require revision of the baseline regeneration assumptions, this only applies to the current and future calculation of net emission reductions. Baseline revisions will not be applied retroactively to credits already verified and issued in earlier years.

3.4 DATA AND PARAMETERS MONITORED

The following data and parameters should be monitored during the project activity. When applying all relevant equations provided in this methodology for the ex ante calculation of net anthropogenic GHG removals by sinks, PPs shall provide transparent estimations for the parameters that are monitored during the crediting period. These estimates shall be based on measured or existing published data where possible and PPs should retain a conservative approach: That is, if different values for a parameter are equally plausible, a value that does not lead to over-estimation of net anthropogenic GHG removals by sinks should be selected.

DATA / PARAMETER	A_i
DATA UNIT	ha
USED IN EQUATIONS	21, 28
DESCRIPTION	Area of tree biomass stratum i
SOURCE OF DATA	Monitoring of strata and stand boundaries shall be done preferably using a Geographical Information System (GIS), which allows for integrating data from different sources (including GPS coordinates and Remote Sensing data)
MEASUREMENT PROCEDURES	See section 3.1 (II)
MONITORING FREQUENCY	Every five years since the year of the initial verification
QA/QC PROCEDURES	See section 3.1 (II)

DATA / PARAMETER	$A_{BSL,j}$
DATA UNIT	ha
USED IN EQUATIONS	4
DESCRIPTION	Area under trees of species j in baseline

SOURCE OF DATA	GPS coordinates and/or remote sensing data
MEASUREMENT PROCEDURES	See section 3.1 (II)

DATA / PARAMETER	$a_{j,p}$
DATA UNIT	m^2
USED IN EQUATIONS	29
DESCRIPTION	Area of sampling frame for plot p in stratum i
SOURCE OF DATA	Simple measurement or manufacturer's data
MEASUREMENT PROCEDURES	See section 3.1(II)
MONITORING FREQUENCY	Every five years since the year of the initial verification
QA/QC PROCEDURES	See section 3.1(II)
COMMENTS	Once selected, the size of the sampling frame shall be fixed until the end of the last crediting period

DATA / PARAMETER	$A_{p,i}$
DATA UNIT	ha
USED IN EQUATIONS	21
DESCRIPTION	Total area of all sample plots in stratum i
SOURCE OF DATA	Field measurement
MEASUREMENT PROCEDURES	See section 3.1(II)

MONITORING FREQUENCY	Every five years since the year of the initial verification
QA/QC PROCEDURES	See section 3.1(II)

DATA / PARAMETER	$B_{LI\_WET,i,p}$
DATA UNIT	kg
USED IN EQUATIONS	29
DESCRIPTION	Wet weight (field) of the litter in plot p of stratum i
SOURCE OF DATA	Field measurements in sample plots
MEASUREMENT PROCEDURES	**STEP 1** Litter shall be sampled using a sampling frame. The frame is placed at four locations within the sample plot. **STEP 2** At each location, all litter (leaves, fruits, small wood, etc.) falling inside the frame shall be collected and the litter from four locations is mixed to get a representative sample for measuring the wet weight of the biomass
MONITORING FREQUENCY	Every five years since the year of the initial verification
QA/QC PROCEDURES	See section 3.1(II)

DATA / PARAMETER	$D_{n,i,t}$
DATA UNIT	cm
USED IN EQUATIONS	27
DESCRIPTION	Diameter of piece n of dead wood along the transect in stratum i, at time t
SOURCE OF DATA	Field measurements in sample plots

MEASUREMENT PROCEDURES	Lying dead wood should be sampled using the line intersect method (Harmon and Sexton, 1996).[15] Two 50-m lines bisecting each plot are established, and the diameters of the lying dead wood (≥5 cm diameter) intersecting the lines are measured
MONITORING FREQUENCY	Every five years since the year of the initial verification
QA/QC PROCEDURES	See section 3.1(II)

DATA / PARAMETER	DBH
DATA UNIT	inch/cm or any unit of length used in the model or data source used
USED IN EQUATIONS	Implicitly used in equation 19, 20
DESCRIPTION	Usually the diameter at breast height of the tree; but it could be any other diameter or dimensional measurement used in the model or data source used, e.g. basal diameter, root-collar diameter, basal area, etc.
SOURCE OF DATA	Field measurements in sample plots. For ex ante estimations, DBH values should be estimated using a growth curve, a growth model, or a yield table that gives the expected tree dimensions as a function of tree age
MEASUREMENT PROCEDURES	See section 3.1(II)
MONITORING FREQUENCY	Every five years since the year of the initial verification
QA/QC PROCEDURES	See section 3.1(II)

DATA / PARAMETER	H

[15] Harmon, M. E. and J. Sexton. (1996) Guidelines for Measurements of Woody Detritus in Forest Ecosystems. US LTER Publication No. 20. US LTER Network Office, University of Washington, Seattle, WA, USA.

DATA UNIT	m or any other unit of length
USED IN EQUATIONS	Implicitly used in equation 19, 20
DESCRIPTION	Height of tree
SOURCE OF DATA	Field measurements in sample plots. For ex ante estimations, H values should be estimated using a growth curve, a growth model, or a yield table that gives the expected tree dimensions as a function of tree age
MEASUREMENT PROCEDURES	See section 3.1(II)
MONITORING FREQUENCY	Every five years since the year of the initial verification
QA/QC PROCEDURES	See section 3.1(II)
COMMENTS	Models used may be based on units of length other than meter (e.g. feet), in which case the appropriate unit of length only should be used

DATA / PARAMETER	L
DATA UNIT	m
USED IN EQUATIONS	27
DESCRIPTION	Length of the transect to determine volume of lying dead wood
SOURCE OF DATA	Field measurements
MEASUREMENT PROCEDURES	See section 3.1(II)
MONITORING FREQUENCY	Every five years since the year of the initial verification
QA/QC PROCEDURES	See section 3.1(II)

DATA / PARAMETER	MP_{LI}
DATA UNIT	Dimensionless
USED IN EQUATIONS	29
DESCRIPTION	Dry-to-wet weight ratio of the litter (dry weight/wet weight)
SOURCE OF DATA	Laboratory measurement of field samples
MEASUREMENT PROCEDURES	Litter samples shall be collected and well mixed into one composite sample at the same time of year in order to account for natural and anthropogenic influences on the litter accumulation and to eliminate seasonal effects. A subsample from the composite sample of litter is taken, oven dried and weighed to determine the dry weight
MONITORING FREQUENCY	Every five years since the year of the initial verification
QA/QC PROCEDURES	See section 3.1(II)

DATA / PARAMETER	N
DATA UNIT	Dimensionless
USED IN EQUATIONS	27
DESCRIPTION	Total number of wood pieces intersecting the transect
SOURCE OF DATA	Field measurements
MEASUREMENT PROCEDURES	See section 3.1(II)
MONITORING FREQUENCY	Every five years since the year of the initial verification
QA/QC PROCEDURES	See section 3.1(II)

DATA / PARAMETER	T
DATA UNIT	Year
USED IN EQUATIONS	17, 23, 30
DESCRIPTION	Time period elapsed between two successive estimations of carbon stock in a carbon pool
SOURCE OF DATA	Recorded time
MEASUREMENT PROCEDURES	N/A
COMMENTS	If the two successive estimations of carbon stock in a carbon pool are carried out at different points of time in year t_2 and t_1, (e.g. in the month of April in year t_1 and in the month of September in year t_2), then a fractional value shall be assigned to T

3.5 CONSERVATIVE APPROACH AND UNCERTAINTIES

While applying this methodology, PPs shall ensure that "Guidelines on conservative choice and application of default data in estimation of the net anthropogenic GHG removals by sinks"[16] are followed for addressing uncertainty.

In choosing key parameters or making important assumptions based on information that is not specific to the project circumstances, such as in use of default data, PPs should select values that will lead to an accurate estimation of net GHG removals by sinks, taking into account uncertainties. If uncertainty is significant, PPs should choose data such that it tends to under-estimate, rather than over-estimate, net GHG removals by sinks.

[16] See http://cdm.unfccc.int/Reference/Guidclarif/ar/methAR_guid26.pdf.

4 ESTIMATES USING THE FOREST VEGETATION SIMULATOR (FVS)

Some sections of this methodology refer to the Forest Vegetation Simulator (FVS) as a tool to estimate carbon stock changes. FVS is the U.S. Forest Service's (USFS) national forest growth model. The FVS software package is free and available on the internet (http://www.fs.fed.us/fmsc/fvs/).

When following this methodology, the version of the FVS software used shall always be at least as recent as the version available at the project start date. If a model user would like to update their FVS software mid-project, this is acceptable as long as consistency is maintained; in this case both the baseline and project calculations must be done with the updated software.

Care and attention to detail must be exercised when using FVS with this methodology. To ensure the best estimates possible, Project Proponents shall follow these guidelines:

- FVS may only be used for projects located within the United States, and only using variants maintained by the FVS staff. Variants for outside the U.S. are available, but are not maintained by the USFS. As a result, USFS cannot verify the biomass and carbon calculation methods used in those variants.
- Select the appropriate geographic variant of FVS. A map and associated GIS shapefiles depicting the suggested FVS variants are available on the FVS website (http://www.fs.fed.us/fmsc/fvs/whatis/index.shtml). If an FVS variant other than the one suggested by the variant map is used, the reasoning behind this substitution must be documented.
- Use current inventory data for model projections. Inventory data older than 10 years may not be used to estimate current carbon stocks.
- Provide as much information with the input data set as possible. As an example, FVS variants often use variables such as slope, aspect, elevation, and a measure of site quality (e.g., site index, habitat type, or plant association) to estimate forest growth over time. Provide this information wherever possible to help ensure accurate predictions. The information relevant to the selected variant is described in the variant overview document available from the FVS website. It is highly recommended that site index or other measures of site quality used by the variant are included as input in FVS simulations. Also, measured growth data (e.g., large tree diameter growth and small tree height growth) can be used to calibrate the growth estimates built into each variant. Including growth sample measurements with simulations will improve model results. Tree records for species not modelled within a specific variant are mapped within FVS to a similar species. If model users change the species designation on input (and hence create their own personally designated species mapping), the reasoning behind this substitution must be documented.

- Be aware of how regeneration is being handled with the variant. Some variants have a full-regeneration model, where regeneration is predicted and added to the model over time. Other variants have a partial-regeneration model that adds in sprouts after fire or harvest, but does not automatically include any other types of regeneration. Understand what the model is doing so you can adjust or add additional regeneration as needed. In addition, the assumptions about baseline regeneration used in FVS must be evaluated through the periodic assessment of Regeneration Monitoring Areas as described in section 3.3.
- Describe which biomass calculation method was selected for the simulations. The FFE method (the default) is the preferred method as it uses more localized volume/biomass equations for each variant and uses species-specific lbs/cubic foot conversion factors. A full description can be found in the FVS Fire and Fuels Extension Guide[18]. The Jenkins' equations, a national set of equations that predict biomass based on species group and dbh, may only be used if it can be demonstrated to the validation/verification body that these are more accurate than the FFE method for the project area.
- Identical settings and model assumptions shall be used to compare project conditions or multiple projects. As an example, make sure the units selected for the carbon calculations are metric tons of carbon/hectare for all simulations. If biomass is calculated using the FFE method, then this method shall be used for all conditions and projects. Similarly, if regeneration has been adjusted, then appropriate adjustments shall be made for all conditions and projects.
- Provide the FVS keyword file (*.key), FVS main output file (*.out) as well as the input data files for review by ACR and/or the validation/verification body.

For additional information about FVS and its carbon calculations, see the Essential FVS Guide[17] and the FVS Fire and Fuels Extension Guide[18]. Variant overviews that describe each individual geographic variant are also available on the FVS website.

[17] Dixon, Gary E. comp. 2002. Essential FVS: A user's guide to the Forest Vegetation Simulator. Internal Rep. Fort Collins, CO: U. S. Department of Agriculture, Forest Service, Forest Management Service Center. 226p. (http://www.fs.fed.us/fmsc/ftp/fvs/docs/gtr/EssentialFVS.pdf)

[18] Rebain, Stephanie A. comp. 2010. The Fire and Fuels Extension to the Forest Vegetation Simulator: Updated Model Documentation. Internal Rep. Fort Collins, CO: U. S. Department of Agriculture, Forest Service, Forest Management Service Center. 396p. (http://www.fs.fed.us/fmsc/ftp/fvs/docs/gtr/FFEguide.pdf).

5 REFERENCES AND OTHER INFORMATION

All references are quoted in footnotes.

5.1 HISTORY OF THE DOCUMENT

VERSION	DATE	NATURE OF REVISION(S)
1.2	31 May 2017	An applicability condition was changed allowing projects to be implemented on wetlands (with conditions).
1.1	12 June 2013	Modification, adding Forest Vegetation Simulator (FVS) as an approved tool to estimate carbon stock changes, following approval by ACR AFOLU Technical Committee.
1.0	08 March 2011	Initial adoption under ACR, following approval by ACR AFOLU Technical Committee.
AR-ACM0001 v05.0.0	EB56, Annex 12 17 September 2010	Adoption by the CDM Executive Board of version 5.0.0 of methodology AR-ACM0001, “Afforestation and reforestation of degraded land,” on which the ACR methodology is based.

DEFINITIONS

Afforestation/ Reforestation (A/R)	Activities to increase carbon stocks by establishing, increasing and restoring vegetative cover through the planting, sowing or human-assisted natural regeneration of woody vegetation. A/R activities must target the eventual establishment of “forest” per the applicable definition. In general, the term afforestation is applied to activities to establish forest on lands that have been in another land use for some relatively long period, while reforestation is applied to activities to reestablish forest on lands that were in forest cover relatively recently. ACR does not make a specific distinction between afforestation and reforestation, since both are eligible
Baseline	Most likely management scenario in the absence of the Project
Basal Area	The area of a given section of land that is occupied by the cross-section of tree trunks and stems at the base.
Buffer Pool	ACR risk mitigation mechanism whereby the Project Proponent contributes an adequate number of ERTs to a buffer pool held by ACR to replace unforeseen losses in carbon stocks. The buffer contribution is a percentage of the project’s reported offsets, determined through a project-specific assessment of the risk of reversal. Buffer contributions may come from the project itself, or be made using ERTs of any other type and vintage.
Carbon Pool	A reservoir of carbon that has the potential to accumulate or lose carbon over time. Common forest carbon pools are aboveground biomass, belowground biomass, litter, dead wood, soil organic carbon, and wood products.
Carbon Stocks	Carbon stocks represent the measured, estimated or modeled quantity of carbon held in a particular carbon pool. Quantifying GHG emissions and removals for terrestrial carbon offset projects involves estimating, for the baseline and project scenarios, changes over time in carbon stocks in relevant pools
Clean Development Mechanism (CDM)	The CDM allows GHG emission reduction and removal projects in developing countries to earn certified emission reduction (CER) credits, each equivalent to one metric ton of CO2, which can be sold and used by industrialized countries to a meet a part of their emission reduction targets under the Kyoto Protocol. The CDM is intended to stimulate sustainable

	development and emission reductions, while giving industrialized countries flexibility in how they meet their emission reduction targets.
Crediting Period	The period of time in which the baseline is considered to be valid and project activities are eligible to generate ERTs
Crown Cover	The proportion of a stand covered by the crowns of live trees
Degraded lands	Degraded land is land that has lost some degree of its natural productivity due to human-caused processes
Ex-ante	“Before the event” or predicted response of Project activity
Ex-post	“After the event” or measured response of Project activity
Leakage	Leakage refers to a decrease in sequestration or increase in emissions outside project boundaries as a result of project implementation. Leakage may be caused by shifting of the activities of people present in the project area, or by market effects whereby emission reductions are countered by emissions created by shifts in supply of and demand for the products and services affected by the project.
Natural Regeneration	The ability of an environment, most often a forest, to regenerate itself without external intervention following a disturbance
Offset	Reduction in emissions of GHG made in order to compensate for or to offset an emission made elsewhere.
Project Proponent	An individual or entity that undertakes, develops, and/or owns a project. This may include the project investor, designer, and/or owner of the lands/facilities on which project activities are conducted. The Project Proponent and landowner/facility owner may be different entities. The Project Proponent is the ACR account holder.
Stand Density Index	A measure of the stocking of a stand of trees based on the number of trees per unit area and diameter at breast height of the tree of average basal area, also known as the quadratic mean diameter.
Stratification	A standard statistical procedure to decrease overall variability of carbon stock estimates by grouping data taken from environments with similar characteristics (e.g., vegetation type, age class, hydrology, elevation)

A.1.2 Avoided Conversion of Grasslands and Shrublands to Crop Production

American Carbon Registry
AT WINROCK INTERNATIONAL

METHODOLOGY FOR THE QUANTIFICATION, MONITORING, REPORTING AND VERIFICATION OF GREENHOUSE GAS EMISSIONS REDUCTIONS AND REMOVALS FROM

AVOIDED CONVERSION OF GRASSLANDS AND SHRUBLANDS TO CROP PRODUCTION

VERSION 2.0

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ABOUT AMERICAN CARBON REGISTRY® (ACR)

A leading carbon offset program founded in 1996 as the first private voluntary GHG registry in the world, ACR operates in the voluntary and regulated carbon markets. ACR has unparalleled experience in the development of environmentally rigorous, science-based offset methodologies as well as operational experience in the oversight of offset project verification, registration, offset issuance and retirement reporting through its online registry system.

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Ducks Unlimited

The Nature Conservancy

American Carbon Registry

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Conservation Service

ACRONYMS

AC	Avoided Conversion
ACoGS	Avoided Conversion of Grasslands and Shrublands
ACR	American Carbon Registry
AFOLU	Agriculture, Forestry and Other Land Use
APEX	Agricultural Policy Environmental eXtender Model
CO_2e	Carbon dioxide equivalent
CH_4	Methane
CDM A/R	Clean Development Mechanism Afforestation/Reforestation
CRP	Conservation Reserve Program
DAYCENT	Daily Time Step Version of the CENTURY Biogeochemical Model
d.u.	Dimensionless unit
EF	Emission Factor
EPA	Environmental Protection Agency
ERS	Economic Research Service
ERT	Emission Reduction Ton
GHG	Greenhouse Gas
IA	Identified Agent
IPCC	Intergovernmental Panel on Climate Change
LU/LC	Land Use/Land Cover
LCA	Land Conservation Agreement
LCC	Land Capability Class

MLRA	Major Land Resource Areas
NH_3	Ammonia
N_2O	Nitrous Oxide
NLCD	National Cropland Data Layer
NO_X	Nitrogen Oxides
PDA	Programmatic Development Approach
REDD	Reduced Emissions from Deforestation and Degradation
SOC	Soil Organic Carbon
SSR	Sources, Sinks and Reservoir
UA	Unidentified Agent
VVB	Validation/Verification Body

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EQUATIONS

1 BACKGROUND AND APPLICABILITY

1.1 SUMMARY DESCRIPTION OF METHODOLOGY

This methodology estimates the emissions avoided by preventing the conversion of Grasslands and Shrublands to annual crop production.[1] Conversion of Grassland and Shrubland to uses other than annual Cropland is not an eligible activity under this methodology. Conversion to orchards and vineyards is not an eligible activity under this methodology. Grassland and shrubland soils are significant reservoirs of organic carbon that will, if left uncultivated, continue to store this carbon belowground. Grassland and shrubland ecosystems may also support greater plant biomass than annual Cropland, especially belowground. In addition to the avoided cultivation and oxidation of soil organic carbon, several crop production practices with GHG implications, such as fertilizer applications, may also be avoided through the project activity. Livestock, primarily cattle, are anticipated to be common in the project scenario and their associated emissions from enteric fermentation and manure deposition are accounted.

This methodology accounts for two Avoided Conversion baseline scenarios: 1) where the conversion agent is identified and 2) where the conversion agent is unidentified. Projects that can identify the conversion agent are required to demonstrate proof of intent to convert by the identified agent. Where the specific conversion agent cannot be identified but a class of likely agents can, the Unidentified Agent baseline approach is used to determine the probability of conversion. This approach is based on historical rates of conversion of existing grasslands and shrublands within a county, in addition to the various land capability classes suitable for agriculture at the field level.

The removal of project lands from the supply of potential Cropland is expected to create leakage effects, all in the form of market leakage.[2] A default market leakage estimate is offered to account for these effects. Standardized values for leakage and baseline determination are specific to the United States.

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[1] Eligible project types may include, but are not limited to, the avoided conversion of native rangeland, and grasslands established under the Conservation Reserve Program (United States) that have been in grassland cover for a minimum of 10 years.

[2] Leakage and market leakage are defined in the ACR Standard. Leakage is a decrease in sequestration or increase in emissions outside project boundaries resulting from project implementation. Leakage may

Unless specified otherwise in this document, projects are subject to all requirements and specifications in the most current version the American Carbon Registry Standard. Definitions specific to this methodology can be found at the end of the document.

1.2 APPLICABILITY CONDITIONS

In addition to satisfying the latest ACR program requirements, project activities must satisfy the following conditions for this methodology to apply:

- All Participant Fields avoid the complete conversion[3] of Grasslands or Shrublands to annual Cropland. Conversion of Grassland and Shrubland to uses other than annual Cropland is not an eligible activity under this methodology.
- All Participant Fields in the Project Area are currently Grassland or Shrubland, have qualified as Grassland or Shrubland for at least 10 years prior to the Start Date[4], will remain as Grassland or Shrubland throughout the Project Term, and are legally able to be converted and would be converted to Cropland in the absence of the project activity.
- All Participant Fields enrolled in the Project Area must be subject to a qualified Land Conservation Agreement (LCA) entered into by the Project Participant prohibiting the conversion of the land from Grassland or Shrubland for the duration of the minimum Project Term or longer. The area bound by the LCA does not have to match the Project Area nor Participant Field enrolled; however, the entire area of the Participant Field must be included in the area covered by the LCA. The LCA must also explicitly prohibit grassland conversion to another land use—often referred to as a “sod-buster” clause—such that avoidable reversals are sufficiently precluded as long as the LCA is enforced.[5] If the easement allows for alternative land use other than grassland preservation, such as building envelopes, gravel sites, road development, etc., those areas must be delineated and removed from the eligible portion of the Participant Field. The LCA must be recorded on the deed of the property encompassing all Participant Fields to ensure transferability among ownership.

be caused by shifting of the activities present in the project area or by market effects whereby emission reductions are countered by emissions created by shifts in supply of and demand for the products and services affected by the project. See Section 6.3 for discussion of leakage as pertains to this project type.

[3] The complete removal of initial vegetation community through complete tillage, chemical treatment, fire, or combinations thereof which are followed by seeding of an annual crop.

[4] In the case of aggregated projects, Participant Fields must have qualified as Grassland or Shrubland for at least 10 years prior to the date the Project Participants agreed to enroll that field into the aggregate.

[5] ERTs will not be issued for any period of non-conformance with the LCA.

- In the case of an unidentified agent of conversion, the Project Area is located entirely in a county or counties listed in Appendix B.[6] In the case of an identified agent of conversion, written offers to lease or buy property must specify cropland as the intended/highest and best use, including reference to available water rights and infrastructure if irrigation is required; in the absence of written offers to lease or buy the property, landowner attestations or other documentation demonstrating threat to conversion must reference the highest and best use as cropland and other comparable conversion events in the region.
- Land may remain in use for livestock grazing and/or haying and be subject to prescribed burning or wildfires during the project scenario, so long as the provisions of the relevant qualified LCA are met. In the project scenario, detrimental overgrazing, overstocking, or overuse of prescribed fires leading to the progressive loss of vegetative cover shall not occur, allowing carbon pools to remain at a steady state. Supplemental management practices that increase carbon stocks in the project scenario are allowable but the resultant emissions avoided or removed are not eligible for crediting under this methodology.
- At least 50% of the project area is in Land Capability Class (LCC) I-IV and no more than 25% of the project area is LCC VII and VIII as assessed using the SSURGO non-irrigated lands database.
- When the landowner will hold title to the carbon rights, a statement of intent[7] to develop a carbon offset project is submitted to ACR no sooner than 12 months before and not longer than 12 months after the date that the qualified LCA is recorded.
- When the landowner will not hold title to the carbon rights, the date of any agreement (e.g. a carbon options agreement) transferring carbon rights from the landowner to the project developer must be enacted no sooner than 12 months before and not longer than 12 months after the date that the qualified LCA is recorded.
- The Project Area includes either one contiguous parcel, or multiple discrete parcels of land. If the Project Area consists of multiple discrete parcels, Project Proponents must demonstrate that each discrete parcel meets all applicability criteria of the methodology.
- Project Areas do not include Grasslands or Shrublands on organic soils or peatlands, nor include wetland acres within Grassland/Shrubland tracts. Additional information on how to appropriately identify and remove wetland acres and organic soils from GHG modeling and ERT calculation is provided in Section 2.1.2.
- An irrigated cropland scenario in the baseline and an irrigated project scenario are allowed. In the baseline scenario, a strong justification must be made for the likelihood of the irrigated cropland scenario that is ultimately subject to the verifier's professional judgement. The justification shall include, at a minimum, an assessment of irrigation water access—both legal and physical—to the Project Field(s) at the Project Start Date and evidence of ongoing irrigation practices on like parcels in the same county. Any biogeochemical models used for GHG

[6] Eligibility maps are updated at minimum every 5 years.

[7] Contact ACR administrator for a Statement of Intent template document or basic requirements.

modelling must have proven capabilities to account for GHG influences from specific irrigation practices.

- Where livestock are present in the project scenario, manure is not managed, stored, or dispersed in liquid form. Livestock are primarily forage fed and not managed in a confined area, e.g., feedlot. There are no restrictions on the application of synthetic or organic amendments, i.e. manure, in the baseline scenario.
- The Project Area is located in the United States.

1.3 PERIODIC REVIEWS AND REVISIONS

ACR may require revisions to this Methodology to ensure that monitoring, reporting, and verification systems adequately reflect changes to project activities. This Methodology may also be periodically updated to reflect regulatory changes, emission factor revisions, or expanded applicability criteria. Before beginning a project, the project proponent should ensure that they are using the latest version of the methodology.

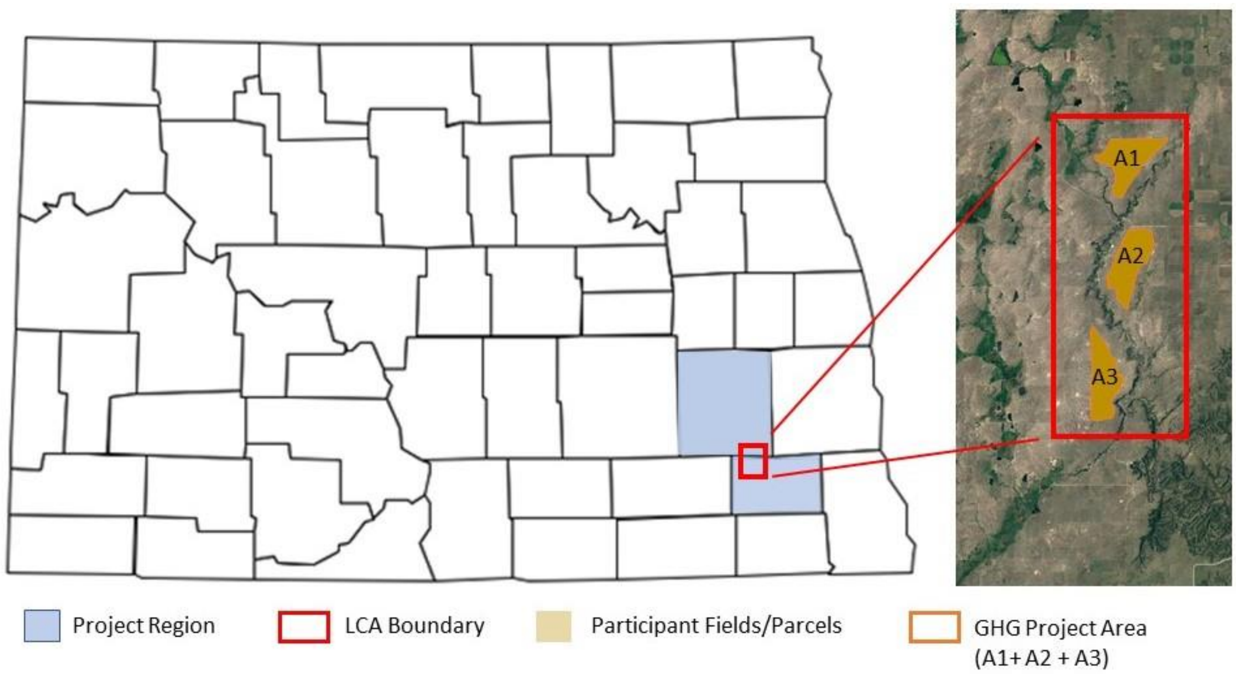
2 PROJECT BOUNDARIES

2.1 SPATIAL BOUNDARY

2.1.1 Field, Area, Region Boundary Terms

Figure 1: Spatial Boundaries

Three spatial boundaries are relevant to this methodology: Participant Fields, Project Area and Project Region.



Participant Fields are the discrete parcels where project activities are implemented, when referred to individually.

All Participant Fields must be covered in full by the qualified LCA and an agreement specifying ownership of any ERTs issued, if not specified in the qualified LCA. The GHG project area (e.g. area within Participant Field boundaries) may be smaller than but must be completely within the qualified LCA boundary.

The Project Area is the collection of Participant Fields. Other areas that may fall within relevant property boundaries but for which Grassland-Shrubland to Cropland conversion is not applicable (e.g., non-Grassland or Shrubland land cover, waterways, residences, etc.) are not included in the Project Area.

The Project Region may be an eco-region or geographic administrative unit of relatively homogenous economic conditions and governance at which baseline activities are occurring, e.g. a state, county, watershed, irrigation district, Major Land Resource Area, etc. The Project Region is the highest-level geographical boundary and is used in this methodology for demonstrating baseline conditions identification of baseline management practices and the quantification of greenhouse gas emission reductions and avoidance, i.e., to define the applicability of models and emission factors. The Project Region shall be further stratified to account for heterogeneity within the Project Region according to the procedures in Section 4 Stratification.

In situations where the Project Proponent (e.g., an aggregator or developer) is not the Project Participant (e.g., an owner of a Participant Field), the Project Proponent must demonstrate that a qualified LCA restricts the management of conversion activities (e.g. via a conservation easement) for the duration of the Project Term on each Participant Field. In situations where the Project Proponent does not take fee-title possession of the land, a conveyance of the associated GHG benefits of the avoided conversion activity from the Project Participant to the Project Proponent must demonstrate clear ownership of any ERTs generated by the project activity.

2.1.2 Recording the Project Area and Project Region

Spatially explicit data files (e.g. shapefiles for GIS) recording the following boundaries must be provided in the GHG Project Plan:

1. Project Region
2. Project Area
3. Participant Fields
4. Wetlands, building envelopes, cultivated areas, streams, roads, gravel pits or other areas not covered by a sod-buster clause and/or excluded from but within the Project boundary
5. LCA Boundary[8]
6. ERT ownership boundary (if different than 3 or 5)

[8] LCA boundary as recorded on the deed; if the LCA is not a recorded easement, adequate evidence, subject to verifier professional judgement, of due diligence in determining spatially accurate boundaries, must be provided.

See Section 7 Monitoring and Data Collection for additional details.

The Project Area is the collection of shape file polygons for all individual Participant Fields boundaries and is not necessarily contiguous.

The Project Region(s) must include the entirety of the Project Area within its (their) boundaries. The Project Region(s) may be comprised of non-contiguous areas so long as all Participant Fields are contained within a Project Region (i.e. the Project Area must be fully contained within the boundaries of the Project Region(s)) and all Participant Fields are within the qualified LCA boundary.

All required shapefiles shall be made available in the GHG Project Plan at time of validation. Wetland acreage delineation can often be subjective given the influence of yearly precipitation and associated variability. Where wetland acres are explicitly accounted in the language of the qualified LCA or otherwise legally encumbered, Project Proponents are to rely on the qualified LCA language or other legal protections for identifying total wetland acreage that is ineligible. Spatially explicit boundary shapefiles must be provided that delineate the total wetland acres in the qualified LCA. These shapefiles can then be either directly uploaded into a GHG accounting platform, or overlaid with the soils maps provided through NRCS's Web Soil Survey (http://websoilsurvey.sc.egov.usda.gov/App/HomePage.htm) as required by biogeochemical models.

If wetland acres are not explicitly identified in the qualified LCA, Project Proponents must demonstrate at the time of project validation that no portion of the project area requires exclusion due to classification as a wetland, either permanent, emergent, seasonal or otherwise. Project Proponents must demonstrate to the satisfaction of the verifier that the project area is limited to the area that would reasonably be plowed under as part of conversion i.e. roads, building envelopes, infrastructure or wet areas are excluded.[9] These boundaries remain constant for the length of the project. The shapefiles delineating wetland acres must be provided and overlaid with the boundaries of the Participant Field(s).

2.2 GHG ASSESSMENT BOUNDARY

The GHG assessment boundary delineates the sources, sinks and reservoirs (SSRs) that must be included or excluded when quantifying the net changes in emissions associated with the avoided conversion of Grassland or Shrubland to Cropland.

All SSRs that are likely to result in a significant increase in GHG emissions or decreased carbon storage in the project scenario relative to the baseline must be accounted for, for each Participant Field.

[9] Verifiers may use SSURGO or other databases to inform the presence of soils that would be too wet or otherwise unsuitable for cultivation.

Specific carbon pools and GHG sources, including carbon pools and GHG sources that cause project and leakage emissions, may be deemed de minimis and do not have to be accounted for if in aggregate the omitted decrease in carbon stocks (in carbon pools) or increase in GHG emissions (from GHG sources) amounts to less than three percent of the total ex ante estimate of GHG benefit generated by the project.

2.2.1 Carbon Pools (Reservoirs)

Table 1: Carbon Pools

CARBON POOL	INCLUDED/ EXCLUDED	JUSTIFICATION
Tree biomass (above-ground, below ground)	Excluded	Tree biomass is conservatively excluded in both the baseline and project scenario.[10]
Above-ground non-tree, woody biomass	Optional	Likely to be a source of carbon loss in the baseline scenario and it is optional to include for both the baseline and project scenario. Where Project Proponents elect to include this pool in the project scenario, it must also be included in the baseline scenario.
Above-ground non-tree, non-woody biomass	Optional	Likely to be a source of carbon loss in the baseline scenario and it is optional to include for both the baseline and project scenario. Where Project Proponents elect to include this pool in the project scenario, it must also be included in the baseline scenario.
Litter	Excluded	Not a major pool in baseline or project scenarios.
Below-ground, non-tree biomass	Optional	Likely to be a significant source of carbon loss in baseline scenario. Projects may elect to account for below-ground biomass. Where Project Propo-

[10] All references to above-ground or below-ground biomass in this methodology are in reference to grassland, shrubland or cropland vegetation that does not meet the definition of a tree according to the U.S. Forest Service https://www.nrs.fs.fed.us/fia/data-tools/state-reports/glossary/default.asp

CARBON POOL	INCLUDED/ EXCLUDED	JUSTIFICATION
		nents elect to include this pool in the project scenario, it must also be included in the baseline scenario.
Soil organic carbon	Included	Major carbon pool subject to project activity.
Dead wood	Excluded	Not a major carbon pool in the baseline or project scenario.
Wood products	Excluded	Not a major carbon pool in the baseline or project scenario.

2.2.2 GHG Sources and Sinks

Table 2: Greenhouse Gas Sources

SOURCE	GAS	INCLUDED/ EXCLUDED	JUSTIFICATION
Soil Management	CO_2	Included	Accounted for in soil organic carbon pool.
	CH_4	Excluded	Not a significant gas for this source.
	N_2O	Included	Covers direct emissions from synthetic and organic N amendment sources. Indirect emissions from synthetic and organic N amendments are excluded.[11]
Fossil Fuel Combustion	CO_2	Optional	Baseline emissions from fossil fuel are likely larger than in the project scenario and may be conservatively excluded. Where Project Proponents elect to include this pool in the project scenario, it must also be included in the baseline scenario.

[11] This methodology assumes that baseline emissions of N_2O (direct or indirect) due to N amendments are always larger than project emissions of N_2O.

SOURCE	GAS	INCLUDED/ EXCLUDED	JUSTIFICATION
	CH_4	Excluded	Not a significant gas for this source.
	N_2O	Excluded	Not a significant gas for this source.
Biomass Burning	CO_2	Excluded	Accounted for in biomass pools.
	CH_4	Excluded	Not a significant gas for this source.
	N_2O	Excluded	Not a significant gas for this source.
Livestock Emissions	CO_2	Excluded	Not a significant gas for this source.
	CH_4	Optional	When livestock are present in the baseline and/or project scenario, this is a major source of emissions and must be included.
	N_2O	Excluded	Emissions of N_2O from livestock waste are captured under Soil Management emissions.

2.3 TEMPORAL BOUNDARY

The dates and time frames for the following project events must be defined in the GHG Project Plan:

- Project Start Date for each Participant Field enrolled
- Project Crediting Period start and end dates
- Date of submittal of Project listing with ACR (date when GHG Project Plan was initially submitted) for initial Participant Fields if a PDA Project
- Date of signature of the agreement specifying ownership of ERTs (if project proponent is not participant field(s) landowner)
- Date of submittal of Statement of Intent to ACR (if project proponent is participant field(s) landowner)
- Projected dates and intervals of revaluation of baseline inputs (at minimum once every 5 years)

- Projected dates of enrollment[12] and validation for new Participant Fields included in the project, if applicable[13] and actual dates as Participant Fields are enrolled.
- Demonstration that each Participant Field was in a Grassland or Shrubland land cover at least 10 years prior to time of executing the qualified Land Conservation Agreement.

The GHG Project Plan shall also include anticipated timeline for monitoring, reporting, and/or verification activities.

2.3.1 Start Date

The earliest Project Start Date for AFOLU projects is specified in the most recent version of the ACR Standard.

The Project Start Date for this project type is the date on which the qualified LCA is recorded. The project shall be submitted for listing with ACR no more than 3 years after the date upon which the qualified LCA is recorded.[14]

2.3.2 Crediting Period

The Project Crediting Period must begin no earlier than the project start date.[15] The Project Crediting Period is the timeframe in which changes are conservatively estimated to occur in a Participant Field's terrestrial carbon pools, i.e. the time as predicted by a biogeochemical model or field measurements[16] that soil carbon loss would continue to occur in the baseline scenario of

[12] The enrollment date is the date where a landowner entered into an agreement with the Project Proponent if not the landowner or the date where a new parcel was added to an existing GHG project plan where the landowner is the Project Proponent.

[13] Projects expecting to add new Participant fields over time must follow the requirements for Programmatic Design Approach in the ACR Standard.

[14] See ACR Standard Section 6A for Project Development Process, requirements for the step Project Listing. The Statement of Intent to develop or participate in a carbon project on the part of the land owner is separate from Project Listing and is required within 12 months of the LCA being recorded. Please contact ACR Administrator for a Statement of Intent template document or requirements.

[15] The start of the first reporting period may be after the project start date such that a project may forego credit issuance for a period of time in order to delay verification provided the validation occurs within 3 years of the start date.

[16] When changes in the soil carbon pool are not modeled and a default value 20 years is used for the parameter D, the transition period between soil organic carbon equilibrium states, the crediting period is also 20 years and cannot be renewed (See Appendix A).

conversion to Cropland. The Crediting Period must be at least 5 years but no more than 40 years and cannot be renewed.

The establishment of the baseline scenario as conversion to Cropland is valid for the duration of the Project Term following a successful initial validation. Updates to the project's baseline land management scenarios shall occur at least once every five years from the project start date.[17]

2.3.3 Project Term

The Minimum Project Term refers to the required duration of crediting, monitoring and reporting of Project Activities. The minimum Project Term for AFOLU projects with a risk of reversal is defined in the latest ACR Standard.

[17] Verifications are required at the same minimum frequency (5 years) but updates to the baseline cropland management scenario not required at every verification necessarily.

3 BASELINE DETERMINATION AND ADDITIONALITY

3.1 BASELINE DETERMINATION

The baseline scenario is the conversion of Grassland or Shrubland to Cropland. Baseline determination requires: 1) demonstration of the land-use scenario of cropland in the absence of the project activity and 2) description of the avoided cropland management practices. Baseline determination should be performed in conjunction with Section 3.2 Additionality Assessment. The baseline land use scenario of conversion to cropland, once determined, is static and made ex ante, with no adjustments during the Project Term. The baseline management scenario must be updated every 5 years, as outlined below in 3.1.2.

3.1.1 Determine Baseline Land-Use Scenario

All Participant Fields must demonstrate that Cropland is the likely land use scenario in the absence of the project activity with conversion of Grassland or Shrubland to Cropland occurring via either an identified or unidentified agent.

3.1.1.1 CONVERSION VIA AN UNIDENTIFIED AGENT

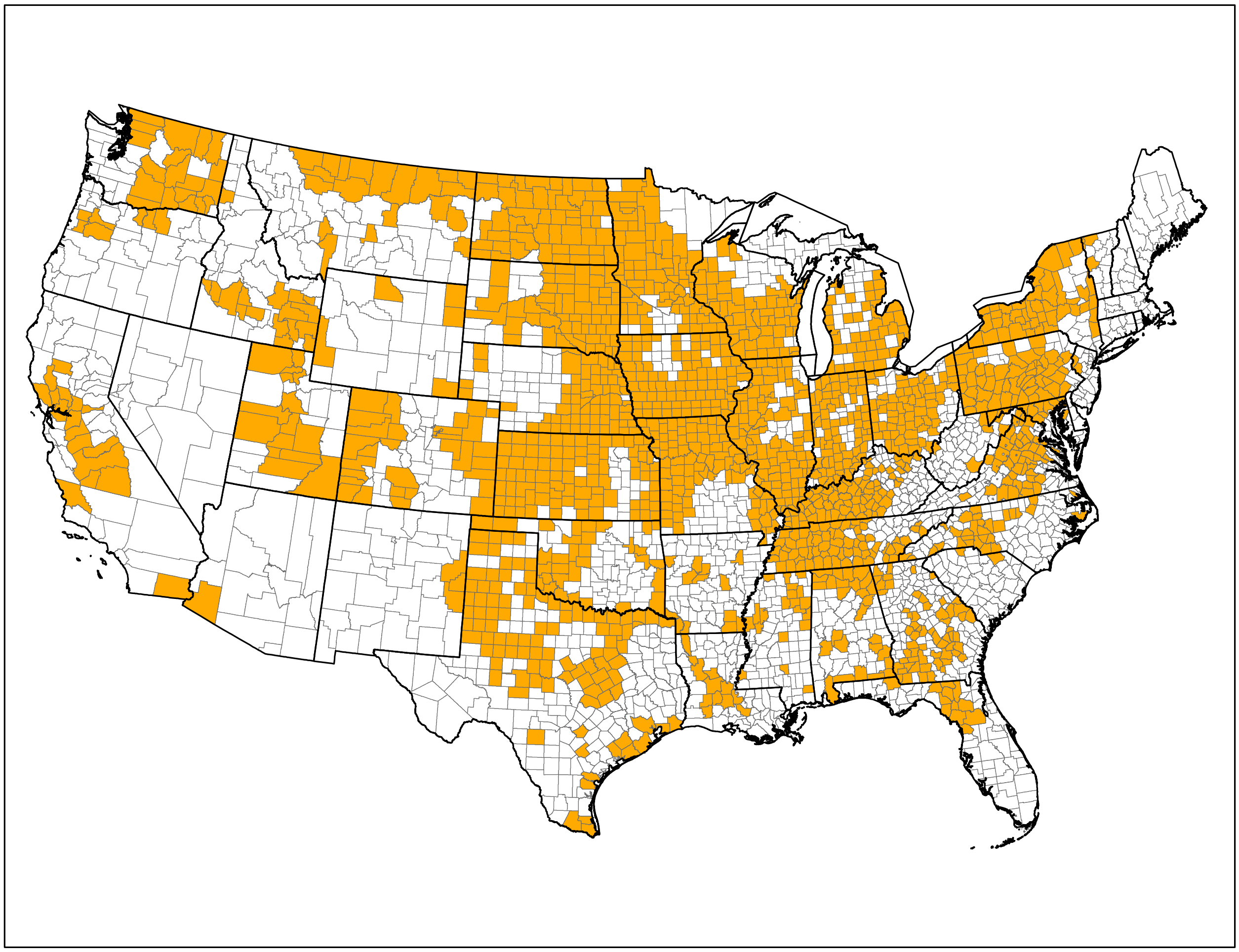
The baseline land use scenario is Cropland for all Participant Fields located in counties shown in the map below, listed in Appendix B and meeting all criteria in Section 1.2.

3.1.1.2 CONVERSION VIA AN IDENTIFIED AGENT

The baseline land use scenario is Cropland for all Participant Fields not located in counties shown in the map below and listed in Appendix B but: 1) meet all criteria in Section 1.2 and 2) are unambiguously identified in written rental or purchase offers with Cropland named as the intended use OR unambiguously identified in other documentation, subject to verifier and ACR review, including landowner affidavits, that can demonstrate a threat to conversion to cropland.

Figure 2: County Map for Unidentified Agents of Conversion, Baseline Land Use Scenario and Practice-Based Performance Standard

Project fields/parcels located in the counties highlighted in orange have a baseline scenario of cropland for unidentified agents of conversion and surpass the practice-based performance standard for demonstrating additionality. Project fields/parcels in white counties must determine the baseline land-use scenario and demonstrate additionality according to sections 3.1.1.2 and 3.2.2.2 respectively.



3.1.2 Determine Baseline Cropland Management Scenario

The baseline crop management scenario is determined ex ante and must be updated at minimum every 5 years from the project start date for the duration of the project term. This re-assessment updates the avoided crop management practices (i.e. the baseline) for the subsequent 5-year period. The baseline management scenario for the previous 5 years will not be altered. New baseline management scenarios are applied to all Participant Fields, including those previously enrolled, such that the baseline scenario for each Participant Field may change every 5 years.[18]

Required projected baseline management practices are listed below. Management practices (including as inputs to approved biogeochemical models) shall be informed from producer surveys conducted by government agricultural agencies or university extension offices[19]; the expert opinion of university extension personnel working in the region and systems of interest; personnel of a governmental agriculture agency field office (e.g., United States Department of Agriculture's Risk Management Agency, Farm Service Agency, Natural Resources Conservation Service) with jurisdiction in the Project Region; or Cropland management plans approved by a lending agency. Alternatively, a survey conducted by the Project Proponent may be used where the above sources are unavailable, unreliable or outdated, or aggregated at a scale larger than the Project Region.

The following baseline data should be defined:

- Field preparation techniques
- Tillage practices and intensity
- Typical cropping sequence (including fallow)
- Timing of planting and harvest of all crops
- Average applied N rates per identified crop
- Type of applied N and application methods employed
- Average application rates of other nutrients, or inputs, if applicable
- Irrigation practice and frequency
- Presence and type of cover crop
- Residue management practice
- Fire practice and frequency

[18] Verifications are required at the same minimum frequency (5 years) but updates to the baseline cropland management scenario not required at every verification necessarily.

[19] The smallest geographic extent for such data shall be used. For example, if fertilizer rates are available at the county level and state level, the county-level estimate shall be used.

- Other necessary inputs for modeling relevant biogeochemical processes
- Stocking rates, season dates for grazing, livestock type
- Equipment types and usage or volumes of fossil fuels by type

3.2 ADDITIONALITY ASSESSMENT

Avoided emissions from the project must be additional. Assessment of the additionality of a project will be made based on passing the tests cited below. These tests require the project proponent to demonstrate that the project activity is surplus to regulations and reduces emissions below "business-as-usual" for rates of conversion of grassland to cropland in the U.S.

- Regulatory Surplus Test (all participant fields)
- Practice Based Performance Standard (participant fields in counties in Appendix B) OR Implementation Barrier (participant fields in all other U.S. locations)

3.2.1 Regulatory Surplus Test

The project activity must meet the requirements of regulatory surplus set out in the latest ACR Standard. The project activity shall not be mandated by any law, statute or other regulatory framework. Specifically, there must not be any federal, state, or local regulations for the project region/area (pre-existing or subsequent), nor other pre-existing legally binding contracts, deed restrictions or encumbrances that require the project fields to be maintained as grassland other than the LCA that is recorded for the project (assessed at Project Start Date and upon initial verification). Furthermore, there must be no federal, state, or local regulation which would prohibit ongoing management of the project area as cropland in the baseline scenario (assessed at Project Start Date and initial verification).

Voluntary agreements that can be rescinded, such as rental contracts, are not considered legal requirements. Non-perpetual payment programs administered by government entities (e.g. Conservation Reserve Program) are not considered legal barriers to participation in a carbon offset program, given that the recordation of a new perpetual 99-year easement would disqualify the lands from continued participation in any such program. Enhancement payments administered by government entities (e.g. Environmental Quality Incentives Program or Conservation Stewardship Program) do not purport to pay for the preservation of grasslands, and thus, are considered compliant with this methodology's regulatory surplus requirements.

3.2.2 Practice-Based Performance Standard (if applicable)

3.2.2.1 UNIDENTIFIED AGENT

Participant Fields located in counties listed in Appendix B pass the Practice Based Performance Standard Test. Participant Fields which meet the eligibility criteria for this methodology can use the performance standard to demonstrate additionality without providing additional implementation barrier analysis.

An assessment of the rate at which unencumbered (available for conversion) Grassland and Shrubland acres as defined by the NCDL on a per county basis were converted to the Cropland land use type over a 10-year period, shows that the counties listed in Appendix B experience a high rate of loss of Grassland and Shrubland to Cropland.[20] Conversion of Grassland and Shrubland to Cropland is considered common practice in these areas, therefore the activity of encumbering fields within a qualified LCA in these counties is considered beyond business as usual.

3.2.2.2 IDENTIFIED AGENT

Participant Fields not located in counties listed in Appendix B may also pass the Practice Based Performance Standard Test when a specific agent of conversion has been identified. Participant Fields which meet the eligibility criteria for this methodology and can document likelihood to conversion via an identified agent and can use the performance standard to demonstrate additionality without providing additional implementation barrier analysis.

The county level analysis conducted to produce the maps in Appendix B may not reflect recent hot spots of conversion, real threats at a smaller scale than county level or where data is incorrect or lacking in the underlying databases. In instances where the Project Participants have received an offer to rent or purchase the Participant Fields for the purposes of cultivation or can

[20] Counties listed in Appendix B represent the top 50% of U.S. counties in terms of loss of available Grassland and Shrubland to Cropland. Loss rates in these counties represent areas where grassland loss in the United States is most extreme, relative to current conditions in the U.S. This calculation produced a county list of grassland conversion rates, normalized by the unique number of grassland/shrubland acres available for conversion in each county in each time step. It would be inaccurate to assume that one county is more at-risk just because more cumulative grassland acres were converted compared to another. By deriving the proportion of converted acres in relation to the grassland base acreage, the analysis avoids this potential bias. A brief description of the analysis to determine counties with high rates of conversion where Grasslands and Shrublands are most under threat can be found in Appendix B. The analysis will be updated every 5 years to reflect the current areas of highest conversion in the United States.

otherwise document such an offer, conversion of grassland and shrubland to cropland is considered common practice in this area (as it is a demonstrable threat), therefore the activity of encumbering fields within a qualified LCA is considered beyond business as usual.

Projects do not need to reassess additionality with each verification during their crediting period. However, ACR will re-assess the performance standard every 5 years.

4 STRATIFICATION

The objective of stratification is to reduce uncertainty of pool and emission estimates at the Project Area level.

When the DAYCENT model (or other approved process based biogeochemical models) are used for quantification of carbon pools, spatial heterogeneity must be accounted for in both baseline and project scenarios via stratification, for example, soil type, climate, cropping scenario and/or previous land use history. For modeling efforts, this requires parameterizing and running the model for each stratum and estimating parameter values separately for each category. The stratification approach must be included in the GHG Project Plan and is subject to verifier review during project validation.

When soil sampling is conducted in the Project Area and this area is not homogeneous, stratification may be used to improve the precision of carbon stock estimates. For estimation of baseline carbon stocks, strata may be defined by parameters that are key variables for estimating changes in baseline and project carbon stocks, for example: soil type, climate, cropping scenario and/or previous land use history.

Stratification accuracy, precision and details such as sample design and plot selection shall be determined following best practices and detailed in the GHG Project Plan. Stratification must consider the biogeochemical and/or empirical models (see Chapter 5) that will be applied for the methodology, where each stratum can be represented by a unique model parameterization. It is not necessary to use the same stratification categories for each pool or for baseline and project scenarios.

5 USE OF MODELS FOR QUANTIFICATION OF GHG EMISSIONS

Under this methodology, the following classes of models shall be used to quantify carbon pools and GHG emissions:

1. Process based biogeochemical models (e.g. DAYCENT)
2. Empirical models based on time series measurements and proxy sites

The DAYCENT model is approved for use with this methodology throughout the continental United States, excluding Alaska. Additional process based biogeochemical models may be approved by ACR[21], according to the criteria specified in the ACR Standard, Section A.6.

Empirical models may be approved on a case by case basis where available. Please contact ACR for approval of new empirical models for use with this methodology. Proposed models shall, at a minimum, meet the following criteria:

- Be published in peer-reviewed, scientific literature;
- Be empirically based;
- Be able to account for changes to soil organic matter and nutrient dynamics that occur following the conversion of Grassland or Shrubland to Cropland;
- Be able to estimate size of relevant carbon pools on an annual basis (mass of carbon/year);
- Be able to make predictions at the scale of a Stratum or Project Area, whichever is smallest;

[21] Proposed biogeochemical or empirical models will be reviewed by ACR and/or Winrock staff as well as ACR's AFOLU Technical Committee. ACR's AFOLU Technical Committee supports the objective of bringing to market high-quality AFOLU carbon offsets based on scientifically sound methodologies. The AFOLU Technical Committee will provide ACR independent advice on a range of agriculture, forestry, grassland, rangeland, wetland and other land-use topics needed for greenhouse gas (GHG) methodologies being brought to ACR and/or developed by Winrock. ACR approves new methodologies, tools and significant methodology modifications through a process of public consultation and expert peer review. The AFOLU Technical Committee will not replace that process, but rather complement it. This is a standing committee with a subset of Committee members, serving on two-year terms, consulted for specific issues that match their expertise.

- A baseline site must be identified and accessible on which one or more parameters are monitored in the baseline scenario; baseline and project site must have similar soil types, climate, and management history[22].
- Directly measure soil carbon (soil carbon loss) in baseline and project sites OR dependent variable is soil carbon (soil carbon loss) and relationship between proxy variable and emissions must be significant at $P < 0.1$ and unbiased (i.e. with minimal trend in residuals)
- Uncertainty in predicted soil carbon loss (emissions - dependent variable) is known and calculated as the root mean squared error (RMSE);
- Be validated for the Project Region to demonstrate that the model can accurately estimate each carbon pool and GHG source in the Project Region including the management systems identified in both the project and baseline scenario and regional weather and climate conditions (average annual precipitation and temperature) applicable to the Project Area. Model validation shall use peer-reviewed or other quality-controlled data (i.e. such as that collected as part of a Government soils inventory or experiment), appropriate for the Project Region. For an example see Ahlering et al. (2016) or Chamberlain et al. (2011).
- Be based on a time series experimental design that includes cropped and grassland sites and t=0 is the conversion event

Output from models should include estimates of uncertainties associated with all pools and sources. In cases where variances are not included in model outputs, additional uncertainty analyses should be performed (e.g., Monte Carlo simulations). In cases where input variances can be calculated through Monte Carlo simulations, then these shall be performed and reported as well. See Section 6.5 Uncertainty Assessment and Conservativeness.

[22] Suitability of the project and baseline sites ultimately to the discretion of the verifier and ACR validation review

6 QUANTIFICATION OF GHG EMISSIONS REDUCTIONS

6.1 QUANTIFICATION OF BASELINE GHG EMISSIONS

Baseline GHG emissions for all Participant Fields in the project area in a single year are calculated according to Equation 1. Baseline emissions for a single Participant Field are calculated according to Equation 2.

Equation 1: Baseline Emissions

$$BE_y = \sum_{p}^{P} BE_{p,y}$$

WHERE

BE_y	Baseline emissions in year y, y = 0 at project start date; $MTCO_2e$
$BE_{p,y}$	Baseline emissions from Participant Field p in year y; $MTCO_2e$
P	Total number of Participant Fields in the Project Area
p	Participant Field
y	Year

Equation 2: Baseline Emissions from Each Participant Field

$$BE_{p,y} = \left(C_{AGB,BL_{p,y-1}} - C_{AGB,BL_{p,y}} + C_{BGB,BL_{p,y-1}} - C_{BGB,BL_{p,y}} + C_{SOC,BL_{p,y-1}} - C_{SOC,BL_{p,y}}\right) + E_{N_2O,BL,_{p,y}} + E_{FERM,BL\ p,y} + E_{FF,_{p,y}}$$

WHERE

$BE_{p,y}$	Baseline emissions from Participant Field p in year y; $MTCO_2e$

$C_{AGB,BL_{p,y}}$	Carbon stock of above-ground biomass for Participant Field **p,** in year **y,** in the baseline scenario; $MTCO_2e$ (optional)
$C_{BGB,BL_{p,y}}$	Carbon stock of below-ground crop biomass for Participant Field **p,** in year **y,** in the baseline scenario; $MTCO_2e$ (optional)
$C_{SOC,BL_{p,y}}$	Carbon stock of soil organic carbon for Participant Field **p,** in year **y,** in the baseline scenario; $MTCO_2e$
$E_{N_2O,BL_{p,y}}$	N_2O emissions from Participant Field **p,** in year **y** in the baseline scenario for; $MTCO_2e$
$E_{FERM,\mathbf{BL}\ p,y}$	CH_4 emissions from livestock – enteric fermentation in Participant Field **p** in year **y** in the baseline scenario; $MTCO_2e$
$\mathbf{E_{FF},_{p,y}}$	Emissions due to the use of fossil fuels in agricultural management in field **p** and year **y** in the baseline scenario; $MTCO_2e$ (optional)

6.1.1 Accounting Baseline Emissions from Aboveground Biomass (Woody and Non-woody)

Accounting for this pool is optional. If included, woody biomass is non-tree. If included, in the baseline scenario, projects must account for remaining Grassland and Shrubland aboveground biomass as Participant Fields are converted over time, as well as the aboveground biomass in annual crops grown following conversion. The aboveground biomass in the baseline scenario shall be calculated each year according to Equation 3.

Equation 3: Baseline Above Ground Biomass

$$\mathbf{C_{AGB,BL_{p,y}} = C_{AGB_{grass},BL_{p,y}} + C_{AGB_{crop},BL_{p,y}}}$$

WHERE

$C_{AGB,BL_{p,y}}$	Carbon stock of aboveground biomass in Participant Field **p** in year **y** in the baseline scenario; $MTCO_2e$
$C_{AGB_{grass},BL_{p,y}}$	Remaining carbon stock of pre-existing aboveground biomass for Participant Field **p** in year **y** in the baseline scenario; $MTCO_2e$

$C_{AGB_{crop},BL_{p,y}}$	Carbon stock of aboveground crop biomass in Participant Field p in year y in the baseline scenario, as calculated from Section 6.1.1.2; $MTCO_2e$

6.1.1.1 CARBON STOCKS OF WOODY AND NON-WOODY, NON-CROP ABOVEGROUND BIOMASS ($C_{AGB,\ GRASS,BL,P,Y}$)

In the conversion of Grassland to Cropland, this methodology treats carbon in aboveground, biomass[23] to be primarily released to the atmosphere in the first 5 years following conversion. Projects that opt to account for the removal of aboveground biomass in conversion to Cropland will do so by first quantifying initial carbon stocks for above-ground grass and shrub biomass in the project scenario (see Section 6.2.1). That is, for projects accounting for the loss of aboveground biomass due to conversion, the initial (year y=0) carbon stocks in aboveground biomass for each Participant Field in both the project and baseline scenarios shall be equal and based upon the estimation of initial carbon storage in aboveground biomass.

The loss of carbon from aboveground biomass due to conversion shall be based upon the proportion of that field that is converted and the decomposition of biomass in the portion of the field that is converted. The most conservative scenario is that biomass would decompose as slow as litter in an untilled Cropland.[24] Project Proponents may use a less conservative estimate of 100% decomposition of aboveground biomass the year following conversion in cases where tillage is used in the baseline scenario. The aboveground biomass estimate, for biomass from the project scenario, shall be the annual peak biomass, i.e. maximum annual growth prior to grazing, harvest or other disturbance.

Equation 4: Baseline Carbon Stocks of Woody and Non-Woody, Non-Crop Above Ground Biomass Loss

$$C_{AGB_{grass},BL_{p,y}} = C_{AGB,PR_{p,y}} \times \left(1 - \sum_{t=0}^{y} FC_{p,t,y}\right) + C_{AGB,PR_{p,y}} \times \sum_{t=0}^{y}\left(FC_{p,t,y} \times e^{(-0.77 \times (y-t))}\right)$$

WHERE

[23] Because this methodology treats the loss of aboveground biomass upon conversion as lost to the atmosphere over a 5-year period, projects are permitted to account for aboveground biomass that is lost upon conversion to Cropland. However, project may not include aboveground Tree biomass in this calculation as the decay period is much longer. Tree biomass removed from the Participant Field during conversion in the baseline scenario may be expected to decay over several years and/or some portion could remain intact over long periods in harvested wood products. This methodology conservatively excludes accounting for the loss of aboveground Tree biomass in the baseline scenario.

[24] Most fields are prepared for conversion to Cropland by destroying existing aboveground biomass through herbicide application and plowing, although it is possible to direct seed into Grassland.

$C_{AGB_{grass},BL_{p,y}}$	Carbon stock of aboveground woody and non-woody biomass from Participant Field p in year y in the baseline scenario; MT CO_2.
$C_{AGB,PR_{p,y}}$	Carbon stock of aboveground non-woody biomass for Participant Field p, in the project scenario, as determined from Section 6.2.1; $MTCO_2e$
$FC_{p,t,y}$	The proportion of Participant Field p that is converted to Cropland in year t, time of conversion, in year y of the baseline scenario. If the entire field will be converted in year 1, $FC_{p,t,y}$ =1, d.u.
$e^{(-0.77 \times (y-t))}$	Decay rate of aboveground biomass following conversion. Note that because conversion often occurs over multiple years, and decay is a nonlinear function, it is necessary to track carbon loss from a given year's conversion event. The decay rate (0.77) is based on leaf decomposition in no-till Cropland (Kochsiek et al. 2009)
t	Time since conversion of Grassland to Cropland in the baseline scenario, maximum value of 40 years

6.1.1.2 CARBON STOCKS OF ABOVEGROUND CROP BIOMASS ($C_{AGB,CROP,BL,P,Y}$)

In the baseline scenario, the aboveground biomass each year is assumed equal to biomass losses from harvest and mortality in that same year. There is no carryover of aboveground crop biomass between years. There is no net accumulation of aboveground biomass stocks once areas have been converted for the duration of the Project Crediting Period (IPCC GL AFOLU 2006, Ch. 5, 5.2.1.1). After 100% conversion for a Participant Field, $C_{AGB_{crop},BL_{p,y}}$ will remain static, except in rotational cropping systems where aboveground biomass values will conform to each crop year.

$C_{AGB_{crop},BL_{b,y}}$ can be estimated by either:

- Approved models (see Section 5)[25]
- Field measurements for crop or forage productivity and Project Region published in peer reviewed literature
- Agricultural statistics for crop or forage productivity and Project Region, including State Agricultural Extension Offices

[25] Where process models require specific crops in a given year, crop selection and assignment to years shall not be done in a manner that would underestimate $C_{AGB_{crop},BL_{b,y}}$.

- Values for the annualized average dry matter ($DMBL,p,y$) and carbon fraction (CFb) for each crop type (Equation 6). Values for $DMBL,p,y$ can be obtained from fixed ratio of crop yield to plant biomass, the Harvest Index ratio, available from peer reviewed literature, or government or University extension for crop and region of interest. A default harvest index of 0.50 can be used for maize (Ciampitti and Vyn 2012), of 0.46 for soybean (Johnson et al. 2006), and 0.45 for wheat (Johson et al. 2006). 5-year average crop yields must be used, and yield data obtained from government or extension crop yield reports for the smallest available administrative unit containing the Participant Field, e.g., county.

Carbon stocks in aboveground crop biomass in the baseline scenario should be calculated for each Participant Field in the Project Area, each year according to Equations 5 and 6.

Equation 5: Baseline Above Ground Crop Biomass

$$\mathbf{C_{AGB_{crop},BL_{p,y}} = \sum_{b}^{B} C_{AGB_{crop},BL_{b,y}}}$$

WHERE

$C_{AGB_{crop},BL_{p,y}}$	Carbon stock of aboveground crop biomass for Participant Field p in the baseline scenario in year y; $MTCO_2e$
$C_{AGB_{crop},BL_{b,y}}$	Carbon stock of aboveground crop biomass in the baseline for crop type b in year y; $MTCO_2e$
B	Total number of crop types

Equation 6: Baseline Above Ground Crop Biomass for Crop Type b

$$\mathbf{C_{AGB_{crop},BL_{b,y}} = DM_{BL,b,y} \times CF_b \times \frac{44}{12} \times A_b}$$

WHERE

$C_{AGB_{crop},BL_{b,y}}$	Baseline above ground crop biomass for crop type b
$DM_{BL,b,y}$	Annualized average dry matter in the baseline for crop type b in year y; MT dry matter per ha
CF_b	Carbon fraction of dry matter for biomass type b; MT-C (MT dry matter)$^{-1}$

A_b	Area of crop type b; hectares
$\frac{44}{12}$	Ratio of molar mass of CO_2 to C

6.1.2 Accounting Baseline Emissions from Belowground Biomass

Accounting for this pool is optional. If included, woody biomass is non-tree (i.e. shrubs). The conversion of Grassland to Cropland is expected to result in the removal or rapid decomposition of belowground biomass.

$C_{BGB,BL_{p,y}}$ can be estimated by either:

- Approved models (see Section 5)[26]
- $C_{AGB,BL_{p,y}}$ (Equation 3) and appropriate root-to-shoot ratios for crop and woody and non-woody components

Below-ground biomass carbon stocks are assumed to decompose at a rate specified in Equation 8 upon conversion to Cropland in the baseline scenario.

Equation 7: Baseline Belowground Biomass

Carbon stocks in belowground biomass in the baseline shall be calculated for each Participant Field in the Project Area according to Equation 7.

$$C_{BGB,BL_{p,y}} = C_{BGB_{grass},BL_{p,y}} + C_{BGB_{crop},BL_{p,y}}$$

WHERE

$C_{BGB,BL_{p,y}}$	Carbon stock of belowground biomass in Participant Field p in year y in the baseline scenario; $MTCO_2e$
$C_{BGB_{grass},BL_{p,y}}$	Carbon stock of woody and non-woody belowground biomass for Participant Field p in year y in the baseline scenario; $MTCO_2e$

[26] Where process models require specific crops in a given year, crop selection and assignment to years shall not be done in a manner that would underestimate $C_{BGB,BL_{p,y}}$.

$C_{BGB_{crop},BL_{p,y}}$	Carbon stock of belowground crop biomass in Participant Field p in year y in the baseline scenario; $MTCO_2e$

6.1.2.1 ACCOUNTING CARBON STOCKS OF WOODY AND NON-WOODY, NON-CROP BELOWGROUND BIOMASS ($C_{BGB,GRASS,P,Y}$)

Projects that opt to account for the decomposition or removal of belowground biomass in conversion to Cropland will do so by first quantifying initial carbon stocks for belowground woody and non-woody biomass in the project scenario (see Section 6.2.2 Below-Ground Biomass). That is, for projects accounting for the loss of belowground biomass due to conversion, the initial (year y=0) carbon stocks in belowground biomass for each Participant Field in both the project and baseline scenarios shall be equal and based upon the estimation of initial carbon storage in belowground biomass.

The loss of carbon from belowground biomass due to conversion shall be based upon the proportion of that field that has been converted ($FC_{p,t,y}$) and the decomposition of biomass in the portion of the field that was converted. The decomposition rate is specified in Equation 8.

Equation 8: Baseline Pre-existing Belowground Grass Biomass

$$C_{BGB_{grass},BL_{p,y}} = C_{BGB,PR_{p,y}} \times \left(1 - \sum_{t=0}^{y} FC_{p,t,y}\right) + C_{BGB,PR_{p,y}} \times \sum_{t=0}^{y} FC_{p,t,y} \times e^{(-1.41 \times (y-t))}$$

WHERE

$C_{BGB_{grass},BL_{p,y}}$	Carbon stock of belowground woody and non-woody biomass from Participant Field p in year y in the baseline scenario; $MTCO_2e$
$C_{BGB,PR_{p,y}}$	Carbon stock of belowground biomass for Participant Field p, in year y, in the project scenario, as determined from Section 6.2.2; $MTCO_2e$
$FC_{p,t,y}$	The cumulative proportion of Participant Field p that has been converted to Cropland in year t, time of conversion, as of year y in the baseline scenario. If the entire field will be converted in year 1, $FC_{p,t,y}$ =1, d.u.
$e^{(-1.41 \times (y-t))}$	The decay function for belowground biomass following conversion. Note that because conversion often occurs over multiple years, and decay is a nonlinear function. It is necessary to track carbon loss from a given year's conversion event, and then sum the loss from all years, as shown in Equation 8. The decay rate (1.41) is based on average grass root decomposition from 46 studies (Silver and Miya 2001). For woody biomass, a decay rate of 0.44

	should be used for broadleaved species and a decay rate of 0.30 should be used for conifer species (Silver and Miya 2001)[27]
t	Time since conversion of Grassland to Cropland in the baseline scenario, maximum value of 40 years

6.1.2.2 ACCOUNTING CARBON STOCKS OF BELOWGROUND CROP BIOMASS

$C_{BGB_{crop},BL_{b,y}}$ can be estimated by:

- Approved models (see Section 5)[28]
- Field measurements for crop or forage productivity and Project Region published in peer reviewed literature
- Agricultural statistics for crop or forage productivity and Project Region, including State Agricultural Extension Offices
- $C_{AGB_{crop},BL_{b,y}}$ and suitable root-to-shoot ratio for crop and region (Equation 9). For maize a default value of 0.07 should be used.[29]

If using a root-to-shoot ratio, carbon stocks in belowground crop biomass in the baseline scenario should be calculated for each Participant Field in the Project Area, each year, and for each crop according to Equation 9.

Equation 9: Baseline Belowground Crop Biomass Using Root to Shoot

$$C_{BGB_{crop},BL_{p,y}} = \sum_{b}^{B} R_b \times C_{AGB_{crop},BL_{b,y}}$$

[27] Project Proponents may replace the default decomposition rate with a site-specific value based on peer reviewed literature.

[28] Where process models require specific crops in a given year, crop selection and assignment to years shall not be done in a manner that would underestimate $C_{BGB_{crop},BL_{b,y}}$.

[29] This is based on a comprehensive analysis of root-to-shoot ratios in maize (Amos and Walters 2006). The review of root-to-shoot ratio in maize provides a value based on an analysis that does not include grain or cobs in its measure of shoot; our default value represents a modified value that can be used to calculate root biomass based on total aboveground biomass, including grain and cobs (Amos and Walters 2006).

WHERE

$C_{BGB_{crop},BL_{p,y}}$	Carbon stock of belowground crop biomass for Participant Field $\mathbf{p}$ in the baseline scenario in year $\mathbf{y}$; $MTCO_2e$
R_b	Root carbon-to-shoot carbon ratio of (crop) biomass type $\mathbf{b}$; d.u.
$C_{AGB_{crop},BL_{b,y}}$	Carbon stock of aboveground crop biomass of crop type $\mathbf{b}$ and year $\mathbf{y}$ of the baseline scenario, as calculated in 6.1.1; $MTCO_2e$
B	Total number of crop types

6.1.3 Accounting Baseline Emissions from Soil Organic Carbon

Accounting for this pool is required. The soil carbon pool is expected to be the primary source of emissions for the project activity, as soil carbon accounts for approximately 90% of ecosystem carbon in Grassland and rangeland systems (Schuman et al. 2001).

$C_{SOC,BL_{p,y}}$ can be estimated by:

- Approved models (see Section 5).[30] This method assumes emissions from SOC following conversion proceed according to the best fit decay curve to the model SOC and for the time up until when SOC levels in the model are changing by no more than ± 3%, not to exceed 40 years.
- Direct measurement of SOC according to requirements in ISO 10381-2:2003 Soil quality – sampling – Part 2: Guidance on sampling techniques.[31] This method assumes the emissions from SOC following conversion proceed linearly for 20 years (i.e., $\mathbf{D}$ = 20), at which point a new equilibrium level of SOC is reached in the converted state. A linear EF function may be used per the IPCC GL AFOLU 2006 (adapted from Eq. 2.25, Ch2, p 2.30).[32,33]

[30] Where process models require specific crops in a given year, crop selection and assignment to years shall not be done in a manner that would underestimate $C_{BGB_{crop},BL_{b,y}}$.

[31] Please see Section B.1.1 Stratification.

[32] http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/4_Volume4/V4_02_Ch2_Generic.pdf

[33] Determination of the equilibrium SOC value resulting after a linear decay of 20 years requires the selection of an appropriate proxy site or chronosequence study. Site similarity or appropriateness must be

- Direct measurement of SOC according to requirements in ACR Tool for Estimation of Stocks in Carbon Pools and Emissions from Emission Sources.[34] This method assumes the emissions from SOC following conversion proceed linearly for 20 years (i.e., D = 20), at which point a new equilibrium level of SOC is reached in the converted state. A linear EF function may be used per the IPCC GL AFOLU 2006 (adapted from Eq. 2.25, Ch2, p 2.30).[35]

Whatever approach is deployed, estimates should be available to the affected depth at which SOC changes are expected to occur in response to baseline activities.[36] The affected depth chosen for sampling or modeling shall be justified to the validator using peer-reviewed scientific data and/or professional expert opinion. Further, direct sampling shall separate and exclude visible root biomass from SOC estimates. If models are utilized, they shall similarly be calibrated with samples that have excluded visible root biomass.

Equation 10: Total Soil Organic Carbon in the Baseline Scenario

Through one or a combination of the above approaches, total soil organic carbon stocks in the baseline scenario for each Participant Field in the Project Area shall be calculated according to Equation 10.

$$\mathbf{C_{SOC,BL_{p,y}} = \sum_{i}^{p,i} C_{SOC_{i,y=0}} \times A_{p,i} \times (1 - EF_{t,y}) \times FC_{p,y}}$$

WHERE

$C_{SOC,BL_{p,y}}$	Carbon stock of soil organic carbon for Participant Field $\mathbf{p}$ in the baseline scenario in year $\mathbf{y}$; $MTCO_2e$
$C_{SOC_{i,y=0}}$	Total initial (year $\mathbf{y}$=0) soil organic carbon stock for soil stratum $\mathbf{i}$, fixed for project duration; $MTCO_2e\ (ha)^{-1}$
$A_{p,i}$	Area of participant field $\mathbf{p}$ in soil strata $\mathbf{i}$; hectares
$EF_{t,y}$	Emission factor for the fraction of soil organic carbon pool remaining $\mathbf{t}$ years since conversion to Cropland in year $\mathbf{y}$; d.u.

demonstrated satisfactorily at the time of validation or a literature study used which meets the standards of best practice for soil chronosequence studies by the USGS e.g. https://pubs.usgs.gov/bul/1648/report.pdf.

[34] Please see Section B.1.1 Stratification.

[35] http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/4_Volume4/V4_02_Ch2_Generic.pdf

[36] Recent syntheses commonly find losses of soil carbon down to 1 meter (Sanderman et al. 2017).

$FC_{p,y}$	Proportion of Participant Field p that has been converted to Cropland in the baseline scenario for year y. If the entire field will be converted in year 1, $FC_{p,y}$ =1, d.u.
t	Time since conversion of Grassland to Cropland in the baseline scenario, maximum value of 40; years

When direct measurement approaches are used to estimate $C_{SOC,BL_{p,y}}$, $EF_{t,y}$ for each soil organic carbon stratum may be determined by:

- Equation 11
- A peer-reviewed study of soils and a region similar to the Project Area or Project Region that examines long-term changes in soil carbon, with samples from sites that have a minimum of 20 years since conversion to cropland.
- An empirical result from field measurements at sites that have and have not been converted to Cropland but are otherwise materially similar to each other and to the Project Area (e.g. in soil type and climate), provided that soil samples are collected from the relevant soil layers that would be affected by the conversion process and baseline activity. A sample-based emission factor shall not be projected for a period of time longer than the Cropland sample sites have been converted to Cropland, and at a minimum shall be measured following the same management treatments for duration of 5 years. Empirical data on soil carbon emissions shall be adjusted for uncertainty as described in Section 5.2.3.5 of IPCC GL AFOLU 2006.
- Approved process based biogeochemical models (see Section 5), e.g., DAYCENT.

Equation 11: Emission Factor for Decay Rate of SOC Following Conversion

$$EF_{t,y} = \frac{1 - (FSOC_{LU} \times FSOC_{MG} \times FSOC_{IN})}{D} \times t$$

WHERE

$EF_{t,y}$	Emission factor describing the fraction of soil organic carbon pool remaining t years since conversion to Cropland in year y; d.u.
$FSOC_{LU}$	Fraction of soil organic carbon pool remaining after transition period, accounting for land use factors; d.u.
$FSOC_{MG}$	Fraction of soil organic carbon pool remaining after transition period, accounting for management factors; d.u.

$FSOC_{IN}$	Fraction of soil organic carbon pool remaining after transition period, accounting for input of organic matter; d.u.
D	Transition period for soil organic carbon, time period for transition between equilibrium SOC values, default value of 20; years
t	Time since conversion of Grassland to Cropland in the baseline scenario, maximum value of 20; years

6.1.4 Accounting Baseline Emissions from Soil N_2O

Accounting for this pool is required. Direct and indirect soil N_2O emissions in the baseline scenario result from nitrogen fertilizer application, both synthetic and organic, as well as the presence of N-fixing plant species such as legumes. Quantification of indirect N_2O emissions from nitrogen fertilizer application is highly uncertain. GHG benefits from this pool cannot be assured to be real and are therefore conservatively excluded from both the baseline and project scenario.[37]

$E_{BL,N_2O_{p,y}}$ may be determined by:

- Approved models (see Section 5).[38]
- Equations 12, 13 and 14.[39]

Equation 12: Baseline N_2O Emissions

Baseline emissions of N_2O from the application of nitrogen fertilizer can be calculated for each Participant Field in the Project Area according to Equation 12.

$$E_{BL,N_2O_{p,y}} = E_{BL,N_2O,direct_{p,y}} = \left(F_{BL,SN_{p,y}} + F_{BL,ON_{p,y}}\right) \times EF_N \times \frac{44}{28} \times GWP_{N_2O}$$

WHERE

[37] Nitrogen application is assumed to be higher in the baseline scenario, crop cultivation, relative to the project scenario, grassland with or without grazing.

[38] Where process models require specific crops in a given year, crop selection and assignment to years shall not be done in a manner that would underestimate $C_{BGB_{crop},BL_{b,y}}$.

[39] CDM A/R Methodological Tool, Estimation of direct nitrous oxide emission from nitrogen fertilization. https://cdm.unfccc.int/methodologies/ARmethodologies/tools/ar-am-tool-07-v1.pdf

$E_{BL,N_2O_{p,y}}$	Total N_2O emissions from Participant Field **p** in year **y**; $MTCO_2e$
$E_{BL,N_2O,direct_{p,y}}$	Direct N_2O emissions from the addition of **N** to Participant Field **p** in the baseline scenario for year **y**; $MTCO_2e$
$F_{BL,SN_{p,y}}$	Mass of synthetic fertilizer nitrogen applied to Participant Field **p** in the baseline scenario in year **y** adjusted for volatilization as NH_3 and NO_X; (See Section 3.1.2. Baseline Cropland Management Scenario); MT N
$F_{BL,ON_{p,y}}$	Mass of organic **N** amendments applied to Participant Field **p** in the baseline scenario in year **y** adjusted for volatilization as NH_3 and NO_X; See Section 3.1.2. Baseline Cropland Management Scenario); MT N
EF_N	Emission Factor for emission from **N** inputs; MT N_2O-N (MT N input)$^{-1}$. A default emission factor of 0.0254 (2.54%) of applied synthetic fertilizer N and 0.02 (2%) of applied organic fertilizer **N** can be assumed to be emitted (Davidson 2009).
$\frac{44}{28}$	Ratio of molecular weights of N_2O to **N**; MT N_2O (MT N)$^{-1}$
GWP_{N_2O}	Global Warming Potential for N_2O[40]

Equation 13: Baseline Mass of Synthetic Fertilizer Nitrogen

$$\mathbf{F_{BL,SN_{p,y}}} = \sum_{j}^{J} \mathbf{M_{BL,SN_{p,j,y}}} \times \mathbf{N_{BL,SN_j}} \times (\mathbf{1} - \mathbf{Frac_{SN}})$$

WHERE

$F_{BL,SN_{p,y}}$	Mass of synthetic fertilizer nitrogen applied to Participant Field **p** in the baseline scenario in year **y** adjusted for volatilization as NH_3 and NO_X; (See Section 3.1.2. Baseline Cropland Management Scenario); MT N
$M_{BL,SN_{p,j,y}}$	Mass of synthetic fertilizer type **j** applied to Participant Field **p** in year **y**; (See Section 3.1.2. Baseline Cropland Management Scenario); MT fertilizer

[40] Project proponents shall refer to the ACR Program Standard for the approved IPCC GWP for nitrous oxide value, which will be updated periodically as new information becomes available.

N_{BL,SN_j}	Nitrogen content of synthetic fertilizer type j; MT N (MT input)$^{-1}$
$Frac_{SN}$	Fraction of synthetic fertilizer nitrogen that volatilizes as NH_3 and NO_X;
J	Total number of synthetic N inputs of type j

Equation 14: Baseline Mass of Organic Fertilizer Nitrogen

$$F_{BL,ON_{p,y}} = \sum_{k}^{K} M_{BL,ON_{p,k,y}} \times N_{BL,ON_k} \times (1 - Frac_{ON})$$

WHERE

$F_{BL,ON_{p,y}}$	Mass of organic N amendments applied to Participant Field p in the baseline scenario in year y adjusted for volatilization as NH_3 and NO_X; (See Section 3.1.2. Baseline Cropland Management Scenario); MT N
$M_{BL,ON_{p,k,y}}$	Mass of organic N amendment type k applied to Participant Field p in year y; (See Section 3.1.2. Baseline Cropland Management Scenario); MT fertilizer
N_{BL,ON_k}	Nitrogen content of organic N amendment type k; MT-N (MT inputs)$^{-1}$
$Frac_{ON}$	Fraction of organic amendment nitrogen that volatilizes as NH_3 and NO_X;
K	Total number of organic N amendments types

6.1.5 Accounting Baseline Emissions from Enteric Fermentation

Livestock, such as cattle, bison and sheep, produce CH_4 due to enteric fermentation in their rumen. Enteric fermentation emissions vary by species, breed, animal size, feed, environment and management systems (Ominski et al. 2007). Estimates of enteric fermentation can also vary widely depending on the level of specificity input data and use of defaults (Ominski et al. 2007). It is therefore encouraged that Project Proponents utilize the most representative input data where possible. Further, calves less than 6 months in age are assumed to have zero CH_4 emissions as their diet will be primarily milk (US EPA 2013).

Accounting for GHG emissions from livestock enteric fermentation is required when livestock would be present in the baseline scenario. In some areas, it is common practice for livestock to graze cultivated fields in the winter or to graze stover following harvest. It must be shown at time of validation that:1) winter grazing is common practice in the region as part of the baseline crop management scenario, per the requirements in section 3.1.2, and 2) winter grazing is feasible and likely at the specific project location because cattle are already present or have been present in the project area[41] or LCA area.

Estimates of enteric CH_4 emissions are restricted to rangeland/pasture manure systems where manure is left unmanaged once deposited by livestock per the Applicability Conditions in Section 1.2. It is recognized that in Grassland ecosystems, the net contribution of livestock in the system may be net GHG sequestration (Liebig et al. 2010). Any stimulation to vegetation growth from soil nutrient amendments, grazing and/or natural manure management, present from pre-project conditions/practices, are assumed to be captured through the model parameterization of soil and biomass carbon pools in the project scenario. Any net sequestration benefits from these activities in the project scenario are conservatively excluded from this methodology but could be eligible for ERTs under a separate but complimentary Grazing Land and Livestock Management methodology. Manure deposited by livestock present in the project scenario shall be accounted for in Soil Nitrogen Emissions, Section 6.1.4 Soil Nitrogen Emissions. Baseline emissions from livestock due to enteric fermentation shall be calculated for each Participant Field in the Project Area according to Equation 15 and 16.

Equation 15: Baseline Enteric Fermentation

$$\mathbf{E_{Ferm,p,y} = \sum_{l}^{L} P_{p,l} \times EF_l \times GD_{p,l,y} \times GWP_{CH_4} \div 1,000}$$

WHERE

$E_{Ferm,p,y}$	CH_4 emission from enteric fermentation due to livestock on Participant Field p in year y; $MTCO_2e$
L	Total number of livestock types in project scenario
$P_{p,l}$	Population of livestock type l on Participant Field p; head
$GD_{p,l,y}$	Grazing days per livestock type l on Participant Field p in year y; grazing days

[41] These emissions are conservatively excluded in the baseline scenario if the project scenario does not also include grazing. These emissions are conservatively excluded if it cannot be demonstrated that grazing was already occurring within the project boundary or by the land manager. These emissions are conservatively excluded if it cannot be demonstrated that grazing is both feasible and likely for the project area in addition to common practice in the region.

EF_l	Enteric CH_4 emission factor for livestock type l; $kgCH_4$ (head^{-1}) (grazing day^{-1})
GWP_{CH4}	Global warming potential for CH_4 (See ACR Standard)
1,000	Conversion kg to MT

Equation 16: Enteric Emission Factor per Head of Livestock

$$\mathbf{EF_l} = \frac{\mathbf{GE} \times \left(\frac{\mathbf{Y_m}}{\mathbf{100}}\right)}{\mathbf{55.65}}$$

WHERE

EF_l	Enteric methane emission factor per head of livestock
GE	Gross energy intake MJ head^{-1} day^{-1}
Y_m	Methane conversion factor, per cent of gross energy in feed converted to methane
55.65	Energy content of methane; MJ/kg CH_4

6.1.6 Accounting Baseline Emissions from Fossil Fuels

Accounting for GHG emissions from fossil fuels is optional. The combustion of fossil fuels used in farm machinery, and potentially construction equipment, to assist with the conversion and ongoing crop management process produces emissions that may optionally be accounted for with Equation 17 and included in Equation 2.

Equation 17: Baseline Fossil Fuel Emissions

Projects that elect to account for fossil fuel emissions in the baseline scenario shall be calculated according to Equation 17.

$$E_{BL,FFp,y} = \sum_{v}^{V}\sum_{f}^{F}\left(FF_{BL_{p,v,f,y}} \times EF_{f,y}\right)$$

WHERE

$E_{BL,FFp,y}$	Emissions due to the use of fossil fuels in agricultural management in the baseline scenario on Participant Field p in year y; $MTCO_2e$
$FF_{BL_{p,v,f,y}}$	Volume of fossil fuel consumed in the baseline scenario on Participant Field p in vehicle/equipment type v with fuel type j during year y; (See Section 3.1.2. Baseline Cropland Management Scenario); liters
EF_f	Emission factor for the type of fossil fuel combusted in vehicle or equipment, j. (See U.S. Energy Information Agency, EIA)[42]
v	Type of vehicle/equipment
V	Total number of types of vehicle/equipment used in the project activity
f	Type of fossil fuel
F	Total number of fuel types

6.2 QUANTIFICATION OF PROJECT GHG EMISSIONS

The greatest net GHG benefit from the project activity is anticipated to be the avoided release of SOC. This methodology conservatively assumes that avoided conversion results in the maintenance (without increase) of carbon stocks in the pools of soil organic carbon, and above-ground and below-ground biomass remain at steady state throughout the project scenario. That is, for

[42] https://www.eia.gov/environment/emissions/co2_vol_mass.php

each included pool, projects must estimate initial carbon stocks and are only allowed to generate credits based on avoided losses from these stocks (i.e., assuming the change in these stocks is on average, zero), rather than accounting for activities that may increase these stocks.

Project GHG emissions for all Participant Fields in the project area in a single year are calculated according to Equation 18. Project GHG emissions for a single Participant Field are calculated according to Equation 19.

Equation 18: Total Project Emissions

$$PE_y = \sum_{p}^{P} PE_{p,y}$$

WHERE

PE_y	Total project emissions in year y; $MTCO_2e$
$PE_{p,y}$	Total project emissions for Participant Field p in year y; $MTCO_2e$
P	Total Project Participant Fields

Equation 19: Project Emissions

$$PE_{p,y} = C_{AGB,PR_{p,y-1}} - C_{AGB,PR_{p,y}} + C_{BGB,PR_{p,y-1}} - C_{BGB,PR_{p,y}} + E_{PR,N_2O_{p,y}} + E_{FERM_{p,y}} + E_{FF,PRy,p}$$

WHERE

$PE_{p,y}$	Project emissions per participating field **p** in year y
$C_{AGB,PR_{p,y}}$	Carbon stock of above-ground crop biomass for Participant Field p in the project scenario in year y; $MTCO_2e$ (optional)
$C_{BGB,PR_{p,y}}$	Carbon stock of below-ground crop biomass for Participant Field p in the project scenario in year y; $MTCO_2e$ (optional)
$E_{PR,N_2O_{p,y}}$	Emissions due to the use of fossil fuels in agricultural management in the project scenario on Participant Field p in year y; $MTCO_2e$
$E_{FERM,p,y}$	Project emissions from livestock – enteric fermentation in Participant Field p in year y; $MTCO_2e$

$E_{FF,PRy,p}$	Emissions due to the use of fossil fuels in project management, fermentation in Participant Field p in year y; $MTCO_2e$ (optional)

6.2.1 Accounting Project Emissions from Aboveground Biomass (Woody and Non-woody)

This pool is optional. If included, woody biomass is non-tree. If included, projects must account for these emissions by determining initial above ground carbon stocks for each biomass type using one of the following methods:

- Models meeting the criteria in Section 5 Use of Models for GHG Estimation.[43]
- Direct field measurements of $C_{AGB_{b,y=0}}$ or $DM_{b,y=0}$ and CF_b (Equation 21) for each biomass type, b, in a year where growing season precipitation is within 30% of average annual growing season precipitation or averaged over three years.[44]
- Remote sensing of $C_{AGB_{b,y=0}}$ or $DM_{b,y=0}$ and CF_b (Equation 21) for each biomass type, b, in a year where growing season precipitation is within 30% of average annual growing season precipitation or averaged over three years. Remote sensing data should be calibrated to the Project Area with field samples.[45]
- Data as available from government agency or University extension office for $DM_{b,y=0}$ and CF_b

This methodology assumes all aboveground biomass from these pools is lost following conversion to Cropland. Typical aboveground biomass may include grasses, leguminous and non-leguminous forbs, shrubs and trees. Above-ground biomass is highly variable in rangeland systems, both geographically and temporally, and is highly dependent upon precipitation. A conservative estimate of peak annual above-ground biomass (excluding trees) shall therefore be assumed to remain at a steady state for the duration of the Project Crediting Period.

Equation 20: Project Aboveground Biomass

$$C_{AGB,PR_{p,y}} = \sum_{b}^{B} C_{AGB_{b,y=0}}$$

[43] Where process models require specific crops in a given year, crop selection and assignment to years shall not be done in a manner that would underestimate $C_{BGB_{crop},BL_{b,y}}$.

[44] Conducted for project or available in peer reviewed literature.

[45] Conducted for project or available in peer reviewed literature.

WHERE

$C_{AGB,PR_{p,y}}$	Carbon stock of above-ground biomass for Participant Field p in the project scenario in year y
$C_{AGB_{b,y=0}}$	Initial (year y=0) carbon stock of above-ground biomass for biomass type b; $MTCO_2e$

Equation 21: Initial Project Aboveground Biomass

$$C_{AGB_{b,y=0}} = DM_{b,y=0} \times CF_b \times \frac{44}{12} \times A_b$$

WHERE

$C_{AGB_{b,y=0}}$	Initial (year y=0) carbon stock of above-ground biomass for biomass type b; $MTCO_2e$
$DM_{b,y=0}$	Dry matter for biomass type b at project initiation (year $y=0$); MT dry matter ha^{-1}
CF_b	Carbon fraction of dry matter for biomass type b; MT C (MT dry matter)$^{-1}$
A_b	Area of biomass type b; hectares
$\frac{44}{12}$	Ratio of molar mass of CO_2 to C

6.2.2 Accounting Project Emissions from Belowground Biomass

This pool is optional. If included, projects must account for these emissions by determining initial below ground carbon stocks for each biomass type using one of the following methods:

- Models meeting the criteria in Section 5 Use of Models for GHG Estimation[46]

[46] Where process models require specific crops in a given year, crop selection and assignment to years shall not be done in a manner that would underestimate $C_{BGB,BL_{p,y}}$.

- $C_{AGB,PR_{p,y}}$ (Equation 22) and appropriate root-to-shoot ratios for crop and woody and non-woody components

Equation 22: Project Belowground Biomass

$$C_{BGB,PR_{p,y}} = \sum_{b}^{B} R_b \times C_{AGB_{b,y=0}}$$

WHERE

$C_{BGB,PR_{p,y}}$	Carbon stock of below-ground biomass for Participant Field p in the project scenario in year y; $MTCO_2e$
B	Total number of biomass types
R_b	Root carbon-to-shoot carbon ratio of biomass type b; default value 4.2 for temperate Grassland, 4.5 for cool temperate Grassland, and 1.8 for Shrub-land (Mokany et al. 2006); d.u.[47,48]
$C_{AGB_{b,y=0}}$	Initial (year $y=0$) carbon stock in above-ground biomass of biomass type b; $MTCO_2e$

As stated in Section 6.2.1, above-ground biomass stocks are assumed to remain in steady-state throughout the project duration; the corresponding carbon stock change in below-ground biomass pools is therefore also assumed to be zero over the project life. Although management activities in the project scenario, such as grazing, haying or prescribed fires have been demonstrated to stimulate below-ground biomass growth, these potential gains are conservatively excluded.

[47] Project Proponents can replace the default rate with a site-specific value or more recent value from peer reviewed literature.

[48] In Grasslands, a global database finds that carbon concentration in roots and shoots are relatively equivalent across sites (median 44% in leaves and 43% in roots; Craine et al. 2005). Therefore, root-to-shoot ratios are equivalent to the root carbon-to-shoot carbon ratios in Grasslands.

6.2.3 Accounting Project Emissions from Soil Organic Carbon

SOC stocks are conservatively assumed to be in a steady state from the date of recording of the easement, such that soil organic carbon stocks in the project scenario are fixed over the project life i.e. do not increase. Because there is no change in SOC during year y in the project scenario, this term is not included in the total project emissions for year y, Equation 19.

6.2.4 Accounting Project Emissions from Soil N_2O

Direct soil N_2O emissions in the project scenario result from nitrogen fertilizer application, both synthetic and organic. Quantification of indirect N_2O emissions from nitrogen fertilizer application is highly uncertain. GHG benefits from this pool cannot be assured to be real and are therefore conservatively excluded from both the baseline and project scenario.[49]

$E_{PR,N_2O_{p,y}}$ may be determined by:

- Models meeting the criteria in Section 5 Use of Models for GHG Estimation.[50]
- Equations 23- 27.[51]

Equation 23: Project N_2O Emissions

$$\mathbf{E_{PR,N_2O_{p,y}} = E_{PR,N_2O,direct_{p,y}} = [\left(F_{PR,SN_{p,y}} + F_{PR,ON_{p,y}}\right) \times EF_N + F_{PRP,p,y} \times EF_{MNR}] \times \frac{44}{28} \times GWP_{N_2O}}$$

WHERE

$E_{PR,N_2O_{p,y}}$	Total N_2O emissions from Participant Field p in year y; $MTCO_2e$
$E_{PR,N_2O,direct_{p,y}}$	Direct N_2O emissions from the addition of N to Participant Field p in the project scenario for year y; $MTCO_2e$

[49] Nitrogen application is assumed to be higher in the baseline scenario, crop cultivation, relative to the project scenario, grassland with or without grazing.

[50] Where process models require specific crops in a given year, crop selection and assignment to years shall not be done in a manner that would underestimate $C_{BGB_{crop},BL_{b,y}}$.

[51] CDM A/R Methodological Tool, Estimation of direct nitrous oxide emission from nitrogen fertilization. https://cdm.unfccc.int/methodologies/ARmethodologies/tools/ar-am-tool-07-v1.pdf

$F_{PRP,p,y}$	Mass of manure and urine N deposited by grazing animals on pasture, range and paddock on participant field p, in year y
$F_{PR,SN_{p,y}}$	Mass of synthetic fertilizer nitrogen applied to Participant Field p in the project scenario in year y adjusted for volatilization as NH_3 and NO_X; MT N
$F_{PR,ON_{p,y}}$	Mass of organic N amendments applied to Participant Field p in the project scenario in year y adjusted for volatilization as NH_3 and NO_X; MT N
EF_N	Emission factor for emission from N inputs; MT N_2O-N (MT N input)$^{-1}$
EF_{MNR}	Emission factor for emissions from manure inputs MT N_2O-N (MT N input)$^{-1}$
$\frac{44}{28}$	Ratio of molecular weights of N_2O to N; MT N_2O (MT N)$^{-1}$
GWP_{N_2O}	Global Warming Potential for N_2O[52]

Equation 24: Project Mass of Synthetic Fertilizer Nitrogen

$$\mathbf{F_{PR,SN_{p,y}}} = \sum_{j}^{J} \mathbf{M_{PR,SN_{p,j,y}}} \times \mathbf{N_{PR,SN_j}} \times (\mathbf{1} - \mathbf{Frac_{SN}})$$

WHERE

$F_{PR,SN_{p,y}}$	Mass of synthetic N amendments applied to Participant Field p in the project scenario in year y adjusted for volatilization as NH_3 and NO_X; See Section 3.1.2. Baseline Cropland Management Scenario); MT N
$M_{PR,SN_{p,j,y}}$	Mass of synthetic fertilizer type j applied to Participant Field p in year y; MT
N_{PR,SN_j}	Nitrogen content of synthetic fertilizer type j; MT-N (MT input)$^{-1}$
$Frac_{SN}$	Fraction of synthetic fertilizer nitrogen that volatilizes as NH_3 and NO_X;
J	Number of synthetic fertilizer types

[52] Project proponents shall refer to the ACR Program Standard for the approved IPCC GWP for nitrous oxide value, which will be updated periodically as new information becomes available.

j	Synthetic fertilizer type

Equation 25: Project Mass of Organic Fertilizer Nitrogen

$$F_{PR,ON_{p,y}} = \sum_{k}^{K} M_{PR,ON_{p,k,y}} \times N_{PR,ON_k} \times (1 - Frac_{ON})$$

WHERE

$F_{PR,ON_{p,y}}$	Mass of organic **N** amendments applied to Participant Field **p** in the project scenario in year **y** adjusted for volatilization as NH_3 and NO_X; See Section 3.1.2. Baseline Cropland Management Scenario); MT N
$M_{PR,ON_{p,k,y}}$	Mass of organic fertilizer type **k** applied to Participant Field **p** in year **y**; MT
N_{PR,ON_k}	Nitrogen content of organic fertilizer type **k**; MT-N (MT input)$^{-1}$
$Frac_{ON}$	Fraction of organic fertilizer nitrogen that volatilizes as NH_3 and NO_X;
K	Number of organic fertilizer types
k	Organic fertilizer type

Equation 26: Percent Excreta Nitrogen

$$F_{PRPp,y} = \sum_{l}^{L} \left(P_{p,l} \times Nex_{l,p,y}\right)$$

WHERE

$F_{PRPp,y}$	Percent excreta nitrogen
L	Number of livestock types
l	livestock type
$P_{p,l}$	Population of livestock type **l**, on participant field **p**; number of head

$Nex_{l,p,y}$	Annual average N excretion per head of species/category, kg N (animal)$^{-1}$ of live-stock type l

Equation 27: Nitrogen Excreta Per Head of Livestock

$$Nex_{l,p,y} = \frac{N_{rate(l)} \times \frac{TAM_l}{1,000} \times GD_{p,l,y}}{1,000}$$

WHERE

$Nex_{l,p,y}$	Nitrogen excreta per head of livestock on participant field p in year y (kg N (ani-mal)-1 (year)-1
$N_{rate(l)}$	N excretion rate; kg N (1,000 kg animal mass)$^{-1}$ day^{-1}
TAM_l	Typical animal mass for livestock category l; kg animal^{-1}
$GD_{p,l,y}$	Grazing days per livestock type l on Participant Field p in year y; grazing days

6.2.5 Accounting Livestock Emissions from Enteric Fermentation

Livestock, such as cattle, bison and sheep, produce CH_4 as a result of enteric fermentation in their rumen. Enteric fermentation emissions vary by species, breed, animal size, feed, environment and management systems (Ominski et al. 2007). Estimates of enteric fermentation can also vary widely depending on the level of specificity of input data and use of defaults (Ominski et al. 2007). It is therefore encouraged that Project Proponents utilize the most representative input data where possible. Further, calves less than 6 months in age are assumed to have zero CH_4 emissions as their diet will be primarily milk (US EPA 2013).

Estimates of enteric CH_4 emissions are restricted to rangeland/pasture manure systems where manure is left unmanaged once deposited by livestock per the Applicability Conditions in Section 1.2. It is recognized that in Grassland ecosystems, the net contribution of livestock in the system may be net GHG sequestration (Liebig et al. 2010). The effects of vegetation stimulation and soil nutrient amendments that grazing and natural manure management, as maintained from pre-project conditions, are assumed to be captured through estimates of soil and biomass carbon pools in the project scenario. Any net sequestration benefits from these activities in the project scenario are conservatively excluded from this methodology but could be eligible for

ERTs under a separate but complimentary Grazing Land and Livestock Management methodology. Manure deposited by livestock present in the project scenario shall be accounted for in Soil Nitrogen Emissions, Section 6.2.4 Soil Nitrogen Emissions. Project emissions from livestock due to enteric fermentation shall be calculated for each Participant Field in the Project Area according to Equation 28 and 29.

Equation 28: Project Enteric Fermentation

$$\mathbf{E_{Ferm,p,y} = \sum_{li}^{L} P_{p,l} \times EF_l \times GD_{p,l,y} \times GWP_{CH_4} \div 1,000}$$

WHERE

$E_{Ferm,p,y}$	CH_4 emission from enteric fermentation due to livestock on Participant Field p in year y; $MTCO_2e$
L	Total number of livestock types in project scenario
$P_{p,l}$	Population of livestock type l on Participant Field p; head
$GD_{p,l,y}$	Grazing days per livestock type l on Participant Field p in year y; grazing days
EF_l	Enteric CH_4 emission factor for livestock type l; $kgCH_4$ ($head^{-1}$) (grazing day^{-1})
GWP_{CH4}	Global warming potential for CH_4 (See ACR Standard)
1,000	Conversion kg to MT

Equation 29: Enteric Emission Factor per Head of Livestock

$$\mathbf{EF_l = \frac{GE \times \left(\frac{Y_m}{100}\right)}{55.65}}$$

WHERE

EF_l	Enteric CH_4 emission factor for livestock type l; $kgCH_4$ ($head^{-1}$) (grazing day^{-1})
GE	Gross energy intake MJ $head^{-1}$ day^{-1}

Y_m	Methane conversion factor, per cent of gross energy in feed converted to methane. 6.5%; Lambs (<1-year-old): 4.5%; and Mature Sheep: 6.5% Source: Chapter 4, Tables 10.12 and 10.13, IPCC 2006 AFOLU GL
55.65	Energy content of methane; MJ/kg CH_4

6.2.6 Accounting Project Emissions from Fossil Fuels

Accounting for GHG emissions from fossil fuels is optional. Where fossil fuel emissions are accounted for in the baseline, project fossil fuel emissions must also be estimated.

Equation 30: Project Fossil Fuel Emissions

$$\mathbf{E_{FF,PRp,y}} = \sum_{v}^{V}\sum_{f}^{F}\left(\mathbf{FF_{PR_{p,v,f,y}}} \times \mathbf{EF_f}\right)$$

WHERE

$E_{FF,PRp,y}$	Emissions due to the use of fossil fuels in project management, on participant field p in year y; $MTCO_2e$
$FF_{PR,p,v,f,y}$	Consumption of fossil fuel in vehicle/equipment type **v** during year **y** per fuel type f; Liters $(yr.)^{-1}$ on participant field p
EF_f	Emission factor for the type of fossil fuel combusted in vehicle or equipment, **v.** See U.S. Energy Information Agency.[53]
v	Type of vehicle/equipment
V	Total number of types of vehicle/equipment used in the project activity
f	Type of fuel
F	Total number of fuel types

[53] https://www.eia.gov/environment/emissions/co2_vol_mass.php

Unlike the baseline scenario, Project Proponents can monitor machinery and equipment use in the project scenario and the quantity of fuel consumed. Where this information is not easily attainable or difficult to estimate, default fuel usage rates from the same sources used to identify fuel usage for the baseline scenario may be used.

6.3 LEAKAGE

Market leakage is the primary source of potential leakage from the avoided conversion of Grassland and Shrubland. Conversion is most likely driven by commodity crops, rather than food crops which would be consumed locally and potentially induce activity shifting leakage. For commodity crops, attempts to estimate activity shifting leakage will double count market leakage. For food crops, the default values provided in this section for market shifting leakage will provide a conservative estimate of activity shifting leakage where it occurs.

Equation 31: Leakage Emissions

$$\mathbf{LE_y = LE_{M,y}}$$

WHERE

LE_y	Leakage factor in year $\mathbf{y}$
$LE_{M,y}$	Market Leakage in year $\mathbf{y}$

6.3.1 Description of Leakage

6.3.1.1 COMMODITY AND FOOD CROP

The crops identified in the baseline analysis shall be assessed for leakage type if they are a food or commodity crop. A commodity crop is traded and consumed in national and/or international markets, traded on a recognized futures exchange, and individual producers are price takers (no ability to affect price). If the majority of crops in a rotation are considered a commodity crop, production is determined to be commodity-dependent, and leakage will therefore be market-driven. Attempts to monitor and estimate activity-shifting leakage in this scenario will lead to double counting of market leakage.

In contrast, non-commodity or food crops are more likely to be purchased or consumed locally or regionally and the displacement of their production will lead to unmet local demand, providing a driver for Activity Shifting leakage. The ability to estimate activity shifting leakage in scenarios where conversion is driven by non-commodity crops is extremely poor with available data. Estimation errors based on aggregation, sampling error or classification error from remotely sensed images may exceed estimates of annual conversion rates. In these situations, it is considered conservative to use the default market leakage rate to account for all leakage.

6.3.1.2 MARKET LEAKAGE

Avoiding the conversion of Grassland and Shrubland will directly remove arable Cropland that would otherwise enter production. Food demand is relatively inelastic globally, requiring that the foregone production will be made up either through changes at the intensive (fertilizer use, crop yield response) or extensive (indirect land use conversion) margin. Since the commodities being displaced are traded in national and international markets, and production is responsive to numerous dynamic phenomena, estimation of market leakage requires use of detailed economic data and complex general equilibrium models. Completion of these analyses are expected to be beyond the capabilities of most Project Proponents, and therefore a simplified default approach is used to provide a default value of $\mathrm{LE_{MY}}$ applicable to avoided conversion to commodity crops in North America that can be used for all Projects using this methodology.

Market leakage is based on the law of supply and demand. Avoided conversion reduces the supply of otherwise arable Cropland, which all else being equal, puts upward pressure on prices, which puts downward pressure on quantity demanded and upward pressure to increase production on non-project lands. The relationship between price and supply and demand are quantified by price elasticities. Price increases can also lead to increased supply through mechanisms other than conversion of additional non-Project lands (i.e. changes at the intensive margin). Price signals inspire farmers to produce more crops on their existing farmland, e.g., by investing in more labor, advanced technology, or inputs (Taheripour 2006). Price signals can also inspire increased investment in yield improvement (Ruttan and Hayami 1984). Thus, avoiding conversion to Cropland is expected to reduce the net amount of land needed for crop production both by increasing yields on existing farmland and by decreasing the quantity of demand. Methods based only on short-run price elasticities generally capture decreased demand but may not capture these additional mechanisms that contribute to meeting demand without requiring Cropland expansion. Therefore, methods based only on price elasticities will tend to overestimate leakage, making them conservative from the standpoint of calculating offsets generated by a project.

The default leakage value is derived from Equation 32, which is derived from Murray, McCarl and Lee (2004).

Equation 32: Market Leakage

$$\mathbf{LE_{M,y}} = \frac{\mathbf{E_S}}{\mathbf{E_S} - \mathbf{E_D}}$$

WHERE

$LE_{M,y}$	Market leakage in year y; (0-1.0)
E_S	Price elasticity of supply
E_D	Price elasticity of demand

Note that Price elasticity of demand (E_D) is generally a negative number (demand goes down as price goes up) and Price elasticity of supply (E_S) is generally a positive number (supply goes up as price goes up), so market leakage will be a percentage that ranges from 0 to 100.

Elasticities may be obtained from the Food and Agriculture Policy Research Institute (FAPRI) Elasticity Database[54,55] as well as peer reviewed literature and state government reports.

To obtain a default value that can be reliably used in the United States, we considered a range of approaches to estimating leakage and used the most conservative result. Several researchers have used estimates of leakage associated with the USDA Conservation Reserve Program (CRP). The retirement of land from crop production as in the Conservation Reserve Program should have similar or larger leakage effects as an avoided conversion project that keeps land out of crop production. Both approaches preclude marginal Cropland from entering crop production. One might expect CRP to have greater leakage because of both the large scale of land retirement and because CRP typically removes land entirely from all productive uses, although some emergency haying and grazing is allowed, whereas, conservation through a carbon offset program such as this one still allow grazing and livestock production.

[54] The USDA Commodity and Food Elasticity Database is no longer being updated (https://www.ers.usda.gov/data-products/commodity-and-food-elasticities/).

[55] http://www.fapri.iastate.edu/tools/elasticity.aspx

Table 3: Literature Values for Leakage Associated with the USDA CRP

SOURCE	ESTIMATE OF MARKET EFFECTS LEAKAGE	APPROACH
Taheripour, (2006)	≤20%	General equilibrium model of CRP leakage.
Wu (2000)	20%	Statistical estimate of leakage based on empirical land use data associated with the implementation of the CRP.
Barr et al. (2011)	<20%	Price elasticity of Cropland supply was found to be 0.029. When combined with reasonable estimates of price elasticity of demand, this consistently results in leakage estimates of <20%.
Murray et al. (2007)	0-20%	Plausible leakage discount for Cropland retirement based on previous literature.

A peer reviewed paper studied actual responses of U.S. land area to changes in prices and found that the price elasticity of Cropland area in the United States is very low (0.029 was the highest of several estimates in the paper) (Barr et al. 2011). Unfortunately, this paper does not provide a comparable estimate for price elasticity of demand. In the absence of a definitive estimate of demand, we are able to show that any reasonable estimate of the price elasticity of demand yields a leakage estimate that is no greater than 20% when paired with Barr et al.'s estimate for price elasticity of supply. Any estimate of the price elasticity of demand that is less than -0.116 would result in leakage of 20% or lower. In drafting of version 1.0 of this methodology, 241 estimates were obtained from the USDA ERS database on own-price demand elasticities for commodities relevant to the United States (corn, soy, legume, grain, cereal, oil, food) for the period prior to 2014. The mean demand elasticity was -0.44, and more than 90% of all values were less than -0.116.

Therefore, a conservative default value of 20% market leakage may be used for avoided conversion of Grasslands or Shrublands to commodity crops in the United States.

6.3.2 Quantification of Leakage Deduction

Equation 33: Leakage Deduction

$$\mathbf{LD_y = LE_y \times \sum_{p}^{P} \left(C_{AGB,BL_{p,y-1}} - C_{AGB,BL_{p,y}} + C_{BGB,BL_{p,y-1}} - C_{BGB,BL_{p,y}} + C_{SOC,BL_{p,y-1}} - C_{SOC,BL_{p,y}} \right)}$$

WHERE

LD_y	Leakage deduction in year y
LE_y	Leakage in year y, $MTCO_2e$ (Equation 31)
$C_{AGB,BL_{p,y}}$	Carbon stock of aboveground biomass in Participant Field p in year y in the baseline scenario; $MTCO_2e$. (Equation 3, optional pool)
$C_{BGB,BL_{p,y}}$	Carbon stock of below-ground crop biomass for Participant Field p in the baseline scenario in year y; $MTCO_2e$. (Equation 7, optional pool)
$C_{SOC,BL_{p,y}}$	Carbon stock of soil organic carbon for Participant Field p in the baseline scenario in year y; $MTCO_2e$. (Equation 10)

6.4 NET GHG EMISSIONS

Equation 34: Net Emission Reductions

$$\mathbf{ER_y = BE_y - PE_y - NP_y - LD_y}$$

WHERE

ER_y	Net GHG emissions reductions and/or removals in year y, $MTCO_2e$
BE_y	Baseline emissions in year y, (Equation 1) $MTCO_2e$
PE_y	Project emissions in year y, (Equation 16) $MTCO_2e$
NP_y	Non-Permanence deduction in year y, (Equation 35) $MTCO_2e$
LD_y	Leakage deduction for year y, (Equation 31) $MTCO_2e$

Where $BEy < PEy$, no ERTs shall be issued for that year.

Equation 35: Non-Permanence Deduction

$$\mathbf{NP_y = BF_y \times \sum_{p}^{P}\left(C_{AGB,BL_{p,y-1}} - C_{AGB,BL_{p,y}} + C_{BGB,BL_{p,y-1}} - C_{BGB,BL_{p,y}} + C_{SOC,BL_{p,y-1}} - C_{SOC,BL_{p,y}}\right)}$$

WHERE

NP_y	Non-Permanence deduction for year y
BF_y	Non-Permanence buffer in year y, result of project analysis using the latest version of the ACR Tool for Risk Analysis and Buffer Determination to determine the overall project risk rating, applied as BFy.[56]
$C_{AGB,BL_{p,y}}$	Carbon stock of aboveground biomass in Participant Field p in year y in the baseline scenario; $MTCO_2e$ (Equation 3, optional pool)
$C_{BGB,BL_{p,y}}$	Carbon stock of below-ground crop biomass for Participant Field p in the baseline scenario in year y; $MTCO_2e$ (Equation 7, optional pool)
$C_{SOC,BL_{p,y}}$	Carbon stock of soil organic carbon for Participant Field p in the baseline scenario in year y; $MTCO_2e$ (Equation 10)

6.5 UNCERTAINTY

Estimation of uncertainty is required for each baseline and project carbon pool and GHG sources. When sampling is conducted, and the 90% confidence limit (high or low) is greater than 10% of the mean value, the confidence limit (resulting in the lowest ERT value) shall be used rather than the sampled mean to ensure conservativeness. Uncertainty estimates or lower bounds are required for default values (such as those by the IPCC), estimates from peer-reviewed literature, and direct measurements or empirical relationships based on measurements. They should be directly estimated per general requirements in the ACR Standard. Where process models are used to estimate pools and sources, key sources of uncertainty in model parameters and inputs should be used to model uncertainty.[57] Models approved for use by ACR

[56] As described in the most recent version of the ACR Standard, the Project Proponent shall use the ACR Tool for Risk Analysis and Buffer Determination.

[57] Where a range of plausible uncertainty values are available for a parameter or input, Project Proponents shall select the most conservative value so as not to overestimate project emission reductions.

with this methodology must meet all criteria for process based biogeochemical models in the ACR Standard. When the DAYCENT model is used, an uncertainty deduction factor of 10% must be subtracted from the difference between baseline and project SOC.[58]

6.6 PERMANENCE AND REVERSALS

Carbon offsets generated through the sequestration of carbon in soil or biomass are inherently at some risk of reversal or termination. Reversals can be unintentional or intentional. Internal risk factors include project management, financial viability, opportunity costs and project longevity. External risk factors include factors related to easement violations and natural risks including fire, flood, and extreme weather events. See specific instructions for agriculture/grassland projects within the ACR Risk Assessment Tool. The risk assessment, overall risk rating, and proposed mitigation or buffer contribution shall be included in the GHG Project Plan.

Per the Buffer Pool Terms and Conditions (see the ACR Standard) sequestration projects will terminate automatically if a Reversal causes project stocks to decrease below baseline levels prior to the end of the Minimum Project Term.

6.6.1 Assessment of Risk

To assess the risk of reversal or termination, the Project Proponents shall conduct a risk assessment addressing internal, external and natural risks using the most recently approved ACR Risk Assessment Tool.[59]

6.6.2 Mitigation of Risk

While prescribed burns are allowed under this Methodology, fire could have negative ecological impacts and reduce aboveground biomass in shrublands in addition to potentially reversing carbon storage resulting from the project when best practices for prescribed burns are not followed. Project Proponents shall know and follow best management practices for use of fire for the vegetation type and region.

An alternative value may be used if Project Proponents can justify why the selected parameter or input value is more appropriate than the most conservatively available value, with the justification transparent in the GHG Project Plan Document and/or Monitoring Report.

58 Based on Ogle et al. 2007 for CRP lands

59 http://americancarbonregistry.org/carbon-accounting/tools-templates/acr-risk-tool-v1-0.pdf

6.6.3 Buffer Pool Contributions

ACR's Risk Assessment Tool produces a total risk rating for the project which equals the percentage of offsets that must be deposited in the ACR buffer pool to compensate for reversal or termination (unless another ACR approved risk mitigation mechanism is used in lieu of buffer contribution). The risk assessment, overall risk rating, and proposed mitigation or buffer contribution shall be included in the GHG Project Plan.

7 MONITORING AND DATA COLLECTION

Each project shall include a GHG project plan sufficiently meeting the requirements of the ACR Standard. The plan shall describe the collection of all data required to be monitored and, in a manner, which meets the requirements for accuracy and precision of this Methodology. Project Proponents shall use the template for GHG project plans available at www.americancarbonregistry.org. Additionally, projects are required to submit a GHG monitoring report for each reporting period. Project Proponents shall use the template for GHG monitoring reports available at http://americancarbonregistry.org/carbon-accounting/tools-templates.

7.1 THE GHG PROJECT PLAN

Requirements for GHG Project Plans for all ACR projects are listed in the ACR Standard. See sections 7.2 and 7.3 for additional GHG Project Plan requirements, specific to this methodology.

7.2 DATA COLLECTION AND PARAMETERS MONITORED

See Appendix A for a list of parameters available at validation, parameters monitored, and parameters determined from equations. Project Proponents are strongly encouraged to maintain area-based parameters in per Hectare (or per acre) units as well per field p, to assist validation and verification events.

7.2.1 Description of the Monitoring Plan

The Monitoring Plan is developed at time of validation, contained in the GHG Project Plan and submitted at each verification event. In addition to the parameters listed in Appendix A the monitoring plan must also include:

- Baseline Crop Management Scenario (Section 3.1.2); updated at minimum every 5 years
- Spatially explicit shapefiles for project boundaries (Section 2.1.2)
- Conversion Agents

- Livestock presence, average annual AUMs of grazing and average annual forage availability in AUMs within the Project Area and the dates of grazing activity[60]
- Cover of Grassland versus Shrubland in Project Area
- Any effects of disturbance, especially of burning (wildfire or prescribed), on aboveground shrub biomass.

The Monitoring Report shall further describe the following:

- Monitoring tasks included or required as part of the LCA and responsible party
- Frequency of monitoring tasks and reporting
- Measurement procedures and frequency of collection (if applicable)
- Biogeochemical model parameter definitions[61]
- Quality Assurance/Quality Control measures
- Archiving measures
- Responsibilities, roles and qualifications of monitoring team
- Any due diligence for boundaries in the LCA

7.2.2 Sampling Design

Where Project Proponents elect to employ direct measurements, the Monitoring Plan in the GHG Project Plan Document shall specify the sampling design, sample size, plot size and determination of plot locations. All sampling must be carried out such that a 90% Confidence Interval does not exceed 10% of the mean. Where uncertainty exceeds 10% of the mean, estimated GHG benefits or values must be discounted by using the boundary of the confidence interval. All measurements will be conducted according to approved sampling standards and subject to Quality Assurance/Quality Control measures, as specified in the Monitoring Plan.

[60] A Grazing Management Plan, when available, meets this monitoring requirement. Grazing practices, including intensity, shall be consistent with the conservation goals set forth in the easement.

[61] Necessary environmental parameters for use in biogeochemical modeling and determination of ex post pools and sources estimated with a biogeochemical model are to be recorded. Sources for such variables may include national databases, or published data with the selection and collection of such data provided in a transparent manner in the Monitoring Report for easy verification and replication. Where meteorological data is collected from a regional meteorology station in the Project Region, information from the nearest station is advised, preferably within 100km of the Participant Field. Where the Project Area exceeds a 100km radius, a single or averaged set of meteorological data may be utilized.

7.3 DATA ARCHIVING

The VVB shall retain reports, measurements and other project related documents, including documentation of LU/LC conversion, per requirements in the ACR Standard. Where soil samples are collected, these shall be maintained by the project developer until at least the next scheduled verification event, i.e. 5 years. Soil and other durable samples shall be stored in an air-dry condition in a cool, dry location.

8 VALIDATION AND VERIFICATION

8.1 ACR VV STANDARD AND DEVIATIONS

Aspects of the avoided conversion project type are unique such that certain validation and verification procedures are allowed that supersede the ACR Verification and Validation Standard.[62] Specific instances where this methodology supersedes requirements in the ACR Validation and Verification Standard are described below. Unless otherwise stated, the requirements in the most recent version of the ACR Validation and Verification Standard apply to all projects.

8.1.1 Listing Requirements

Submittal of a full GHG Project Plan is not required at listing for this project type. Project Proponents can submit basic project information and the Statement of Intent or GHG ownership agreement and estimated future properties (if PDA) within ± 12 months of date of recording of the LCA. A complete GHG Project Plan can be submitted up until the time of validation.[63]

8.1.2 Site Visits

Site-visits are not required at validation nor at subsequent verifications for this project type, provided the verifier can reach a reasonable level of assurance via review of required documents and supplemental material (e.g. images, on-going monitoring reports as required as part of the LCA, telephone interviews, including those with the responsible entity for the LCA, remote sensing, third party datasets etc.). The verifier has discretion to request a site-visit at the following times in the project life cycle IF he/she determines that a reasonable level of assurance is unattainable without a site visit: at validation, if a reversal occurs, if LCA or regulatory infraction occurs, or change in VVB.

At a minimum, the following must be included in a remote verification:

[62] These include: 1) the baseline scenario is a counter factual scenario and cannot be monitored, rather the baseline assumptions are justified ex ante 2) the project activity requires a qualified LCA be recorded, which in and of itself includes due diligence prior to recording and on-going monitoring and reporting and 3) LCAs are complex legal agreements that vary geographically and upon the nature of the organizations entering into the agreement; it is difficult to predict with accuracy when an LCA will be completed and recorded and thus to know in advance the official project start date.

[63] Per the ACR Standard, AFOLU projects must COMPLETE validation within 3 years of the start date of the project; i.e. the date of qualified LCA recording.

- Spatially-explicit boundary shape file of Project Region, Project Area, and Participant Fields, including delineation of any wetlands, building envelopes, cultivated areas, gravel pits, or other acres not governed by a sod-busting/no-conversion clause. Participant Field boundaries will not be made public.
- Spatially-explicit boundary shapefiles of the area covered by the qualified LCA.
- Copy of the recorded Land Conservation Agreement(s)/Easement(s) that encompass all Participant Fields.
- Record of due diligence for accurate boundary definition prior to LCA recording.
- Links to recent LANDSAT imagery of the project area or time stamped LANDSAT image files.
- Record or image of the Participant Fields being Grassland or Shrubland at 10 years prior to start date.
- Monitoring Plan for the qualified LCA.
- Evidence of ownership/right-to the GHG offsets for Project Participant on all Participant Fields for the crediting period being verified.
- GHG Project Plan and associated components. This includes documentation on how any models were parameterized and a detailed Monitoring Plan.
- GHG Quantification documents with modeling output, assumptions, and net GHG calculations.
- If applicable, an electronic copy of the appraisal and valid appraiser's license.

Annual easement monitoring reports are sufficient for demonstrating that the land has not been converted or undergone significant changes and is being managed in a way consistent with the protected conservation values. If an easement violation occurs, the registry must be informed in accordance with ACR's Standard, and it must be referenced in the project plan being verified, including any remediation steps taken.

8.1.3 Requirements for PDA Projects

Requirements for PDA projects as defined in the ACR Standard apply. Regarding site visits, this methodology supersedes requirements in the ACR Standard (See Section 8.1.2).

8.1.4 Significant Changes to a Project

If a significant or a substantial change occurs to the project after validation and/or initial verification, a site visit may be required either by the verifier or ACR, before the next issuance of ERTs. Examples of significant changes include:

- Partial reversal of credits issued to date for a specific parcel and it intends to continue to participate in the project.
- Unintentional reversals resulting from extreme weather events that cause a change to the baseline soil carbon stocks.
- If a parcel is considered a full reversal and it’s intentional.
- Material regulatory violations that exclude parcels from future inclusion.

DEFINITIONS

If not explicitly defined here, the current definitions in the latest version of the American Carbon Registry Standard apply.

Cropland	A land-use category that includes areas used for the production of crops for harvest on cultivated lands. Cultivated crops include row crops or close grown crops and also hay or pasture in rotation with cultivated crops. Cropland also includes land with alley cropping and windbreaks as well as lands in temporary fallow.[64]
Grassland and Shrubland	A land-use category on which the plant cover is composed principally of grasses, grass-like plants (i.e., sedges and rushes), forbs, or shrubs suitable for grazing and browsing, and includes both pastures and native rangelands. This includes areas where practices such as clearing, burning, chaining, and/or chemicals are applied to maintain the grass vegetation. Savannas, some wetlands and deserts, in addition to tundra are considered Grassland. Woody plant communities of low forbs and shrubs, such as mesquite, chaparral, mountain shrub, and pinyon-juniper, are also classified as Grassland and Shrubland if they do not meet the criteria for Forest Land. Grassland includes land managed with agroforestry practices such as silvipasture and windbreaks, assuming the stand or woodlot does not meet the criteria for Forest Land.[65]
Forest Land	Land with at least 10 percent cover (or equivalent stocking) by live Trees of any size, including land that formerly had such Tree cover and that will be naturally or artificially regenerated. To qualify, the area must be at least 1 acre in size. Forest Land includes transition zones, such as areas between Forest and non-Forest Lands that have at least 10% cover (or equivalent stocking) with live Trees and forest areas adjacent to urban and built-up lands.[66]

[64] Adapted from: https://www.nrcs.usda.gov/wps/portal/nrcs/detail/national/technical/nra/nri/?cid=nrcs143_014127

[65] Adapted from: https://www.nrcs.usda.gov/wps/portal/nrcs/detail/national/technical/nra/nri/?cid=nrcs143_014127 Spatial analysis uses the unique definitions of Grassland and Shrubland, respectively, in the NLCD.

[66] https://americancarbonregistry.org/carbon-accounting/standards-methodologies/american-carbon-registry-standard

Identified Agent	The known entity that is planning to convert a particular parcel of Grassland or Shrubland to Cropland (e.g., a particular local landowner).
Indirect N_2O Emissions	N_2O emissions that result from microbial nitrification and denitrification of Nitrogen that has first been removed from agricultural soils and animal waste management systems within the project boundary via volatilization, leaching, runoff, or harvest of crop biomass.[67, 68]
Land Conservation Agreement	An easement, covenant, deed restriction, or other legal agreement that may be employed to maintain the project land cover during the Project Crediting Period. The Land Conservation Agreement, as defined in this methodology, does not necessarily contain language pertaining to ownership of carbon or greenhouse gas emissions.
Participant Field	A particular parcel of Grassland or Shrubland where conversion to Cropland is planned by an identified agent or anticipated by an unidentified agent, analogous to the use of project activity in the ACR Standard.
Price Elasticity of Demand	A measure used in economics to show the responsiveness, or elasticity, of the quantity demanded of a good or service to a change in its price, ceteris paribus.
Price Elasticity of Supply	A measure used in economics to show the responsiveness, or elasticity, of the quantity supplied of a good or service to a change in its price.
Project Area	The collection of all participant fields where project activities are implemented.
Project Crediting Period	The length for which project activities are eligible to earn ERTs and the baseline determination remains valid.
Project Participant	A landowner or the manager of a Participant Field.
Project Proponent	An individual or entity that undertakes, develops, and/or owns a project. This may include the project investor, designer, and/or owner of the lands/facilities on which project activities are conducted. The Project

[67] IPCC Good Practice Guidance and Uncertainty Management in National GHG Inventories; https://www.ipcc-nggip.iges.or.jp/public/gp/bgp/4_6_Indirect_N2O_Agriculture.pdf

[68] American Carbon Registry Standard, https://americancarbonregistry.org/carbon-accounting/standards-methodologies/american-carbon-registry-standard/acr-standard-v5-1-july-2018.pdf

	Proponent and landowner/facility owner may be different entities. The Project Proponent is the ACR account holder.
Project Region	The larger region including and encompassing the entire Project Area. The Project Region may be an eco-region or geographic administrative unit.
Soil texture	The proportion of sand, silt and clay sized particles that make up the mineral fraction of the soil. It is a classification instrument used both in the field and laboratory to determine soil classes based on their physical texture.
Stratum	An area of land within which the value of a variable, and the processes leading to change in that variable, are relatively homogenous.
Succession	The process of change in the species structure of an ecological community over time.
Tree	A woody perennial plant, typically large, with a single well-defined stem carrying a more or less definite crown; sometimes defined as attaining a minimum diameter of 3 inches (7.6 cm) and a minimum height of 15 ft (4.6 m) at maturity. For FIA, any plant on the tree list in the current field manual is measured as a tree.[69]
Unidentified Agent	A particular entity that cannot be uniquely identified, but that belongs to a class of known conversion agents (e.g., farm corporations) who plan to convert Grassland or Shrubland to Cropland in the Project Area.

[69] https://www.nrs.fs.fed.us/fia/data-tools/state-reports/glossary/default.asp

APPENDIX A: PARAMETERS

A.1 PARAMETERS DEFINED BY METHODOLOGY EQUATIONS

All parameters in A.1 can also be obtained as outputs from approved biogeochemical models.

PARAMETER	UNIT	DESCRIPTION	SOURCE	USED IN EQ.
BE_y	$MTCO_2e$	Baseline emissions in year y, all field. y=0 at project start date		1
$BE_{p,y}$	$MTCO_2e$	Baseline emissions from participant field p, in year y		1,2
$C_{AGB,BL_{p,y}}$	$MTCO_2e$	Carbon stock of above-ground biomass for Participant Field p in the baseline scenario in year y		2,3
$C_{AGB_{b,y=0}}$	$MTCO_2e$	Initial (year y=0) carbon stock of above-ground biomass for biomass type b		20, 22
$C_{AGB,PR\ p,y}$	$MTCO_2e$	Carbon stock of above-ground biomass for Participant Field p in the project scenario in year y		4, 19, 21
$C_{AGB_{grass},BL_{p,y}}$	$MTCO_2e$	Carbon stock of (remaining, pre-existing) above ground for Participant Field p in year y in the baseline scenario, as calculated from Section 6.2.1		3

PARAMETER	UNIT	DESCRIPTION	SOURCE	USED IN EQ.
$C_{AGB_{crop},BL_{p,y}}$	$MTCO_2e$	Carbon stock of aboveground crop biomass in Participant Field p in year y in the baseline scenario		5
$C_{AGB_{crop},BL_{b,y}}$	$MTCO_2e$	Carbon stock of aboveground crop biomass in Participant Field p, for crop type b, in year y in the baseline scenario		5, 6
$C_{BGB,BL_{p,y}}$	$MTCO_2e$	Carbon stock of belowground biomass in Participant Field p in year y in the baseline scenario		2,7
$C_{BGB_{crop},BL_{p,y}}$	$MTCO_2e$	Carbon stock of belowground crop biomass in Participant Field p in year y in the baseline scenario		7, 9
$C_{BGB_{grass},BL_{p,y}}$	$MTCO_2e$	Carbon stock of (remaining, pre-existing) belowground biomass from Participant Field p in year y in the baseline scenario		7, 8
$C_{BGB,PR_{p,y}}$	$MTCO_2e$	Carbon stock of below-ground biomass for Participant Field p in the project scenario in year y		8, 19, 22
$C_{SOC,BL_{p,y}}$	$MTCO_2e$	Carbon stock of soil organic carbon for Participant Field p in the baseline scenario in year y		2,10
$F_{BL/PR,ON_{p,y}}$	MT-N	Mass of organic N amendments applied to Participant Field p in the baseline/project scenario in year y adjusted for volatilization as NH_3 and NO_X		12, 14, 23, 25

PARAMETER	UNIT	DESCRIPTION	SOURCE	USED IN EQ.
$F_{BL/PR,SN_{p,y}}$	MT-N	Mass of synthetic fertilizer nitrogen applied to Participant Field p in the baseline/project scenario in year y adjusted for volatilization as NH_3 and NO_X		12, 13, 23, 24
$E_{BL/PR,N_2O_{p,y}} = E_{BL/PR,N_2Odirect_{p,y}}$	$MTCO_2e$	Total N_2O emissions from Participant Field p in the baseline/project scenario in year y. Indirect emissions are conservatively excluded		2, 12, 19, 23
$E_{(BL/PR),FF_{p,y}}$	$MTCO_2e$	Emissions due to the use of fossil fuels in agricultural management in the baseline/project scenario on Participant Field p in year y		2, 17, 19, 30
$EF_{t,y}$	d.u.	Emission factor for the fraction of soil organic carbon pool remaining t years since conversion to Cropland in year y		10, 11
$Nex_{l,p,y}$	kg N $(animal)^{-1}$ $(yr.)^{-1}$	Annual average N excretion per head of species/category l, Participant Field p in year y		26, 27
$E_{FERM_{p,y}}$	$MTCO_2e$	CH_4 emission from enteric fermentation due to livestock on Participant Field p in year y		28
PE_y	$MTCO_2e$	Total project emissions in year y		18
$PE_{p,y}$	$MTCO_2e$	Total project emissions from participant field p in year y		18, 19

A.2 PARAMETERS AVAILABLE AT VALIDATION

PARAMETER	UNIT	DESCRIPTION	SOURCE	USED IN EQ.
A_b	ha	Area of biomass/crop type **b**	Project Proponent	6, 21
$A_{p,i}$	ha	Area of Participant Field in soil strata **i**	Project Proponent	10
$C_{AGB_{b,y=0}}$	$MTCO_2e$	Initial (year **y**=0) carbon stock of aboveground biomass for Participant Field **p**	Measured, Modeled, values from literature	20, 22
$C_{SOC_{i,y=0}}$	$MTCO_2e$ $(ha)^{-1}$	Total initial (year **y**=0) soil organic carbon stock in soil strata **i**, fixed for project duration	Measured, modeled, or literature. Where unavailable, default values from IPCC 2006 AFOLU GL, Table 2.3 may be used.	10
CF_b	MT C (MT dry matter)$^{-1}$	Carbon fraction of dry matter for biomass type **b**	Literature, Table 11.2 IPCC 2006 GL AFOLU	6, 21
D	years	Transition period for soil organic carbon, time period for transition between equilibrium SOC values, default value of 20	Measured, Modeled, literature, or default value of 20 years (IPCC 2006 AFOLU GL, Ch. 2).	11

PARAMETER	UNIT	DESCRIPTION	SOURCE	USED IN EQ.
$DM_{b,y=0}$	$MTCO_2e$	Average, annual, dry matter for biomass type b at project initiation (year y=0)	Measured, Modeled, literature	6, 21
$e^{(-0.77\times(y-t))}$	d.u.	The decay function for aboveground biomass following conversion	Kochsiek et al. 2009	4
$e^{(-1.41\times(y-t))}$	d.u.	The decay function for belowground biomass following conversion	Silver and Miya 2001	8
EF_f	$MTCO_2e$ (liter of fuel)$^{-1}$	Emission factor for the type of fossil fuel combusted in vehicle or equipment	For gasoline EF CO_2e = 8.89 kg CO_2e/gallon. For diesel EF CO_2e = 10.16 kg CO_2e/gallon. Source: EIA	17, 30
EF_l	kg-CH_4 head^{-1} grazing day^{-1}	Enteric CH_4 emission factor for livestock type l	Default value for Cattle in Cool Climate Zone: 1; default for Temperate or Warm Climate Zone: 2 Source: Chapter 10, Table 10.14, IPCC 2006 AFOLU GL	28, 29
EF_N	MT-N_2O-N (MT-N input)$^{-1}$	Emission Factor for emission from N inputs	0.0254 (2.54%) of applied synthetic fertilizer N and 0.02 (2%) of applied organic fertilizer N (Davidson, 2009)	12, 23

PARAMETER	UNIT	DESCRIPTION	SOURCE	USED IN EQ.
EF_{MNR}	MT-N_2O-N (MT-N input)$^{-1}$	Emission Factor for emission from manure inputs	Literature, Default values may be found Table 11.1, Chapter 11 IPCC 2006 AFOLU GL	23
$FC_{p,y}$	d.u	Proportion of Participant Field p that has been converted to Cropland in the baseline scenario for year y, d.u.	Project Proponent	10
$FC_{p,t,y}$	d.u.	The cumulative proportion of Participant Field p that has been converted to Cropland in year t, time of conversion, as of year y in the baseline scenario, determined based on rates and extents of conversion	Project Proponent	4, 8
$Frac_{ON}$	kg N volatilized (kg of N applied or deposited)$^{-1}$	Fraction of organic N applied to soils that volatilizes as NH_3 and NO_x	Default value of 0.20 Source: Chapter 11, Table 11.3, p. 11.24, IPCC 2006 AFOLU GL	14, 25
$Frac_{SN}$	kg N volatilized (kg of N applied or deposited)$^{-1}$	Fraction of synthetic N applied to soils that volatilizes as NH_3 and NO_x	Default value of 0.10 Source: Chapter 11, Table 11.3, p. 11.24, IPCC 2006 AFOLU GL	13, 24

PARAMETER	UNIT	DESCRIPTION	SOURCE	USED IN EQ.
GWP_{CH_4}	$MTCO_2e$	Global warming potential for CH_4	See ACR Standard	28
GWP_{N_2O}	$MTCO_2e$	Global warming potential for N_2O	See ACR Standard	12, 23
Y_m	d.u.	Methane conversion factor, per cent of gross energy in feed converted to methane	Suggested Default for Cattle or Buffalo-grazing: 6.5%; Lambs (<1-year-old): 4.5%; and Mature Sheep: 6.5% Source: Chapter 4, Tables 10.12 and 10.13, IPCC 2006 AFOLU GL	29
P		Total number of participant fields, p	Project Proponent	
t	years	Time since conversion of Grassland to Cropland in the baseline scenario	Project Proponent	
R_b	d.u.	Root carbon-to-shoot carbon ratio of (crop) biomass type b; default value 4.2 for temperate grassland, 4.5 for cool temperate grassland and 1.8 for shrubland	Literature, Craine et al. 2005, Mokany et al 2006; or IPCC 2006 AFOLU GL	9, 22

PARAMETER	UNIT	DESCRIPTION	SOURCE	USED IN EQ.
$\frac{44}{12}$		Ratio of molar mass of CO_2 to C	NA	6, 21
$\frac{44}{28}$		Ratio of molar mass of N_2O to N	NA	12

A.3 PARAMETERS MONITORED

PARAMETER	UNIT	DESCRIPTION	SOURCE	USED IN EQ.
B		Total number of crop/biomass types b		
$DM_{BL,b,y}$	MT dry matter $(ha)^{-1}$	Annualized average dry matter in the baseline for crop type b in year y	Harvest Index: ratio of economic product dry mass to plant aboveground dry mass. Alternatively, Values from literature, where none are available use of Harvest Index applied to crop yield guides for the Project Region may be used, or the IPCC default value of 5.0 MT C $(ha)^{-1}$ for annual crops following one year after conversion (IPCC 2006 AFOLU GL, Table 5.9)	6

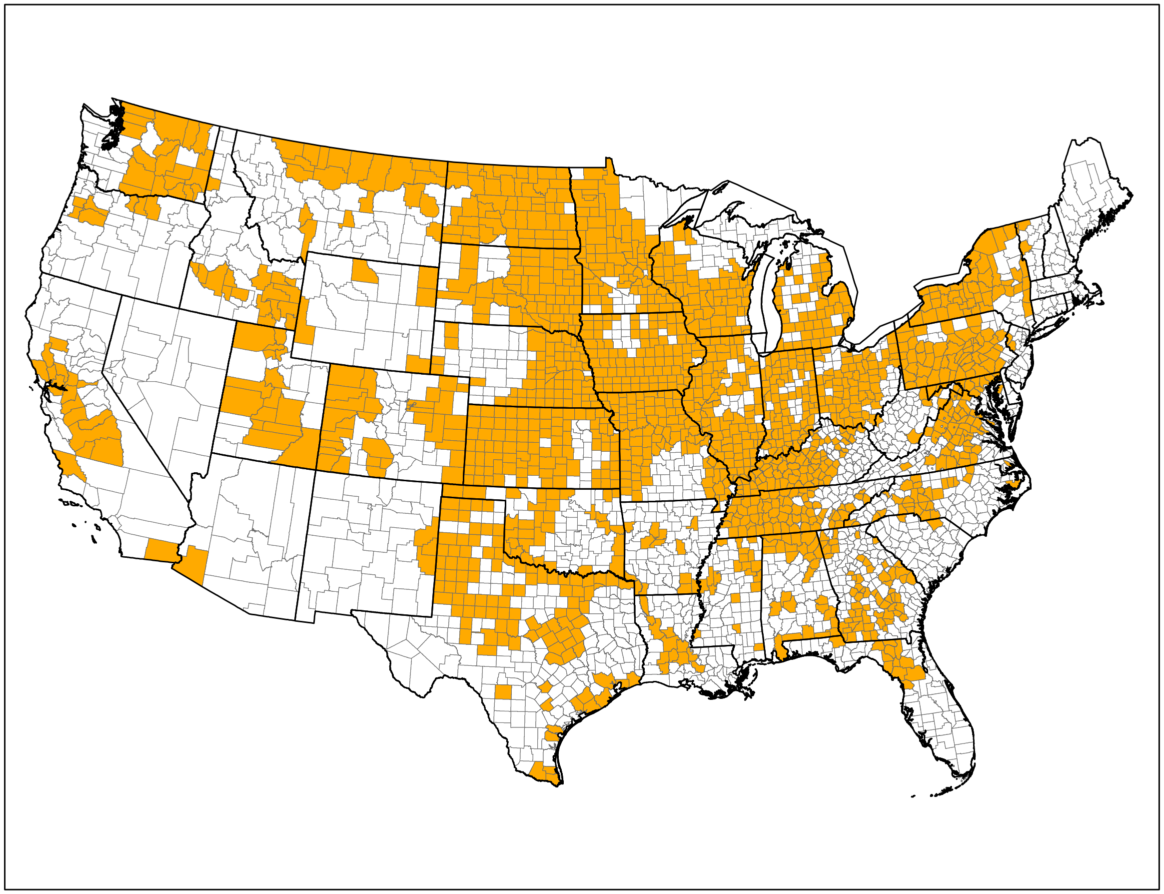
PARAMETER	UNIT	DESCRIPTION	SOURCE	USED IN EQ.
$F_{PRP_{p,y}}$	MT-N	Mass of manure and urine N deposited by grazing animals on pasture, range and paddock	Producer records, or a university extension or other production report containing grazing animal population multiplied by per animal manure and urine N deposition.	23
$FSOC_{LU}$	d.u.	Fraction of soil organic carbon pool remaining after transition period, accounting for land use factors	Literature, model, measured, or IPCC defaults Table 5.5 AFOLU GL 2006	11
$FSOC_{MG}$	d.u.	Fraction of soil organic carbon pool remaining after transition period, accounting for management factors	Literature, model, measured, or IPCC defaults Table 5.5 AFOLU GL 2006	11
$FSOC_{IN}$	d.u.	Fraction of soil organic carbon pool remaining after transition period, accounting for input of organic matter	Literature, model, measured, or IPCC defaults Table 5.5 AFOLU GL 2006	11
$FF_{BL/PR_{p,v,j,y}}$	liters	Volume of fossil fuel consumed in the baseline/project scenario on Participant Field p in vehicle/equipment type v with fuel type j during year y	Expert opinion or extension/agency report (baseline) or producer report (project) that contains vehicle/equipment hours and fuel needed per unit of use.	17, 30

PARAMETER	UNIT	DESCRIPTION	SOURCE	USED IN EQ.
$GD_{p,l,y}$	days	Grazing days per livestock type l on Participant Field p in year y	University extension, producer, or other production report containing average grazing days per livestock type l in the project region.	27, 28
GE	MJ head^{-1} day^{-1}	Gross energy intake	Literature, government reports, or expert opinion.	29
$M_{BL/PR,SN_{p,j,y}}$	MT	Mass of synthetic fertilizer type j applied to Participant Field p in year y	County-level producer surveys conducted by a government agricultural agency(ies) or university extension offices, or the expert opinion of an university extension personnel working in the region and systems of interest, personnel of a governmental agriculture agency field office (e.g., USDA's RMA, FSA, NRCS) with jurisdiction in the Project Region, or Cropland management plans approved by a lending agency.	13, 24
$M_{BL/PR,ON_{p,k,y}}$	MT	Mass of organic N amendment type k applied to Participant Field p in year y	County-level producer surveys conducted by a government agricultural agency(ies) or university extension offices, or the expert opinion of an university extension personnel working in the region and systems of interest, personnel of a governmental agriculture agency field office (e.g., USDA's RMA, FSA,	14, 25

PARAMETER	UNIT	DESCRIPTION	SOURCE	USED IN EQ.
			NRCS) with jurisdiction in the Project Region, or Cropland management plans approved by a lending agency.	
$N_{BL/PR,ON_k}$	MT-N (MT input)$^{-1}$	Nitrogen content of organic N amendment type k	Producer of nitrogen if a commercially produced product. Otherwise IPCC defaults or values from the literature.	14, 25
$N_{BL/PR,SN_j}$	MT-N (MT input)$^{-1}$	Nitrogen content of synthetic fertilizer type j	Producer of fertilizer	13, 24
N_{rate_l}	kg N (1,000 kg animal mass)$^{-1}$ day^{-1}	N excretion rate	Default values may be found in Table 10.19, Chapter 10 IPCC 2006 AFOLU GL	27
$P_{p,l}$	number of head	Population of livestock type l	Where the Project Proponent can demonstrate that any positive change in enteric methane would be de minimus then it is not required that livestock populations must be monitored at the level of the Participant Field. This could be done by identifying the maximum stocking rate observed in the Project Region and calculating the difference in enteric methane emission between the baseline and maximum stocking rate.	26, 28

PARAMETER	UNIT	DESCRIPTION	SOURCE	USED IN EQ.
TAM_l	kg animal^{-1}	Typical animal mass for livestock category l	Literature, government reports, or expert opinion.	27
L		Total number of livestock types in project scenario	Project Proponent	26, 28
J		Total number of synthetic N inputs, j	Project Proponent	13, 24
K		Total number of organic N amendments, k	Project Proponent	14, 25
V		Total number of vehicles, v	Project Proponent	17, 30
F		Total number of fossil fuels, f	Project Proponent	17, 30

APPENDIX B: COUNTY MAP FOR UNIDENTIFIED AGENT OF CONVERSION



Project fields/parcels located in the counties highlighted in orange have a baseline scenario of cropland for unidentified agents of conversion and surpass the practice-based performance standard for demonstrating additionality. Project fields/parcels in white counties must determine the baseline land-use scenario and demonstrate additionality according to sections 3.1.1.2 and 3.2.2.2 respectively.

STATE	COUNTY
AL	Baldwin County
	Barbour County
	Bullock County
	Calhoun County
	Cherokee County
	Colbert County
	Covington County
	Cullman County
	Dallas County
	DeKalb County
	Escambia County
	Etowah County
	Franklin County
	Geneva County
	Henry County
	Houston County
	Jackson County
	Lauderdale County
	Lawrence County
	Limestone County
	Macon County
	Madison County
	Marengo County
	Marshall County
	Morgan County
	Perry County
	Talladega County
AR	Ashley County
	Chicot County
	Conway County
	Crawford County
	Drew County
	Jackson County
	Lafayette County
	Little River County
	Lonoke County
	Miller County
	Perry County
	Pope County
	Yell County
AZ	Yuma County
CA	Amador County
	Contra Costa County
	Fresno County
	Glenn County
	Imperial County
	Kings County
	Lake County
	Madera County
	Merced County
	Napa County
	Sacramento County
	San Joaquin County
	San Luis Obispo County
	Solano County
	Sonoma County
	Stanislaus County
	Tulare County
	Yolo County
CO	Adams County
	Alamosa County
	Arapahoe County
	Baca County
	Cheyenne County
	Conejos County
	Delta County
	Denver County
	Dolores County
	Eagle County
	Elbert County
	Garfield County
	Kiowa County
	Kit Carson County
	La Plata County
	Lincoln County
	Logan County
	Mesa County
	Moffat County
	Montezuma County
	Montrose County
	Morgan County
	Phillips County
	Pitkin County
	Prowers County
	Rio Blanco County
	Rio Grande County
	Routt County
	Saguache County
	San Miguel County
	Washington County
FL	Alachua County
	Citrus County
	Columbia County
	Dixie County
	Gilchrist County
	Hamilton County
	Jackson County
	Lafayette County
	Levy County
	Madison County
	Marion County
	Suwannee County
GA	Appling County
	Atkinson County
	Bacon County

STATE	COUNTY
	Baker County
	Bartow County
	Berrien County
	Bleckley County
	Brooks County
	Burke County
	Calhoun County
	Chattooga County
	Coffee County
	Colquitt County
	Crawford County
	Crisp County
	Decatur County
	Dodge County
	Dougherty County
	Early County
	Floyd County
	Gordon County
	Hart County
	Houston County
	Irwin County
	Jeff Davis County
	Jefferson County
	Jenkins County
	Johnson County
	Lamar County
	Lanier County
	Lee County
	Macon County
	Miller County
	Mitchell County
	Monroe County
	Montgomery County
	Morgan County
	Murray County
	Peach County
	Pierce County
	Polk County
	Putnam County
	Richmond County
	Screven County
	Seminole County
	Spalding County
	Sumter County
	Taylor County
	Telfair County
	Terrell County
	Thomas County
	Toombs County
	Treutlen County
	Walker County
	Walton County
	Warren County
	Washington County
	Wheeler County
	White County
	Worth County
IA	Adair County
	Adams County
	Allamakee County
	Appanoose County
	Audubon County
	Benton County
	Black Hawk County
	Butler County
	Carroll County
	Cass County
	Cedar County
	Cherokee County
	Chickasaw County
	Clarke County
	Clay County
	Clayton County
	Clinton County
	Crawford County
	Dallas County
	Davis County
	Decatur County
	Delaware County
	Des Moines County
	Dickinson County
	Dubuque County
	Emmet County
	Fayette County
	Floyd County
	Franklin County
	Fremont County
	Greene County
	Grundy County
	Guthrie County
	Hancock County
	Hardin County
	Harrison County
	Henry County
	Howard County
	Ida County
	Iowa County
	Jackson County
	Jasper County
	Jefferson County
	Johnson County
	Jones County
	Keokuk County
	Lee County
	Linn County
	Louisa County
	Lucas County
	Lyon County

STATE	COUNTY
	Madison County
	Mahaska County
	Marion County
	Marshall County
	Mills County
	Mitchell County
	Monona County
	Monroe County
	Montgomery County
	Muscatine County
	O'Brien County
	Osceola County
	Page County
	Plymouth County
	Polk County
	Pottawattamie County
	Poweshiek County
	Ringgold County
	Sac County
	Shelby County
	Sioux County
	Story County
	Tama County
	Taylor County
	Union County
	Van Buren County
	Wapello County
	Warren County
	Washington County
	Wayne County
	Winnebago County
	Winneshiek County
	Woodbury County
	Wright County
ID	Ada County
	Bannock County
	Bear Lake County
	Bingham County
	Bonneville County
	Butte County
	Camas County
	Canyon County
	Caribou County
	Elmore County
	Gooding County
	Jefferson County
	Latah County
	Lincoln County
	Madison County
	Oneida County
	Power County
IL	Adams County
	Alexander County
	Bond County
	Boone County
	Brown County
	Bureau County
	Calhoun County
	Carroll County
	Cass County
	Christian County
	Clay County
	Clinton County
	Coles County
	Crawford County
	Cumberland County
	DeKalb County
	Douglas County
	Edgar County
	Edwards County
	Effingham County
	Fayette County
	Ford County
	Franklin County
	Fulton County
	Gallatin County
	Greene County
	Hamilton County
	Hancock County
	Hardin County
	Henderson County
	Henry County
	Jackson County
	Jasper County
	Jefferson County
	Jersey County
	Jo Daviess County
	Johnson County
	Kane County
	Kankakee County
	Kendall County
	Knox County
	Lawrence County
	Lee County
	Livingston County
	Macoupin County
	Madison County
	Marion County
	Marshall County
	Mason County
	Massac County
	McDonough County
	McHenry County
	McLean County
	Menard County
	Mercer County
	Monroe County
	Montgomery County

STATE	COUNTY
	Morgan County
	Ogle County
	Peoria County
	Perry County
	Pike County
	Pope County
	Pulaski County
	Putnam County
	Randolph County
	Richland County
	Rock Island County
	Saint Clair County
	Saline County
	Schuyler County
	Scott County
	Shelby County
	Stark County
	Stephenson County
	Tazewell County
	Union County
	Vermilion County
	Wabash County
	Warren County
	Washington County
	Wayne County
	White County
	Whiteside County
	Will County
	Williamson County
	Winnebago County
IN	Adams County
	Allen County
	Benton County
	Blackford County
	Boone County
	Brown County
	Carroll County
	Cass County
	Clark County
	Clay County
	Crawford County
	Daviess County
	Decatur County
	DeKalb County
	Delaware County
	Dubois County
	Elkhart County
	Fayette County
	Floyd County
	Fountain County
	Franklin County
	Fulton County
	Gibson County
	Greene County
	Hamilton County
	Harrison County
	Hendricks County
	Henry County
	Huntington County
	Jackson County
	Jasper County
	Jay County
	Jefferson County
	Jennings County
	Knox County
	Kosciusko County
	LaGrange County
	LaPorte County
	Lawrence County
	Madison County
	Marshall County
	Martin County
	Miami County
	Monroe County
	Montgomery County
	Morgan County
	Newton County
	Noble County
	Orange County
	Owen County
	Perry County
	Pike County
	Porter County
	Pulaski County
	Putnam County
	Randolph County
	Ripley County
	Rush County
	Saint Joseph County
	Scott County
	Spencer County
	Starke County
	Steuben County
	Tippecanoe County
	Union County
	Vermillion County
	Vigo County
	Warren County
	Warrick County
	Washington County
	Wayne County
	White County
	Whitley County
KS	Allen County
	Atchison County
	Barton County
	Bourbon County
	Brown County

STATE	COUNTY
	Butler County
	Cherokee County
	Cheyenne County
	Clay County
	Cloud County
	Comanche County
	Crawford County
	Decatur County
	Dickinson County
	Doniphan County
	Douglas County
	Edwards County
	Ellis County
	Finney County
	Ford County
	Franklin County
	Gove County
	Graham County
	Grant County
	Gray County
	Greeley County
	Hamilton County
	Harper County
	Harvey County
	Haskell County
	Hodgeman County
	Jackson County
	Jefferson County
	Jewell County
	Johnson County
	Kearny County
	Kingman County
	Kiowa County
	Labette County
	Lane County
	Leavenworth County

STATE	COUNTY
	Lincoln County
	Linn County
	Logan County
	Marion County
	Marshall County
	McPherson County
	Meade County
	Miami County
	Mitchell County
	Montgomery County
	Morton County
	Nemaha County
	Neosho County
	Ness County
	Norton County
	Osage County
	Osborne County
	Ottawa County
	Pawnee County
	Phillips County
	Pratt County
	Rawlins County
	Reno County
	Republic County
	Rice County
	Rooks County
	Rush County
	Russell County
	Saline County
	Scott County
	Sedgwick County
	Seward County
	Shawnee County
	Sheridan County
	Sherman County
	Smith County

STATE	COUNTY
	Stafford County
	Stanton County
	Stevens County
	Sumner County
	Thomas County
	Trego County
	Wallace County
	Washington County
	Wichita County
	Wilson County
KY	Adair County
	Allen County
	Ballard County
	Barren County
	Bath County
	Bourbon County
	Boyle County
	Breckinridge County
	Bullitt County
	Butler County
	Caldwell County
	Calloway County
	Carlisle County
	Carroll County
	Casey County
	Christian County
	Clark County
	Clinton County
	Crittenden County
	Cumberland County
	Daviess County
	Edmonson County
	Estill County
	Fleming County
	Franklin County
	Fulton County

STATE	COUNTY
	Graves County
	Grayson County
	Green County
	Greenup County
	Hancock County
	Hardin County
	Hart County
	Henderson County
	Henry County
	Hickman County
	Hopkins County
	Larue County
	Lewis County
	Lincoln County
	Livingston County
	Logan County
	Lyon County
	Marion County
	Marshall County
	Mason County
	McCracken County
	McLean County
	Meade County
	Mercer County
	Metcalfe County
	Monroe County
	Muhlenberg County
	Nelson County
	Ohio County
	Powell County
	Pulaski County
	Rockcastle County
	Rowan County
	Russell County
	Scott County
	Shelby County

STATE	COUNTY
	Simpson County
	Spencer County
	Taylor County
	Todd County
	Trigg County
	Trimble County
	Union County
	Warren County
	Washington County
	Wayne County
	Webster County
LA	Allen Parish
	Avoyelles Parish
	Bossier Parish
	Evangeline Parish
	Grant Parish
	Iberville Parish
	Jefferson Davis Parish
	Natchitoches Parish
	Pointe Coupee Parish
	Rapides Parish
	Red River Parish
	Saint Landry Parish
MD	Allegany County
	Baltimore County
	Carroll County
	Cecil County
	Frederick County
	Garrett County
	Harford County
	Howard County
	Montgomery County
	Queen Anne's County
	Washington County
MI	Alcona County

STATE	COUNTY
	Allegan County
	Alpena County
	Arenac County
	Barry County
	Bay County
	Berrien County
	Branch County
	Calhoun County
	Cass County
	Clinton County
	Eaton County
	Genesee County
	Gladwin County
	Grand Traverse County
	Hillsdale County
	Huron County
	Ingham County
	Ionia County
	Iosco County
	Isabella County
	Jackson County
	Lapeer County
	Leelanau County
	Lenawee County
	Livingston County
	Macomb County
	Manistee County
	Mason County
	Mecosta County
	Missaukee County
	Muskegon County
	Oceana County
	Ogemaw County
	Oscoda County
	Ottawa County
	Saginaw County

STATE	COUNTY
	Saint Clair County
	Saint Joseph County
	Sanilac County
	Shiawassee County
	Tuscola County
	Washtenaw County
	Wayne County
MN	Aitkin County
	Anoka County
	Becker County
	Beltrami County
	Benton County
	Big Stone County
	Carver County
	Cass County
	Chippewa County
	Chisago County
	Clay County
	Clearwater County
	Cottonwood County
	Crow Wing County
	Dakota County
	Dodge County
	Douglas County
	Fillmore County
	Freeborn County
	Goodhue County
	Grant County
	Hennepin County
	Houston County
	Hubbard County
	Isanti County
	Jackson County
	Kanabec County
	Kandiyohi County
	Lac qui Parle County
	Lake of the Woods County
	Le Sueur County
	Lincoln County
	Lyon County
	Mahnomen County
	Marshall County
	McLeod County
	Meeker County
	Mille Lacs County
	Morrison County
	Mower County
	Murray County
	Norman County
	Olmsted County
	Otter Tail County
	Pennington County
	Pine County
	Pipestone County
	Polk County
	Pope County
	Red Lake County
	Redwood County
	Rice County
	Roseau County
	Scott County
	Sherburne County
	Sibley County
	Stearns County
	Steele County
	Stevens County
	Swift County
	Todd County
	Traverse County
	Wabasha County
	Wadena County
	Washington County
	Wilkin County
	Winona County
	Wright County
	Yellow Medicine County
MO	Adair County
	Andrew County
	Atchison County
	Audrain County
	Barry County
	Barton County
	Bates County
	Benton County
	Bollinger County
	Boone County
	Buchanan County
	Butler County
	Caldwell County
	Callaway County
	Cape Girardeau County
	Carroll County
	Cass County
	Cedar County
	Chariton County
	Clark County
	Clay County
	Clinton County
	Cole County
	Cooper County
	Dade County
	Daviess County
	DeKalb County
	Dunklin County
	Franklin County
	Gasconade County
	Gentry County
	Greene County

STATE	COUNTY
	Grundy County
	Harrison County
	Henry County
	Hickory County
	Holt County
	Howard County
	Jackson County
	Jasper County
	Johnson County
	Knox County
	Lafayette County
	Lawrence County
	Lewis County
	Lincoln County
	Linn County
	Livingston County
	Macon County
	Madison County
	Marion County
	Mercer County
	Moniteau County
	Monroe County
	Montgomery County
	Morgan County
	New Madrid County
	Newton County
	Nodaway County
	Perry County
	Pettis County
	Pike County
	Platte County
	Polk County
	Putnam County
	Ralls County
	Randolph County
	Ray County

STATE	COUNTY
	Saint Charles County
	Saint Clair County
	Saint Francois County
	Saint Louis County
	Sainte Genevieve County
	Saline County
	Schuyler County
	Scotland County
	Scott County
	Shelby County
	Stoddard County
	Sullivan County
	Vernon County
	Warren County
	Wayne County
	Worth County
MS	Adams County
	Alcorn County
	Benton County
	Calhoun County
	Chickasaw County
	Clay County
	Covington County
	DeSoto County
	George County
	Humphreys County
	Leake County
	Lee County
	Leflore County
	Lowndes County
	Monroe County
	Noxubee County
	Pontotoc County
	Sunflower County
	Union County
	Washington County

STATE	COUNTY
MT	Blaine County
	Broadwater County
	Chouteau County
	Daniels County
	Dawson County
	Fallon County
	Gallatin County
	Glacier County
	Golden Valley County
	Hill County
	Liberty County
	McCone County
	Petroleum County
	Phillips County
	Pondera County
	Roosevelt County
	Sheridan County
	Teton County
	Toole County
	Valley County
NC	Alamance County
	Anson County
	Burke County
	Cabarrus County
	Catawba County
	Cherokee County
	Clay County
	Cleveland County
	Davidson County
	Davie County
	Durham County
	Franklin County
	Gaston County
	Henderson County
	Hyde County

STATE	COUNTY
	Iredell County
	Lincoln County
	Mecklenburg County
	Mitchell County
	Orange County
	Pasquotank County
	Randolph County
	Rowan County
	Stanly County
	Surry County
	Transylvania County
	Union County
	Warren County
	Wilkes County
	Yadkin County
ND	Adams County
	Barnes County
	Benson County
	Billings County
	Bottineau County
	Bowman County
	Burke County
	Burleigh County
	Cass County
	Cavalier County
	Dickey County
	Divide County
	Dunn County
	Eddy County
	Emmons County
	Foster County
	Grand Forks County
	Grant County
	Griggs County
	Hettinger County
	Kidder County
	LaMoure County
	Logan County
	McHenry County
	McIntosh County
	McLean County
	Mercer County
	Morton County
	Mountrail County
	Nelson County
	Oliver County
	Pembina County
	Pierce County
	Ramsey County
	Ransom County
	Renville County
	Richland County
	Rolette County
	Sargent County
	Sheridan County
	Slope County
	Stark County
	Steele County
	Stutsman County
	Towner County
	Walsh County
	Ward County
	Wells County
	Williams County
NE	Adams County
	Antelope County
	Banner County
	Boone County
	Box Butte County
	Boyd County
	Buffalo County
	Burt County
	Butler County
	Cass County
	Cedar County
	Clay County
	Colfax County
	Cuming County
	Dakota County
	Dawes County
	Dixon County
	Dodge County
	Fillmore County
	Franklin County
	Furnas County
	Gage County
	Gosper County
	Greeley County
	Hall County
	Hamilton County
	Harlan County
	Holt County
	Howard County
	Jefferson County
	Johnson County
	Kearney County
	Kimball County
	Knox County
	Lancaster County
	Madison County
	Merrick County
	Nance County
	Nemaha County
	Nuckolls County
	Otoe County
	Pawnee County
	Perkins County
	Phelps County

STATE	COUNTY
	Pierce County
	Platte County
	Polk County
	Red Willow County
	Richardson County
	Saline County
	Sarpy County
	Saunders County
	Seward County
	Sherman County
	Stanton County
	Thayer County
	Thurston County
	Valley County
	Washington County
	Wayne County
	Webster County
	Wheeler County
	York County
NJ	Hunterdon County
	Warren County
NM	Curry County
	Quay County
	Roosevelt County
NY	Albany County
	Allegany County
	Broome County
	Cattaraugus County
	Cayuga County
	Chautauqua County
	Chemung County
	Chenango County
	Clinton County
	Columbia County
	Cortland County

STATE	COUNTY
	Dutchess County
	Erie County
	Franklin County
	Genesee County
	Herkimer County
	Jefferson County
	Lewis County
	Livingston County
	Madison County
	Monroe County
	Montgomery County
	Niagara County
	Oneida County
	Onondaga County
	Ontario County
	Orleans County
	Oswego County
	Otsego County
	Rensselaer County
	Saint Lawrence County
	Saratoga County
	Schoharie County
	Schuyler County
	Seneca County
	Steuben County
	Tioga County
	Tompkins County
	Washington County
	Wayne County
	Wyoming County
	Yates County
OH	Adams County
	Allen County
	Ashland County
	Ashtabula County
	Athens County

STATE	COUNTY
	Auglaize County
	Brown County
	Butler County
	Champaign County
	Clark County
	Clermont County
	Clinton County
	Columbiana County
	Coshocton County
	Crawford County
	Darke County
	Defiance County
	Delaware County
	Fairfield County
	Fayette County
	Franklin County
	Fulton County
	Gallia County
	Greene County
	Hardin County
	Highland County
	Hocking County
	Holmes County
	Huron County
	Jackson County
	Knox County
	Licking County
	Logan County
	Lorain County
	Madison County
	Mahoning County
	Marion County
	Medina County
	Mercer County
	Montgomery County
	Morgan County

STATE	COUNTY
	Morrow County
	Muskingum County
	Perry County
	Pickaway County
	Pike County
	Portage County
	Preble County
	Richland County
	Ross County
	Sandusky County
	Scioto County
	Seneca County
	Shelby County
	Stark County
	Trumbull County
	Tuscarawas County
	Union County
	Warren County
	Wayne County
	Williams County
	Wyandot County
OK	Alfalfa County
	Beckham County
	Blaine County
	Bryan County
	Caddo County
	Canadian County
	Cimarron County
	Cotton County
	Craig County
	Custer County
	Garfield County
	Grant County
	Greer County
	Harmon County
	Harper County
	Jackson County
	Jefferson County
	Kay County
	Kingfisher County
	Kiowa County
	Le Flore County
	Major County
	McCurtain County
	Muskogee County
	Ottawa County
	Roger Mills County
	Sequoyah County
	Texas County
	Tillman County
	Tulsa County
	Wagoner County
	Washita County
OR	Benton County
	Gilliam County
	Linn County
	Marion County
	Morrow County
	Polk County
	Sherman County
PA	Adams County
	Allegheny County
	Armstrong County
	Beaver County
	Bedford County
	Berks County
	Blair County
	Bradford County
	Butler County
	Cambria County
	Carbon County
	Centre County
	Chester County
	Clarion County
	Clearfield County
	Clinton County
	Columbia County
	Crawford County
	Cumberland County
	Dauphin County
	Erie County
	Fayette County
	Franklin County
	Fulton County
	Greene County
	Huntingdon County
	Indiana County
	Jefferson County
	Juniata County
	Lancaster County
	Lawrence County
	Lebanon County
	Lehigh County
	Luzerne County
	Lycoming County
	Mercer County
	Mifflin County
	Monroe County
	Montour County
	Northumberland County
	Perry County
	Potter County
	Schuylkill County
	Snyder County
	Somerset County
	Sullivan County
	Union County

STATE	COUNTY
	Venango County
	Warren County
	Washington County
	Westmoreland County
	York County
SC	Cherokee County
	Chesterfield County
SD	Aurora County
	Beadle County
	Bennett County
	Bon Homme County
	Brookings County
	Brown County
	Brule County
	Buffalo County
	Campbell County
	Charles Mix County
	Clark County
	Clay County
	Codington County
	Davison County
	Day County
	Deuel County
	Douglas County
	Edmunds County
	Faulk County
	Grant County
	Gregory County
	Haakon County
	Hamlin County
	Hand County
	Hanson County
	Hughes County
	Hutchinson County
	Hyde County
	Jackson County
	Jerauld County
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	Kingsbury County
	Lake County
	Lincoln County
	Lyman County
	Marshall County
	McCook County
	McPherson County
	Meade County
	Miner County
	Minnehaha County
	Moody County
	Pennington County
	Perkins County
	Potter County
	Roberts County
	Sanborn County
	Spink County
	Stanley County
	Sully County
	Tripp County
	Turner County
	Union County
	Walworth County
	Yankton County
TN	Bedford County
	Benton County
	Bledsoe County
	Blount County
	Bradley County
	Cannon County
	Carroll County
	Cheatham County
	Chester County
	Clay County
	Cocke County
	Coffee County
	Crockett County
	Davidson County
	Decatur County
	DeKalb County
	Dickson County
	Dyer County
	Fayette County
	Franklin County
	Gibson County
	Giles County
	Grundy County
	Hamblen County
	Hardeman County
	Hardin County
	Haywood County
	Henderson County
	Henry County
	Hickman County
	Houston County
	Humphreys County
	Jackson County
	Jefferson County
	Lauderdale County
	Lawrence County
	Lewis County
	Lincoln County
	Loudon County
	Macon County
	Madison County
	Marion County
	Marshall County
	Maury County
	McMinn County

STATE	COUNTY
	McNairy County
	Meigs County
	Monroe County
	Montgomery County
	Obion County
	Perry County
	Polk County
	Robertson County
	Rutherford County
	Sequatchie County
	Smith County
	Stewart County
	Sumner County
	Tipton County
	Trousdale County
	Warren County
	Wayne County
	Weakley County
	White County
	Williamson County
TX	Archer County
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	Lamb County
	Limestone County
	Lubbock County
	Lynn County
	Martin County
	Matagorda County
	McCulloch County
	McLennan County
	Milam County
	Mills County
	Mitchell County
	Montague County
	Moore County
	Navarro County
	Nolan County
	Nueces County
	Ochiltree County
	Parmer County
	Randall County
	Reagan County
	Red River County
	Robertson County
	Rockwall County
	Runnels County
	San Patricio County
	Schleicher County
	Scurry County

STATE	COUNTY	STATE	COUNTY	STATE	COUNTY
	Sherman County		Buckingham County		Wythe County
	Swisher County		Campbell County	VT	Addison County
	Taylor County		Caroline County		Franklin County
	Terry County		Charlotte County		Grand Isle County
	Throckmorton County		Clarke County	WA	Adams County
	Tom Green County		Culpeper County		Benton County
	Uvalde County		Cumberland County		Columbia County
	Wharton County		Dinwiddie County		Douglas County
	Wheeler County		Fauquier County		Ferry County
	Wichita County		Fluvanna County		Franklin County
	Wilbarger County		Franklin County		Garfield County
	Willacy County		Frederick County		Grant County
	Williamson County		Goochland County		Kittitas County
	Yoakum County		Greene County		Klickitat County
UT	Box Elder County		Halifax County		Okanogan County
	Cache County		Hanover County		Skagit County
	Davis County		King George County		Snohomish County
	Emery County		King William County		Spokane County
	Garfield County		Loudoun County		Stevens County
	Juab County		Louisa County		Walla Walla County
	Millard County		Lunenburg County		Whatcom County
	Morgan County		Madison County		Whitman County
	Piute County		Mecklenburg County		Yakima County
	San Juan County		Nelson County	WI	Adams County
	Sanpete County		Nottoway County		Ashland County
	Sevier County		Orange County		Barron County
	Utah County		Page County		Bayfield County
	Wayne County		Pittsylvania County		Brown County
	Weber County		Powhatan County		Buffalo County
VA	Albemarle County		Rappahannock County		Burnett County
	Amelia County		Richmond County		Calumet County
	Appomattox County		Rockbridge County		Chippewa County
	Augusta County		Rockingham County		Clark County
	Bath County		Shenandoah County		Columbia County
	Brunswick County		Spotsylvania County		Crawford County
			Stafford County		

STATE	COUNTY
	Dane County
	Dodge County
	Door County
	Dunn County
	Eau Claire County
	Fond du Lac County
	Grant County
	Green County
	Green Lake County
	Iowa County
	Jackson County
	Jefferson County
	Juneau County
	Kenosha County
	Kewaunee County
	La Crosse County
	Lafayette County
	Manitowoc County
	Marquette County
	Monroe County
	Oconto County
	Outagamie County
	Ozaukee County
	Pepin County
	Pierce County
	Polk County
	Portage County
	Racine County
	Richland County
	Rock County
	Rusk County
	Saint Croix County
	Sauk County
	Shawano County
	Sheboygan County
	Trempealeau County

STATE	COUNTY
	Vernon County
	Walworth County
	Washburn County
	Washington County
	Waupaca County
	Waushara County
	Winnebago County
	Wood County
WV	Berkeley County
	Greenbrier County
	Hardy County
	Jefferson County
	Mason County
	Mineral County
	Preston County
	Tucker County
WY	Big Horn County
	Crook County
	Laramie County
	Lincoln County
	Weston County

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A.1.3 Compost Additions to Grazed Grasslands

The American Carbon Registry™

Methodology for
Compost Additions to Grazed Grasslands

Version 1.0

October 2014

A nonprofit enterprise of

WINROCK INTERNATIONAL

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Table of Contents

A. Methodology Description

A.1 Acronyms

ACR	American Carbon Registry
CDM	Clean Development Mechanism
CH_4	Methane
CO_2	Carbon Dioxide
EPA	Environmental Protection Agency
ERT	Emission Reduction Ton
GHG	Greenhouse Gas
N_2O	Nitrous Oxide
NRCS	Natural Resources Conservation Service
PBM	Process-based Biogeochemical Model
SOC	Soil Organic Carbon
VCS	Verified Carbon Standard
VVB	Validation and Verification Body

A.2 Background

Grazed grasslands are defined by the Natural Resource Conservation Service (NRCS) of the United States Department of Agriculture (USDA) as "land on which the vegetation is dominated by grasses, grass-like plants, shrubs and forbs." This definition includes land that contains forbs, shrubland, improved pastureland, and improved rangeland for which grazing is the predominant use (NRCS 2009). Adding compost to Grazed Grasslands can be an effective way to increase soil carbon sequestration and avoid emissions related to the anaerobic decomposition of organic waste material in landfills. In addition to climate benefits, adding compost stimulates forage growth and can improve the quality of soils. This document contains a methodology to account for the carbon sequestration and avoided GHG emissions related to compost additions to Grazed Grasslands, following specifications by the American Carbon Registry (ACR). The current version of this methodology includes only one project activity – compost addition to Grazed Grasslands. Additional project practices and additional organic soil amendment types may be added in future revisions. This approach will allow the experience gained from the first projects to be incorporated in future versions of the methodology.

Grassland soils are an important sink for carbon, accounting for approximately 20 % of the world's soil carbon stocks (FAOSTAT 2009; Conant 2010). The amount of carbon stored in grassland soils is largely driven by environmental conditions such as temperature, rainfall, and soil characteristics, as well as the productivity of various grassland plant communities (Derner and Schuman 2007). These factors are subject to temporal variability both within seasons and across multiple years (Svejcar et al. 2008; Ingrahm et al. 2008). Many grasslands in the US have been degraded through overgrazing which in some cases can lead to declines in soil organic matter (Conant and Paustian 2002). However, research also suggests that with improved management grassland soils can also offer considerable potential to aid greenhouse mitigation efforts through additional soil carbon sequestration (Lal 2002; Conant and Paustian 2002; Derner and Schuman 2007).

One management strategy that may hold promise for enhancing carbon sequestration in grasslands is the application of organic soil amendments such as compost or composted biosolids. A growing body of research indicates that the application of these organic materials can often have positive impacts on the amount of carbon stored in both grassland (Walter et al. 2006; Ippolito et al. 2010; Kowaljow et al. 2010; Ryals et al. 2014) and cropland soils (Canali et al. 2004; Celic et al. 2004; Montovi et al. 2005; Cai and Qin 2006). The buildup of soil carbon occurs via two mechanisms; 1) directly from carbon contained in the compost, and 2) indirectly through enhanced plant growth and subsequent deposition of plant biomass (Walton et al. 2001; Walter et al. 2006; Ryals and Silver 2013). The recent model work of Zhai et al. 2014 demonstrates gains in soil organic carbon due to application of biosolids for 10 years, with further SOC gains over the next 10 or more years due to biomass and/or carbon sequestration.

A number of peer-reviewed studies involving the application of compost or composted biosolids to temperate grasslands have been carried out over both short-term (0-5 yrs) and long-term (5-14 yrs) experimental periods. At two Mediterranean grassland sites in California, Ryals et al. (2014) measured C sequestration years after a single compost addition. Compost amendment resulted in a significant increase in bulk soil organic C content at a Central Valley site, and a similar but non-significant trend at a Coast Range site. Compost additions also significantly increased plant growth as measured by net primary productivity at both the Central Valley and Coast Range sites (Ryals and Silver 2013). Likewise, in a three year study conducted at a semi-arid steppe site in northwest Patagonia, the application of composted biosolids (40 t ha-1) also increased plant growth and soil organic matter relative to an untreated control (Kowaljow et al. 2010). More importantly, several long-term grassland experiments have also found that the effect of compost application on plant growth and soil C can persist for more than a decade (Sullivan et al. 2006; Ippolito et al. 2010; Walton et al. 2001). For instance, at a semi-arid grassland site in Colorado differences in plant growth (Sullivan et al. 2006) and total soil C (Ippolito et al. 2010) were still detectable 14 years after applying compost at 6 different rates (0, 2.5, 5, 10, 21, and 30 t ha-1). Similarly Walton et al. (2001) found that 32% of applied biosolids remained as particles greater than 2mm 18 years after application to an arid rangeland site in New Mexico. The above-mentioned studies and others in the broader peer-reviewed literature provide evidence that compost application to grasslands can facilitate long-term soil C sequestration and improved plant growth, and thus form the scientific basis for the current methodology.

A.3 Summary Description of the Methodology

Compost additions to Grazed Grasslands can generate Emission Reduction Tons (ERTs) from avoided Greenhouse Gas (GHG) emissions and removals resulting from three processes:

1) **Avoidance of anaerobic decomposition (Optional)** of the organic material used in compost production. Methane (CH_4) emissions that result from anaerobic decomposition of the organic material used in the production of compost under baseline conditions – for example, when the organic matter is buried in landfills – can be avoided by composting[1] and applying compost on Grazed Grasslands. It is not required in this methodology to include the avoided emissions from preventing the anaerobic decomposition of the organic material used in the production of compost. However, if these avoided emissions are included, evidence must be provided that (1) the avoided emissions have not been claimed under a different Carbon Credit program, such as the Climate Action Reserve's composting methodology, and that (2) the baseline fate of the organic matter can be demonstrated following the procedures included in Section C of this methodology.
2) **Direct increase in soil organic carbon (SOC) content (Required)** through adding a carbon source from compost. The carbon (C) content of applied compost will lead to a direct increase in soil organic carbon (SOC) content of the Grazed Grasslands where the compost is applied. Even though the carbon added through compost additions will gradually decompose over time, a significant portion will end up in stable carbon pools. The portion of the compost carbon that will remain in the stable pools is likely to be greater than the portion that would be stabilized under baseline conditions. Only the stable carbon pools that are predicted to remain after 40 years after compost addition can be counted. These stable soil C pools are conceptually equivalent to the "intermediate" and "passive" C pools defined in recent literature reviews by Trumbore (1997) and Adams *et al.* (2011). This 40 year period is also similar in duration to the 40 year minimum project term used in the approved ACR Forest Carbon Project protocol (ACR 2010). As such, the minimum project period for this protocol is 40 years.
3) **Indirect increase in SOC sequestration (Required)** through enhanced plant growth in Grazed Grasslands amended with compost. The N and P content of the compost, as well as the improved soil water holding capacity of soils amended with compost, may in some cases lead to an indirect increase in SOC content through an increase in net primary productivity (NPP). The impact of compost on SOC content will depend on the compost's nutrient content and availability, the soil properties, and grazing management strategies.

This methodology requires the use of a model to predict direct and indirect changes in SOC under the baseline and project scenarios. This methodology does not prescribe a specific model. The model can be either a process-based biogeochemical model (PBM) such as the DAYCENT or Denitrification-Decomposition (DNDC) models, or an empirical model such as a Tier-2 Empirical Model that is shown to

[1] Whereas composting is mostly an aerobic process that occurs in presence of oxygen, composting may still release a small amount of methane.

be effective for the conditions of the Project Parcels (see Section D.1). It is up to the project proponents to demonstrate that the model is sufficiently accurate for the Project Parcels (see section D.1 for model requirements). Under the baseline scenario, the model is used to simulate any on-going changes to SOC, including potential continuing loss of SOC. Under the project scenario, the model is used to simulate the amount of compost carbon that is stored in recalcitrant SOC pools, and any indirect changes in SOC due to an increase in net primary production and under specific grazing management strategies. Even though empirical models and PBMs have been shown to be highly valid across a wide range of management practices and geographic areas, soil samples and field measurements are required to validate the models for use in specific Project Parcels. As a consequence, this methodology requires monitoring by periodic (10 year) analyses of soil samples for model validation at different times throughout the project's lifetime.

Adding compost to Grazed Grasslands has the potential to increase GHG emissions from secondary sources. Specifically, N_2O emissions from soils are produced due to nitrification and de-nitrification of the available N added through the compost addition (Box 1). These processes further require a carbon source, which is readily available after compost addition. Indirect emissions from nitrate leaching may also occur but GHG emissions resulting from the leached nitrate are expected to be insignificant, at the rate compost is applied in projects under this methodology based on findings reported by DeLonge et al. (2013) for California grasslands. In addition to soil N_2O emissions (from de-nitrification), all emissions from fuel that was used to create, transport, or apply the compost is included in the quantification procedure. Under this methodology, soil N_2O emissions are quantified using an applicable Tier-2 Empirical Model, or a calibrated PBM. The GHG emissions from increased fuel use must be quantified using standard emission factors. Likewise, enteric emissions from increases in stocking must be quantified with the ACR Grazing Land and Livestock Management MICROSCALE Tool for Tier I estimation of emissions from enteric methane.

Apart from the economic benefit of increased forage production, applying compost to Grazed Grasslands also has many environmental co-benefits, such as improved soil quality and increased nutrient and water availability for vegetation due to improved soil water holding capacity, which increases resilience to more intense precipitation events, slows the onset of drought, and confers additional ecosystem services. Compost application may also reduce erosion in certain contexts due to improvements in vegetation cover. Compost can be added to most existing Grazed Grasslands.

Box 1. Further background on N_2O fluxes after compost application

The magnitude of the N_2O fluxes after compost addition may be highly variable and difficult to predict. For example, in an experiment where N_2O fluxes were measured after a one-time compost addition on two sites in California, no significant increases in N_2O fluxes were observed (Ryals and Silver 2012). In laboratory incubations under controlled conditions, however, a pulse of N_2O emissions was detected in soils after compost addition that was significantly greater than soils to which no compost was added. However, the pulse was short-lived (four days), and represented only a very small component of the net soil GHG emissions (expressed as CO_2-equivalents) released from the controlled wet up event (Ryals and

Silver 2012). Such conditions represent ideal conditions for N_2O release and are unlikely to be present for a long period of time in the field. High-nitrogen organic materials such as manure or processed manure additions may be more prone to N_2O emissions. Due to the difficulty in predicting N_2O emissions, this methodology allows some flexibility in the approach to quantify N_2O.

Production of N_2O is generally greatest under warm and humid conditions and where soil nitrogen concentrations are highest. Therefore, the timing of compost application relative to weather conditions and plant demand is crucial to minimize N_2O emissions. If the Grazed Grassland is dominated by annual plants and the compost application occurs before plant establishment, a significant amount of inorganic N may remain in the soil, resulting in significant N_2O fluxes. However, in a Mediterranean climate, there is an ideal window for applying compost. Specifically, fall applications are preferred, ideally shortly before first rains and prior to plant establishment in annual-dominated grasslands. Once the soil gets wet, compost applications may become more logistically challenging due to restricted access to the field as well as less beneficial, while initial growth of annuals in response to early rains can be expected to help limit inorganic N losses from the soil. The ideal window for compost addition may be different for other climates. In this protocol we require following the advice from a Qualified Expert (i.e., a Certified Rangeland Manager, NRCS Soil Conservationist or Qualified Extension Agent) as to when to apply compost.

A.4 Definitions

If not explicitly defined here, the current definitions in the latest version of the American Carbon Registry Standard apply.

Compost	The end product of a process of controlled aerobic decomposition of organic materials, consistent with California Department of Resources Recycling and Recovery (CalRecycle) standards (http://www.calrecycle.ca.gov/Laws/Regulations/Title14/ch31.htm).
Grassland	We follow the terminology of Allen et al. (2011), who indicate that the term grassland bridges pastureland and rangeland and may be either a natural or an imposed ecosystem. Grassland has evolved to imply a broad interpretation for lands committed to a forage use.
Grazed Grassland	Grassland on which annual grazing by livestock (including cattle, horses, sheep and goats) is the primary means of forage/biomass removal. In this protocol, if any grazing takes place on a yearly basis under historical baseline management the parcel may be considered “grazed” (see section E.1).
Native Grassland	A grassland where native plant species comprise greater than 10 percent of the

	total relative cover (Stromberg et al. 2007).
Process-based Biogeochemical Model	Computer model that is able to simulate biogeochemical processes and predict GHG fluxes, nutrient contents and/or water contents.
Project	The activities undertaken on a Project Parcel to generate GHG emission reductions.
Project Parcel	Individual contiguous parcel unit of grassland under control of the same entity/entities.
Qualified Expert	A Qualified Expert can be a Certified Rangeland Manager, NRCS Soil Conservationist or Qualified Extension Agent. A Qualified Expert is a professional certified to provide consulting services on all activities devoted to rangeland resources. These services include, but are not limited to, making management recommendations, developing conservation plans and management plans, monitoring, and other activities associated with professional rangeland management.
Stocking Rate	The amount of land allocated to each livestock unit for the grazing period of each year, or alternatively, the number of livestock units per hectare for the grazing period. Stocking Rate must include the number of livestock units (LU)[2], land area per LU, and the amount of time a given number of LUs occupy a given unit of land. In case rotational grazing is employed, the Stocking Rate shall include specifics on the rotational grazing management, including such factors as species, numbers, length of stay, length of rest between grazing periods, frequency of return per annum or season, season(s) of use, etc.
Tier-2 Empirical Model	Empirical model such as a linear regression model calibrated for a specific region. In the context of this methodology, a Tier-2 Empirical Model predicts SOC content or N_2O emissions as a function of one or more driving variables, such as compost carbon added, nitrogen added, clay content, annual rainfall, etc.
Waste Material	The original material that was Composted.

[2] Livestock units (also known as animal units) are a standardized measure used by the UN Food and Agriculture Organization to quantify Stocking Rates for multiple animal types and growth stages based on an estimate of the metabolic weight of the animals. A livestock unit is measured as livestock unit/time/hectare. More information on the quantification of livestock units for grazing systems in North America can be found at: http://www.lrrd.org/lrrd18/8/chil18117.htm

A.5 Applicability Conditions

In addition to satisfying the latest ACR program requirements, project activities must satisfy the following conditions for this methodology to apply:

- The Project includes one or more Project Parcels that are Grazed Grasslands at the start of the Project and remain Grazed Grasslands for the duration of the Project (Box 2).
- The annual, minimum and maximum Stocking Rate shall be determined via consultation with a Qualified Expert (see definitions – a Certified Rangeland Manager, NRCS Soil Conservationist or Qualified Extension Agent) and duly justified by the Project Proponent. Justification for the annual Stocking Rate should include a calculation of the historical Stocking Rate averaged over a 5 year period prior to the start of the Project, and an assessment of whether or not the forage productivity and quality of the parcel can sustainably support the historical Stocking Rate. In some cases the conditions of the parcel will justify using the historical Stocking Rate as the annual, while in other cases the Qualified Expert may set an annual Stocking Rate that differs from the historical Stocking Rate. Validation of the GHG project plan will include a review of the criteria used by the Qualified Expert to ensure annual Stocking Rates during the Project lifetime are sustainable, and will not lead to erosion or negatively affect species composition; subsequent verifications will review changes to the annual Stocking Rate and ensure that a Qualified Expert was properly consulted. The maximum Stocking Rate shall be set so that rangeland utilization remains sustainable, taking into account an increase in forage production and any changes in the percentage of grazer feed coming from purchased sources after the start of the crediting period.[3] The minimum Stocking Rate shall be set to ensure that plant community species composition does not change toward a less desirable plant community in response to soil quality changes following compost application.
- Any soils that are regularly flooded (i.e. more than two months per year), shall be excluded from the Project Parcels.[4] At the start of the Project the Qualified Expert must identify any land within the parcel that ought to be excluded due to a high likelihood of annual flooding. These areas can be detected by observing the topographic position in the landscape, as well as clear shifts in vegetation and soil redox features (e.g. gleying). These areas must be excluded from the Project Parcel at the beginning of the crediting period. Additionally, and in consultation with a Qualified Expert, compost application should occur in accordance with local and/or state regulations regarding application and water quality concerns. In order to prevent any unintended negative impact on forage growth, compost should not be more than ½ inch in depth at any part of the application area.
- The compost added to the Project Parcel must be within the following specifications:

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[3] This approach is fully compatible with a rotational grazing strategy.

[4] The no-flood requirement is added to prevent the inclusion of land areas where a significant amount of CH_4 is likely to be emitted from soils in the project area; the accounting for methanogenesis is not included.

- The final end product after composting must have a nitrogen concentration of less than 3%[5] on a dry-weight basis.
- Best Management Practices put forward by state agencies have been followed in making the compost free of any seeds or propagules capable of germination or growth.
- The heavy metal and contaminant content of composts shall not exceed limits of the US EPA under 40 CFR 503.[6]
- The compost must be produced in accordance with Chapter 5 of EPA Part 503 Biosolids Rule process to further reduce pathogens (PFRP) and other contaminants.[7]
- Waste Material containing food waste or manure must be either (1) mixed and incorporated into the composting process within 24 hours of delivery of the waste to the composting facility, (2) covered or blended with a layer of high-carbon materials such as wood chips or finished compost within 24 hours of delivery, and mixed and incorporated into the composting process no more than 72 hours after delivery, (3) placed in a controlled environment within 24 hours of delivery, or (4) handled using any other alternative Best Management Practices to avoid anaerobic decomposition after delivery and before incorporation into the composting process of the source material.[8]

  Compost material that was produced consistently with the standards put forward by the California Department of Resources Recycling and Recovery is automatically approved.

Box 2. Further background on species composition changes and minimum grazing requirements

Compost applications may lead to changes in the plant community (either positive or negative) due to impacts of compost on nutrient concentrations and hydrology of treated soils (Bremer, 2009). The protocol does not support application of compost to intact, healthy native plant communities. Whether a grassland constitutes a healthy native plant community is best determined in consultation with a

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[5] This would prevent materials that more closely resemble synthetic fertilizers from being used as an amendment.

[6] Because compost may contain trace levels of heavy metals, limits on the heavy metal contents in fertilizers, organic amendments, and biosolids are regulated through US EPA, 40 CFR Part 503. Under EPA regulations, managers must maintain records on the cumulative loading of trace elements only when bulk biosolids do not meet EPA Exceptional Quality Standards for trace elements.

[7] Chapter 5 focuses on Pathogen and Vector Attraction Reduction Requirements. On page 116, the Process to Further Reduce Pathogens is defined as "*using either the within-vessel composting method or the static aerated pile composting method, the temperature of the biosolids is maintained at 55/degree C or higher for 3 days. Using the windrow composting method, the temperature of the biosolids is maintained at 55/degree C for 15 days or longer. During the period when the compost is maintained at 55/degree C or higher, the windrow is turned a minimum of five times.*". The text is available at http://water.epa.gov/scitech/wastetech/biosolids/upload/2002_06_28_mtb_biosolids_503pe_503pe_5.pdf

[8] These requirements will ensure that emissions from storing waste at the composting facility are negligible, as justified in the "Organic Waste Composting Project Protocol" approved for use under the Climate Action Reserve.

qualified expert, as native plant communities are defined by their geography and are thus impacted by local conditions. Species composition may also change where grazing is discontinued due to factors unrelated to the project activity, such as extended periods of drought.[9] To reduce this risk, validation of the GHG project plan will include a review of the criteria used by the Qualified Expert to ensure that annual Project Stocking Rates will not contribute to erosion or otherwise negatively impact plant species composition. Changes to the annual Stocking Rate will be assessed during each subsequent verification to ensure changes were implemented in consultation with a Qualified Expert. The minimum Stocking Rate shall be set to ensure that plant community species composition is not negatively affected in response to soil quality improvement following compost application.

[9] Guidance on best practices for drought management can be found online at: http://pss.okstate.edu/publications/publications-master-list/copy_of_publications/forages/F-2870web.pdf

B. Project Boundaries

B.1 Geographic Boundary

B.1.1 Project Parcel

The GHG removals from carbon sequestration in the soil organic carbon pools of the Project Parcels are the focus of this methodology. The geographical boundary encompassing these Project Parcels is, therefore, the main geographic boundary of the Project. The geographical coordinates of the boundaries of each Project Parcel must be unambiguously defined by providing geographic coordinates.

New Project Parcels may be added to an existing Project after the start of the crediting period as long as all the applicability criteria are met for each individual Project Parcel, as outlined in ACR's most recent Standard.

B.1.2 Composting Facility (Optional)

In case GHG emission reductions from composting source material and avoidance of anaerobic decomposition are claimed as Emission Reduction Tons (ERTs) under this methodology, the composting facility shall be included in the geographic boundary. In this case, the project proponent(s) shall include a formal affidavit indicating that the emission reductions from composting source material and avoidance of anaerobic decomposition have never been claimed under any compliance or voluntary carbon registry. This affidavit would be issued by the project proponent(s) but will also include a signature from the owner of the composting facility attesting that the facility is not claiming carbon credits.

In case emission reductions from composting source materials are not claimed by the project participants, the composting facility is excluded from the Project's Geographic Boundary.

B.1.3 Stratification

This methodology encourages combining Project Parcels spread over a large geographic region within one Project to reduce costs. However, environmental, soil, and management conditions may not be homogeneous across a large geographic region. Non-homogeneous conditions may affect the validity of baseline calculations and additionality checks. Therefore, heterogeneous Project Parcels shall be subdivided into smaller units or strata that are considered homogeneous for the purpose of carbon accounting. A different set of input parameters to the model(s) for carbon accounting selected in Section D.1 shall be prepared for each different stratum. Parameters that shall be considered to stratify the Project Parcels are:

- Historical rangeland management practices
- Future rangeland management practices after the start of the Project

- Different soil types, especially special status soils (e.g., serpentine soils, histosols, etc.); official soil series description
- Ecological characteristics (soil texture, aspect, slope, hydrology, climate, plant communities)
- Degradation status (initial soil C content, soil bulk density)
- Differences in legally binding requirements affecting management of the Project (e.g., easement status of land, ownership)

The stratification must be conducted or approved by a Qualified Expert. A description and justification of the stratification procedure must be included in the GHG Project Plan. All subsequent procedures in this methodology, including baseline scenario identification and additionality tests must treat each identified stratum separately.

B.2 Greenhouse Gas Boundary

This section includes all sources, sinks, and reservoirs that are quantified in this methodology.

Baseline scenario:

- Emissions resulting from anaerobic decay of organic waste at a final disposal/treatment system (e.g., landfill or manure management system). This source is optional and may be omitted; doing so is conservative. If the composting facility will claim emission reductions from avoiding emissions from anaerobic decay of organic waste, this source may not be included in the GHG accounting for the project. If this source of emission reductions is claimed by the Project, the project proponent(s) shall include a formal affidavit indicating that no other party than the project proponent(s) have claimed the emission reductions from composting source material and avoidance of anaerobic decomposition under any compliance or voluntary carbon registry.
- Background changes of SOC, potentially related to continuous loss of soil organic carbon[10] of the Grassland as predicted through modeling.
- Enteric fermentation CH_4 emissions from ruminants grazing on project parcels.

Project scenario:

- Emissions resulting from the composting process, including active composting and curing of compost at project facilities. To avoid double deductions, this source of emissions shall be omitted in case the composting facility claims emission reductions for avoiding emissions from anaerobic decay of organic waste.
- Enteric fermentation CH_4 emissions from ruminants grazing on project parcels.
- Fossil fuel emissions from the transport of the finished compost to the Project Parcels.
- Emissions related to the land application of compost.

[10] Some evidence indicates that many grasslands are losing soil carbon (Chou *et al*. 2008, Ryals et al. submitted). Through compost additions, one may be able to slow down or reverse the carbon loss (Ryals & Silver 2013).

- Emissions of CO_2 and N_2O related to the decomposition of compost after application.
- Sequestration of carbon related to the increase in plant productivity on the grassland.
- Sequestration related to the transfer of compost into recalcitrant SOC pools.[11]

Fossil fuel emissions from transport of organic waste materials to final disposal/treatment system (e.g. garbage trucks, hauling trucks, etc.) under baseline conditions are assumed to be equal to the fossil fuel emissions from transporting waste materials to the compost facility in the project case[12], and are therefore not included in the GHG accounting (Brown et al*.* 2009).

The GHG emissions from storage of waste in the composting facility are assumed to be insignificant when the applicability conditions laid out in Section A.5 are followed.

[11] Only carbon stored in recalcitrant soil pools is considered sequestered

[12] Note that in case of on-farm composting, the fossil fuel emissions will likely be smaller in the project scenario. However, it is conservative to omit this extra emission reduction in case of on-farm composting.

Table 1. Overview of included Greenhouse Gas sources.

	Source	Gas	Included?	Justification/Explanation
Baseline	Project Parcels soil	CO_2	Yes	Emissions from decomposition of soil organic carbon
		CH_4	No	Non-flooded soils can be a source or sink of Methane but fluxes are negligible.
		N_2O	Yes	Nitrous oxide emissions from non-fertilized grassland soils are small but not negligible.
	Landfill or other waste sink	CO_2	Yes/No	Carbon dioxide emissions from organic materials are potentially significant in case these materials would have been deposited in landfills. This emission source is optional; omitting this source of emissions is conservative. However, when the composting facility claims emission reductions for avoiding emissions from anaerobic decay of organic waste, this source of emissions shall be omitted to avoid double deductions. This source must also be omitted in cases where the project developer does not know which landfill or other waste sink the material would have gone in the baseline scenario.
		CH_4	Yes/No	Methane emissions from organic materials are potentially significant in case these materials would have been deposited in landfills. This emission source is optional; omitting this source of emissions is conservative. However, when the composting facility claims emission reductions for avoiding emissions from anaerobic decay of organic waste, this source of emissions shall be omitted to avoid double deductions. This source must also be omitted in cases where the project developer does not know which landfill or other waste sink the material would have gone in the baseline scenario.
		N_2O	Yes/No	Nitrous oxide emissions from organic materials are potentially significant in case these materials would have been deposited in

				landfills. This emission source is optional; omitting this source of emissions is conservative. However, when the composting facility claims emission reductions for avoiding emissions from anaerobic decay of organic waste, this source of emissions shall be omitted to avoid double deductions. This source must also be omitted in cases where the project developer does not know which landfill or other waste sink the material would have gone.
	Ruminants	CH_4	Yes	Methane emissions from enteric fermentation from ruminants grazing on the land.
	Fossil fuel emissions from transport of organic waste to landfill	CO_2	No	Assumed to be equivalent to fossil fuel emissions from transport of organic waste to composting facility.
	Fossil fuel emissions from transport of imported forage	CO_2	No	Assumed to be conservative as project scenario is likely to require less importation of feed.
Project	Project Parcels soil	CO_2	Yes	Additional CO_2 emissions from compost application may occur and are included.
		N_2O	Yes	Additional N_2O emissions from compost application may occur and are included.
		CH_4	No	Non-flooded soils can be a source or sink of Methane but fluxes are negligible
	Ruminants	CH_4	Yes	Methane emissions from enteric fermentation from ruminants grazing on the land.
	Emissions due to leaching	N_2O	No	Secondary emissions from leachates of the composted material are negligible due to the complex nature of compost and the low nitrogen content of compost.
	Fossil fuel emissions from transport of organic waste	CO_2	No	Assumed to be equivalent to fossil fuel emissions from transport

	to the compost facility			of organic waste to landfill.
	Fossil fuel emissions from transport of compost to project parcel and application	CO_2	Yes	Assumed to be additional to the fossil fuel emissions from transport of organic waste to landfill or composting facility.
	Fossil fuel emissions from transport of imported forage	CO_2	No	Assumed to be conservative as project scenario is likely to require less importation of feed.
	Emissions due to composting	CO_2	No	Carbon dioxide emissions released during composting are biogenic. These emissions are not quantified in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 5: Waste, Chapter 4: Biological Treatment of Solid Waste and therefore are not included in this calculation of project emissions.
		CH_4	Yes/No	Some methane may be produced during composting. To avoid double deductions, this source of emissions shall be omitted in case the composting facility claims emission reductions for avoiding emissions from anaerobic decay of organic waste.
		N_2O	No	Nitrous oxide emissions during composting are negligible.

Table 2. Overview of included pools (baseline and project)

Pool	Included in emissions reductions quantification	Rationale
Above-ground non-woody biomass	No	The above-ground non-woody biomass pool will not be directly quantified in the protocol, however during decomposition some carbon from this pool will eventually enter the soil carbon pool that is accounted for and quantified by the methodology.
Below-ground non-woody biomass	No	The below-ground non-woody biomass pool will not be directly quantified in the protocol, however during decomposition some carbon from this pool will eventually enter the soil carbon pool that is accounted for and quantified by the methodology.
Litter	No	The litter pool will not be directly quantified in the protocol, however during decomposition some carbon from this pool will eventually enter the soil carbon pool that is accounted for and quantified by the methodology.
Dead wood	No	Not a major pool affected by project activities.
Soil	Yes	Potentially significantly affected by project activities. The increased forage production and the addition of compost are expected to increase the soil organic content.

B.3 Temporal Boundary

The project start date shall coincide with the first compost application event. The minimum project term will be 40 years due to the fact that the ERTs claimed as a result of the compost additions to grassland soils are calculated based on the stability of the "intermediate" and "passive" C pools being greater than 40 years (see Sections A.3 and D.2). The crediting period is defined by the ACR Standard as the finite length of time for which a GHG Project Plan is valid, and during which a project can generate offsets against its baseline scenario.[13] The crediting period for each project will be 10 years and validation of the GHG Project Plan will occur once per crediting period. Crediting periods are limited in order to require project proponents to reconfirm at set intervals that the baseline scenario remains realistic, credible, additional, and that the current best GHG accounting practice is being used. Since ACR places no limit on the number of crediting period renewals, the project proponent may renew the crediting period in 10-year increments thereafter, provided that the project still meets the protocol requirements. The

[13] The current version of the ACR Standard can be found online at http://americancarbonregistry.org/carbon-accounting/standards-methodologies/american-carbon-registry-standard

methodology allows for multiple compost applications as long as there are at least three years between each application and the new application rate is explicitly reviewed and approved by a Qualified Expert. The three-year rule, combined with the review of the Qualified Expert, is intended to allow enough time between compost additions so that any potential negative impacts on plant communities can be detected and mitigated before a new application is scheduled.

C. Procedure for Determining the Baseline Scenario and Demonstrating Additionality

Emission reductions from avoidance of anaerobic decomposition have very different additionality considerations than emission reductions from direct and indirect increases in SOC. Project proponents who are not claiming any ERTs from avoidance of anaerobic decomposition do not have to consider the additionality requirements related to this source of emission reductions, covered in Section C.1. Since all projects using this methodology will add compost to Grazed Grasslands, all project proponents shall follow the additionality requirements related to direct and indirect increases in SOC, covered in Section C.2.

C.1 Additionality of Emission Reductions from Avoidance of Anaerobic Decomposition

Project proponents shall use ACR's three-prong approach[14] to demonstrate additionality. Specifically, in cases where ERTs from landfill diversion are obtained, it must be demonstrated that the source material used for composting was diverted from a landfill or anaerobic manure storage facility. ERTs cannot be claimed in instances where the landfill or anaerobic processing facility that would otherwise receive the waste material cannot be identified, or if the facility from which source material was diverted already captures methane. Evidence must be provided demonstrating that the specific source of the waste material used for composting (e.g., the specific waste collector) has been deposited in a landfill or storage under anaerobic conditions (in the case of manure) for a period of five years prior to the project's starting date. Valid evidence includes economic analyses, reports, peer-reviewed literature, industry group publications, surveys, etc. Note that examples of the application of these approaches are provided in Section C.1.2.

C.1.1 Co-composting

Often, multiple waste sources are composted together to get an optimal composting C-to-N ratio and increase the waste streams that can be processed. This is referred to as co-composting. In case one of the materials used during co-composting is non-additional, the proportion of the waste that is additional shall be recorded and used in subsequent calculations in Section C.2 as parameter $f_{diverted}$. In case all the waste material is additional, $f_{diverted}$ shall be set to 1. The $f_{diverted}$ factor is used in subsequent calculations to discount any GHG benefits so that only additional benefits are counted.

[14] The three-prong test is described in detail in the ACR Standard.

C.1.2 Examples of determining additionality through diversion of waste materials

- Studies by *Biocycle Magazine*, referenced in a report published by the EPA in 2008,[15] estimate that, at a national level, 97.4% of solid food waste (e.g., milk solids, condemned animal carcasses, meat scraps, and pomace wastes from wineries) were landfilled in 2007. Therefore, compost made from solid food waste is additional without the need for any further evidence.
- The same report published by the EPA in 2008 estimated that 35.9% of the total quantity of yard waste was landfilled. Therefore, a project developer must demonstrate that the specific source of the waste material, i.e., the waste collector of a specific municipality, has landfilled the yard waste for a period of five years prior to the Project's starting date.
- California generates 750,000 dry tons of biosolids, the by-product of channeling human waste through treatment plants and collection systems (California Association of Sanitation Agencies). In total, 54% is land applied and 16% is composted according to statistics from CalRecycle, available at http://www.calrecycle.ca.gov/organics/biosolids/#Composting. Therefore, a project developer using compost derived from biosolids must demonstrate that the specific source of the biosolids, i.e., the biosolids of a specific municipality, have been landfilled in the past.
- The biosolids from sources that are already land-applied (currently 54%) are not compost and not considered additional under this methodology. However, these biosolids could potentially be co-composted by blending it with carbonaceous material such as paper diverted from landfills. The resulting compost is eligible to be used within this methodology on the condition that $f_{diverted}$ is set to the percentage of the compost feedstock (biosolids plus carbonaceous material) actually diverted from landfill.

C.2 Additionality of Emission Reductions from Increases in SOC

The additionality of emission reductions from direct or indirect increases in SOC related to the addition of compost to Grazed Grassland can be tested in a straightforward fashion using ACR's standard three-prong approach, based on Regulatory Surplus, Common Practice, and Implementation Barriers.

C.3 Baseline Determination

Once ACR's three-prong test is passed, the baseline management is set as a continuation of the historical management. The historical management is defined by acquiring the following three parameters for a period of at least five years[16] before the start of the Project:

- Stocking rates

[15] Municipal Solid Waste in the United States. 2007 Facts and Figures. Environmental Protection Agency Office of Solid Waste (5306P). EPA530-R-08-010. Available at http://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1001UYV.PDF

[16] Note that in areas with a longer history of fire, significant changes in plant cover, or other disturbances, more details may be needed to adequately parameterize PBM models.

- Stocking periods
- Incidence of fires

The historical grazing management shall be duly described. These management parameters and other site-specific parameters that are required to define the baseline are included in the list of parameters available at model validation (Section E.1). Key parameters such as the site-specific grazing intensity, soil properties, and climate will be required for all baseline model validation efforts. However, since process based models vary in the ancillary input parameters that they require, appropriate discretion on what must be included will be given to those tasked with validating the model for a given site.

Baseline stocking rate shall be the average of at least 3 of the last 5 years prior to the project start date. The project proponent shall select the most representative years to include and must provide a verifiable justification of the year selection in the GHG project plan.

D. Quantification of GHG Emission Reductions and Removals

D.1 Requirements for Models used for Quantifying GHG emissions and removals

This methodology does not prescribe a model to quantify changes in SOC and soil N_2O emissions. A variety of models are eligible to quantify GHG emissions and removals on the condition that (1) project developers demonstrate the use of the selected model is sufficiently accurate for their study area, as explained in the remainder of this section, and (2) an appropriate uncertainty deduction is applied. Either PBMs or empirical models such as emission factors may be used. Multiple models may be used during the carbon accounting. For example, it is allowed to use a PBM for one variable, such as SOC, and use a Tier-2 Emission Factor for N_2O emissions. The remainder of this section contains general requirements related to the use of Tier-2 Empirical Models and PBMs.

The uncertainty deduction shall have two components: one component related to the inherent, or structural, uncertainty from the model, and another component related to the variability of the input data, such as the variability of the N content in the compost, or the soil texture. Each of the three potential quantification approaches detailed below contains a section on how to calculate structural uncertainty. The structural uncertainty shall further be adjusted for aggregation. The input uncertainty shall be calculated using a Monte Carlo approach and using a 90% confidence level. The two sources of uncertainty, structural uncertainty and input uncertainty, shall simply be summed to calculate the total uncertainty. For the N_2O and ΔSOC components, the total uncertainty shall be calculated as:

$$u_{total} = \frac{u_{struct}}{\sqrt{n}} + u_{input}$$

u_{total}	=	Total uncertainty deduction [MT CO_2-eq]
u_{struct}	=	Structural uncertainty deduction related to the use of a specific model [MT CO_2-eq]
n	=	Number of Project Parcels or the total size of the Project Parcels in hectares divided by 250, whichever is smallest [-]
u_{input}	=	Input uncertainty deduction [MT CO_2-eq]

D.1.1 Tier-2 Empirical Models

Project proponents may develop Tier-2 Empirical Models, which may be used once they appear in the peer-reviewed scientific literature. Project Proponents shall justify in the GHG Project Plan that the sampling locations to create the regionally applicable Tier-2 Empirical Models are representative for the Project. Data from at least five sites across two years must be used to calculate the Tier-2 Empirical Model.

STRUCTURAL UNCERTAINTY FOR TIER-2 EMPIRICAL MODELS A bootstrapping method of resampling shall be used to estimate the deviation between measured and modeled emission reductions. The structural uncertainty shall be calculated as the half-width of the 90% confidence interval around the deviations and shall be deducted from the final ERTs.
INPUT UNCERTAINTY FOR TIER-2 EMPIRICAL MODELS The input uncertainty shall be calculated using simple propagation of errors around input parameters such as the quantity of carbon or nitrogen added through the compost additions. The error shall equal the half-width of the 90% confidence interval, e.g., from the error around the N content of the compost.

D.1.2 Process-based Biogeochemical Models (PBMs)

PBMs such as Century, Daycent,[17] EPIC, ROTH-C, or DNDC may be used on the condition that they are validated for the conditions of the Project Parcels and for the specific variable that is under consideration (i.e., annual change in SOC content, SOC content, or annual N_2O emissions). The PBM must be peer reviewed in at least three scientific publications. The PBMs indicated above meet the requirement on the scientific publications. In addition, the project proponents must develop an objective and unambiguous operating procedure to parameterize and run the PBMs. This procedure document must spell out how every input parameter shall be set. The applicability of the selected model is dependent on the soil type(s), climate, and broad management of the area in which the model is applied. Therefore, it is required to (1) validate the model for the conditions of the Project Parcels, and (2) specify the conditions under which the model's operating procedures remain valid. The validation of a model shall be conducted by comparing field measurements to model predictions. Once model validation has been completed, it does not need to be repeated.

The nature of geographic variability in conditions requires that some degree of judgment to be left to the model validator in order to determine the number of field measurement that will be adequate for local circumstances. Heterogeneous conditions may require more samples, while flatter or otherwise homogenous scenarios may require fewer.

The slope of the relation between modeled and measured values shall be between 0.9 and 1.1 as tested using two one-sided t-tests using a significance of 90%.

[17] Daycent is a version of the Century model with a daily time step, and these two models are essentially the same if it comes to simulating SOC. However, DAYCENT can also simulate soil N_2O and CH_4 emissions whereas Century cannot.

STRUCTURAL UNCERTAINTY FOR PBMs

For PBMs, the structural uncertainty for soil C sequestration shall be calculated as the half-width of the 90% confidence interval around the mean deviation between modeled and measured differences between baseline and project SOC quantities, multiplied by 44/12 to convert the uncertainty into CO_2-equivalents, as is commonly done in GHG accounting methodologies. This uncertainty shall be noted and subtracted from the final ERTs, as explained in Section D.4. An uncertainty for N_2O emissions shall be calculated similarly as the half-width of the 90% confidence interval around the mean deviation between modeled and measured differences of project N_2O emissions, except for a multiplication with 310 x 44 / 28, to account for the radiative forcing and molecular weight of N_2O.

INPUT UNCERTAINTY FOR PBMs

The input uncertainty for PBMs shall be calculated using a Monte Carlo analysis based on a multivariate distribution of the input parameters. At least 200 different draws out of this multivariate distribution for both the Baseline Scenario and the Project Scenario and subsequent model simulations must be executed. For each of the draws of the distribution, one emission reduction is calculated by subtracting the Baseline emissions from the Project emissions. Calculate the uncertainty as the value corresponding to the 10% quantile for the distribution of values.

D.2 Baseline Emissions

D.2.1 General Equation

If avoided landfill emissions are claimed by the project, the emissions of the waste material when deposited in a landfill must be calculated for each project parcel separately using the following equations:

[EQ 1]

$$BE(y,i) = f_{diverted}(BE_{landfill}(y,i)) + \ BE_{\Delta SOC}(y,i) + BE_{N2O}(y,i)$$

Sub-equations for Components:

[EQ 2]

$$BE_{landfill,}(y,i) = BE_{landfill.CH4} - \left(\frac{\sum_{i=1}^{j} W_j \cdot DOC_j \cdot DOC_f}{40} \cdot \frac{44}{12}\right)$$

[EQ 3]

$$BE_{\Delta SOC}(y,i) = A(i) \cdot \Delta SOC(y,i) \cdot \frac{44}{12}$$

[EQ 4]

$$BE_{N2O}(y,i) = A(i) \cdot CE_{N2O}(y,i)$$

Where:

$BE(y,i)$	=	The total sum of the baseline emissions associated with project parcel i during year y. See EQ 1 above. [MT CO_2-eq yr^{-1}]
$f_{diverted}$	=	The percentage of the waste source that is additional. See Section C.1.1.
$BE_{landfill}(y,i)$	=	The cumulative baseline emissions of Methane and Carbon Dioxide from waste material at the landfill under the baseline scenario during year y. To be set to 0 when emission reductions at the landfill claimed by an entity other than the Project Proponents. See EQ 2 above. [MT CO_2-eq yr^{-1}]
$BE_{landfil,CH4}(y,i)$	=	The cumulative baseline Methane emissions from waste material at the landfill or waste storage pond under the baseline scenario during year y. To be set to 0 when emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents. [MT CO_2-eq yr^{-1}]
W_j	=	Amount of organic waste type j prevented from disposal, expressed as dry mass. To be set to 0 when emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents.
DOC_j	=	Fraction of waste type j that is degradable organic carbon (by weight). To be set to 0 when emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents.
DOC_f	=	Fraction of degradable organic carbon (DOC) that fully decomposes to CO_2. To be set to 0 when emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents.
$\frac{44}{12}$	=	Factor to convert the mass of C to CO_2.
$BE_{\Delta SOC}(y,i)$	=	Annual CO_2 emissions from the change in soil organic C for project parcel i during year y of the baseline scenario, calculated using a model that

meets the requirements of Section D.1. The sign of this component is determined by the baseline trends in SOC, which can be either positive when soil is a net source of CO_2 or negative when it is net sink of CO_2. See EQ 3 above. [MT CO_2-eq yr^{-1}]

$A(i)$	=	Size of project parcel i. [ha]
$\Delta SOC(y,i)$	=	Change in baseline soil organic carbon of project parcel i during year y of the baseline scenario, calculated using a model that meets the requirements of Section D.1. [MT C ha^{-1} yr^{-1}]
$BE_{N2O}(y,i)$	=	Cumulative baseline Nitrous Oxide emissions from soils of the project parcel i during year y of the baseline scenario, expressed in CO_2-eq. To be calculated using a model that meets the requirements of Section D.1. See EQ 4 above. [MT CO_2-eq yr^{-1}]
$CE_{N2O}(y,i)$	=	Annual N_2O emissions rate from soils of project parcel i during year y of the baseline scenario. To be calculated using a model that meets the requirements of Section D.1. [MT CO_2-eq ha^{-1} yr^{-1}]

Note that the “44/12” factor converts a mass of carbon into a mass of Carbon Dioxide. In addition, the quantity $W_j \cdot DOC_j \cdot DOC_f$ represents the cumulative mass of carbon that is decomposed after 40 years in a landfill for waste material. Therefore, $\frac{44}{12}\frac{\sum_{i=1}^{j} W_j \cdot DOC_j . DOC_f}{40}$ represents the annual CO_2 emissions from decomposition of the waste material in the landfill under the baseline scenario.

D.2.2 Quantification Procedure

The value $BE_{landfill,CH4}(y,i)$ shall be calculated as the quantity $BE_{CH4,SWDS,y}$ using the CDM tool “Tool to determine Methane emissions avoided from disposal of dumping waste at a solid waste disposal site.” The quantities W_j, DOC_j, and DOC_f shall be set according to this CDM tool. Finally, the quantity $BE_{\Delta SOC}(y,i)$ shall be calculated using a model that meets the requirements of Section D.1.

D.3 Project Emissions

D.3.1 General Equation

[EQ 5]

$$PE(y,i) = PE_{\Delta SOC}(y,i) + PE_{N2O}(y,i) + PE_{fuel}(y,i) + PE_{compost,CH4}(y,i)$$

Sub-Equations for Components

[EQ 6]

$$PE_{\Delta SOC}(y,i) = A(i) \cdot \left(\frac{\Delta SOC_d(40)}{40} + \Delta SOC_i(y,i) \right) \cdot \frac{44}{12}$$

[EQ 7]

$$PE_{N2O}(y,i) = A(i) \cdot CE_{N2O}(y,i)$$

Where:

$PE(y,i)$	=	The total sum of the project emissions during year y. [MT CO_2-eq yr^{-1}]
$PE_{\Delta SOC}(y,i)$	=	Annual CO_2 emissions from the change in soil organic C for project parcel i during year y of the project, calculated using a model that meets the requirements of Section D.1. The sign of this component is determined by the baseline trends in SOC, which can be either positive when soil is a net source of CO2 or negative when it is net sink of CO_2. See EQ 6 above. [MT CO_2-eq yr^{-1}]
$A(i) \cdot$	=	Size of project parcel i. [ha]
$\Delta SOC_d(40)$	=	Change in carbon from added compost remaining in the soil at year 40. To be calculated using a model that meets the requirements of Section D.1 [MT C ha^{-1} yr^{-1}]
$\Delta SOC_i(y,i)$	=	Annual indirect change in soil carbon due to increases in plant productivity during year. To be calculated using a model that meets the requirements of Section D.1. [MT C ha^{-1} yr^{-1}]
$\frac{44}{12}$	=	Factor to convert the mass of C to CO_2.
$CE_{N2O}(y,i)$	=	Cumulative Nitrous Oxide emissions from soils of the project parcel i during year y of the project, expressed in CO_2-eq. To be calculated using a model that meets the requirements of Section D.1. See EQ 7 above. [MT CO_2-eq yr^{-1}]
$PE_{N2O}(y,i)$		Annual N_2O emissions rate from soils of project parcel i during year y of the project. To be calculated using a model that meets the requirements of Section D.1. [MT CO_2-eq ha^{-1} yr^{-1}]
$PE_{fuel}(y,i)$	=	Fuel emissions from transportation to the project parcel and application of the organic material on the land during year y. [MT CO_2-

eq yr^{-1}]

$PE_{compost,CH4}(y,i)$ = At a year when compost is added, e.g., when $y = 1$, the Methane emissions emitted during composting of the organic material, expressed in CO_2-eq. At all other years, this quantity is to be set to 0. When emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents, this quantity is to be set to 0 at all times to avoid double discounting [MT CO_2-eq yr^{-1}]

Because $\Delta SOC_d(40)$ represents the compost carbon remaining after 40 years, $\frac{\Delta SOC_d(40)}{40}$ represents the fraction of the compost carbon remaining that can be claimed as a GHG benefit for every year of the project period.

D.3.2 Quantification Procedure

The quantities $\Delta SOC_d(40)$, $\Delta SOC_i(y)$, and $PE_{N2O}(i,y)$ shall be calculated using a Tier-2 Empirical Model, or a PBM. If a PBM is used that is based on conceptual C-pools, only pools that have a turnover time of greater than 2 years shall be counted towards $\Delta SOC_d(40)$ and $\Delta SOC_i(y)$. This provision is included to avoid incorporating carbon sources that are readily decomposable as carbon sequestration. $\Delta SOC_d 40$ and $\Delta SOC_i(y)$ must be *reduced* by an appropriate discounting factor, while $PE_{N2O}(i,y)$ must be increased by an appropriate discounting factor, as specified in Section D.1.

$PE_{fuel}(i,y)$ is the sum of the emissions from fuel use from transportation and the fuel use from application of the compost. The fuel use from transportation of the compost shall be calculated using the CDM tool "Project and leakage emissions from road transportation of freight." The fuel use from application of the compost shall be calculated using the CDM tool "Tool to calculate project or leakage CO2 emissions from fossil fuel combustion."

The project proponent must account for any increase in enteric emissions associated with the project activity, likely due to an increased stocking rate. The ACR Tool for Tier I Estimation of Emissions from Livestock Management Projects shall be used to calculate the net enteric emissions. The project proponent must enter all baseline and project scenario data required by the "2. Enteric" tab in the tool (all other data input tabs can be excluded). The value for the net emissions from Enteric shall be pulled from cell J13 of the "6. X-ANTE" tab and included in equation 8 below. If the result is a positive number (emission reductions), it will be considered "zero" for the purposes of conservativeness.

$PE_{compost,CH4}(i)$ shall be calculated using the most recent default emission factor available from the IPCC for the CH_4 emissions from biological treatment of waste.[18]

[18] As of the writing of this methodology, the emissions factor is found in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 5: Waste, Chapter 4: Biological Treatment of Solid Waste.

D.4 Summary of GHG Emission Reduction and/or Removals

[EQ 8]

$$ER_y = \sum_{i=1}^{nrParcels} \left(PE(y,i) - BE(y,i)\right) + \Delta CH_4enteric - u_{total}$$

Where:

ER_y	=	GHG emissions reductions and/or removals in year y [tCO_2-eq yr^{-1}]
$nrParcels$	=	Number of individual Project Parcels
$PE(y,i)$	=	Project emissions in year y for individual parcel i [$MTCO_2$-eq yr^{-1}]
$BE(y,i)$	=	Baseline emissions in year y for individual parcel i [$MTCO_2$-eq yr^{-1}]
$\Delta CH_4enteric$	=	Enteric emissions associated with an increase in stocking rate over each project parcel. Either enter zero, or the value from cell J13 of the 6.T-XANTE tab of the *ACR Tool for Estimation of Emissions from Livestock Management Projects*, whichever is less. [$MTCO_2$-eq yr^{-1}]
u_{total}	=	Total uncertainty deduction [MT CO_2-eq]

D.5 Leakage

Emissions leakage refers to instances where activities to reduce emissions from a project parcel may result in increased emissions due to activities and market shifts occurring at locations beyond the project boundaries. Available field research suggests that the addition of compost to grasslands will generally increase soil carbon and the production of forage for livestock. Although not directly connected to the project activities, increases or decreases in stocking rate have been accounted for in this methodology in the spirit of whole-system accounting and conservativeness.

Voluntary and significant stocking rate reductions (more than three percent of the baseline) will make the project ineligible for crediting over the quantification period, until the stocking rate has returned to within -3% of the baseline level. Monitoring and reporting would be required to continue to ensure permanence of sequestered carbon. A leakage deduction will not need to be taken for any stocking rate reductions of greater than 3% from the baseline if justifiably attributable to verifiable instances of natural disaster, disease or otherwise that significantly reduces the stocking rates involuntarily. These circumstances must be verified by an accredited VVB with sufficient documentation including an attestation by the Proponent, demonstrating that this circumstance would have also affected the baseline in a business as usual situation.

E. Monitoring

E.1 Data and Parameters Available at Validation

Various data elements related to compost, soil, weather, and management must be available at model validation. The specific data elements required are detailed below, and explicitly outlined in Appendix A.

- **Compost**. The following data must be available for each batch of compost. Unless sound data for these parameters are available (e.g., as a result from a certification), the compost must undergo laboratory tests.
  - The **carbon concentration** is required to convert mass of dry compost to mass of carbon added, which is a property that is required by a model.
  - The **nitrogen concentration** is required to convert mass of dry compost to mass of nitrogen added, which is needed to verify the applicability conditions and may also be required for the model used.
  - The **C:N ratio** is required to be calculated based on the aforementioned data availability.
  - It is advised, but not required, to include the **phosphorus concentration** in the elemental analysis, as this may improve the models' ability to simulate changes in SOC related to compost addition.
  - The **bulk density** is required to convert a volume of compost, a very common unit used by compost facilities, spreaders, and transporters, into a mass of compost.
  - The **moisture content** is required to convert a mass of moist compost into dry compost.
  - The **pH** of the compost must be measured and recorded

  In addition, the following information shall be obtained if available:
  - Source of the compost raw materials
  - Fate of the organic matter under baseline conditions
- **Soil**. At least three soil samples per parcel shall be taken within each stratum representing at least 0-20 cm. If the relative standard error among the three samples is greater than 20%, more samples shall be taken until the relative standard error is less than 20%. Project developers may choose to take more and deeper samples than this minimum requirement, which is beneficial in improving both model runs and the potential for demonstrating carbon sequestration at greater depths. Samples shall not be composited. The following measurements shall be conducted on the soil samples based on standard analytical protocols described in the Soil Science Society of America Methods of Soil Analysis (Sparks et al. 1996):
  - Total soil carbon
  - Soil texture
  - Soil bulk density
  - Soil pH

  Note that the project developer is allowed to measure the soil carbon at the start of the project *after* compost application on reference locations within the Project Parcels that did not receive the compost application. The latter is feasible when reference locations are shielded from compost application by putting a tarp at that location and removing the compost that is deposited on the tarp before soil carbon analysis.

- **Historical weather**. Daily minimum and maximum temperatures and rainfall shall be obtained for a period of five years before the start of the Project. Historical weather data must come from the nearest weather station or other published weather records (such as Daymet).
- **Project weather**. Daily minimum and maximum temperatures and rainfall shall be obtained through the duration of the Project. This data must come from the nearest weather station or other published weather records (such as Daymet).
- **Historical management**. The following parameters shall be provided for each stratum for a period of at least 5 years before the start of the project. Additional years of data are highly recommended if significant changes in land cover or management are known to have occurred
    - Stocking rates
    - Stocking periods
    - Incidence of fires
- **Project management**. The following parameters shall be provided for each stratum of a project
    - Project population
    - Stocking rate
    - Stocking period
    - Average stocking rate (average over all project years)
    - Minimum stocking rate
    - Maximum stocking rate
    - Incidence of fires
- **Plants and plant communities**. A land assessment by a Qualified Expert must be provided that this consistent with standard NRCS ecological site descriptions[19]. This land assessment report should include a stratification of the land and a description of plant productivity (which is inclusive of species type and forage quality) into three groups: “poor”, “medium”, or “high”. Values of net primary productivity are required in order to better determine yield response.. These values should be obtained through the creation of an exclusion area where livestock are not able to graze so that primary productivity can be measured in dry matter/unit area. The land assessment report shall contain a broad description of the plant communities, percentage cover of natives as well as any problems with invasive weeds before the start of the project. Finally, the land assessment report shall also contain an assessment of the fire risk.

In addition to the parameters described above, various additional soil and site parameters may be needed to parameterize the model runs. The onus is on the project developer to demonstrate that a model was used and parameterized correctly.

[19] Information on NRCS ecological site descriptions may be found online at http://www.nrcs.usda.gov/wps/portal/nrcs/main/national/technical/ecoscience/desc/

E.2 Data and Parameters Recorded during Compost Application

In addition, a description of the application procedure must be provided. This description must include:

- Application date
- Machinery used
- Application method
- Broadcast rate (tons/ha)
- Rationale for application procedure and reference source if available

Receipts of compost purchase, transportation, and application shall be kept and made available to the validator. In addition, it is strongly recommended to take pictures during the application of the compost. All data collected as part of monitoring must be archived electronically and be kept at least for two years after the end of the project crediting period.

E.3 Data and Parameters Monitored after Compost Application

Total soil carbon, texture, bulk density and pH shall be measured for the 0-20cm soil depth at the start of the project and at least every 10 years thereafter as described in Section E.1. In addition, an update of the land assessment report by a Qualified Expert shall be conducted two and five years after compost application.

Actual weather shall be recorded from the same weather station used during model validation. In addition, Stocking Rates and periods shall be provided for each stratum for every year after the start of the project. Every incidence of wildfire shall be reported and used in ex-post simulation, if the selected model allows.

E.4 Updating Models and Model Structural Uncertainty Deduction

The model uncertainty must be updated at least every 10 years, which is also the time frame of a project’s crediting period extension. However, it is allowed to update a model’s structural uncertainty deductions more frequently as new field data becomes available during a project’s crediting period. The new structural uncertainty deductions must be proposed in a monitoring report and explicitly approved by a VVB before ERTs are issued using the new structural uncertainty deductions. The calculation of Baseline and Project emissions must always use the same structural uncertainty deductions.

In addition to updating the structural uncertainty deduction, it is allowed to use (a) different model(s) after the start of the project. For example, it is allowed to switch from a Tier-2 Empirical Model to a PBM. All requirements related to the selection of the model(s) and the calculation of its/their structural uncertainty deduction must be met. This switch must be proposed in a monitoring report and explicitly approved by a VVB before ERTs are issued using the new model(s). The calculation of Baseline and Project emissions must always use the same modeling approach.

F. Permanence

Projects must be consistent with the ACR Standards for permanence, which require proponents to sign ACR's risk mitigation agreement.[20] This risk mitigation agreement legally requires the project proponents to conduct a risk assessment using the latest ACR-approved Non-Permanence Risk Analysis and Buffer Determination tool[21]. The result of this assessment is an overall risk category for the project, translating into a percentage or number of ERTs that the project proponent must deposit, at each new ERT issuance, into a shared non-permanence buffer pool managed by ACR. For instance, ERTs contributed from the Project or those purchased from other Projects may be used to satisfy this buffer pool requirement. Alternatively, the proponent may also meet its legal obligations by providing evidence of sufficient insurance coverage with an ACR-approved insurance product. Reversals need only be fully compensated when they occur during the period in which monitoring is required (i.e. during the minimum project term).

In addition, the proponent shall take measures to reduce the risk of reversal from the following types of reversals that may occur, namely inundation, land use conversion and tillage. Every incidence of inundation due to extensive rainfall or large scale flooding of rivers and streams that lasts for longer than two months in a given crediting year shall be reported. All areas that were inundated for longer than two months shall be excluded from crediting during that year. It is likely that the boundaries of the flooded area do not coincide with the boundaries of strata established during stratification. Therefore, the flooded areas shall be cut out from existing strata for the duration of the year during which the flood happened. If the flood straddles a crediting year, ERTs may not be generated for both years during which the flood occurred. Unless specific circumstances indicate that that the Project Proponent flooded the parcel intentionally, inundation shall be considered a non-intentional reversal according to terms of the risk mitigation agreement.

Any conversion of a project parcel to any other land use than Grazed Grassland, such as annual arable crops or development, will immediately exclude this parcel from generating future ERTs. Unless the soil carbon loss due to the conversion on this Project Parcel is duly replaced by acquiring ERTs from this or other projects and project types, all ERTs from previously stored soil carbon shall be considered a reversal of previously credited ERTs. In addition to the aforementioned risk mitigation mechanisms discussed above, the project proponent may replace the reversed ERTs with ERTs issued from other project parcels within the same project within two years of the date of the conversion. Note that even after replacing the ERTs lost to conversion, the project parcel that was converted must be permanently excluded from issuing ERTs. All other Project Parcels within the Project are not affected by one project

[20] The current version of the ACR Standard can be found online at http://americancarbonregistry.org/carbon-accounting/standards-methodologies/american-carbon-registry-standard

[21] The Tool for AFOLU Non-Permanence Risk Analysis and Buffer Determination can be found online at http://www.v-c-s.org/sites/v-c-s.org/files/Tool%20for%20AFOLU%20Non-Permanence%20Risk%20Analysis%20and%20Buffer%20Determination.pdf

parcel being converted to another land-use. In case only part of a parcel was converted to another land use, it is allowed to pro-rate the reversed ERTs or re-purchase ERTs based on the relative proportion of the conversion within the parcel. Land use conversion shall be considered an intentional reversal according to terms of the risk mitigation agreement.

In the unlikely case that a tillage event occurs on the Project Parcel without a conversion of the grassland to agricultural or any other land use, all soil carbon ERTs previously issued from this Project Parcel will be considered to have been reversed unless the carbon losses resulting from the tillage event on the Project Parcel are duly accounted for and compensated by retiring existing ERTs from the current or other projects and project types. Similarly to land conversions, this carbon loss shall be verified in a monitoring report and must be verified by a VVB. In addition, unless such a true-up occurs, the project parcel shall be permanently excluded from issuing ERTs. Tillage shall be considered an intentional reversal according to terms of the risk mitigation agreement.

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G.1 Sources

This methodology has adopted aspects of the following sources for its carbon accounting:

- ACR's Grazing Land and Livestock Management (GLLM) Methodology, available at http://americancarbonregistry.org/carbon-accounting/standards-methodologies/grazing-land-and-livestock-management-gllm-ghg-methodology
- "Adoption of sustainable agricultural land management (SALM)," available at http://www.v-c-s.org/sites/v-c-s.org/files/SALM%20Methodolgy%20V5%202011_02%20-14_accepted%20SCS.pdf, submitted to and approved by the Verified Carbon Standard (VCS); developed by the World Bank's BioCarbon fund
- Clean Development Mechanism (CDM) "Tool to determine Methane emissions avoided from disposal of dumping waste at a solid waste disposal site," available at http://cdm.unfccc.int/EB/041/eb41_repan10.pdf
- CDM tool "Project and leakage emissions from road transportation of freight," available at http://cdm.unfccc.int/methodologies/PAmethodologies/tools/am-tool-12-v1.pdf
- CDM "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion," available at http://cdm.unfccc.int/methodologies/PAmethodologies/tools/am-tool-03-v2.pdf
- "Organic Waste Composting Project Protocol," (Version 1.0), available at http://www.climateactionreserve.org/how/protocols/organic-waste-composting/, approved for use under the Climate Action Reserve.

Appendix A: Parameter List

A.1 Parameters for Baseline and Project Emissions, and Overall Emissions Reductions and/or Removals Quantification

Parameter	$BE(y,i)$
Units	MT CO_2-eq yr^{-1}
Description	Sum of baseline emissions associated with project parcel *i* during year *y*
Relevant Section	D.2, D.4
Relevant Equation(s)	1, 8
Source of Data	Calculated in equation 1
Data Requirements	$BE_{landfill}(y,i)$, $BE_{landfill,CH4}(y,i)$, $BE_{\Delta SOC}(y,i)$
Collection Procedure	Based on calculations from equations 2, 3, and 4
Revision Frequency	At the start of each crediting period
Comments	

Parameter	$f_{diverted}$
Units	%
Description	The percentage of the waste source that is additional
Relevant Section	C.1.1, C.1.2, D.4
Relevant Equation(s)	1
Source of Data	Determination through 8.1.1
Data Requirements	Compost source materials and additionality
Collection Procedure	Project Proponent obtains records of waste diverted from landfill to compost facility.
Revision Frequency	Each time Project Proponent uses new composting facility.
Comments	

Parameter	$BE_{landfill}(y,i)$
Units	MT CO_2-eq yr^{-1}
Description	The cumulative baseline emissions of Methane and Carbon Dioxide from waste material at the landfill under the baseline scenario during year y
Relevant Section	D.2
Relevant Equation(s)	1, 2
Source of Data	Calculated in equation 2
Data Requirements	$BE_{landfill.CH4}$, W_j, DOC_j , DOC_f
Collection Procedure	Project Proponent obtains records of waste diverted from landfill to compost facility.
Revision Frequency	Each time Project Proponent uses new composting facility
Comments	To be set to 0 when emission reductions at the landfill claimed by an entity other than the Project Proponents

Parameter	$BE_{landfill,CH4}(y,i)$
Units	MT CO_2-eq yr^{-1}

Description	The cumulative baseline Methane emissions from waste material at the landfill or waste storage pond under the baseline scenario during year y
Relevant Section	D.2
Relevant Equation(s)	2
Source of Data	Quantity $BE_{CH4,SWDS,y}$ using the CDM tool "Tool to determine Methane emissions avoided from disposal of dumping waste at a solid waste disposal site"
Data Requirements	W_j and IPCC factors
Collection Procedure	Project Proponent obtains records of waste diverted from landfill to compost facility.
Revision Frequency	Each time Project Proponent uses new composting facility
Comments	To be set to 0 when emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents

Parameter	W_j
Units	Tons of dry mass
Description	Amount of organic waste type j prevented from disposal, expressed as dry mass
Relevant Section	D.2
Relevant Equation(s)	2
Source of Data	Uncomposted organic waste diverted from landfill
Data Requirements	Tons and type of organic waste prevented from disposal
Collection Procedure	Project Proponent obtains records of waste diverted from landfill to compost facility
Revision Frequency	Each time Project Proponent uses new composting facility
Comments	To be set to 0 when emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents

Parameter	DOC_j
Units	%
Description	Fraction of waste type *j* that is degradable organic carbon (by weight)
Relevant Section	D.2
Relevant Equation(s)	2
Source of Data	Characteristics of waste type *j*
Data Requirements	Fraction of degradable organic carbon(by weight) in the waste type j
Collection Procedure	Project Proponent obtains records of waste diverted from landfill to compost facility.
Revision Frequency	Each time Project Proponent uses new composting facility
Comments	To be set to 0 when emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents

Parameter	DOC_f
Units	%
Description	Fraction of degradable organic carbon (DOC) that fully decomposes to CO_2.
Relevant Section	D.2

Relevant Equation(s)	2
Source of Data	Characteristics of DOC
Data Requirements	W_j and amount of DOC in compost that fully decomposes to CO_2.
Collection Procedure	Project Proponent obtains records of waste diverted from landfill to compost facility.
Revision Frequency	Each time Project Proponent uses new composting facility
Comments	To be set to 0 when emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents

Parameter	$BE_{\Delta SOC}(y,i)$
Units	MT CO_2-eq yr^{-1}
Description	Annual CO_2 emissions from the change in soil organic C for project parcel i during year y of the baseline scenario. The sign of this component is determined by the baseline trends in SOC, which can be either positive when soil is a net source of CO_2 or negative when it is net sink of CO_2.
Relevant Section	D.2
Relevant Equation(s)	3
Source of Data	Model estimates
Data Requirements	$A(i)$, $\Delta SOC(y,i)$
Collection Procedure	Calculated from equation 3
Revision Frequency	At the start of each crediting period
Comments	

Parameter	$A(i)$
Units	hectares
Description	Size of project parcel i
Relevant Section	D.2, D.3
Relevant Equation(s)	2, 6, 7
Source of Data	Project Proponent records
Data Requirements	Coordinates and area of project parcels
Collection Procedure	Project Proponents will collect and record area of participating project parcels.
Revision Frequency	At the start of each crediting period
Comments	

Parameter	$\Delta SOC(y,i)$
Units	MT C ha^{-1} yr^{-1}
Description	Change in baseline soil organic carbon of project parcel i during year y of the baseline scenario
Relevant Section	D.2
Relevant Equation(s)	3
Source of Data	
Data Requirements	
Collection Procedure	To be calculated using a model that meets the requirements of Section D.1.
Revision Frequency	At the start of each crediting period
Comments	

Parameter	$BE_{N2O}(y,i)$
Units	MT CO_2-eq yr^{-1}
Description	Cumulative baseline Nitrous Oxide emissions from soils of the project parcel i during year y of the baseline scenario, expressed in CO_2-eq.
Relevant Section	D.2
Relevant Equation(s)	4
Source of Data	Model outputs and Project Proponent records
Data Requirements	$A(i)$, $CE_{N2O}(y,i)$
Collection Procedure	Calculated from equation 4
Revision Frequency	At the start of each crediting period
Comments	

Parameter	$CE_{N2O}(y,i)$
Units	MT CO_2-eq ha^{-1} yr^{-1}
Description	Annual N_2O emissions rate from soils of project parcel i during year y of the baseline scenario.
Relevant Section	D.2
Relevant Equation(s)	4
Source of Data	Model input data requirements, multiple sources
Data Requirements	Model specific
Collection Procedure	To be calculated using a model that meets the requirements of Section D.1
Revision Frequency	At the start of each crediting period
Comments	

Parameter	$PE(y,i)$
Units	MT CO_2-eq yr^{-1}
Description	The total sum of the project emissions during year y
Relevant Section	D.3
Relevant Equation(s)	6, 8
Source of Data	Calculated in equation 5
Data Requirements	$PE_{\Delta SOC}(y,i)$, $PE_{N2O}(y,i)$, $PE_{fuel}(y,i)$, $PE_{compost,CH4}(y,i)$
Collection Procedure	Based on calculations from equations 6 and 7
Revision Frequency	Project year (annually)
Comments	

Parameter	$PE_{\Delta SOC}(y,i)$
Units	MT CO_2-eq yr^{-1}
Description	Annual CO_2 emissions from the change in soil organic C for project parcel i during year y of the project
Relevant Section	D.3
Relevant Equation(s)	5, 6
Source of Data	Model outputs and Project Proponent records
Data Requirements	$A(i)$, $\Delta SOC_d(40)$, $\Delta SOC_i(y,i)$

Collection Procedure	Calculated in equation 6
Revision Frequency	Project year (annually)
Comments	The sign of this component is determined by the baseline trends in SOC, which can be either positive when soil is a net source of CO2 or negative when it is net sink of CO_2.

Parameter	$\Delta SOC_d(40)$
Units	MT C ha^{-1} yr^{-1}
Description	Change in carbon from added compost remaining in the soil at year 40
Relevant Section	D.3
Relevant Equation(s)	6
Source of Data	Model input data requirements, multiple sources
Data Requirements	Model specific
Collection Procedure	To be calculated using a model that meets the requirements of Section D.1.
Revision Frequency	Project year (annually)
Comments	

Parameter	$\Delta SOC_i(y, i)$
Units	MT C ha^{-1} yr^{-1}
Description	Annual indirect change in soil carbon due to increases in plant productivity during year.
Relevant Section	D.3
Relevant Equation(s)	6
Source of Data	Model input data requirements, multiple sources
Data Requirements	Model specific
Collection Procedure	To be calculated using a model that meets the requirements of Section D.1
Revision Frequency	Project year (annually)
Comments	

Parameter	$PE_{N2O}(y, i)$
Units	MT CO_2-eq ha^{-1} yr^{-1}
Description	Annual N_2O emissions rate from soils of project parcel i during year y of the project.
Relevant Section	D.3
Relevant Equation(s)	5, 7
Source of Data	Model outputs and Project Proponent records
Data Requirements	$A(i)$, $CE_{N2O}(y, i)$
Collection Procedure	Calculated in equation 7
Revision Frequency	Project year (annually)
Comments	
Parameter	$CE_{N2O}(y, i)$
Units	MT CO_2-eq yr^{-1}
Description	Cumulative Nitrous Oxide emissions from soils of the project parcel i during year y of the project, expressed in CO_2-eq.
Relevant Section	D.3

Relevant Equation(s)	7
Source of Data	Model input data requirements, multiple sources
Data Requirements	Model specific
Collection Procedure	To be calculated using a model that meets the requirements of Section D.1
Revision Frequency	Project year (annually)
Comments	

Parameter	$PE_{fuel}(y,i)$
Units	MT CO_2-eq yr^{-1}
Description	Sum of fuel emissions from transportation to the project parcel and application of the organic material on the land during year y.
Relevant Section	D.3
Relevant Equation(s)	5
Source of Data	Calculated using CDM tool "Project and leakage emissions from road transportation of freight" and CDM tool "Tool to calculate project or leakage CO2 emissions from fossil fuel combustion"
Data Requirements	Quantity and type of fuel consumed and combusted during transportation and application of compost
Collection Procedure	Project Proponent records from transportation and/or compost application receipts
Revision Frequency	Project year when compost is added
Comments	

Parameter	$PE_{compost,CH4}(y,i)$
Units	MT CO_2-eq yr^{-1}
Description	At a year when compost is added, e.g., when $y = 1$, the Methane emissions emitted during composting of the organic material, expressed in CO_2-eq. At all other years, this quantity is to be set to 0. When emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents, this quantity is to be set to 0 at all times to avoid double discounting.
Relevant Section	D.3
Relevant Equation(s)	5
Source of Data	Calculated the most recent emission factor available from the IPCC.
Data Requirements	kg of dry weight organic waste, factor to convert g CH4 to MT CO_2-eq
Collection Procedure	
Revision Frequency	Project year when compost is added
Comments	

Parameter	ER_y
Units	tCO_2-eq yr^{-1}
Description	GHG emissions reductions and/or removals in year y
Relevant Section	D.4
Relevant Equation(s)	8
Source of Data	Calculated in equation 8

Data Requirements	$nrParcels$, $PE(y,i)$, $BE(y,i)$, $CH_4enteric$
Collection Procedure	Based on Project Proponent records, as well as calculations from equations 1 and 5.
Revision Frequency	Project year (annually)
Comments	

Parameter	$nrParcels$
Units	#
Description	Number of project parcels
Relevant Section	D.4
Relevant Equation(s)	8
Source of Data	Project Proponent records
Data Requirements	Parcels participating in the project
Collection Procedure	Counting parcels participating in project
Revision Frequency	For each change in number of project parcel participating- revised before each new crediting period
Comments	

Parameter	$CH_4enteric$
Units	$MTCO_2$-eq yr^{-1}
Description	Enteric emissions associated with an increase in stocking rate over each project parcel.
Relevant Section	D.3, D.4
Relevant Equation(s)	8
Source of Data	Either a value of zero, or the value from cell J13 of the 6.T-XANTE tab of the *ACR Tool for Estimation of Emissions from Livestock Management Projects*, whichever is less.
Data Requirements	Grazing ruminant population, feeding situation (i.e. grazing or not grazing), percentage imported feed vs. grazing, mean daily temperature during winter
Collection Procedure	Project Proponent records
Revision Frequency	Data collected monthly and parameter revised each project year (annually)
Comments	

A.2 Other Project Data Required for Validation

Parameter	$compost$
Units	Multiple
Description	Analysis every time of compost applied
Relevant Section	E
Relevant Equation(s)	
Source of Data	Project Proponent records (from certification or from laboratory test results)
Data Requirements	Carbon concentration, nitrogen concentration, C:N ratio, bulk density, moisture content, pH, phosphorus concentration (optional), source of compost raw

	materials (optional), fate of organic matter under baseline conditions (optional)
Collection Procedure	Project Proponent reports from records
Revision Frequency	Every time compost is applied throughout project
Comments	

Parameter	*soil*
Units	Multiple
Description	Analysis for each stratum representing at least 0-20cm both before and after compost application for baseline and project calculations
Relevant Section	E
Relevant Equation(s)	
Source of Data	Laboratory test results
Data Requirements	Total soil carbon, soil texture, soil bulk density, soil pH
Collection Procedure	Project Proponent collects soil samples submits for analysis
Revision Frequency	Once at the beginning of project and again after the compost application, then at least every 10 years thereafter
Comments	

Parameter	*historical weather*
Units	Multiple (degrees, inches)
Description	Characterizes important weather and climate characteristics for each project
Relevant Section	E
Relevant Equation(s)	
Source of Data	Weather station or other published weather records
Data Requirements	Daily minimum and maximum temperatures, rainfall
Collection Procedure	Project Proponent uses nearest weather station to project or other published weather records (such as Daymet) for use in model
Revision Frequency	Once at the beginning of project to establish a baseline
Comments	

Parameter	*project weather*
Units	Multiple (degrees, inches)
Description	Characterizes important weather and climate characteristics for each project
Relevant Section	E
Relevant Equation(s)	
Source of Data	Weather station or other published weather records used for historical weather
Data Requirements	Daily minimum and maximum temperatures, rainfall
Collection Procedure	Project Proponent uses nearest weather station to project or other published weather records (such as Daymet) for use in model
Revision Frequency	Project year (annually)
Comments	

Parameter	*historical management*
Units	Multiple
Description	Historical grazing practices on Project Proponent’s land

Relevant Section	C
Relevant Equation(s)	
Source of Data	Project Proponent records
Data Requirements	Stocking period (averaged over at least 3 of past 5 years), stocking rate(averaged over at least 3 of past 5 years), incidence of fires
Collection Procedure	Project Proponent records
Revision Frequency	When setting baseline
Comments	

Parameter	*project management*
Units	Multiple
Description	Grazing practices throughout project
Relevant Section	
Relevant Equation(s)	
Source of Data	Project Proponent records
Data Requirements	Project population, stocking period, average stocking rate(averaged over the years), minimum stocking rate, maximum stocking rate, incidence of fires
Collection Procedure	Project Proponent reports from records
Revision Frequency	Project year (annually)
Comments	

Parameter	*Plants and plant communities*
Units	Multiple
Description	Characterizes important plant communities present for each project
Relevant Section	E
Relevant Equation(s)	
Source of Data	Project parcels (Land assessment by a Qualified Expert, consistent with standard NRCS ecological site descriptions)
Data Requirements	Stratification of land, description of plant productivity (species type and forage quality), broad description of plant communities, percentage cover of native plants, indication of any problems with invasive weeds, assessment of fire risk)
Collection Procedure	Land assessment by a Qualified Expert, consistent with standard NRCS ecological site descriptions
Revision Frequency	Once at the beginning of project and at year 2 and year 5 after compost application
Comments	

Parameter	*Compost application*
Units	Multiple
Description	Description of application procedure
Relevant Section	E
Relevant Equation(s)	
Source of Data	
Data Requirements	Application date, machinery used, application method, broadcast rate (tons/ha), rationale for application procedure and reference source (if

	available), receipts of compost purchase, transportation, and application, pictures during application (optional)
Collection Procedure	Collected during compost application
Revision Frequency	Every time compost is applied throughout project
Comments	All data collected as part of monitoring must be archived electronically and be kept at least for two years after the end of the project crediting period.

A.1.4 Improved Forest Management

The American Carbon Registry™

Improved Forest Management Methodology for Quantifying GHG Removals and Emission Reductions through Increased Forest Carbon Sequestration on Non-Federal U.S. Forestlands

Version 1.3

April 2018

Methodology developed by Columbia Carbon, LLC

Contents

This methodology was drafted by Matt Delaney and David Ford of L&C Carbon, based in Salem, Oregon, and Greg Latta of Oregon State University, based in Corvallis, Oregon. The methodology was approved by ACR through the public consultation and scientific peer review process.

A. METHODOLOGY DESCRIPTION

A1. SCOPE AND DEFINITIONS

This methodology is designed to quantify GHG emission reductions resulting from forest carbon projects that reduce emissions by exceeding baseline forest management practices. Removals are quantified for increased sequestration through retention of annual forest growth when project activities exceed the baseline.

Baseline determination is project-specific and must describe the harvesting scenario that would maximize net present value (NPV) of perpetual wood products harvests per the assumptions as described in section C1, where various discount rates for different land ownership classes are used as proxies for the multiple forest management objectives typical of each owner class eligible under this methodology.

Project Proponents must demonstrate there is no activity-shifting leakage above the *de minimis* threshold. Market leakage must be assessed and accounted for in the quantification of net project benefits.

Definitions and Acronyms

ACR	American Carbon Registry
ATFS	American Tree Farm System
Activity Shifting Leakage	Increases in harvest levels on non-project lands owned or under management control of the project area timber rights owner
Baseline Management	Scenario in the absence of project activities
Carrying Costs	Property taxes, mortgage interest, and insurance premiums
Crediting Period	The period of time in which the baseline is considered to be valid and project activities are eligible to generate ERTs
De minimis	Threshold of 3% of the final calculation of emission reductions or removals
CO_2	Carbon Dioxide. All pools and emissions in this methodology are represented by either CO_2 or CO_2 equivalents. Biomass is converted to carbon by multiplying by 0.5 and then to CO_2 by multiplying by the molecular weight ratio of CO_2 to Carbon (3.664)
CO_2e	Carbon Dioxide equivalent. The amount of CO_2 that would have the same global warming potential (GWP) as other greenhouse

	gases over a 100-year lifetime using SAR-100 GWP values from the IPCC's fourth assessment report.
ERT	Emission Reduction Ton
Ex ante	Prior to project certification
Ex post	After the event, a measure of past performance
FSC	Forest Stewardship Council
Forestland	Forest land is defined as land at least 10 percent stocked by trees of any size, or land formerly having such tree cover, and not currently developed for non-forest uses. Land proposed for inclusion in this project area shall meet the stocking requirement, in aggregate, over the entire area
IFM	Improved Forest Management
IPCC	Intergovernmental Panel on Climate Change
Minimum Project Term	Time Period for which project activities must be maintained and monitored through third-party verification
Native Species	Trees listed as native to a particular region by the Native Plant Society, SAF Forestry Handbook, or State-adopted list
Net Present Value (NPV)	The difference between the present value of cash inflows and the present value of cash outflows over the life of the project
SFI	Sustainable Forestry Initiative
Timberlands	Forestlands managed for commercial timber production
Tree	A perennial woody plant with a diameter at breast height (4.5') greater than or equal to 1" and a height of greater than 4.5', with the capacity to attain a minimum diameter at breast height of 5" and a minimum height of 15' (shrub species are not eligible).
Ton	A unit of mass equal to 1000 kg
VCS	Verified Carbon Standard

A2. APPLICABILITY CONDITIONS

- This methodology is applicable only on non-federally owned forestland within the United States
- The methodology applies to lands that can be legally harvested by entities owning or controlling timber rights on forestland
- Private or non-governmental organization ownerships subject to commercial timber harvesting at the project Start Date in the with-project scenario must be certified by FSC, SFI, or ATFS or become certified within one year of the project Start Date. If there are no ongoing harvests at the project Start Date, but harvests occur later in the project life cycle, the project area must become certified before any commercial timber harvesting can occur
- All Tribal lands in the United States, except those lands that are managed or administered by the Bureau of Indian Affairs, are eligible under this methodology, provided that they meet ACR requirements for Tribal lands
- Public non-federal ownerships currently subject to commercial timber harvesting in the with-project scenario must:
  - be certified by FSC, SFI, or ATFS or become certified within one year of the project Start Date; *or*
  - have its forest management plan sanctioned by a by a senior government official within a state, or a state agency, or a federal agency
    - Please note that any such forest management plans must be updated at minimum every 10 years
  - If there are no ongoing harvests on a public non-federal ownership at the project Start Date, but harvests occur later in the project life cycle, the project area must become certified by FSC, SFI, or ATFS, or develop a sanctioned management plan before any commercial timber harvesting can occur
- Use of non-native species is prohibited where adequately stocked native stands were converted for forestry or other land uses after 1997
- Draining or flooding of wetlands is prohibited
- Project proponent must demonstrate its ownership or control of timber rights at the project start date
- The project must demonstrate an increase in on-site stocking levels above the baseline condition by the end of the Crediting Period

A3. POOLS AND SOURCES

Carbon pools	Included / Optional / Excluded	Justification / Explanation of choice
Above-ground biomass carbon	Included	Major carbon pool subjected to the project activity
Below-ground biomass carbon	Included	Major carbon pool subjected to the project activity
Standing dead wood	Included/Optional	Major carbon pool in unmanaged stands subjected to the project activity. Project Proponents may also elect to include the pool in managed stands. Where included, the

		pool must be estimated in both the baseline and with project cases.
Lying dead wood	Optional	Project Proponents may elect to include the pool. Where included, the pool must be estimated in both the baseline and with project cases.
Harvested wood products	Included	Major carbon pool subjected to the project activity
Litter / Forest Floor	Excluded	Changes in the litter pool are considered *de minimis* as a result of project implementation
Soil organic carbon	Excluded	Changes in the soil carbon pool are considered *de minimis* as a result of project implementation

Gas	Source	Included/ Excluded	Justification / Explanation of choice
CO_2	Burning of biomass	Excluded	However, carbon stock decreases due to burning are accounted as a carbon stock change
CH_4	Burning of biomass	Included	Non-CO_2 gas emitted from biomass burning
N_2O	Burning of biomass	Excluded	Potential emissions are negligibly small

Leakage Source		Included / Optional / Excluded	Justification / Explanation of choice
Activity-Shifting	Timber Harvesting	Excluded	Project Proponent must demonstrate no activity-shifting leakage beyond the *de minimis* threshold will occur as a result of project implementation
	Crops	Excluded	Forestlands eligible for this methodology do not produce agricultural crops that could cause activity shifting
	Livestock	Excluded	Grazing activities, if occurring in the baseline scenario, are assumed to continue at the same levels under the project scenario and thus there are no leakage impacts.
Market Effects	Timber	Included	Reductions in product outputs due to project activity may be compensated by other entities in the marketplace. Those emissions must be included in the quantification of project benefits.

A4. METHODOLOGY SUMMARY

This methodology is designed to quantify GHG emission reductions resulting from forest carbon projects that reduce emissions by exceeding baseline forest management practices. Removals are quantified for increased sequestration through retention of annual forest growth when project activities exceed the baseline.

The IFM baseline is the legally permissible harvest scenario that would maximize net present value (NPV) of perpetual wood products harvests, used as a proxy for the multiple forest management objectives typical of each owner class eligible under this methodology. The baseline management scenario shall be based on silvicultural prescriptions recommended by published state or federal agencies to perpetuate existing onsite timber-producing species while fully utilizing available growing space.

In developing the baseline scenario, exceptions to the requirement that the baseline management scenario shall perpetuate existing onsite timber-producing species may be made where it can be demonstrated that a baseline management scenario involving replacement of existing onsite timber producing species (e.g. where forest is converted to plantations, replacing existing onsite timber-producing species) is feasible and has been implemented in the region within 10 years of the project start date. This shall be substantiated either by (1) demonstrating with management records that the baseline management scenario involving replacement of existing onsite timber producing species has been implemented within 10 years of the project start date on lands in the state containing the project area owned or managed by the project proponent (or by the previous project area owner/manager) or by (2) providing dated (from previous 10 years) aerial imagery that identifies at least two properties (of similar site conditions and forest type) in the state showing, first, the initial or existing onsite timber, and second, the replacement use (e.g. commercial plantation). The areas of forest conversion identified must have combined acreage equal to or greater than the annual acreage converted in the project baseline scenario. Published or written evidence that the baseline scenario (e.g., conversion of existing onsite timber) is common practice in the region (this can be a state or local forester, a consulting forester, an owner of a mill, etc.) must also be provided.

The resulting harvest schedule is used to establish baseline stocking levels through the Crediting Period.

This methodology is similar to a previously approved ACR IFM methodology developed by Finite Carbon Corporation[1] in that it quantifies GHG emission reductions resulting from forest carbon projects that reduce emissions by exceeding baseline management practice levels.

The discount rate assumptions for calculating NPV vary by ownership class (see Table 1, Section C1) and include the 6% rate for private industrial timberlands from the earlier IFM methodology. Actual landowner discount rate assumptions are typically not publicized in the scientific literature and companies, individuals, and organizations by and large do not share the values they use. However,

[1] American Carbon Registry *Improved Forest Management Methodology for Quantifying GHG Removals and Emission Reductions through Increased Forest Carbon Sequestration on U.S. Timberlands.* September 2010.

approximate discount rates can be indirectly estimated by using forest economic theory and the age-class structure distribution of different U.S. forest ownership classes.

This methodology establishes an average baseline determination technique for all major forest ownership classes in the United States with the exception of federal lands. The appropriate ownership class is used to identify a project-specific NPV-maximizing baseline scenario as described in section C1. Project Proponents then design a project scenario for the purposes of increased carbon sequestration. The project scenario by definition will result in a lower NPV than the baseline scenario. Project Proponents use the baseline discount rate values for NPV maximization for the appropriate ownership class and run a project scenario for purposes of increased carbon sequestration. The difference between these two harvest forecasts are the basis for determining carbon impacts and ERTs attributable to the project.

B. ELIGIBILITY, BOUNDARIES, ADDITIONALITY, AND PERMANENCE

B1. PROJECT ELIGIBILITY

This methodology applies to non-federal U.S. forestlands that are able to document 1) clear land title or timber rights and 2) offsets title. Projects must also meet all other requirements of the *ACR Standard, Version 5.0*.

This methodology applies to lands that could be legally harvested by entities owning or controlling timber rights.

Proponents must demonstrate that the project area, in aggregate, meets the definition of Forestland provided in Section A1 above.

B2. PROJECT GEOGRAPHIC BOUNDARY

The Project Proponent must provide a detailed description of the geographic boundary of project activities. Note that the project activity may contain more than one discrete area of land, that each area must have a unique geographical identification, and that each area must meet the eligibility requirements. Information to delineate the project boundary must include:

- Project area delineated on USGS topographic map
- General location map
- Property parcel map

Aggregation of forest properties with multiple landowners is permitted under the methodology consistent with Chapter 6 of the *ACR Standard, Version 5.0* which provides guidelines for aggregating multiple landholdings into a single forest carbon project, as a means to reduce per-acre transaction costs of inventory and verification.

B3. PROJECT TEMPORAL BOUNDARY

Projects with a Start Date of November 1, 1997 or later are eligible[2]. The Start Date is when the Project Proponent began to apply the land management regime to increase carbon stocks and/or reduce emissions.

In accordance with the *ACR Standard, Version 5.0*, all projects will have a Crediting Period of twenty (20) years. The minimum Project Term is forty (40) years. The minimum Project Term begins on the Start Date (not the first or last year of crediting).

[2] American Carbon Registry (2018), *American Carbon Registry Standard, Version 5.0.* Winrock International, Little Rock, Arkansas.

If the project Start Date is more than one year before submission of the GHG plan, the Project Proponent shall provide evidence that GHG mitigation was seriously considered in the decision to proceed with the project activity. Evidence shall be based on official and/or legal documentation. Early actors undertaking voluntary activities to increase forest carbon sequestration prior to the release of this requirement may submit as evidence recorded conservation easements or other deed restrictions that affect onsite carbon stocks.

B4. ADDITIONALITY

Projects must apply a three-prong additionality test[3] to demonstrate that they exceed currently effective and enforced laws and regulations; exceed common practice in the forestry sector and geographic region; and face a financial implementation barrier.

The regulatory surplus test involves existing laws, regulations, statutes, legal rulings, or other regulatory frameworks that directly or indirectly affect GHG emissions associated with a project action or its baseline candidates, and which require technical, performance, or management actions. Voluntary guidelines are not considered in the regulatory surplus test.

The common practice test requires Project Proponents to evaluate the predominant forest industry technologies and practices in the project's geographic region. The Project Proponent shall demonstrate that the proposed project activity exceeds the common practice of similar landowners managing similar forests in the region. Projects initially deemed to go beyond common practice are considered to meet the requirement for the duration of their Crediting Period. If common practice adoption rates of a particular practice change during the Crediting Period, this may make the project non-additional and thus ineligible for renewal, but does not affect its additionality during the current Crediting Period.

An implementation barrier represents any factor or consideration that would prevent the adoption of the practice/activity proposed by the Project Proponent. Financial barriers can include high costs, limited access to capital, or an internal rate of return in the absence of carbon revenues that is lower than the Proponent's established minimum acceptable rate. Financial barriers can also include high risks such as unproven technologies or business models, poor credit rating of project partners, and project failure risk. When applying the financial implementation barrier test, Project Proponents should include solid quantitative evidence such as NPV and Internal Rate of Return (IRR) calculations. The project must face capital constraints that carbon revenues can potentially address; or carbon funding is reasonably expected to incentivize the project's implementation; or carbon revenues must be a key element to maintaining the project action's ongoing economic viability after its implementation.[4]

B5. PERMANENCE

Project Proponents commit to a minimum Project Term of 40 years. Projects must have effective risk mitigation measures in place to compensate fully for any loss of sequestered carbon whether this occurs through an unforeseen natural disturbance or through a Project Proponent or landowners' choice to discontinue forest carbon project activities. Such mitigation measures can include contributions to the buffer pool, insurance, or other risk mitigation measures approved by ACR.

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[3] Ibid.

[4] American Carbon Registry (2018), *American Carbon Registry Standard, Version 5.0.* Winrock International, Little Rock, Arkansas.

If using a buffer contribution to mitigate reversals, the Project Proponent must conduct a risk assessment addressing both general and project-specific risk factors. General risk factors include risks such as financial failure, technical failure, management failure, rising land opportunity costs, regulatory and social instability, and natural disturbances. Project-specific risk factors vary by project type but can include land tenure, technical capability and experience of the project developer, fire potential, risks of insect/disease, flooding and extreme weather events, illegal logging potential, and others. If they are using an alternate ACR-approved risk mitigation product, they will not do this risk assessment.

Project Proponents must conduct their risk assessment using the ACR *Tool for Risk Analysis and Buffer Determination.* The output of either tool is an overall risk category, expressed as a fraction, for the project translating into the buffer deduction that must be applied in the calculation of net ERTs (section G1). This deduction must be applied unless the Project Proponent uses another ACR-approved risk mitigation product.

C. BASELINE

C1. IDENTIFICATION OF BASELINE

The Finite Carbon Corporation IFM methodology[5] (approved by ACR in September 2010), takes a Faustmann approach to baseline determination using NPV maximization with a 6% discount rate on future cash flows. The literature supporting Faustmann's original 1849 work forms the basis for modern optimal rotation/investment decisions and forest economics (summarized in Newman 2002[6]) in addition to appearing in over 300 other book and journal articles. One of the reasons there is such an extensive literature base for NPV maximization is that the Faustmann approach to forest investment and optimal rotation is not perfect. Like the basic economic model of supply and demand, these underlying theorems go far to predict how agents will act, however they do not correctly account for all situations.

In the Finite IFM methodology, the 6% discount is an assumption for how a common industrial forest landowner would make their forest management decisions. This 6% NPV maximization determination of the baseline level of emission and sequestration is appropriate in that it gives a common transparent and conservative metric by which landowners, project developers, verifiers, and offset purchasers can base their assessment of an ACR IFM carbon project. However, less than 40% of aggregate U.S. timber supply comes from Private Industrial (PI) timberland[7] necessitating an adaption of the methodology to allow consideration of other landowner classes who are actively managing their forests.

This methodology is the same as the Finite Carbon methodology in that it quantifies GHG emission reductions resulting from forest carbon projects that reduce emissions by exceeding baseline management practice levels. Emission Reduction Tons (ERTs) are quantified for increased sequestration through retention of annual forest growth when project activities exceed the baseline.

The baseline determination is project-specific and must describe the harvesting scenario that would maximize NPV of perpetual wood products harvests over a 100-year modeling period. The discount rate assumptions for calculating NPV[8] vary by ownership class (Table 1) and include the 6% rate for PI timberlands from the Finite methodology. Actual landowner discount rate assumptions are typically not

[5] ACR Approved Methodology (2010), *Methodology for Quantifying GHG Removals and Emission Reductions through Increased Forest Carbon Sequestration on U.S. Timberlands.* Finite Carbon Corporation. https://americancarbonregistry.org/carbon-accounting/standards-methodologies/improved-forest-management-ifm-methodology-for-non-federal-u-s-forestlands/ifm-methodology-for-non-federal-u-s-forestlands_v1-0_semptember-2011_final.pdf

[6] Newman, D.H. 2002. Forestry's golden rule and the development of the optimal forest rotation literature. J. Econ. 8: 5–27

[7] See Tables 7-10 in Adams, D.M.; Haynes, R.W. and A. Daigneault. 2006. Estimated timber harvest by U.S. region and ownership, 1950-2002. PNW-GTR-659. Portland, OR: USDA, Forest Service, Pacific Northwest Research Station. 64 p

[8] Sewall, Sizemore & Sizemore, Mason, Bruce & Girard, Inc and Brookfield internal research.2010.Global Timberlands Research Report. http://www.industryintel.com/Corporate/downloads/4QBrookfield2010.pdf

publicized in the scientific literature and companies, individuals, and organizations by and large do not share the values they use. However, approximate discount rates can be indirectly estimated by using forest economic theory and the age-class structure distribution of different U.S. forest ownership classes.

Amacher et al. (2003)[9] and Beach et al. (2005)[10] provide literature reviews and a basis of economic analysis of non-industrial private forest (NIPF) harvesting decisions. Newman and Wear (1993)[11] show that Industrial and NIPF owners both demonstrate behavior consistent with profit maximization, yet the determinants of profit differ with the NIPF owners deriving significant non-market benefits associated with standing timber. Pattanayak et al. (2002)[12] revisited the problem as they studied NIPF timber supply and found joint optimization of timber and non-timber values while Gan et al. (2001)[13] showed that the impact of a reduced discount rate actually had the same impact as the addition of an amenity value.

The United States Department of Agriculture (USDA) Forest Inventory and Analysis (FIA) group provides inventory data on forests in their periodic assessment of forest resources (Smith et al. 2009[14]). This data allows for the analysis of total U.S. forest acres by age class for three broad ownership classes: Private, State, and National Forest. While the publicly available FIA data does not include any further breakdown of the private ownership group, we were provided with the twenty-year age class data from USDA FIA research foresters, including private corporate and private non-corporate classes. Bringing this economic theoretical framework together with this data aided in the derivation of discount rate value estimates for other forestland ownership classes (Table 1).

This methodology establishes an average baseline determination technique for all major non-federal forest ownership classes in the United States. Project Proponents shall use the baseline discount rate values in Table 1 for the appropriate ownership class to identify a project-specific NPV-maximizing baseline scenario. Project Proponents then design a project scenario for the purposes of increased carbon sequestration. The project scenario by definition will result in a lower NPV than the baseline scenario. The difference between these two harvest forecasts are the basis for determining carbon impacts and ERTs attributable to the project.

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[9] Amacher, G.S., Conway, M.C., and J. Sullivan. 2003. Econometric analyses of nonindustrial forest landowners: is there anything left to study? Journal of Forest Economics 9, 137–164

[10] Beach, R.H., Pattanayak, S.K., Yang, J.C., Murray, B.C., and R.C. Abt. 2005. Econometric studies of non-industrial private forest management a review and synthesis. Forest Policy and Economics, 7(3), 261-281

[11] Newman, D.H. and D.N. Wear. 1993. Production economics of private forestry: a comparison of industrial and nonindustrial forest owners. American Journal of Agricultural Economics 75:674-684

[12] Pattanayak, S., Murray, B., Abt, R., 2002. How joint is joint forest production? An econometric analysis of timber supply conditional on endogenous amenity values. Forest Science 47 (3), 479– 491

[13] Gan, J., Kolison Jr., S.H. and J.P. Colletti. 2001. Optimal forest stock and harvest with valuing non-timber benefits: a case of U.S. coniferous forests. Forest Policy and Economics 2(2001), 167-178

[14] Smith, W. Brad, tech. coord.; Miles, Patrick D., data coord.; Perry, Charles H., map coord.; Pugh, Scott A., Data CD coord. 2009. Forest Resources of the United States, 2007. GTR WO-78. Washington, DC: USDA, Forest Service, Washington Office. 336 p

Table 1. Discount rates for Net Present Value determinations by U.S. Forestland Ownership Class.

Ownership	Annual Discount Rate
Private Industrial	6%
Private Non-Industrial	5%
Tribal	5%
Non-governmental organization	4%
Non-federal public lands	4%

The IFM baseline is the legally permissible harvest scenario that would maximize NPV of perpetual wood products harvests. The baseline management scenario shall be based on silvicultural prescriptions recommended by published state or federal agencies to perpetuate existing onsite timber producing species while fully utilizing available growing space. Where the baseline management scenario involves replacement of existing onsite timber producing species (e.g. where forest is converted to plantations, replacing existing onsite timber-producing species), the management regime should similarly be based on silvicultural prescriptions recommended by published state or federal agencies, and must adhere to all applicable laws and regulations. The resulting harvest schedule is used to establish baseline stocking levels through the Crediting Period.

Required inputs for the project NPV calculation include the results of a recent timber inventory of the project lands, prices for wood products of grades that the project would produce, costs of logging, reforestation and related costs, silvicultural treatment costs, and carrying costs. Project Proponents shall include roading and harvesting costs as appropriate to the terrain and unit size. Project Proponents must model growth of forest stands through the Crediting Period. Project Proponents should use a constrained optimization program that calculates the maximum NPV for the harvesting schedule while meeting any forest practice legal requirements. The annual real (without inflation) discount rate for each non-federal owner class is given in Table 1. Wood products must be accounted.

Consideration shall be given to a reasonable range of feasible baseline assumptions and the selected assumptions should be plausible for the duration of the baseline application.

The ISO 14064-2 principle of conservativeness must be applied for the determination of the baseline scenario. In particular, the conservativeness of the baseline is established with reference to the choice of assumptions, parameters, data sources and key factors so that project emission reductions and removals are more likely to be under-estimated rather than over-estimated, and that reliable results are maintained over a range of probable assumptions. However, using the conservativeness principle does not always imply the use of the “most” conservative choice of assumptions or methodologies[15].

C 1.1 Confidentiality of Proprietary Information

While it remains in the interest of the general public for Project Proponents to be as transparent as possible regarding GHG reduction projects, the Project Proponent may choose at their own option to designate any information regarded as confidential due to proprietary considerations. If the Project Proponent chooses to identify information related to financial performance as confidential, the Project Proponent must submit the confidential baseline and project documentation in a separate file marked

[15] ISO 14064-2:2006(E)

"Confidential" to ACR and this information shall not be made available to the public. ACR and the validation/verification body shall utilize this information only to the extent required to register the project and issue ERTs. If the Project Proponent chooses to keep financial information confidential, a publically available GHG Project Plan must still be provided to ACR.

C2. BASELINE STRATIFICATION

If the project activity area is not homogeneous, stratification may be used to improve the modeling of management scenarios and precision of carbon stock estimates. Different stratifications may be used for the baseline and project scenarios. For estimation of baseline carbon stocks, strata may be defined on the basis of parameters that are key variables for estimating changes in managed forest carbon stocks, for example:[16]

a. Management regime
b. Species or cover types
c. Size and density class
d. Site class
e. Age Class

C3. BASELINE NET REDUCTIONS AND REMOVALS

Baseline carbon stock change must be calculated for the entire Crediting Period. The baseline stocking level used for the stock change calculation is derived from the baseline management scenario developed in section C1. This methodology requires 1) annual baseline stocking levels to be determined for the entire Crediting Period, 2) a long-term average baseline stocking level be calculated for the Crediting Period, and 3) the change in baseline carbon stocks be computed for each time period, t.

The following equations are used to construct the baseline stocking levels using models described in section 3.1 and wood products calculations described in section 3.2:

$$\Delta C_{BSL,TREE,t} = \left(C_{BSL,TREE,t} - C_{BSL,TREE,t-1}\right) \tag{1}$$

where:

t	Time in years
$\Delta C_{BSL,TREE,t}$	Change in the baseline carbon stock stored in above and below ground live trees (in metric tons CO_2) for year t.
$C_{BSL,TREE,t}$	Change in the baseline value of carbon stored in above and below ground live trees at the beginning of the year t (in metric tons CO_2) and t-1 signifies the value in the prior year.

[16] Please note this list is not exhaustive and only includes examples of some common stratification parameters.

$$\Delta C_{BSL,DEAD,t} = \left(C_{BSL,DEAD,t} - C_{BSL,DEAD,t-1}\right) \quad (2)$$

where:

t	Time in years
$\Delta C_{BSL,\ DEAD,t}$	Change in the baseline carbon stock stored in dead wood (in metric tons CO_2) for year t.
$C_{BSL,\ DEAD,t}$	Change in the baseline value of carbon stored in dead wood at the beginning of the year t (in metric tons CO_2) and t-1 signifies the value in the prior year.

$$\overline{C}_{BSL,HWP} = \frac{\sum_{t=1}^{20} C_{BSL,HWP,t}}{20} \quad (3)$$

where:

t	Time in years
$\overline{C}_{BSL,HWP}$	Twenty-year average value of annual carbon remaining stored in wood products 100 years after harvest (in metric tons of CO_2)
$C_{BSL,HWP,t}$	Baseline value of carbon remaining in wood products 100 years after being harvested in the year t (in metric tons CO_2).

Note: Please see section 3.2 for detailed instructions on baseline wood products calculations.

$$\overline{GHG}_{BSL} = \frac{\sum_{t=1}^{20}\left(BS_{BSL,t} \cdot ER_{CH_4} \cdot \frac{16}{44} \cdot GWP_{CH_4}\right)}{20} \quad (4)$$

where:

t	Time in years
$\overline{GHG}_{BSL}$	Twenty-year average value of greenhouse gas emissions (in metric tons CO_2e) resulting from the implementation of the baseline.
$BS_{BSL,t}$	Carbon stock (in metric tons CO_2) in logging slash burned in the baseline in year t.

ER_{CH4}	Methane (CH_4) emission ratio (ratio of CO_2 as CH_4 to CO_2 burned). If local data on combustion efficiency is not available or if combustion efficiency cannot be estimated from fuel information, use IPCC default value[17] of 0.012
16/44	Molar mass ratio of CH_4 to CO_2
GWP_{CH4}	100-year global warming potential (in CO_2 per CH_4) for CH_4 (IPCC SAR-100 value of 21 per the Fourth Assessment Report)[18]

Carbon stock calculation for logging slash burned ($BS_{BSL,t}$) shall use the method described in Section 3.1.1 for bark, tops and branches, and section 3.1.2 if dead wood is selected. The reduction in carbon stocks due to slash burning in the baseline must be properly accounted in equations 1 and 2.

To calculate long-term average baseline stocking level for the Crediting Period use:

$$C_{BSL,AVE} = \frac{\sum_{t=0}^{20}\left(C_{BSL,TREE,t} + C_{BSL,DEAD,t}\right)}{20} + \overline{C}_{BSL,HWP} \qquad (5)$$

where:

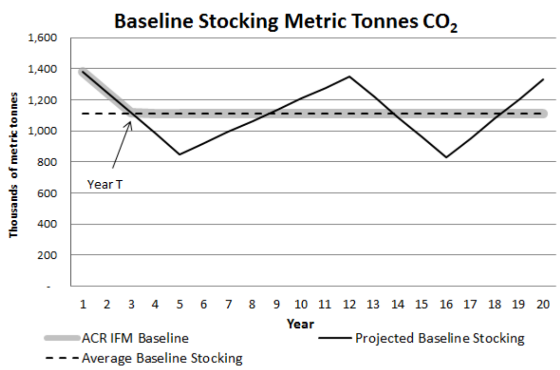
t	Time period (in years)
t^*	A rolling value from 1 to 21 years to reference the accumulated stock in HWP in each year t=1 to t=21
$C_{BSL,AVE}$	20-year average baseline carbon stock (in metric tons CO_2)
$C_{BSL,TREE,t}$	Baseline value of carbon stored in above and below ground live trees (in metric tons CO_2) at the beginning of the year *t*
$C_{BSL,DEAD,t}$	Baseline value of carbon stored in standing and lying dead trees at the beginning of the year *t* (in metric tons CO_2)
$\overline{C}_{BSL,HWP}$	Twenty-year average value of annual carbon remaining stored in wood products 100 years after harvest (in metric tons of CO_2)

[17] Table 3A.1.15, Annex 3A.1, GPG-LULUCF (IPCC 2003)

[18] Table 2.14, Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, 2007. Solomon, S., D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M. Tignor and H.L. Miller (eds.). Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. http://ipccwg1. ucar.edu/wg1/Report/AR4WG1_Print_Ch02.pdf.

Change in baseline carbon stock is computed for each time period. The Project Proponent shall provide a graph of the projected baseline stocking levels and the long-term average baseline stocking level for the entire Crediting Period (see Figure1). Annual projected stocking levels are used for the baseline stock change calculation until the projected stocking level reaches the long term average (time t = T). Thereafter, the long-term average stocking level is used in the baseline stock change calculation for the entire Project Period.

a) Above average stocking



b) Below average stocking

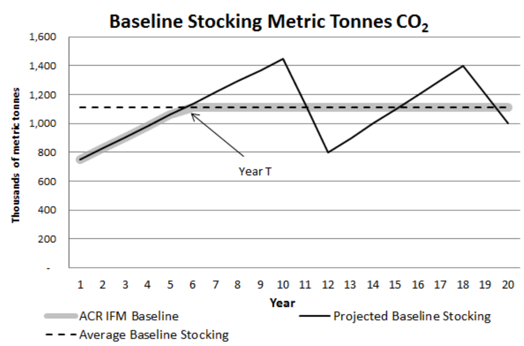


Figure 1. Sample Baseline Stocking Graph for project beginning: a) above 20-year average baseline stocking, and b) below 20-year baseline stocking.

The following equations must be applied until year t equals T:

$$\Delta C_{BSL,t} = \Delta C_{BSL,TREE,t} + \Delta C_{BSL,DEAD,t} + \overline{C}_{BSL,HWP} - \overline{GHG}_{BSL} \tag{6}$$

where:

t	Time in years
$\Delta C_{BSL,t}$	Change in the baseline carbon stock (in metric tons CO_2) for year *t*.
$\Delta C_{BSL,TREE,t}$	Change in the baseline carbon stock stored in above and below ground live trees (in metric tons CO_2) for year *t*.
$\Delta C_{BSL,DEAD,t}$	Change in the baseline carbon stock stored in dead wood pools live trees (in metric tons CO_2) for year *t*.
$\overline{C}_{BSL,HWP}$	Twenty-year average value of annual carbon remaining in wood products 100 years after harvest (in metric tons CO_2).
$\overline{GHG}_{BSL}$	Twenty-year average value of annual greenhouse gas emissions (in metric tons CO_2) resulting from the implementation of the baseline.

Prior to year T (T = year projected stocking reaches the long-term baseline average) the value of $\Delta C_{BSL,t}$ will most likely be negative for projects with initial stocking levels higher than $C_{BSL,AVE}$ or positive for projects with initial stocking levels lower than $C_{BSL,AVE}$. If years elapsed since the start of the IFM project activity (t) is $\geq T$ to compute long-term average stock change use:

$$\Delta C_{BSL,t} = 0 \quad (7)$$

3.1 Stocking Level Projections in the Baseline

$C_{BSL,TREE,t}$ and $C_{BSL,DEAD,t}$ must be estimated using models of forest management across the baseline period. Modeling must be completed with a peer reviewed forestry model that has been calibrated for use in the project region. The GHG Plan must detail what model is being used and what variants have been selected. All model inputs and outputs must be available for inspection by the verifier. The baseline must be modeled over a 20-year period.

Examples of appropriate models include:

- FVS: Forest Vegetation Simulator
- SPS: Stand Projection System
- FIBER: USDA, Forest Service
- FPS: Forest Projection System by Forest Biometrics
- CRYPTOS and CACTOS: California Conifer Timber Output Simulator

Models must be:

- Peer reviewed in a process involving experts in modeling and biology/forestry/ecology
- Used only in scenarios relevant to the scope for which the model was developed and evaluated
- Parameterized for the specific conditions of the project

The output of the models must include either projected total aboveground and below ground carbon per acre, volume in live aboveground tree biomass, or another appropriate unit by strata in the baseline. Where model projections are output in five or ten year increments, the numbers shall be annualized to give a stock change number for each year.

If the output for the tree is the volume, then this must be converted to biomass and carbon using equations in Section 3.1.1. If processing of alternative data on dead wood is necessary, equations in section 3.1.2 may be used. Where models do not predict dead wood dynamics, the baseline harvesting scenario may not decrease dead wood more than 50% through the Crediting Period.

3.1.1 Tree Carbon Stock Calculation

The mean carbon stock in aboveground biomass per unit area is estimated based on field measurements in sample plots. A sampling plan must be developed that describes the inventory process including sample size, determination of plot numbers, plot layout and locations, and data collected. Plot data used for biomass calculations may not be older than 10 years. Plots may be permanent or temporary and they may have a defined boundary or use variable radius sampling methods. Biomass for each tree is calculated from its merchantable volume using a component ratio method. The Project Proponent must use the same set of equations, diameter at breast height thresholds, and selected biomass components for *ex ante* and *ex post* baseline and project estimates.

To ensure accuracy and conservative estimation of the mean aboveground live biomass per unit area within the Project Area, Projects must account for missing cull in both the *ex ante* and *ex post* baseline and project scenarios. Determine missing cull deductions with cull attribute data collected during field measurement of sample plots.

The following steps are used to calculate tree biomass:

Step 1: Determine the biomass of the merchantable component of each tree based on appropriate volume equations published by USDA Forest Service (if locally derived equations are not available use regional or national equations as appropriate) and green volume inside bark, oven-dry tree specific gravity for each species.

Step 2: Determine aboveground biomass by choosing a combination of the following components: stump, bark, tops and branches, and/or foliage, in addition to below-ground biomass, by applying component ratios from Jenkins *et al* (2003) Table 6[19], where biomass of each component is calculated as its component ratio * merchantable stem biomass from Step 1 * (1 / stem wood component ratio). If stump, top, and branch components are included, please use the quantification methodology found in Woodall et al. 2011[20]. Note that the same components must be calculated for *ex ante* and *ex post* baseline and project estimates.

Step 3: Using the sum of the selected biomass components for individual trees, determine the per plot estimate of total tree biomass for each plot.

Step 4: Determine the tree biomass estimate for each stratum by calculating a mean biomass per acre estimate from plot level biomass derived in step 3 multiplied by the number acres in the stratum.

Step 5: Determine total project carbon (in metric tons CO_2) by summing the biomass of each stratum for the project area and converting biomass to carbon by multiplying by 0.5, kilograms to metric tons by dividing by 1000, and finally carbon to CO_2 by multiplying by 3.664.

Note: The FVS Fire and Fuels Extension volume-based default estimates[21] of Live Carbon are compliant with the above, but do not include bark and stump components.

3.1.2 Dead Wood Calculation

Dead wood included in the methodology comprises two components only – standing dead wood and lying dead wood. Below-ground dead wood is conservatively neglected. Considering the differences in the two components, different sampling and estimation procedures shall be used to calculate the changes in dead wood biomass of the two components.

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[19] Jenkins, J.; Chojnacky, D.C.; Heath, L.S.; Birdsey, R.A. 2003. National Scale Biomass Estimators for United States Tree Species. Forest Science. 49(1): 12-35

[20] Woodall, Christopher W.; Heath, Linda S.; Domke, Grant M.; Nichols, Michael C. 2011. Methods and equations for estimating aboveground volume, biomass, and carbon for trees in the U.S. forest inventory, 2010. Gen. Tech. Rep. NRS-88. Newtown Square, PA: U.S. Department of Agriculture, Forest Service, Northern Research Station.

[21] Hoover, C.M. and Rebain, S.A., 2011. Forest carbon estimation using the Forest Vegetation Simulator: Seven things you need to know. http://www.nrs.fs.fed.us/pubs/gtr/gtr_nrs77.pdf

3.1.2.1 Standing Dead Wood (if included)

Step 1: Standing dead trees shall be measured using the same criteria and monitoring frequency used for measuring live trees. The decomposed portion that corresponds to the original above-ground biomass is discounted.

Step 2: The decomposition class of the dead tree and the diameter at breast height shall be recorded and the standing dead wood is categorized under the following four decomposition classes:

1. Tree with branches and twigs that resembles a live tree (except for leaves)
2. Tree with no twigs but with persistent small and large branches
3. Tree with large branches only
4. Bole only, no branches

Step 3: Biomass must be estimated using the component ratio method used for live trees for decomposition classes 1, 2, and 3 with deductions as stated in Step 4 (below). When the standing dead tree is in decomposition class 4, the biomass estimate must be limited to the main stem of the tree. If the top of the standing dead tree is missing, then top and branch biomass may be assumed to be zero. Identifiable tops on the ground meeting category 1 criteria may be directly measured. For trees broken below minimum merchantability specifications used in the tree biomass equation, existing standing dead tree height shall be used to determine tree bole biomass.

Step 4: The biomass of dead wood is determined by using the following dead wood density classes deductions: Class 1 – 97% of live tree biomass; Class 2 – 95% of live tree biomass; Class 3 – 90% of live tree biomass; Class 4 – 80% of live tree biomass[22].

Step 5: Determine total project standing dead carbon (in metric tons CO_2) by summing the biomass of each stratum for the project area and converting biomass to carbon by multiplying by 0.5, kilograms to metric tons by dividing by 1000, and finally carbon to CO_2 by multiplying by 3.664.

Note: The FVS Fire and Fuels Extension estimates of Standing Dead Carbon are compliant with this methodology, but do not include bark and stump components.

3.1.2.2 Lying Dead Wood (if selected)

The lying dead wood pool is highly variable, and stocks may or may not increase as the stands age depending if the forest was previously unmanaged (mature or unlogged) where it would likely increase or logged with logging slash left behind where it may decrease through time.

[22] IPCC Good Practice Guidelines 2006. http://www.ipcc-nggip.iges.or.jp/public/gpglulucf/gpglulucf_files/Chp4/Chp4_3_Projects.pdf

Step 1: Lying dead wood must be sampled using the line intersect method (Harmon and Sexton 1996).[23,24] At least two 50-meter lines (164 ft) are established bisecting each plot and the diameters of the lying dead wood (≥ 10 cm diameter [≥ 3.9 inches]) intersecting the lines are measured.

Step 2: The dead wood is assigned to one of the three density states (sound, intermediate and rotten) by species using the 'machete test', as recommended by IPCC Good Practice Guidance for LULUCF (2003), Section 4.3.3.5.3. The following dead wood density class deductions must be applied to the three decay classes: For Hardwoods, sound – no deduction, intermediate - 0.45, rotten - 0.42; for Softwoods, sound – no deduction, intermediate - 0.71, rotten - 0.45.[25]

Step 3: The volume of lying dead wood per unit area is calculated using the equation (Warren and Olsen 1964)[26] as modified by Van Wagner (1968)[27] separately for each density class

$$V_{LDW,DC} = \pi^2 \left(\sum_{n=1}^{N} D_{n,DC}^2 \right) \Big/ (8 \cdot L) \tag{8}$$

where:

$V_{LDW,\ DC}$	Volume (in cubic meters per hectare) of lying dead wood in density class *DC* per unit area;
$D_{n,DC}$	Diameter (in centimeters) of piece number *n*, of *N* total pieces in density class DC along the transect;
L	Length (in meters) of transect

Step 4: Volume of lying dead wood shall be converted into biomass using the following relationship:

$$B_{LDW} = A \sum_{DC=1}^{3} V_{LDW,DC} \cdot WD_{DC} \tag{9}$$

where:

B_{LDW}	Biomass (in kilograms per hectare) of lying dead wood per unit area;
A	Area (in hectares);

[23] Harmon, M.E. and J. Sexton. (1996) Guidelines for measurements of wood detritus in forest ecosystems. U.S. LTER Publication No. 20. U.S. LTER Network Office, University of Washington, Seattle, WA, USA.
[24] A variant on the line intersect method is described by Waddell, K.L. 2002. Sampling coarse wood debris for multiple attributes in extensive resource inventories. Ecological Indicators 1: 139-153. This method may be used in place of Steps 1 to 3
[25] USFS FIA Phase 3 proportions
[26] Warren, W.G. and Olsen, P.F. (1964) A line intersect technique for assessing logging waste. *Forest Science* 10:267-276
[27] Van Wagner, C.E. (1968). The line intersect method in forest fuel sampling. *Forest Science* 14: 20-26

$V_{LDW,DC}$	Volume (in cubic meters per hectare) of lying dead wood in density class DC per unit area
WD_{DC}	Basic wood density (in kilograms per cubic meter) of dead wood in the density class—sound (1), intermediate (2), and rotten (3)

Step 5: Determine total project lying dead carbon by summing the biomass of each stratum for the project area and converting biomass to dry metric tons of Carbon by multiplying by 0.5, kilograms to metric tons by dividing by 1000, and finally carbon to CO_2 by multiplying by 3.664.

3.2 Wood Products Calculations

There are five steps required to account for the harvesting of trees and to determine carbon stored in wood products in the baseline and project scenarios[28]:

1. Determining the amount of carbon in trees harvested that is delivered to mills (bole without bark).
2. Accounting for mill efficiencies.
3. Estimating the carbon remaining in in-use wood products 100 years after harvest.
4. Estimating the carbon remaining in landfills 100 years after harvest.
5. Summing the carbon remaining in wood products 100 years after harvest.

Step 1: Determine the Amount of Carbon in Harvested Wood Delivered to Mills

The following steps must be followed to determine the amount of carbon in harvested wood if the biomass model does not provide metric tons carbon in the bole, without bark. If it does, skip to step 2

1. Determine the amount of wood harvested (actual or baseline) that will be delivered to mills, by volume (cubic feet) or by green weight (lbs.), and by species for the current year (y). In all cases, harvested wood volumes and/or weights must exclude bark.
    a. Baseline harvested wood quantities and species are derived from modeling a baseline harvesting scenario using an approved growth model.
    b. Actual harvested wood volumes and species must be based on verified third party scaling reports, where available. Where not available, documentation must be provided to support the quantity of wood volume harvested.
        i. If actual or baseline harvested wood volumes are reported in units besides cubic feet or green weight, convert to cubic feet using the following conversion factors:

Volume multipliers for converting timber and chip units to Cubic Feet	
Unit	**Factor**

[28] Adapted from Appendix C of the California Air Resources Board Compliance Offset Protocol - U.S. Forest Projects, November 14, 2014.

Bone Dry Tons	71.3
Bone Dry Units	82.5
Cords	75
Cubic Meters	35.3
Cunits-Chips (CCF)	100
Cunits-Roundwood	100
Cunits-Whole tree chip	126
Green tons	31.5
MBF-Doyle	222
MBF-International 1/4"	146
MBF-Scribner ("C" or "Small")	165
MBF-Scribner ("Large" or "Long")	145
MCF-Thousand Cubic Feet	1000
Oven Dried Tonnes	75.8

2. If a volume measurement is used, multiply the cubic foot volume by the appropriate green specific gravity by species from table 5-3a of the USFS Wood Handbook[29]. This results in pounds of biomass with zero moisture content. If a particular species is not listed in the Wood Handbook, it shall be at the verifier's discretion to approve a substitute species. Any substitute species must be consistently applied across the baseline and with-project calculations.

3. If a weight measurement is used, subtract the water weight based on the moisture content of the wood. This results in pounds of biomass with zero moisture content.

4. Multiply the dry weight values by 0.5 pounds of carbon/pound of wood to compute the total carbon weight.

5. Divide the carbon weight by 2,204.6 pounds/metric ton and multiply by 3.664 to convert to metric tons of CO_2. Sum the CO2 for each species into saw log and pulp volumes (if applicable), and then again into softwood species and hardwood species. These values are used in the next step, accounting for mill efficiencies. Please note that the categorization criteria (upper and lower DBH limits) for hardwood/softwood saw log and pulp volumes are to remain the same between the baseline and project scenario.

Step 2: Account for Mill Efficiencies

Multiply the total carbon weight (metric tons of carbon) for each group derived in Step 1 by the mill efficiency identified for the project's mill location(s) in the Regional Mill Efficiency Database, found on the Reference documents section of this methodology's website. This is the total carbon transferred into

[29] Forest Products Laboratory. Wood handbook - Wood as an engineering material. General Technical Report FPL-GTR-190. Madison, WI: U.S. Department of Agriculture, Forest Service, Forest Products Laboratory: 508 p. 2010.

wood products. The remainder (sawdust and other byproducts) of the harvested carbon is considered to be immediately emitted to the atmosphere for accounting purposes in this methodology.

Step 3: Estimate the Carbon Storage 100 Years after Harvest in In-Use Wood Products

The amount of carbon that will remain stored in in-use wood products for 100 years depends on the rate at which wood products either decay or are sent to landfills. Decay rates depend on the type of wood product that is produced. Thus, in order to account for the decomposition of harvested wood over time, a decay rate is applied to methodology wood products according to their product class. To approximate the climate benefits of carbon storage, this methodology accounts for the amount of carbon stored 100 years after harvest. Thus, decay rates for each wood product class have been converted into "storage factors" in the table below.

100-year storage factors[30]		
Wood Product Class	**In-Use**	**Landfills**
Softwood Lumber	0.234	0.405
Hardwood Lumber	0.064	0.490
Softwood Plywood	0.245	0.400
Oriented Strandboard	0.349	0.347
Non Structural Panels	0.138	0.454
Miscellaneous Products	0.003	0.518
Paper	0	0.151

<u>Steps to Estimate Carbon Storage in In-Use Products 100 Years after Harvest</u>

To determine the carbon storage in in-use wood products after 100 years, the first step is to determine what percentage of a Project Area's harvest will end up in each wood product class for each species (where applicable), separated into hardwoods and softwoods. This must be done by either:

- Obtaining a verified report from the mill(s) where the Project Area's logs are sold indicating the product categories the mill(s) sold for the year in question; or
- If a verified report cannot be obtained, looking up default wood product classes for the project's Assessment Area, as given in the most current Assessment Area Data File found on the Reference Documents section of this methodology's website.

If breakdowns for wood product classes are not available from either of these sources, classify all wood products as "miscellaneous."

[30] Smith JE, Heath LS, Skog KE, Birdsey RA (2006) Methods for calculating forest ecosystem and harvested carbon with standard estimates for forest types of the United States. In: General Technical Report NE-343 (eds Usdafs), PP. 218. USDA Forest service, Washington, DC, USA.

Once the breakdown of in-use wood product categories is determined, use the 100-year storage factors to estimate the amount of carbon stored in in-use wood products 100 years after harvest:

1. Assign a percentage to each product class for hardwoods and softwoods according to mill data or default values for the project.
2. Multiply the total carbon transferred into wood products by the % in each product class
3. Multiply the values for each product class by the storage factor for in-use wood products
4. Sum all of the resulting values to calculate the carbon stored in in-use wood products after 100 years (in units of CO2-equivalent metric tons).

Step 4: Estimate the Carbon Storage 100 Years after Harvest for Wood Products in Landfills

To determine the appropriate value for landfill carbon storage, perform the following steps:

1. Assign a percentage to each product class for hardwoods and softwoods according to mill data or default values for the project.
2. Multiply the total carbon transferred into wood products by the % in each product class.
3. Multiply the values for each product class by the storage factor for landfill carbon.
4. Sum all of the resulting values to calculate the carbon stored in landfills after 100 years (in units of CO2-equivalent metric tons).

Step 5: Determine Total Carbon Storage in Wood Products 100 Years after Harvest

The total carbon storage in wood products after 100 years for a given harvest volume is the sum of the carbon stored in landfills after 100 years and the carbon stored in in-use wood products after 100 years. This value is used for input into the ERT calculation worksheet. The value for the actual harvested wood products will vary every year depending on the total amount of harvesting that has taken place. The baseline value is the 100-year average value, and does not change from year to year.

C4. MONITORING REQUIREMENTS FOR BASELINE RENEWAL

A project's Crediting Period is the finite length of time for which the baseline scenario is valid and during which a project can generate offsets against its baseline.

A Project Proponent may apply to renew the Crediting Period by[31]:

- Re-submitting the GHG Project Plan in compliance with then-current ACR standards and criteria
- Re-evaluating the project baseline
- Demonstrating additionality against then-current regulations, common practice and implementation barriers

[31] American Carbon Registry (2018), *American Carbon Registry Standard, Version 5.0.* Winrock International, Little Rock, Arkansas.

- Using ACR-approved baseline methods, emission factors, and tools in effect at the time of Crediting Period renewal, and
- Undergoing validation and verification by an approved validation/verifier body

C5. ESTIMATION OF BASELINE UNCERTAINTY

It is assumed that the uncertainties associated with the estimates of the various input data are available, either as default values given in IPCC Guidelines (2006), IPCC GPG-LULUCF (2003), or estimates based on sound statistical sampling. Uncertainties arising from the measurement and monitoring of carbon pools and the changes in carbon pools shall always be quantified.

Indisputably conservative estimates can also be used instead of uncertainties, provided that they are based on verifiable literature sources. In this case the uncertainty is assumed to be zero. However, this section provides a procedure to combine uncertainty information and conservative estimates resulting in an overall project scenario uncertainty.

It is important that the process of project planning consider uncertainty. Procedures including stratification and the allocation of sufficient measurement plots can help ensure low uncertainty. It is good practice to consider uncertainty at an early stage to identify the data sources with the highest risk to allow the opportunity to conduct further work to diminish uncertainty. Estimation of uncertainty for pools and emissions sources for each measurement pool requires calculation of both the mean and the 90% confidence interval. In all cases uncertainty should be expressed as the 90% confidence interval as a percentage of the mean.

The uncertainty in the baseline scenario should be defined as the square root of the summed errors in each of the measurement pools. For modeled results use the confidence interval of the input inventory data. For wood products and logging slash burning emissions use the confidence interval of the inventory data. The errors in each pool shall be weighted by the size of the pool so that projects may reasonably target a lower precision level in pools that only form a small proportion of the total stock.

Therefore,

$$UNC_{BSL} = \frac{\sqrt{\left(C_{BSL,TREE,1} \cdot e_{BSL,TREE}\right)^2 + \left(C_{BSL,DEAD,1} \cdot e_{BSL,DEAD}\right)^2 + \left(\overline{C}_{BSL,HWP} \cdot e_{BSL,TREE}\right)^2 + \left(\overline{GHG}_{BSL} \cdot e_{BSL,TREE}\right)^2}}{C_{BSL,TREE,1} + C_{BSL,DEAD,1} + C_{BSL,HWP} + \overline{GHG}_{BSL}} \qquad (10)$$

where:

UNC_{BSL}	Percentage uncertainty in the combined carbon stocks in the baseline.
$C_{BSL,TREE,1}$	Carbon stock in the baseline stored in above and below ground live trees (in metric tons CO_2) for the initial inventory in year *1*.
$C_{BSL,DEAD,1}$	Carbon stock in the baseline stored in dead wood (in metric tons CO_2) for the initial inventory in year *1*.

$\overline{C}_{BSL,HWP}$	Twenty-year baseline average value of annual carbon (in metric tons CO_2) remaining stored in wood products 100 years after harvest.
$\overline{GHG}_{BSL}$	Twenty-year average value of annual greenhouse gas emissions (in metric tons CO_2e) resulting from the implementation of the baseline.
$e_{BSL,TREE}$	Percentage uncertainty expressed as 90% confidence interval percentage of the mean of the carbon stock in above and below ground live trees (in metric tons CO_2) for the initial inventory in year *1*.
$e_{BSL,DEAD}$	Percentage uncertainty expressed as 90% confidence interval percentage of the mean of the carbon stock in dead wood (in metric tons CO_2) for the initial inventory in year *1*.

D. WITH-PROJECT SCENARIO

D1. WITH-PROJECT STRATIFICATION

If the project activity area is not homogeneous, stratification may be carried out to improve the precision of carbon stock estimates. Different stratifications may be used for the baseline and project scenarios. For estimation of with-project scenario carbon stocks, strata may be defined on the basis of parameters that are key variables determining forest carbon stocks, for example:

a. Management regime
b. Species or cover types
c. Size and density class
d. Site class
e. Age class

Project Proponents must present in the GHG Plan an *ex ante* stratification of the project area or justify the lack of it. The number and boundaries of the strata defined *ex ante* may change during the Crediting Period (*ex post*).

The *ex post* stratification shall be updated due to the following reasons:

- Unexpected disturbances occurring during the Crediting Period (e.g. due to fire, pests or disease outbreaks), affecting differently various parts of an originally homogeneous stratum
- Forest management activities (e.g. cleaning, planting, thinning, harvesting, coppicing, replanting) may be implemented in a way that affects the existing stratification
- Established strata may be merged if reason for their establishment has disappeared

D2. MONITORING PROJECT IMPLEMENTATION

Information shall be provided, and recorded in the GHG Plan, to establish that:

- The geographic position of the project boundary is recorded for all areas of land
- The geographic coordinates of the project boundary (and any stratification inside the boundary) are established, recorded and archived. This can be achieved by field mapping (e.g. using GPS), or by using georeferenced spatial data (e.g. maps, GIS datasets, orthorectified aerial photography or georeferenced remote sensing images)
- Professionally accepted principles of forest inventory and management are implemented
- Standard operating procedures (SOPs) and quality control / quality assurance (QA/QC) procedures for forest inventory including field data collection and data management shall be applied. Use or adaptation of SOPs already applied in national forest monitoring, or available from published handbooks, or from the IPCC GPG LULUCF 2003, is recommended
- Where commercial timber harvesting occurs in the project area in the with-project scenario, the forest management plan, together with a record of the plan as actually implemented during the project shall be available for validation and verification, as appropriate

D3. MONITORING OF CARBON STOCKS IN SELECTED POOLS

Information shall be provided, and recorded in the GHG Plan, to establish that professionally accepted principles of forest inventory and management are implemented. Standard operating procedures (SOPs) and quality control / quality assurance (QA/QC) procedures for forest inventory including field data collection and data management shall be applied. Use or adaptation of SOPs already applied in national forest monitoring, or available from published handbooks, or from the *IPCC GPG LULUCF 2003*, is recommended. The forest management plan, together with a record of the plan as actually implemented during the project shall be available for validation and verification, as appropriate.

The 90% statistical confidence interval (CI) of sampling can be no more than ±10% of the mean estimated amount of the combined carbon stock at the project area level[32]. If the Project Proponent cannot meet the targeted ±10% of the mean at 90% confidence, then the reportable amount shall be the lower bound of the 90% confidence interval.

At a minimum the following data parameters must be monitored:

- Project area
- Sample plot area
- Tree species
- Tree Biomass
- Wood products volume
- Dead wood pool, if selected

D4. MONITORING OF EMISSION SOURCES

Emissions from biomass burning must be monitored during project activities. When applying all relevant equations provided in this methodology for the *ex ante* calculation of net anthropogenic GHG removals by sinks, Project Proponents shall provide transparent estimations for the parameters that are monitored during the Crediting Period. These estimates shall be based on measured or existing published data where possible. In addition, Project Proponents must apply the principle of

[32] For calculating pooled CI of carbon pools across strata, see equations in Barry D. Shiver, *Sampling Techniques for Forest Resource Inventory (John Wiley & Sons, Inc, 1996)*

conservativeness. If different values for a parameter are equally plausible, a value that does not lead to over-estimation of net anthropogenic GHG removals by sinks must be selected.

D5. ESTIMATION OF PROJECT EMISSION REDUCTIONS OR ENHANCED REMOVALS

This section describes the steps required to calculate $\Delta C_{P,t}$ (net annual carbon stock change under the project scenario; tons CO_2e). This methodology requires: 1) carbon stock levels to be determined in each time period, t, for which a valid verification report is submitted, and 2) the change in project carbon stock be computed from the prior verification time period, t-1.

The following equations are used to construct the project stocking levels using models described in section 3.1 and wood products calculations described in section 3.2:

$$\Delta C_{P,TREE,t} = \left(C_{P,TREE,t} - C_{P,TREE,t-1}\right) \tag{11}$$

where:

t	Time in years
$\Delta C_{P,TREE,t}$	Change in the project carbon stock stored in above and below ground live trees (in metric tons CO_2) for year t.
$C_{P,TREE,t}$	Change in the project value of carbon stored in above and below ground live trees at the beginning of the year t (in metric tons CO_2) and t-1 signifies the value in the prior year.

$$\Delta C_{P,DEAD,t} = \left(C_{P,DEAD,t} - C_{P,DEAD,t-1}\right) \tag{12}$$

where:

t	Time in years
$\Delta C_{P,DEAD,,t}$	Change in the project carbon stock (in metric tons CO_2) for year t.
$C_{P,DEAD,t}$	Change in the project value of carbon stored in dead wood at the beginning of the year t (in metric tons CO_2) and t-1 signifies the value in the prior year.

$$GHG_{P,t} = BS_{P,t} \cdot ER_{CH_4} \cdot \frac{16}{44} \cdot GWP_{CH_4} \tag{13}$$

where:

t	Time in years
$GHG_{P,t}$	Greenhouse gas emission (in metric tons CO2e) resulting from the implementation of the project in year (t).

$BS_{P,t}$	Carbon stock (in metric tons CO_2) in logging slash burned in the project in year *t*.
ER_{CH4}	Methane (CH_4) emission ratio (ratio of CO_2 as CH_4 to CO_2 burned). If local data on combustion efficiency is not available or if combustion efficiency cannot be estimated from fuel information, use IPCC default value of 0.012[33]
16/44	Molar mass ratio of CH_4 to CO_2
GWP_{CH4}	100-year global warming potential (in CO_2e per CH_4) for CH_4 (IPCC SAR-100 value of 21 per the Fourth Assessment Report)[34]

Carbon stock calculation for logging slash burned shall use the method described in Section 3.1.1 for bark, tops and branches, and Section 3.1.2 if dead wood is selected. The reduction in carbon stocks due to slash burning due to project activities must be properly accounted in equations 11 and 12.

To compute change in project carbon stock for each time period use:

$$\Delta C_{P,t} = \Delta C_{P,TREE,t} + \Delta C_{P,DEAD,t} + C_{P,HWP,t} - GHG_{P,t} \tag{14}$$

where:

t	Time in years
$\Delta C_{P,t}$	Change in the project carbon stock (in metric tons CO_2) for year *t*.
$\Delta C_{P,TREE,t}$	Change in the project carbon stock stored in above and below ground live trees (in metric tons CO_2) for year *t*.
$\Delta C_{P,DEAD,t}$	Change in the project carbon stock stored in dead wood pools live trees (in metric tons CO_2) for year *t*.
$C_{P,HWP,t}$	Carbon remaining stored in wood products 100 years after harvest (in metric tons CO_2) for the project in year t.
$GHG_{P,t}$	Greenhouse gas emission (in metric tons CO2e) resulting from the implementation of the project in year (t).

5.1 Tree Biomass, Dead Wood Carbon Calculation, Wood Products

The Project Proponent must use the same set of equations used in Section C3.1.1, C3.1.2, and C3.2 to calculate carbon stocks in the project scenario.

[33] Table 3A.1.15, Annex 3A.1, GPG-LULUCF (IPCC 2003)

[34] Table 2.14, Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, 2007. Solomon, S., D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M. Tignor and H.L. Miller (eds.). Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA

D6. MONITORING OF ACTIVITY-SHIFTING LEAKAGE

There may be no leakage beyond *de minimis* levels through activity shifting to other lands owned, or under management control, by the timber rights owner.

If the project decreases wood product production by >5% relative to the baseline then the Project Proponent and all associated land owners must demonstrate that there is no leakage within their operations – i.e., on other lands they manage/operate outside the bounds of the ACR carbon project.

Such a demonstration must include one of the following:

- Historical records covering all Project Proponent ownership trends in harvest volumes paired with records from the with-project time period showing no deviation from historical trends over most recent 10-year average; *or*

- Forest management plans prepared ≥24 months prior to the start of the project showing harvest plans on all owned/managed lands paired with records from the with-project time period showing no deviation from management plans; *or*

- Entity-wide management certification that requires sustainable practices (programs can include FSC, SFI, or ATFS). Management certification must cover *all* entity owned lands with active timber management programs.

D7. ESTIMATION OF EMISSIONS DUE TO MARKET LEAKAGE

Reductions in product outputs due to project activity may be compensated by other entities in the marketplace. Those emissions must be included in the quantification of project benefits. Market Leakage shall be quantified by either of the following:

1. Applying the appropriate default market leakage discount factor (15, 16, or 17):

    - If the project is able to demonstrate that any decrease in total wood products produced by the project relative to the baseline is less than 5% over the Crediting Period then:

      $$LK = 0 \tag{15}$$

    - Where project activities decrease total wood products produced by the project relative to the baseline by more than 5% but less than 25% over the Crediting Period, the market leakage deduction is 10% (according to VCS AFOLU Guidance Document[35]).

      $$LK = 0.1 \tag{16}$$

    - Where project activities decrease total wood products produced by the project relative to the baseline by 25% or more over the Crediting Period, the market leakage deduction is 40%[36].

[35] http://www.v-c-s.org/sites/v-c-s.org/files/Guidance for AFOLU Projects.pdf

[36] We assume that any decrease in production would be transferred to forests of a similar type.

$$LK = 0.4 \tag{17}$$

2. Directly accounting for market leakage associated with the project activity:

Where directly accounting for leakage, market leakage shall be accounted for at the regional-scale applied to the same general forest type as the project (ie, forests containing the same or substitutable commercial species as the forest in the project area) and shall be based on verifiable methods for quantifying leakage. It is at the verifier's discretion to determine whether the method for quantifying market leakage is appropriate for the project.

D8. ESTIMATION OF WITH-PROJECT UNCERTAINTY

It is assumed that the uncertainties associated with the estimates of the various input data are available, either as default values given in IPCC Guidelines (2006), IPCC GPG-LULUCF (2003), or estimates based on sound statistical sampling. Uncertainties arising from the measurement and monitoring of carbon pools and the changes in carbon pools shall always be quantified.

Indisputably conservative estimates can also be used instead of uncertainties, provided that they are based on verifiable literature sources. In this case the uncertainty is assumed to be zero. However, this section provides a procedure to combine uncertainty information and conservative estimates resulting in an overall project scenario uncertainty.

As with baseline uncertainty, it is important that the process of project planning consider uncertainty. Procedures including stratification and the allocation of sufficient measurement plots can help ensure low uncertainty. It is good practice to consider uncertainty at an early stage to identify the data sources with the highest risk to allow the opportunity to conduct further work to diminish uncertainty. Estimation of uncertainty for pools and emissions sources for each measurement pool requires calculation of both the mean and the 90% confidence interval. In all cases uncertainty should be expressed as the 90% confidence interval as a percentage of the mean.

The uncertainty in the project scenario should be defined as the square root of the summed errors in each of the measurement pools. For modeled results use the confidence interval of the input inventory data. For wood products with measured and documented harvest volume removals use zero as the confidence interval. For estimated wood product removal use the confidence interval of the inventory data. The errors in each pool can be weighted by the size of the pool so that projects may reasonably target a lower precision level in pools that only form a small proportion of the total stock.

Therefore,

$$UNC_{P,t} = \frac{\sqrt{\left(C_{P,TREE,t} \cdot e_{P,TREE}\right)^2 + \left(C_{P,DEAD,t} \cdot e_{P,DEAD}\right)^2 + \left(C_{P,HWP,t} \cdot e_{P,TREE}\right)^2 + \left(GHG_{P,t} \cdot e_{P,TREE}\right)^2}}{C_{P,TREE,t} + C_{P,DEAD,t} + C_{P,HWP,t} + GHG_{P,t}} \tag{18}$$

where:

$UNC_{P,t}$ Percentage uncertainty in the combined carbon stocks in the project in year *t*.

$C_{P,TREE,t}$	Carbon stock in the project stored in above and below ground live trees (in metric tons CO_2) in year *t*.
$C_{P,DEAD,t}$	Carbon stock in the baseline stored in dead wood (in metric tons CO_2) in year *t*.
$C_{P,HWP,t}$	Annual carbon (in metric tons CO_2) remaining stored in wood products in the project 100 years after harvest in year *t*.
$GHG_{P,t}$	Greenhouse gas emission (in metric tons CO_2e) resulting from the implementation of the project in year t.
$e_{P,TREE}$	Percentage uncertainty expressed as 90% confidence interval percentage of the mean of the carbon stock in above and below ground live trees (in metric tons CO_2) for the last remeasurement of the inventory prior to year *t*.
$e_{P,DEAD}$	Percentage uncertainty expressed as 90% confidence interval percentage of the mean of the carbon stock in dead wood (in metric tons CO_2) for the last remeasurement of the inventory prior to year *t*.

E. EX-ANTE ESTIMATION

E1. EX-ANTE ESTIMATION METHODS

The Project Proponent must make an *ex ante* calculation of all net anthropogenic GHG removals and emissions for all included sinks and sources for the entire Crediting Period. Project Proponents shall provide estimates of the values of those parameters that are not available before the start of monitoring activities. Project Proponents must retain a conservative approach in making these estimates.

Uncertainties arising from, for example, biomass expansion factors or wood density, could result in unreliable estimates of both baseline net GHG removals by sinks and the actual net GHG removals by sinks especially when global default values are used. Project Proponents shall identify key parameters that would significantly influence the accuracy of estimates. Local values that are specific to the project circumstances must then be obtained for these key parameters, whenever possible. These values must be based on:

- Data from well-referenced peer-reviewed literature or other well-established published sources; *or*
- National inventory data or default data from IPCC literature that has, whenever possible and necessary, been checked for consistency against available local data specific to the project circumstances; *or*
- In the absence of the above sources of information, expert opinion may be used to assist with data selection. Experts will often provide a range of data, as well as a most probable value for the data. The rationale for selecting a particular data value must be briefly noted in the GHG

plan. For any data provided by experts, the GHG Plan shall also record the expert's name, affiliation, and principal qualification as an expert– plus inclusion of a 1-page summary CV for each expert consulted, included in an annex.

When choosing key parameters based on information that is not specific to the project circumstances, such as in use of default data, Project Proponents must select values that will lead to an accurate estimation of net GHG removals by sinks, taking into account uncertainties. If uncertainty is significant, Project Proponents must choose data such that it tends to under-estimate, rather than over-estimate, net GHG removals by sinks[37].

[37] CDM Approved Consolidated Methodology AR-ACM0001, "Afforestation and Reforestation of Degraded Land"

F. QA/QC AND UNCERTAINTY

F1. METHODS FOR QUALITY ASSURANCE

Standard operating procedures (SOPs) and quality control / quality assurance (QA/QC) procedures for forest inventory including field data collection and data management shall be documented. Use or adaptation of SOPs already applied in national forest monitoring, or available from published handbooks, or from the IPCC GPG LULUCF 2003, is recommended.

F2. METHODS FOR QUALITY CONTROL

Project Proponents shall consider all relevant information that may affect the accounting and quantification of GHG reductions/removals, including estimating and accounting for any decreases in carbon pools and/or increases in GHG emission sources. This methodology sets a *de minimis* threshold of 3% of the final calculation of emission reductions. For the purpose of completeness any decreases in carbon pools and/or increases in GHG emission sources must be included if they exceed the *de minimis* threshold. Any exclusion using the *de minimis* principle shall be justified using fully documented *ex ante* calculations.

F3. CALCULATION OF TOTAL PROJECT UNCERTAINTY

The following equation must be applied:

$$UNC_t = \frac{\sqrt{(\Delta C_{BSL,t} \cdot UNC_{BSL})^2 + (\Delta C_{P,t} \cdot UNC_{P,t})^2}}{\Delta C_{BSL,t} + \Delta C_{P,t}} \qquad (19)$$

where:

UNC_t	Total project uncertainty in year *t*, in %
$\Delta C_{BSL,t}$	Change in the baseline carbon stock and GHG emissions (in metric tons CO_2e) for year *t*. (Section C3)
UNC_{BSL}	Baseline uncertainty, in % (Section C5)
$\Delta C_{P,t}$	Change in the project carbon stock and GHG emissions (in metric tons CO_2e) for year *t*. (Section D5)
$UNC_{P,t}$	With-project uncertainty in year *t*, in % (Section D8)

If calculated *UNC* in equation (19) is <10%, then *UNC* shall be considered 0% in equation (20).

G. CALCULATION OF ERTs

This section describes the process of determining additional annual net greenhouse gas emission reductions and Emission Reduction Tons (ERTs) issued for a time period for which a valid verification report has been filed with ACR. Annual net greenhouse gas emission reductions ($C_{ACR,t}$) are calculated using equation 20 by adjusting the difference between the project and baseline carbon stock changes for leakage and uncertainty then multiplying by a non-permanence buffer deduction.

$$ERT_t = C_{ACR,t} = (\Delta C_{P,t} - \Delta C_{BSL,t}) \cdot (1 - LK) \cdot (1 - UNC_t) \cdot (1 - BUF) \quad (20)$$

where:

ERT_t	Emission Reduction Tons issued with vintage year t.
$C_{ACR,t}$	Annual net greenhouse gas emission reductions (in metric tons CO_2e) at time *t.*
$\Delta C_{P,t}$	Change in the project carbon stock and GHG emissions (in metric tons CO_2e) for year *t*. (Section D5)
$\Delta C_{BSL,t}$	Change in the baseline carbon stock and GHG emissions (in metric tons CO_2e) for year *t*. (Section C3)
LK	Leakage discount (Section D7)
UNC_t	Total Project Uncertainty, (in %) for year *t* (Section F3). UNC_t will be set to zero if the project meets ACR's precision requirement of within ±10% of the mean with 90% confidence. If the project does not meet this precision target, UNC_t should be the half-width of the confidence interval of calculated net GHG emission reductions.
BUF	The non-permanence buffer deduction as calculated in Section B5. *BUF* will be set to zero if an ACR approved insurance product is used.

Negative project stock change ($C_{ACR,t}$) before the first offset credit issuance is a negative balance of greenhouse gas emissions. After the first offset issuance, negative project stock change is a Reversal. AFOLU reversals must be reported and compensated following requirements detailed in the Reversal Risk Mitigation Agreement and the Buffer Pool Terms and Conditions, Exhibit 1 of the *ACR Standard, Version 5.0*. As outlined in Exhibit 1, sequestration projects will terminate automatically if a Reversal causes project stocks to decrease below baseline levels prior to the end of the Minimum Project Term.

A.1.5 Thermal Energy Production

CLEAN DEVELOPMENT MECHANISM

AMS-I.C

Small-scale Methodology

Thermal energy production with or without electricity

Version 20.0

Sectoral scope(s): 01

United Nations
Framework Convention on
Climate Change

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1. Introduction

1. The following table describes the key elements of the methodology:

Table 1. Methodology key elements

Typical project(s)	Thermal energy production using renewable energy sources including biomass-based cogeneration and/or trigeneration. Projects that seek to retrofit or modify existing facilities for renewable energy generation are also applicable
Type of GHG emissions mitigation action	Renewable energy. Displacement of more-GHG-intensive thermal energy production, displacement of more-GHG-intensive thermal energy and/or electricity generation

2. Scope, applicability, and entry into force

2.1. Scope

2. This methodology comprises renewable energy technologies that supply users i.e. residential, industrial or commercial facilities with thermal energy that displaces fossil fuel use. These units include technologies such as solar thermal water heaters and dryers, solar cookers, energy derived from renewable biomass and other technologies that provide thermal energy that displaces fossil fuel.

2.2. Applicability

3. Biomass-based cogeneration and trigeneration systems are included in this category.

4. Emission reductions from a biomass cogeneration or trigeneration system can accrue from one of the following activities:

    (a) Electricity supply to a grid;

    (b) Electricity and/or thermal energy production for on-site consumption or for consumption by other facilities;

    (c) Combination of (a) and (b).

5. Project activities that seek to retrofit or modify an existing facility for renewable energy generation are included in this category.

6. In the case of new facilities (Greenfield projects) and project activities involving capacity additions the relevant requirements related to determination of baseline scenario provided in the “General guidelines for SSC CDM methodologies” for Type-II and Type-III Greenfield/capacity expansion project activities also apply.

7. The total installed/rated thermal energy generation capacity of the project equipment is equal to or less than 45 MW thermal[1] (see paragraph 9 for the applicable limits for cogeneration and trigeneration project activities).

8. For co-fired systems, the total installed thermal energy generation capacity of the project equipment, when using both fossil and renewable fuel, shall not exceed 45 MW thermal (see paragraph 9 for the applicable limits for cogeneration project activities).

9. The following capacity limits apply for biomass cogeneration and trigeneration units:

   (a) If the emission reductions of the project activity are on account of thermal and electrical energy production, the total installed thermal and electrical energy generation capacity of the project equipment shall not exceed 45 MW thermal. For the purpose of calculating the capacity limit the conversion factor of 1:3 shall be used for converting electrical energy to thermal energy (i.e. for renewable energy project activities, the installed capacity of 15 MW(e) is equivalent to 45 MW thermal output of the equipment or the plant);

   (b) If the emission reductions of the project activity are solely on account of thermal energy production (i.e. no emission reductions accrue from the electricity component), the total installed thermal energy production capacity of the project equipment shall not exceed 45 MW thermal;

   (c) If the emission reductions of the project activity are solely on account of electrical energy production (i.e. no emission reductions accrue from the thermal energy component), the total installed electrical energy generation capacity of the project equipment shall not exceed 15 MW.

10. The capacity limits specified in paragraphs 7 to 9 above apply to both new facilities and retrofit projects. In the case of project activities that involve the addition of renewable energy units at an existing renewable energy facility, the total capacity of the units added by the project shall comply with capacity limits specified in the paragraphs 7 to 9, and shall be physically distinct[2] from the existing units.

11. If solid biomass fuel (e.g. briquette) is used, it shall be demonstrated that it has been produced using solely renewable biomass and all project or leakage emissions associated with its production shall be taken into account in the emissions reduction calculation.

12. Where the project participant is not the producer of the processed solid biomass fuel, the project participant and the producer are bound by a contract that shall enable the project

[1] Thermal energy generation capacity shall be manufacturer's rated thermal energy output, or if that rating is not available the capacity shall be determined by taking the difference between enthalpy of total output (for example steam or hot air or chilled water in kcal/kg or kcal/m^3) leaving the project equipment and the total enthalpy of input (for example feed water or air in kcal/kg or kcal/m^3) entering the project equipment. For boilers, condensate return (if any) must be incorporated into enthalpy of the feed.

[2] Physically distinct units are those that are capable of producing thermal/electrical energy without the operation of existing units, and that do not directly affect the mechanical, thermal, or electrical characteristics of the existing facility. For example, the addition of a steam turbine to an existing combustion turbine to create a combined cycle unit would not be considered "physically distinct".

participant to monitor the source of the renewable biomass to account for any emissions associated with solid biomass fuel production. Such a contract shall also ensure that there is no double-counting of emission reductions.

13. If electricity and/or thermal energy produced by the project activity is delivered to a third party i.e. another facility or facilities within the project boundary, a contract between the supplier and consumer(s) of the energy will have to be entered into that ensures there is no double-counting of emission reductions.

14. If the project activity recovers and utilizes biogas for producing electricity and/or thermal energy and applies this methodology on a standalone basis i.e. without using a Type III component of a SSC methodology, any incremental emissions occurring due to the implementation of the project activity (e.g. physical leakage of the anaerobic digester, emissions due to inefficiency of the flaring), shall be taken into account either as project or leakage emissions as per relevant procedures in the tool “Emissions from solid waste disposal sites” and/or “Project emissions from flaring”. In the event that the biomass fuel (solid/liquid/gas) is sourced from an existing CDM project, then the emissions associated with the production of the fuel shall be accounted with that project.

15. If project equipment contains refrigerants, then the refrigerant used in the project case shall have no ozone depleting potential (ODP).

16. Charcoal based biomass energy generation project activities are eligible to apply the methodology only if the charcoal is produced from renewable biomass sources-provided:

    (a) Charcoal is produced in kilns equipped with methane recovery and destruction facility; or

    (b) If charcoal is produced in kilns not equipped with a methane recovery and destruction facility, methane emissions from the production of charcoal shall be considered. These emissions shall be calculated as per the procedures defined in the approved methodology “AMS-III.K: Avoidance of methane release from charcoal production by shifting from traditional open-ended methods to mechanized charcoaling process”. Alternatively, conservative emission factor values from peer reviewed literature or from a registered CDM project activity can be used, provided that it can be demonstrated that the parameters from these are comparable e.g. source of biomass, characteristics of biomass such as moisture, carbon content, type of kiln, operating conditions such as ambient temperature.

17. In cases where the project activity utilizes biomass, sourced from dedicated plantations, applicability conditions prescribed in the tool “Project emissions from cultivation of biomass” shall apply.

2.3. Entry into force

18. The date of entry into force is the date of the publication of the EB 79 meeting report on 1 June 2014.

3. Normative references

19. Project participants shall apply the “General guidelines for SSC CDM methodologies”, “Guidelines on the demonstration of additionality of small-scale project activities” and “General guidance on leakage in biomass project activities” (attachment C to Appendix

B) provided at <http://cdm.unfccc.int/methodologies/SSCmethodologies/approved.html> mutatis mutandis.

20. This methodology also refers to the latest approved versions of the following approved methodologies, tools and guidelines:

(a) "AMS-I.D: Grid connected renewable electricity generation";

(b) "AMS-I.F: Renewable electricity generation for captive use and mini-grid";

(c) "AMS-III.K: Avoidance of methane release from charcoal production by shifting from traditional open-ended methods to mechanized charcoaling process";

(d) "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion";

(e) "Tool to calculate baseline, project and/or leakage emissions from electricity consumption";

(f) "Tool to determine the baseline efficiency of thermal or electric energy generation systems"

(g) Tool: "Project emissions from cultivation of biomass";

(h) Tool: "Emissions from solid waste disposal sites";

(i) Tool: "Project emissions from flaring";

(j) Tool: "Project and leakage emissions from transportation of freight";

(k) Guideline: "Sampling and surveys for CDM project activities and programmes of activities".

4. Definitions

21. The definitions contained in the Glossary of CDM terms shall apply.

22. For the purpose of this methodology following definitions shall apply:

(a) **Cogeneration** - means the simultaneous generation of heat and electrical energy in one process.[3] Project activities that produce heat and electrical energy in separate element processes (for example heat from a boiler and electricity from a biogas engine) do not fit under the definition of cogeneration;

(b) **Trigeneration** - means the simultaneous generation of electrical energy and thermal energy in the form of cooling and heating in one process.[4] Project activities that produce electrical energy and thermal energy in separate element

[3] This methodology, however, does not preclude production of heat and power from the same heat generating equipment, for example a portion of steam produced in a boiler is used for process heat and another portion of steam from the same boiler is used for electricity production.

[4] This methodology, however, does not preclude production of thermal energy in the form of heating and cooling and power from the same heat generating equipment, for example a portion of steam produced in a boiler is used as process heat and another portion to generate chilled water and remaining portion of steam from the same boiler is used for electricity production.

processes (for example thermal energy from a boiler and electricity from a biogas engine) do not fit under the definition of trigeneration;

(c) **Existing facilities** - are those that have been in operation for at least three years immediately prior to the start date of the project activity;

(d) **Thermal energy** - means either heating (e.g. steam or hot water or hot air) or cooling (e.g. chilled water), or both;

(e) **Co-fired system** - uses both fossil and renewable fuels in a single boiler for simultaneous combustion and fossil fuel may be used during a period of time when the biomass is not available.

5. Baseline methodology

5.1. Project boundary

23. The spatial extent of the project boundary encompasses:

(a) All plants generating electricity and/or thermal energy located at the project site, whether fired with biomass, fossil fuels or a combination of both;

(b) All power plants connected physically to the electricity system (grid) that the project plant is connected to;

(c) Industrial, commercial or residential facility, or facilities, consuming energy generated by the system and the processes or equipment affected by the project activity;

(d) The processing plant of biomass residues, for project activities using solid biomass fuel (e.g. briquette), unless all associated emissions are accounted for as leakage emissions or are part of an independently registered CDM project;

(e) The transportation itineraries, if the biomass is transported over distances greater than 200 kilometres, unless all associated emissions are accounted for as leakage emissions;

(f) The site of the anaerobic digester in the case of project activity that recovers and utilizes biogas for producing electricity and/or thermal energy and applies this methodology on a standalone basis, i.e. without using a Type III component of a SSC methodology.

5.2. Baseline emissions

5.2.1. General criteria on determining baseline emissions

24. For renewable energy technologies that displace technologies using fossil fuels, the simplified baseline is the fuel consumption of the technologies that would have been used in the absence of the project activity, times an emission factor for the fossil fuel displaced.

25. For project activities implemented in existing facilities, baseline calculations shall be based on operational data on energy use (e.g. electricity, fossil fuel) and plant output (e.g. thermal and/or electrical energy) using;

    (a) Most recent three years operational data immediately prior to the start date of the project activity in case of existing facilities which has more than three years of operation history;

    (b) A minimum of most recent one year data in case of existing facilities which has more than three years of operation history but do not have three years operational data; or

    (c) A performance test/measurement campaign carried out prior to the implementation of the project activity in case of existing facilities which has more than three years of operation history but do not have operational data/information such as efficiency, energy consumption and output or the available data is not reliable due to various factors such as the use of imprecise or non-calibrated measuring equipment. The project proponent may follow the relevant provisions from the "Tool to determine baseline efficiency of thermal and electricity systems".

26. In the case of project activities that export thermal and/or electrical energy to other facilities, historical data from the recipient plants is also required.

27. For project activities implemented in existing facilities where the additionality is demonstrated based on a baseline scenario that is not the continuation of the current practice (e.g. continued use of the fossil fuel that was used prior to the implementation of the project activity), the baseline emission factor is chosen as lower of the two: (a) the emission factor of the fossil fuel that would have been used in the absence of the project activity; and (b) the emission factor of the fossil fuel that was used prior to the implementation of the project activity.

5.2.2. Baseline scenario for electrical and/or thermal energy production

28. Project activities producing both electricity and thermal energy shall use one of the following baseline scenarios:

    (a) Electricity is imported from a grid and thermal energy is produced using fossil fuel;

    (b) Electricity is produced in an on-site captive power plant using fossil fuel (with a possibility of export to the grid) and thermal energy is produced using fossil fuel;

    (c) A combination of (a) and (b);

    (d) Electricity and thermal energy are produced in a cogeneration or trigeneration unit using fossil fuel (with a possibility of export of electricity to a grid/other facilities and/or thermal energy to other facilities);

    (e) Electricity is imported from a grid and/or produced in an on-site captive power plant using fossil fuels (with a possibility of export to the grid); thermal energy is produced using biomass;

(f) Electricity is produced in an on-site captive power plant using biomass (with a possibility of export to a grid) and/or imported from a grid; thermal energy is produced using fossil fuel;

(g) Electricity and thermal energy are produced in a biomass fired cogeneration or trigeneration unit (without a possibility of export of electricity either to a grid or to other facilities and without a possibility of export of thermal energy to other facilities);

(h) Electricity and/or thermal energy produced in a co-fired system;

(i) Electricity is imported from a grid and/or produced in a biomass fired cogeneration or trigeneration unit (without a possibility of export of electricity either to the grid or to other facilities); thermal energy is produced in a biomass fired cogeneration or trigeneration unit and/or a biomass fired boiler (without a possibility of export of thermal energy to other facilities);

(j) Electricity is imported from a grid and/or produced in an on-site captive power plant using fossil fuel and thermal energy is produced using electricity.

29. The scenario mentioned in paragraph 28(g) applies to a project activity that installs a new grid connected biomass cogeneration or trigeneration system that produces surplus electricity and this surplus electricity is exported to a grid.[5]

30. This scenario mentioned in paragraph 28(i) to a project activity that installs a new biomass cogeneration or trigeneration system that displaces electricity which otherwise would have been imported from a grid.[6]

5.2.3. Baseline emissions for electricity production

31. Baseline emissions for electricity produced in captive plants shall be calculated as follows:

$$BE_{captelec,y} = \left(\frac{EG_{captelec,PJ,y}}{\eta_{BL,captive\ plant}}\right) \times EF_{BL,FF,CO2} \qquad \text{Equation (1)}$$

Where:

$BE_{captelec,y}$	=	Baseline emissions from electricity displaced by the project activity during the year *y* (t CO_2)
$EG_{captelec,PJ,y}$	=	Amount of electricity produced by the project activity during the year *y* (MWh)

[5] All the services provided in pre-project scenario baseline i.e. energy supply (process heat, cooling, chilled water and electricity) are maintained at the same level or improved during the crediting period. This shall be demonstrated using the most recent three years of historical data. (see also paragraph 25).

[6] It shall be demonstrated using the three most recent years of historical data that electricity imported from the grid is more than captive electricity generated using biomass. All the services provided in pre-project scenario i.e. energy supply (process heat and electricity) are maintained at the same level or improved during the crediting period (see also paragraph 25).

$EF_{BL,FF,CO2}$	=	CO_2 emission factor of the fossil fuel that would have been used in the baseline plant (t CO_2/MWh)
$\eta_{BL,captive\ plant}$	=	Efficiency of the plant using fossil fuel that would have been used in the absence of the project activity determined using paragraph 39 or 40 below

32. Baseline emissions for supply of electricity to and/or displacement of electricity from a grid shall be calculated as follows:

$$BE_{grid,y} = EG_{grid,y} \times EF_{grid,y}$$ Equation (2)

Where:

$BE_{grid,y}$	=	Baseline emissions for the grid electricity displaced by the project in year *y* (t CO_2e)
$EG_{grid,y}$	=	Amount of grid electricity displaced by project in year *y* (MWh)
$EF_{grid,y}$	=	Emission factor of the grid (t CO_2e/MWh)

5.2.4. Baseline emissions for heat production

33. For thermal energy produced using fossil fuels and/or grid electricity the baseline emissions are calculated as follows:

$$BE_{thermal,Co2,y} = \left(\frac{EG_{thermal,y}}{\eta_{BL,thermal}}\right) \times EF_{FF,CO2}$$ Equation (3)

Where:

$BE_{thermal,Co2,y}$	=	Baseline emissions from thermal energy displaced by the project activity during the year *y* (t CO_2)
$EG_{thermal,y}$	=	Net quantity of thermal energy supplied by the project activity during the year *y* (TJ)
$EF_{FF,CO2}$	=	CO_2 emission factor of the fossil fuel that would have been used in the baseline plant obtained from reliable local or national data if available, alternatively, IPCC default emission factors can be used (t CO_2/TJ)
$\eta_{BL,thermal}$	=	Efficiency of the plant using fossil fuel that would have been used in the absence of the project activity determined as per paragraph 39 or 40

34. For cases 28(a), (b) and (c), baseline emissions shall be calculated as the sum of emissions from the production of electricity and thermal energy considering most recent historical records (average of the data from a minimum of the three most recent years excluding abnormal years is required).

5.2.5. Determination of emission factor for electricity

35. For project activities that displace on-site captive electricity and/or displace grid electricity import and/or supply electricity to a grid, the electricity emission factor should reflect the emissions intensity of the captive power plant and the grid of the baseline scenario. If annual electricity produced in the project activity is less than or equal to the sum of on-site captive generation and net grid import[7] in the baseline scenario, the emission factor shall be calculated as the weighted average of on-site captive electricity generation and the net grid electricity import in the baseline.[8] If annual electricity produced in the project activity is greater than the sum of on-site captive generation and net grid import in the baseline, the lower of the two, i.e. the emission factor of the grid or the emission factor of the baseline captive plant shall be used for the incremental generation (i.e. the difference between the electricity generation in the project activity and the sum of captive generation and net grid import).

36. For project activities that do not displace captive electricity generated by an existing plant but displace grid electricity import and/or supply electricity to a grid, the emission factor of the grid shall be calculated as per the procedures detailed in "AMS-I.D: Grid connected renewable electricity generation" or "AMS-I.F: Renewable electricity generation for captive use and mini-grid".

37. For new facilities, the most conservative (lowest) emission factor of the two power sources (captive power plant and grid) should be used.

5.2.6. Baseline emissions for electricity and heat production

38. For electricity and thermal energy produced in a baseline cogeneration or trigeneration unit, using fossil fuel (case 28(d)), the following equation shall be used to determine baseline emissions:

$$BE_{cogen/trigen,CO2,y} = \left[\left(\frac{EG_{PJ,thermal,y} + EG_{PJ,electrical,y} \times 3.6}{\eta_{BL,cogen/trigen}}\right)\right] \times EF_{FF,CO2} \qquad \text{Equation (4)}$$

Where:

$BE_{cogen/trigen,CO2,y}$	=	Baseline emissions from electricity and thermal energy displaced by the project activity during the year *y* (t CO_2)
$EG_{PJ,electrical,y}$	=	Amount of electricity supplied by the project activity during the year *y*; (GWh)
3.6	=	Conversion factor (TJ/GWh)

[7] Difference of total electricity imported from the grid and total electricity exported to the grid.

[8] For example in the baseline if 80 per cent of annual electricity requirement was met by grid import and the rest by captive generation, the weighted average emission factor (*EF*) would be 0.8 EF_{grid} + 0.2 $EF_{captive}$.

$EG_{PJ,thermal,y}$	=	Net quantity of thermal energy supplied by the project activity during the year *y* (TJ)
$EF_{FF,CO2}$	=	CO_2 emission factor of the fossil fuel that would have been used in the baseline cogeneration plant obtained from reliable local or national data if available, alternatively, IPCC default emission factors can be used (t CO_2/TJ)
$\eta_{BL,cogen/trigen}$	=	Total annual average efficiency of the cogeneration or trigeneration plant using fossil fuel determined as per paragraph 39 or 40

39. In the case of an existing baseline cogeneration or trigeneration plant, the efficiency shall be calculated as the total annual energy produced over the last three years using the historical data as prescribed in paragraph 25 above (total electricity generated and total thermal energy extracted divided by the thermal energy value of the fuel use).

40. In the case of a Greenfield project cogeneration or trigeneration plant where the baseline is a cogeneration or trigeneration plant (e.g. using a steam turbine and steam generator that would have been built in the absence of the project activity), the total annual average efficiency of the cogeneration or trigeneration plant using fossil fuel shall be defined as the ratio of thermal energy and electricity produced to total thermal energy value of the fuel use. This ratio shall be determined using one of the two following options (in preferential order):

   (a) Calculated as a single value with consideration of the following:

      (i) Step 1:

         a. The total annual average efficiency of the cogeneration or trigeneration plant using fossil fuel is determined using documented efficiency specification for new steam turbines and steam generators provided by two or more manufacturers for each type of such equipment within in the region:[9]

         b. Efficiency values for the steam turbine(s) and steam generator(s) shall be based on turbines and steam generators with specifications nearly equivalent to baseline units that would have been utilized in the absence of the project activity;

         c. The efficiency values utilized shall be the highest individual efficiency values (over the full range of expected operating conditions of the baseline cogeneration or trigeneration system) that can be achieved by the steam turbine(s) and steam generator(s).

      (ii) Step 2:

         a. The total annual average efficiency of the cogeneration or trigeneration plant using fossil fuel is then calculated as the product of the highest efficiency value for the steam turbine(s) and the

[9] In case equipment is not available within the region the project proponent shall consider adjoining regions.

highest efficiency value of the steam generator(s), assuming both efficiencies are in the form of a percentage of output per input;

(b) Calculated as a single value with consideration of the following:

(i) Step 1:

a. A default steam turbine efficiency of 100 per cent;

b. Default steam generator efficiency determined using the values provided in appendix;

(ii) Step 2:

a. The total annual average efficiency of the cogeneration or trigeneration plant using fossil fuel is then calculated as the product of the efficiency value for the steam turbine(s) and the efficiency value of the steam generator(s), assuming both efficiencies are in the form of a percentage of output per input.

41. Efficiency of the baseline units (excluding cogeneration or trigeneration plants) shall be determined by adopting one of the following criteria (in preferential order):

(a) Highest measured operational efficiency over the full range of operating conditions of a unit with similar specifications, using baseline fuel. The efficiency tests shall be conducted following the guidance provided in relevant national/international standards;

(b) Highest of the efficiency values provided by two or more manufacturers for units with similar specifications, using the baseline fuel;

(c) A default efficiency of 100 per cent.

42. For household or commercial applications/systems, whose maximum output capacity is less than 45 kW thermal and where it can be demonstrated that the metering of thermal energy output is not plausible, as in the case of cooking stoves, gasifiers, driers, water heaters etc., efficiency of the baseline units shall be determined by adopting one of the following criteria:

(a) Highest measured operational efficiency over the full range of operating conditions of a representative sample of units with similar specifications, using baseline fuel. The efficiency tests shall be conducted following the guidance provided in relevant national/international standards;

(b) Highest of the efficiency values provided by two or more manufacturers for units with similar specifications using the baseline fuel;

(c) Highest efficiency from referenced literature values or default efficiency of 100 per cent.

43. For case 28(e), baseline emissions from the production of electricity shall be calculated as per paragraph 29 and 30. Emission reductions from heat generation are not eligible.

44. For case 28(f), baseline emissions from the production of thermal energy using fossil fuel shall be calculated as per paragraph 31. Emission reductions from displacing on-site electricity generation are not eligible.

45. For case 28(g) and (i), baseline emissions from the additional production of electricity that displaces grid electricity import and/or supply electricity to the grid, shall be calculated as per paragraph 29.

5.2.7. Baseline emissions for co-fired systems

46. For case 28(h) and other project activities where the baseline is co-fired system,[10] baseline emissions shall be determined based on three years average historical data on the relative share of fossil fuel and biomass in the baseline fuel mix.[11] The relative share is determined based on the energy content of each fuel.

$$BE_{cofire,Co2,y} = \left(\frac{EG_{cofire,PJ,y}}{\eta_{BL,cofire}}\right) \times EF_{cofire,CO2} \quad \text{Equation (5)}$$

Where:

$BE_{cofire,Co2,y}$	=	Baseline emissions from thermal and/or electrical energy displaced by the project activity during the year *y* (t CO_2e)
$EG_{cofire,PJ,y}$	=	Net quantity of energy (electricity/thermal) supplied by the project activity during the year *y* (TJ)
$EF_{cofire,CO2}$	=	CO_2 emission factor of the baseline co-fired plant established using three years average historical data (t CO_2/TJ)
$\eta_{BL,cofire}$	=	Efficiency of the co-fired plant that would have been used in the absence of the project activity determined using paragraph 39 or 40 above

5.2.8. Baseline emissions for trigeneration systems

47. For case 28(j) the baseline emissions, BE_y are calculated using equation (6):

$$BE_y = BE_{grid,y} + BE_{captelec,y} + B_{BC,y} + BE_{BH,y} \quad \text{Equation (6)}$$

Where:

$BE_{grid,y}$	=	Baseline emissions associated with the grid electricity displaced by the project in year *y* (t CO_2e)
$BE_{captelec,y}$	=	Baseline emissions from electricity displaced by the project activity during the year *y* (t CO_2)

[10] For project activities where the baseline is not a co-fired system equation (1) for electricity and equation (2) for heat/steam can be applied.

[11] In the case where more than one fossil fuel is used by the co-fired plant, the weighted average emission factor (in energy basis) among the identified fossil fuels shall be used.

$B_{BC,y}$	=	Baseline emissions associated with the cooling (e.g. chilled water) produced in year *y* (t CO_2e)
$BE_{BH,y}$	=	Baseline emissions associated with the heat (e.g. steam or hot water) produced in year *y* (t CO_2e)

48. Baseline electricity related emissions ($BE_{grid,y}$) are calculated as per equation (2) above.

49. The baseline emissions ($BE_{captelec,y}$) from electricity obtained from captive power plant(s), is calculated using equation (1) above.

50. Baseline emissions associated with the electricity consumed, whether it is from captive power plants and/or power from the grid, to produce chilled water within the project boundary are determined per equation (7).

$$BE_{BC,y} = EF_{grid,y} \times \sum_{i} \frac{C_{P,i,y}}{COP_{c,i}} \qquad \text{Equation (7)}$$

Where:

$EF_{grid,y}$	=	Electricity emission factor of the grid (t CO_2e/MWh)
$COP_{c,i}$	=	Coefficient of Performance (COP) of the baseline scenario chiller(s) *i* (MWh_{th}/MWh_e). The COP estimated as 'cooling output divided by electricity input'
$C_{P,i,y}$	=	Cooling output of baseline scenario chiller(s) *i* in year y (MWh_{th})

(a) Baseline scenario chiller COP ($COP_{c,i}$) is determined as follows:

(i) If the baseline scenario is an existing chiller or chillers, then the COP shall be based on existing chiller performance data as specified in paragraph 25. In the case where multiple chillers exist, average performance data shall be used in a conservative manner with consideration of the historic output and power consumption of each chiller;

(ii) If the baseline scenario is a chiller or chillers that would have been built (i.e. not existing chillers), the COP shall be determined as the highest COP full load performance value provided by two or more manufacturers for chillers commonly sold in the project country for the indicated commercial application;

(b) The cooling output of each baseline scenario chiller *i* is calculated using measured values of the total chilled water mass flow-rate and of the differential temperature of incoming and outgoing chilled water; as recorded on an hourly basis per equation (8).

$$C_{p,i,y} = \frac{\sum_{h=1}^{8,760} m_{C,i,h} \times C_{pw} \times \Delta T_{C,i,h}}{3600} \qquad \text{Equation (8)}$$

Where:

$C_{p,i,y}$	=	Cooling output of the baseline chiller(s) *i* in year *y* (MWh_{th})
$m_{C,i,h}$	=	Chilled water mass flow-rate for chiller(s) *i* produced by project in hour *h* of year *y* (tonnes/hour)
C_{pw}	=	Specific heat capacity of water (MJ/tonnes°C)
$\Delta T_{C,i,h}$	=	Differential temperature of inlet and outlet chilled water for chiller(s) *i* in hour *h* of year *y* of incoming and outgoing water from project (°C)

51. For project activities with water heating systems, that use electricity, the baseline emissions are determined using the electricity emission factor and hourly measurements of the total water mass flow-rate and differential temperature of incoming and outgoing water, per equation (9). This equation is based on the assumption that the efficiency of electric water heating systems is 100 per cent.

$$BE_{BH,y} = EF_{grid,y} \times \frac{\sum_{h=1}^{8,760} m_h \times C_{pw} \times \Delta T_h}{3600}$$ Equation (9)

Where:

$BE_{BH,y}$	=	Baseline emissions for hot water produced in the project activity in year *y* (t CO_2e)
$EF_{grid,y}$	=	Electricity emission factor of the grid(t CO_2e/MWh)
m_h	=	The water mass flow-rate from heater(s) during hour *h* in year *y* (tonnes)
C_{pw}	=	Specific heat capacity of water (MJ/tonnes^{0}C)
ΔT_h	=	Differential temperature of inlet and outlet hot water for heater(s) during hour *h* (°C)

5.2.9. Baseline emissions for project activities involving new renewable energy units

52. In the case of project activities that involve the addition of renewable energy units at an existing renewable energy production facility, where the existing and new units share the use of common and limited renewable resources (e.g. biomass residues), the potential for the project activity to reduce the amount of renewable resource available to, and thus thermal energy production by, existing units must be considered in the determination of baseline emissions, project emissions, and/or leakage, as relevant.

53. For project activities that involve the addition of new energy production units (e.g. turbines) at an existing facility, net increase in thermal energy generation should be calculated as follows:

$$EG_{thermal,add,y} = EG_{thermal,PJ,y} - EG_{thermal,old,y}$$ Equation (10)

Where:

$EG_{thermal,add,y}$	=	Net increase in thermal energy generation at existing plant in year *y* that should be considered as energy baseline (EG_{BL}) (TJ)
$EG_{thermal,PJ,y}$	=	Total actual thermal energy produced in year *y* by all units, existing and new project units (TJ)
$EG_{thermal,old,y}$	=	Estimated thermal energy that would have been produced by existing units (installed before the project activity) in year *y* in the absence of the project activity (TJ)

54. The value $EG_{thermal,old,y}$ is given by:

$$EG_{thermal,old,y} = MAX\left(EG_{thermal,actual,y}, EG_{thermal,estimated,y}\right) \quad \text{Equation (11)}$$

Where:

$EG_{thermal,actual,y}$	=	Actual, measured thermal energy production of the existing units in year *y* (TJ)
$EG_{thermal,estimated,y}$	=	Estimated thermal energy that would have been produced by the existing units under the observed availability of the renewable resource for year *y* (TJ)

55. If the existing units shut down, are derated, or otherwise become limited in production, the project activity should not get credit for generating thermal energy from the same renewable resources that would have otherwise been used by the existing units (or their replacements). Therefore, the equation for $EG_{thermal,old,y}$ still holds, and the value for $EG_{thermal,estimated,y}$ should continue to be estimated assuming the capacity and operating parameters are the same as that at the time of the start of the project activity.

56. If the existing units are subject to modifications or retrofits that increase production, then $EG_{thermal,old,y}$ can be estimated using the procedures described for $EG_{BL,thermal,retrofit,y}$ below.

5.2.10. Baseline emissions for retrofit project activities

57. For project activities that seek to retrofit or modify an existing facility for renewable energy generation, the baseline scenario is the following:

58. In the absence of the CDM project activity, the existing facility would continue to provide thermal energy $EG_{BL,thermal,retrofit,y}$ at historical average levels $EG_{HY,thermal,retrofit,y}$, until the time at which the thermal energy facility would be likely to be replaced or retrofitted in the absence of the CDM project activity ($DATE_{BaselineRetrofit}$). From that point of time onwards, the baseline scenario is assumed to correspond to the project activity, and baseline thermal energy production is assumed to equal project thermal energy production and no emission reductions are assumed to occur.

$$EG_{BL,thermal,retrofit,y} = MAX\left(EG_{HY,thermal,retrofit,y}, EG_{estimated,thermal,y}\right)\ until\ DATE_{BaselineRetrofit} \quad \text{Equation (12)}$$

Where:

$EG_{BL,thermal,retrofit,y}$	=	Thermal energy production by an existing facility in the absence of the project activity in year *y* (TJ)
$EG_{HY,thermal,retrofit,y}$	=	Average of historical thermal energy levels delivered by the existing facility, spanning all data from the most recent available year (or month, week or other time period) to the time at which the facility was constructed, retrofitted, or modified in a manner that significantly affected output (i.e. by five per cent or more) (TJ)
$EG_{estimated,thermal,y}$	=	Estimated thermal energy that would have been produced by the existing units under the observed availability of renewable resources in year *y* (TJ)
$DATE_{BaselineRetrofit}$	=	Date at which the existing generation facility is likely to be replaced or retrofitted in the absence of the CDM project activity

59. For project activities that seek to retrofit or modify an existing facility to enhance the energy conversion efficiency, the baseline emissions $BE_{retrofit,CO2,y}$ then correspond to the difference of the thermal energy supplied by the project activity and the baseline thermal energy supplied in the case of modified or retrofit facilities multiplied by the emission factor of the fuel that would have been used to generate the incremental energy:

$$BE_{retrofit,CO2,y} = \left(EG_{thermal,retrofit,y} - EG_{BL,thermal,retrofit,y}\right) \times EF_{FF,CO2} \quad \text{Equation (13)}$$

Where:

$BE_{retrofit,CO2,y}$	=	Baseline emissions from the incremental thermal energy supplied due to retrofit (t CO_2)
$EG_{thermal,retrofit,y}$	=	Thermal energy supplied by the project activity (after retrofit) in year *y* (TJ)
$EG_{BL,thermal,retrofit,y}$	=	Thermal energy production by an existing facility in the absence of the project activity (before retrofit) in year *y* (TJ)
$EF_{FF,CO2}$	=	CO_2 emission factor of the fossil fuel that would have been used in the baseline plant to generate the incremental energy obtained from reliable local or national data if available, alternatively, IPCC default emission factors can be used (t CO_2/TJ)

60. The requirements concerning demonstration of the remaining lifetime of the replaced equipment shall be met as described in the “General guidelines for SSC CDM methodologies”. If the remaining lifetime of the affected systems increases due to the project activity, the crediting period shall be limited to the estimated remaining lifetime, i.e. the time when the affected systems would have been replaced in the absence of the project activity.

61. In order to estimate the point in time when the existing equipment would need to be replaced in the absence of the project activity *($DATE_{BaselineRetrofit}$)*, project participants may

follow the procedures described in the “General guidelines for SSC CDM methodologies”.

62. For project activities that seek to retrofit or modify an existing facility for the purpose of fuel switch from fossil fuels to biomass in heat generation equipment, the baseline emissions shall be calculated as per equation (2).

5.2.11. Baseline emissions for project activities with capacity less than 45 kW thermal

63. For household or commercial applications/systems, whose maximum output capacity is less than 45 kW thermal and where it can be demonstrated that the metering of thermal energy output is not plausible, as in the case of biomass stoves, gasifiers, driers, water heaters etc., the project output energy shall be estimated based on consumption of the biomass (in terms of energy quantity) times the efficiency of the project equipment. The equation below shall be used:

$$BE_y = \left[\frac{HG_{PJ,y}}{\eta_{BL}}\right] \times EF_{FF,CO2} = \left\{\left[\frac{B_{biomass,PJ,y} \times NCV_{biomass} \times \eta_{PJ}}{\eta_{BL}}\right]\right\} \times EF_{FF,CO2} \quad \text{Equation (14)}$$

Where:

BE_y	=	Baseline emissions from thermal energy displaced by the project activity using renewable biomass during the year *y* (t CO_2)
$HG_{PJ,y}$	=	Net quantity of thermal energy supplied by the project activity using renewable biomass during the year *y* (TJ)
η_{BL}	=	Efficiency of the baseline equipment being replaced determined as per paragraph 39 or 40
η_{PJ}	=	Efficiency of the project equipment measured using representative sampling methods or based on referenced literature values. The efficiency tests shall be conducted following the guidance provided in the relevant national/international standards
$EF_{FF,CO2}$	=	CO_2 emission factor of the fossil fuel that would have been used in the baseline (t CO_2/TJ)
$B_{biomass,PJ,y}$	=	Net quantity of the biomass consumed in year *y* (tonnes)
$NCV_{biomass}$	=	Net calorific value of the biomass (TJ/tonnes)

5.2.12. Ex ante estimations

64. The quantities and types of biomass and the biomass to fossil fuel ratio (in the case of co-fired systems) to be used during the crediting period should be explained and documented transparently in the CDM-PDD. For the selection of the baseline scenario, an ex ante estimation of these quantities should be provided.

5.3. Project emissions

65. Project emissions shall be calculated using the following equation:

$$PE_y = PE_{FF,y} + PE_{Ec,y} + PE_{Geo,y} + PE_{ref,y} + PE_{cultivation,y}$$ Equation (15)

Where:

PE_y	=	Project emissions from the project activity during the year *y* (t CO_2)
$PE_{FF,y}$	=	Project emissions from fossil fuel consumption during the year *y* (t CO_2)
$PE_{Ec,y}$	=	Project emissions from electricity consumption during the year *y* (t CO_2)
$PE_{Geo,y}$	=	Project emissions from a geothermal project activity in year *y* (t CO_2)
$PE_{ref,y}$	=	Project emissions from use of refrigerant in project activity in year *y* (t CO_2)
$PE_{cultivation,y}$	=	Project emissions from cultivation of biomass in a dedicated plantation in year *y* (t CO_2e)

5.3.1. Emissions from fuel combustion

66. CO_2 emissions from on-site combustion of fossil fuels ($PE_{FF,y}$) shall be calculated using the latest version of the "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion".

5.3.2. Emissions from electricity consumption

67. CO_2 emissions from electricity consumption ($PE_{EC,y}$) shall be calculated using the latest version of the "Tool to calculate baseline, project and/or leakage emissions from electricity consumption".

5.3.3. Emissions from geothermal project activities

68. For geothermal project activities, project participants shall account for the following emission sources, where applicable: fugitive emissions of carbon dioxide and methane due to release of non-condensable gases from produced steam; and carbon dioxide emissions resulting from combustion of fossil fuels related to the operation of the geothermal power plant.[12]

69. Project emissions in the case of geothermal project activities ($PE_{Geo,y}$) are calculated as follows:

$$PE_{Geo,y} = PE_{s,y} + PE_{FF,y}$$ Equation (16)

[12] Fugitive carbon dioxide and methane emissions due to well testing and well bleeding are not considered, as they are negligible.

Where:

$PE_{s,y}$	=	Project emissions of carbon dioxide and methane due to the release of non-condensable gases from the steam produced in the geothermal power plant in year *y* (t CO_2)
$PE_{FF,y}$	=	Project emissions from combustion of fossil fuels related to the operation of the geothermal power plant in year *y* (t CO_2)

70. Project emissions of carbon dioxide and methane due to the release of non-condensable gases from the steam produced in the geothermal power plant are calculated as:

$$PE_{s,y} = \left(w_{Main,CO2} + w_{Main,CH4} \times GWP_{CH4}\right) \times M_{s,y} \qquad \text{Equation (17)}$$

Where:

$w_{Main,CO2}$	=	Average mass fraction of carbon dioxide in the produced steam (non-dimensional)
$w_{Main,CH4}$	=	Average mass fraction of methane in the produced steam (non-dimensional)
GWP_{CH4}	=	Global warming potential of methane valid for the relevant commitment period (t CO_2e/t CH_4)
$M_{s,y}$	=	Quantity of steam produced during the year *y* (tonnes)

71. Project emissions from combustion of fossil fuels related to the operation of the geothermal power plant are calculated as:

$$PE_{FF,y} = PE_{FC,j,y} \qquad \text{Equation (18)}$$

Where:

$PE_{FC,j,y}$	=	CO_2 emissions from fossil fuel combustion in process *j* during the year *y* (t CO_2). This parameter shall be calculated as per the latest version of the "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion" where *j* stands for the processes required for the operation of the geothermal power plant

5.3.4. Project emissions from use of refrigerant

72. For trigeneration project activities, the project participants shall account for emissions due to physical leakage of refrigerant from new cooling equipment (e.g. electrical compression chillers which are an integral part of a cogeneration and/or trigeneration system or in the case of a new facility where electrical compression chillers are used as a backup).

73. Project emissions due to physical leakage of refrigerant from new cooling equipment in cogeneration and/or trigeneration project activities ($PE_{ref,y}$) shall be calculated as follows:[13]

[13] Baseline emissions related to refrigerant use are assumed to equal zero.

(a) For first year of the monitoring period:

$$PE_{ref,1} = \left(Q_{ref,PJ,start}\right) \times GWP_{ref,PJ} \quad \text{Equation (19)}$$

(b) For rest of the monitoring period:

$$PE_{ref,y} = \left(Q_{ref,PJ,y}\right) \times GWP_{ref,PJ} \quad \text{Equation (20)}$$

Where:

$PE_{ref,y}$	=	Project emissions from physical leakage of refrigerant from new cooling equipment in year *y* (t CO_2e)
$Q_{ref,PJ,start}$	=	Quantity of refrigerant charge in new cooling equipment at its start of operation (tonnes)
$Q_{ref,PJ,y}$	=	Quantity of refrigerant used in year *y* to replace refrigerant that has leaked in year *y* (tonnes)
$GWP_{ref,PJ}$	=	Global warming potential of the refrigerant that is used in new cooling equipment (t CO_2e/t refrigerant)

74. $Q_{ref,PJ,y}$ can be determined using one of the following options:

(a) **Option A:** using the higher of the two quantities below:

(i) The monitored quantity of refrigerant used for top-up to compensate for the leaked quantity during the year *y*; or

(ii) The typical refrigerant leakage rate for the type of cooling equipment as determined from the emission factors (expressed in terms percentage of the initial charge/year) provided in the IPCC 2006 Guidelines, Chapter 7, Table 7.9 “Estimates for charge, lifetime and emissions factors for refrigeration and air conditioning systems”;

(b) **Option B:** use a default value of 35 per cent of the initial refrigerant charge, i.e. $Q_{ref,PJ,y}$ = 0.35 x $Q_{ref,PJ,start}$.

5.3.5. Project emissions from cultivation of biomass

75. In cases where the project activity utilizes biomass sourced from dedicated plantations, the project emissions from biomass cultivation shall be calculated according to the tool “Project emissions from cultivation of biomass”.

5.4. Leakage

76. If the energy generating equipment currently being utilised is transferred from outside the boundary to the project activity, leakage is to be considered.

77. In cases where the collection, processing and transportation of biomass residues is outside the project boundary and due to the implementation of the project activity biomass residues are transported over a distance of 200 kilometres CO_2 emissions from the collection, processing and transportation of biomass residues to the project site shall

be taken into account as leakage using with the latest version of tool "Project and leakage emissions from transportation of freight".

78. If the displaced refrigerant is a greenhouse gas as defined in annex A of the Kyoto Protocol or in paragraph 1 of the Convention and is not destroyed, emissions from its storage or usage in equipment must be considered[14] as leakage.

79. Leakage emissions on account of the diversion of biomass residues from other uses (competing uses) shall be calculated as per the "General guidance on leakage in biomass project activities".

5.5. Emission reductions

80. Emission reductions are calculated as follows:

$$ER_y = BE_y - PE_y - LE_y \qquad \text{Equation (21)}$$

Where:

ER_y	=	Emission reductions in year *y* (t CO_2e)
BE_y	=	Baseline emissions in year *y* (t CO_2e)
PE_y	=	Project emissions in year *y* (t CO_2)
LE_y	=	Leakage emissions in year *y* (t CO_2)

6. Monitoring

81. Relevant parameters shall be monitored as indicated in the tables below:[15]

Data / Parameter table 1.

Data / Parameter:	**-**
Data unit:	-
Description:	Continuous operation of the equipment/system
Source of data	Records maintained by PP/CME

[14] The global warming potentials used to calculate the carbon dioxide equivalence of anthropogenic emissions by sources of greenhouse gases not listed in annex A of the Kyoto Protocol, shall be those accepted by the Intergovernmental Panel on Climate Change in its third assessment report.

[15] For example, if emission reductions of the cogeneration project activity are solely on account of electrical energy production (i.e. no emission reductions accrue from the thermal energy component), thermal energy used to produce electrical energy also need to be monitored where applicable. Also those parameters are required to be monitored where energy balance is used to cross-check the net quantity of biomass consumed in year *y*.

Measurement procedures (if any):	If the emissions reduction per system is less than five tonnes of CO_2e a year; or In the case of household or commercial applications/systems, whose maximum output capacity is less than 45 kW thermal and where it can be demonstrated that the metering of thermal energy output is not plausible: (i) Recording annually the number of systems operating (evidence of continuing operation, such as on-going rental/lease payments could be a substitute), if necessary using survey methods; (ii) Estimating the annual hours of operation of an average system, if necessary using survey methods. Annual hours of operation can be estimated from total output (e.g. tonnes of grain dried) and output per hour if an accurate value of output per hour is available. Where necessary refer to the "~~General~~ Guideline~~s~~ for sampling and surveys for CDM ~~SSC~~ project activities and programmes of activities"
Monitoring frequency:	Annual
QA/QC procedure	Check of all appliances or a representative sample thereof to ensure that they are still operating or are replaced by an equivalent in service appliance
Any comment:	-

Data / Parameter table 2.

Data / Parameter:	$\mathbf{EF_{grid,y}}$
Data unit:	t CO_2e/kWh
Description:	CO_2 emission factor for the grid electricity in year *y*
Source of data	-
Measurement procedures (if any):	As described in AMS-I.D
Monitoring frequency:	Annual
QA/QC procedure	-
Any comment:	The parameter need to be monitored for project activities which export and/or displaces or import grid electricity

Data / Parameter table 3.

Data / Parameter:	$\mathbf{EF_{FF,CO2,i}}$
Data unit:	t CO_2e/GJ
Description:	CO_2 emission factor of fossil fuel type *i*
Source of data	As per the "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion"
Measurement procedures (if any):	As per the "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion"

Monitoring frequency:	As per the “Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion”
QA/QC procedure	-
Any comment:	The parameter need to monitor for project activities which displaces electricity from the fossil fuel based captive power plants

Data / Parameter table 4.

Data / Parameter:	$EG_{grid,y}$
Data unit:	MWh
Description:	Quantity of electricity generated/supplied
Source of data	Plant records
Measurement procedures (if any):	Measured using calibrated meters. Calibration shall be as per the relevant paragraphs of “General guidelines for SSC CDM methodologies”. In case the project activity is exporting electricity to other facilities, the metering shall be carried out at the recipient’s end and measurement results shall be cross checked with records for sold/purchased electricity (e.g. invoices/receipts). Metering the energy produced by a sample of the systems where the simplified baseline is based on the energy produced multiplied by an emission coefficient
Monitoring frequency:	Continuous monitoring, integrated hourly and at least monthly recording
QA/QC procedure	-
Any comment:	The parameter need to be monitored for project activities which export and/or displaces or import grid electricity

Data / Parameter table 5.

Data / Parameter:	**-**
Data unit:	Nm^3/hr
Description:	Quantity of hot air
Source of data	Plant records
Measurement procedures (if any):	Measured using calibrated meters. Where it is not feasible (e.g. because of too high temperature), spot measurements can be used through sampling with a 90 per cent confidence level and a 10 per cent precision
Monitoring frequency:	Continuous monitoring, integrated hourly and at least monthly recordings
QA/QC procedure	Calibration shall be as per the relevant paragraphs of “General guidelines for SSC CDM methodologies”.
Any comment:	If applicable, measurement results shall be cross checked with records for sold/purchased thermal energy (e.g. invoices/receipts)

Data / Parameter table 6.

Data / Parameter:	**-**
Data unit:	Nm^3/hr
Description:	Quantity of steam
Source of data	Plant records
Measurement procedures (if any):	Measured using calibrated meters
Monitoring frequency:	Continuous monitoring, integrated hourly and at least monthly recording
QA/QC procedure	Calibration shall be as per the relevant paragraphs of the “General guidelines for SSC CDM methodologies”
Any comment:	If applicable, measurement results shall be cross checked with records for sold/purchased thermal energy e.g. invoices/receipts)

Data / Parameter table 7.

Data / Parameter:	$\mathbf{EG_{thermal,y}}$
Data unit:	TJ
Description:	Net quantity of thermal energy supplied by the project activity during the year *y*
Source of data	Plant records
Measurement procedures (if any):	Heat generation is determined as the difference of the enthalpy of the steam or hot fluid and/or gases generated by the heat generation equipment and the sum of the enthalpies of the feed-fluid and/or gases blow-down and if applicable any condensate returns. The respective enthalpies should be determined based on the mass (or volume) flows, the temperatures and, in case of superheated steam, the pressure. Steam tables or appropriate thermodynamic equations may be used to calculate the enthalpy as a function of temperature and pressure. In case of equipment that produces hot water/oil this is expressed as the difference in the enthalpy between the hot water/oil supplied to and returned by the plant. In case of equipment that produces hot gases or combustion gases, this is expressed as the difference in the enthalpy between the hot gas produced and all streams supplied to the plant. The enthalpy of all relevant streams shall be determined based on the monitored mass flow, temperature, pressure, density and specific heat of the gas. In case the project activity is exporting heat to other facilities, the metering shall be carried out at the recipient’s end
Monitoring frequency:	Continuous monitoring, aggregated annually
QA/QC procedure	Measurement results shall be cross checked with records for sold/purchased thermal energy (e.g. invoices/receipts)
Any comment:	Metering the energy produced by a sample of the systems where the simplified baseline is based on the energy produced multiplied by an emission coefficient

Data / Parameter table 8.

Data / Parameter:	**$PE_{FF,y}$**
Data unit:	t CO_2/yr
Description:	Project emissions from fossil fuel combustion in year *y*
Source of data	-
Measurement procedures (if any):	As per the “Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion”
Monitoring frequency:	As per the “Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion”
QA/QC procedure	As per the “Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion”
Any comment:	-

Data / Parameter table 9.

Data / Parameter:	**$PE_{EC,y}$**
Data unit:	t CO_2/yr
Description:	Project emissions from electricity consumption in year *y*
Source of data	-
Measurement procedures (if any):	As per the “Tool to calculate baseline, project and/or leakage emissions from electricity consumption”
Monitoring frequency:	As per the “Tool to calculate baseline, project and/or leakage emissions from electricity consumption”
QA/QC procedure	As per the “Tool to calculate baseline, project and/or leakage emissions from electricity consumption”
Any comment:	-

Data / Parameter table 10.

Data / Parameter:	**$B_{Biomass,y}$**
Data unit:	Mass or volume
Description:	Net quantity of biomass consumed in year *y*
Source of data	Plant records
Measurement procedures (if any):	Use mass or volume based measurements. Adjust for the moisture content in order to determine the quantity of dry biomass. The quantity of biomass shall be measured continuously or in batches. If more than one type of biomass fuel is consumed, each shall be monitored separately. For the case of processed renewable biomass (e.g. briquettes) data shall be collected for mass, moisture content, NCV of the processed biomass that is supplied to users with an appropriate sampling frequency
Monitoring frequency:	Continuously and estimate using annual mass/energy balance

QA/QC procedure	Cross-check the measurements with an annual energy balance that is based on purchased quantities (e.g. with sales receipts) and stock changes. In cases where emission reductions are calculated based on energy output, check the consistency of measurements ex post with annual data on energy generation, fossil fuels and biomass used and the efficiency of energy generation as determined ex ante
Any comment:	-

Data / Parameter table 11.

Data / Parameter:	**-**
Data unit:	%
Description:	Moisture content of the biomass (wet basis)
Source of data	Plant records
Measurement procedures (if any):	On-site measurements. This applies in the case where emission reductions are calculated based on biomass energy input. For all cases, ex ante estimates should be provided in the PDD and used during the crediting period. Alternatively, moisture content value provided by supplier of biomass should be used if it can be shown that it is reliable (e.g. the price paid for the biomass procured depends on its moisture content) and provided that the project continues to use same type of biomass during the rest of the crediting period. In case of dry biomass, monitoring of this parameter is not necessary
Monitoring frequency:	The moisture content of biomass of homogeneous quality shall be monitored for each batch of biomass. The weighted average should be calculated for each monitoring period and used in the calculations
QA/QC procedure	-
Any comment:	-

Data / Parameter table 12.

Data / Parameter:	**T**
Data unit:	°C
Description:	Temperature
Source of data	Plant records
Measurement procedures (if any):	Measured using calibrated meters
Monitoring frequency:	Continuous monitoring, integrated hourly and at least monthly recording
QA/QC procedure	Calibration shall be as per the relevant paragraphs of the “General guidelines for SSC CDM methodologies”
Any comment:	-

Data / Parameter table 13.

Data / Parameter:	**P**
Data unit:	kg/cm^2
Description:	Pressure
Source of data	Plant records
Measurement procedures (if any):	Measured using calibrated meters
Monitoring frequency:	Continuous monitoring, integrated hourly and at least monthly recording
QA/QC procedure	Calibration shall be as per the relevant paragraphs of the “General guidelines for SSC CDM methodologies”
Any comment:	-

Data / Parameter table 14.

Data / Parameter:	**$NCV_{i,y}$**
Data unit:	GJ/mass or volume unit
Description:	Net calorific value of fossil fuel type *i*
Source of data	As per the “Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion”
Measurement procedures (if any):	As per the “Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion”
Monitoring frequency:	As per the “Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion”
QA/QC procedure	As per the “Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion”
Any comment:	-

Data / Parameter table 15.

Data / Parameter:	**NCV_k**
Data unit:	GJ/mass or volume unit
Description:	Net calorific value of biomass type *k*
Source of data	Plant records
Measurement procedures (if any):	Measurement in laboratories according to relevant national/international standards. Measure quarterly, taking at least three samples for each measurement. The average value can be used for the rest of the crediting period. Measure the NCV based on dry biomass - Check the consistency of the measurements by comparing the measurement results with, relevant data sources (e.g. values in the literature, values used in the national GHG inventory) and default values by the IPCC
Monitoring frequency:	Determine once in the first year of the crediting period
QA/QC procedure	If the measurement results differ significantly from previous measurements or other relevant data sources, conduct additional measurements
Any comment:	-

6.1. Parameters related to geothermal project activity

Data / Parameter table 16.

Data / Parameter:	**$w_{Main,CO2}$**
Data unit:	t CO_2/t steam
Description:	Average mass fraction of carbon dioxide in the produced steam
Source of data	Plant records
Measurement procedures (if any):	Non-condensable gases sampling should be carried out in production wells and/or at the steam field-power plant interface using ASTM Standard Practice E1675 for Sampling 2-Phase Geothermal Fluid for Purposes of Chemical Analysis (as applicable to sampling single phase steam only). The CO_2 and CH_4 sampling and analysis procedure consists of collecting non-condensable gases samples from the main steam line with glass flasks, filled with sodium hydroxide solution and additional chemicals to prevent oxidation. Hydrogen sulphide (H_2S) and carbon dioxide (CO_2) dissolve in the solvent while the residual compounds remain in their gaseous phase. The gas portion is then analyzed using gas chromatography to determine the content of the residuals including CH_4. All alkanes concentrations are reported in terms of methane
Monitoring frequency:	At least every three months and more frequently, if necessary
QA/QC procedure	-
Any comment:	-

Data / Parameter table 17.

Data / Parameter:	**$w_{Main,CH4}$**
Data unit:	t CH_4/t steam
Description:	Average mass fraction of methane in the produced steam
Source of data	Plant records
Measurement procedures (if any):	As per the procedures outlined for $w_{Main,CO2}$
Monitoring frequency:	At least every three months and more frequently, if necessary
QA/QC procedure	-
Any comment:	-

Data / Parameter table 18.

Data / Parameter:	**$M_{S,y}$**
Data unit:	Nm^3/hr
Description:	Quantity of steam produced during the year *y*
Source of data	Plant records

Measurement procedures (if any):	The steam quantity discharged from the geothermal wells should be measured with a venture flow meter (or other equipment with at least the same accuracy). Measurement of temperature and pressure upstream of the venture meter is required to define the steam properties. The calculation of steam quantities should be conducted on a continuous basis and should be based on international standards. The measurement results should be summarized transparently in regular production reports
Monitoring frequency:	Daily
QA/QC procedure	-
Any comment:	-

6.2. Parameters related to trigeneration project activity

Data / Parameter table 19.

Data / Parameter:	$\mathbf{C_{P,I,y}}$
Data unit:	MWh_{th}/yr
Description:	Cooling output of the baseline chiller *i* displaced as a result of the installation of project activity in year *y*
Source of data	Plant records
Measurement procedures (if any):	Measured using calibrated meters
Monitoring frequency:	Continuous monitoring, hourly measurement and at least monthly recording
QA/QC procedure	The cooling output of each baseline scenario chiller *i* is calculated using measured values of the total chilled water mass flow-rate and of the differential temperature of incoming and outgoing chilled water; as recorded on an hourly basis
Any comment:	-

Data / Parameter table 20.

Data / Parameter:	$\mathbf{C_{P,I,y}}$
Data unit:	MWh_{th}/yr
Description:	Cooling output of the baseline chiller *i* displaced as a result of the installation of project activity in year *y*
Source of data	Plant records
Measurement procedures (if any):	Measured using calibrated meters
Monitoring frequency:	Continuous monitoring, hourly measurement and at least monthly recording
QA/QC procedure	The cooling output of each baseline scenario chiller *i* is calculated using measured values of the total chilled water mass flow-rate and of the differential temperature of incoming and outgoing chilled water; as recorded on an hourly basis
Any comment:	-

Data / Parameter table 21.

Data / Parameter:	$\mathbf{m_{C,I,h}}$
Data unit:	tonnes/hour
Description:	The chilled water mass flow-rate for chiller(s) *i* produced by project in hour *h* of year *y*
Source of data	Plant records
Measurement procedures (if any):	Measured using calibrated meters
Monitoring frequency:	Continuous, integrated hourly, at least monthly recording
QA/QC procedure	The cooling output of each baseline scenario chiller *i* is calculated using measured values of the total chilled water mass flow-rate and of the differential temperature of incoming and outgoing chilled water; as recorded on an hourly basis
Any comment:	-

Data / Parameter table 22.

Data / Parameter:	$\mathbf{C_{pw}}$
Data unit:	MJ/tonne °C
Description:	Specific heat capacity of water
Source of data	4.2
Measurement procedures (if any):	-
Monitoring frequency:	-
QA/QC procedure	-
Any comment:	-

Data / Parameter table 23.

Data / Parameter:	$\mathbf{\Delta T_{C,I,h}}$
Data unit:	°C
Description:	Differential temperature for chiller(s) *i* in hour *h* of year *y* of incoming and outgoing water from project
Source of data	Plant records
Measurement procedures (if any):	Measured using calibrated meters
Monitoring frequency:	Continuous, integrated hourly, at least monthly recording
QA/QC procedure	-
Any comment:	-

Data / Parameter table 24.

Data / Parameter:	$\mathbf{m_{H,I,h}}$
Data unit:	tonnes/hour
Description:	The waster mass flow-rate from heater unit(s) *i* in the year *y*
Source of data	Plant records

Measurement procedures (if any):	Measured using calibrated meters
Monitoring frequency:	Continuous, integrated hourly, at least monthly recording
QA/QC procedure	-
Any comment:	-

Data / Parameter table 25.

Data / Parameter:	$\Delta T_{HI,h}$
Data unit:	°C
Description:	Differential temperature of incoming and outgoing water from heater unit *i*
Source of data	Plant records
Measurement procedures (if any):	Measured using calibrated meters
Monitoring frequency:	Continuous, integrated hourly, at least monthly recording
QA/QC procedure	-
Any comment:	-

Data / Parameter table 26.

Data / Parameter:	$Q_{ref,PJ,start}$
Data unit:	Tonnes
Description:	Quantity of refrigerant charge in new cooling equipment at its start of operation
Source of data	Plant records
Measurement procedures (if any):	As per manufacturer's specifications of the cooling equipment
Monitoring frequency:	Only accounted for in the first year of the first crediting period
QA/QC procedure	-
Any comment:	-

Data / Parameter table 27.

Data / Parameter:	$Q_{ref,PJ,y}$
Data unit:	tonnes/yr
Description:	Quantity of refrigerant used in year *y* to replace refrigerant that has leaked in year *y*
Source of data	Plant records
Measurement procedures (if any):	Based on inventory of refrigerant cylinders consumed in year *y*
Monitoring frequency:	Annually
QA/QC procedure	-
Any comment:	The total annual amount of refrigerant ordered as indicated in purchase orders cross checked against invoices

Data / Parameter table 28.

Data / Parameter:	**$GWP_{ref,PJ}$**
Data unit:	t CO_2e/t refrigerant
Description:	Global warming potential of the refrigerant that is used in new cooling equipment
Source of data	-
Measurement procedures (if any):	-
Monitoring frequency:	Annually
QA/QC procedure	-
Any comment:	If the refrigerants have no GWP, this term shall be taken as zero

6.3 Project activity under a Programme of Activities

82. The methodology is applicable to a programme of activities, no additional leakage estimations are necessary other than that indicated under leakage section above.

Appendix. Default baseline efficiency values

Table 1: Default baseline efficiency values for different technologies

Technology of the energy generation system	Default efficiency
New natural gas fired boiler (w/o condenser)	92%
New oil fired boiler	90%
Old natural gas fired boiler (w/o condenser)	87%
New coal fired boiler	85%
Old oil fired boiler	85%
Old coal fired boiler	80%

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Document information

Version	*Date*	*Description*
20.0	1 June 2014	EB 79, Annex 14 To extend the applicability of the methodology to trigeneration projects and include a reference to tool “Project emissions from cultivation of biomass”. Further clarifies baseline and monitoring procedures taking into account clarifications issued by the SSC WG.
19.0	3 June 2011	EB 61, Annex 16 To simplify the monitoring requirements for quantity, net calorific value and moisture content of biomass; and include an additional scenario for cogeneration project activities.
18.0	17 September 2010	EB 56, Annex 18 To include a procedure for determining baseline efficiency for a new cogeneration system.
17.0	28 May 2010	EB 54, Annex 9 To include additional guidelines on determining baseline emissions for project activities involving fuel switch from fossil fuel to biomass in thermal generating equipment. An applicability criterion on the use of biomass briquette has also been provided.
16.0	04 December 2009	EB 51, Annex 19 To expand the applicability of the methodology to biomass based cogeneration project activities supplying surplus electricity to a grid.
15.0	17 July 2009	EB 48, Annex 24 To: (a) Include simplified procedures for determining efficiency of small thermal appliances used in household or commercial applications (<45kW thermal capacity); and (b) Include procedures for the estimation of baseline emission factors for co-fired systems.
14.0	25 March 2009	EB 46, Annex 21 To include additional baseline scenarios; expanded applicability of the methodology for renewable fuel based heat and/or power generation project activities (including cogeneration) that supply: (a) Electricity to a grid and/or displace grid electricity; (b) Electricity and/or thermal energy for on-site consumption or for consumption by other facilities and combination of (a) and (b); guidance on use of charcoal from renewable biomass sources; procedures for project emission calculations when applying to geothermal projects; more guidance on metering of thermal energy output.

Version	*Date*	*Description*
13.0	14 March 2008	EB 38, Annex 9 To expand its applicability to include additional baseline scenarios (e.g. steam/heat produced from renewable biomass and electricity imported from the grid and/or generated in a captive plant in the baseline, while in the project case heat and electricity are produced by a renewable biomass based co-generation unit).
12.0	27 July 2007	EB 33, Annex 22 To allow for their application under a programme of activities (PoA), where the limit of the entire PoA exceeds the limit for small-scale CDM project activities.
11.0	22 June 2007	EB 32, Annex 27 To clarify the monitoring of biomass in project activities that apply these methodologies which is consistent with monitoring of biomass in the approved methodology AMS-I.D.
10.0	04 May 2007	EB 31, Annex 20 To provide options for baseline calculations when cogeneration from fossil fuels is the baseline activity thereby broadening the applicability of AMS-I.C.
09.0	15 December 2006	EB 28, Annex 23 To align the guidance on capacity addition and retrofit activities to be consistent with the revisions of AMS-I.D.
08.0	24 February 2006	EB 23, Annex 31 To: (i) Include provisions for retrofit and renewable energy capacity additions as eligible activities; (ii) Provide clarification for baseline calculations under category I.D; and (iii) Provide clarification on the applicability of Category I.A as against Category I.D.

* This document, together with the 'General Guidance' and all other approved SSC methodologies, was part of a single document entitled: Appendix B of the Simplified Modalities and Procedures for Small-Scale CDM project activities until version 07.

Appendix B of the Simplified Modalities and Procedures for Small-Scale CDM project activities contained both the General Guidance and Approved Methodologies until version 07. After version 07 the document was divided into separate documents: 'General Guidance' and separate approved small-scale methodologies (AMS).

07.0	25 November 2005	EB 22, Para. 59 References to "non-renewable biomass" in Appendix B deleted.
06.0	30 September 2005	EB 21, Annex 22 Guidance on consideration of non-renewable biomass in Type I methodologies, thermal equivalence of Type II GWhe limits included.
05.0	25 February 2005	EB 18, Annex 6 Guidance on 'capacity addition' and 'cofiring' in Type I methodologies and monitoring of methane in AMS-III.D included.

Version	*Date*	*Description*
04.0	22 October 2004	EB 16, Annex 2 AMS-II.F was adopted; leakage due to equipment transfer was included in all Type I and Type II methodologies.
03.0	14 June 2004	EB 14, Annex 2 New methodology AMS-III.E was adopted.
02.0	28 November 2003	EB 12, Annex 2 Definition of build margin included in AMS-I.D, minor revisions to AMS I.A, AMS-III.D, AMS-II.E.
01.0	21 January 2003	EB 7, Annex 6 Initial adoption. The Board at its seventh meeting noted the adoption by the Conference of the Parties (COP), by its decision 21/CP.8, of simplified modalities and procedures for small-scale CDM project activities (SSC M&P).

Decision Class: Regulatory
Document Type: Standard
Business Function: Methodology
Keywords: : cogeneration, thermal energy production, retrofit, simplified methodologies, type (i) projects

A.2 Climate Action Reserve GHG Protocols

A.2.1 Reserve Offset Program Manual

CLIMATE ACTION RESERVE

Reserve Offset Program Manual

November 12, 2019

NOTE TO USERS:

From time to time, the Climate Action Reserve updates this manual. Please make sure you are using the latest version, available at www.climateactionreserve.org.

For information, comments or questions, please email reserve@climateactionreserve.org.

Climate Action Reserve
www.climateactionreserve.org

Released November 12, 2019

Reserve Offset Program Manual

1 Introduction

The voluntary carbon market has the potential to significantly facilitate efforts to reduce greenhouse gases in the atmosphere and to help mitigate climate change. At the same time, there has been a great need for increased environmental integrity, transparency, rigor, and accuracy in this market. The Climate Action Reserve (Reserve) was created to meet this need by providing a rigorous set of protocols, guidelines, and tools to support the voluntary carbon market. The Reserve is intended to increase certainty and build confidence in the greenhouse gas (GHG) reduction market on the part of investors, project developers, the environmental community, and the public.

The Reserve Offset Program Manual summarizes the Reserve's overarching principles, its general project accounting guidelines, and its rules and procedures for registering projects and creating offset credits for the voluntary market. It also describes the process used by the Reserve to develop protocols for determining the eligibility of, and quantifying reductions from, carbon offset projects.

Detailed information on the Reserve's general operating procedures and verification program can be found in the following documents:

- Climate Action Reserve User Guide
  http://www.climateactionreserve.org/open-an-account/
- Climate Action Reserve Terms of Use
  http://www.climateactionreserve.org/open-an-account/
- Climate Action Reserve Verification Program Manual
  http://www.climateactionreserve.org/how/program/program-manual/

Guidance in this Reserve Offset Program Manual is limited to the Reserve's program serving the voluntary carbon market. For information on the Reserve's role as an Early Action Offset Program and Offset Project Registry for the California Compliance Offset Program, please see the following resources:

- Climate Action Reserve California Compliance Offset Program website
  http://www.climateactionreserve.org/how/california-compliance-projects/
- California Air Resources Board Compliance Offset Program website
  http://www.arb.ca.gov/cc/capandtrade/offsets/offsets.htm

1.1 The Climate Action Reserve

The Climate Action Reserve is an offsets program working to ensure integrity, transparency, and financial value in the North American carbon market. It does this by establishing regulatory-quality standards for the development, quantification, and verification of GHG emission reduction projects in North America; issuing carbon offset credits known as Climate Reserve Tonnes (CRTs) generated from such projects; and tracking the transaction of credits over time in a transparent, publicly-accessible system. Adherence to the Reserve's high standards ensures that emission reductions associated with projects are real, permanent, and additional, thereby instilling confidence in the environmental benefit, credibility, and efficiency of the U.S. carbon market.

At the heart of the Reserve is a publicly accessible web-based system where owners and developers of carbon offset projects can register project information along with verification reports demonstrating GHG emission reductions. Emission reductions are verified as CRTs, which provide title assurance and unique serial number identifiers to assure that each metric ton is counted and retired only once.

The Reserve uses a rigorous, open, and comprehensive process for developing all of its protocols. The Reserve's primary focus is on accurate and conservative GHG accounting to ensure that the emission reductions it certifies are real, permanent, additional, verifiable, and enforceable.

1.2 Reserve Program Principles

The Reserve's program rules and procedures, eligibility criteria, and quantification and verification protocols are designed to ensure that GHG emission reductions certified by the Reserve are:

- **Real:** Estimated GHG reductions should not be an artifact of incomplete or inaccurate emissions accounting. Methods for quantifying emission reductions should be conservative to avoid overstating a project's effects. The effects of a project on GHG emissions must be comprehensively accounted for, including unintended effects (often referred to as "leakage").
- **Additional:** GHG reductions must be additional to any that would have occurred in the absence of the Climate Action Reserve, or of a market for GHG reductions generally. "Business as usual" reductions – i.e., those that would occur in the absence of a GHG-reduction market – should not be eligible for registration.
- **Permanent:** In order to function as offsets to GHG emissions, GHG reductions must effectively be "permanent." This means, in general, that any net reversal in GHG reductions used to offset emissions must be fully accounted for and compensated through the achievement of additional reductions.
- **Verified:** GHG reductions must result from activities that have been verified on an *ex post* basis. Verification requires third-party review of monitoring data for a project to ensure the data are complete and accurate.
- **Owned Unambiguously:** No parties other than the registered project developer must be able to reasonably claim ownership of the GHG reductions.

In addition, the Reserve strives to ensure that the offset projects it registers are **not harmful**. Project activities should not cause or contribute to negative social, economic or environmental outcomes and ideally should result in benefits beyond climate change mitigation. Projects are encouraged to identify, measure, and report on any non-GHG benefits of the project activities, such as alignment with the United Nations' Sustainable Development Goals or other identified co-benefits.[1]

Finally, the Reserve strives for **practicality**, by integrating rigorous requirements with time- and cost-minimizing steps for project developers. Practicality involves alleviating potential barriers to GHG project implementation without compromising credibility.

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[1] More information on the UN Sustainable Development Goals may be found at: https://sustainabledevelopment.un.org/sdgs.

2 Program Level GHG Reduction Accounting Guidelines

The Reserve develops protocols specifying eligibility criteria and detailing steps to estimate, monitor, and verify GHG reductions achieved by specific types of projects. While each project protocol contains guidance specific to individual project types, Reserve protocols also adhere to general project accounting principles. This section describes the Reserve's standardized project accounting guidelines that are the foundation for all project protocols.

2.1 General Approach, Principles, and References

The Reserve strives to develop protocols that are "standardized" in nature, meaning they apply standardized factors and eligibility rules to the extent possible while maintaining sufficient rigor and accuracy. In addition, the form and content of Reserve protocols follow internationally established accounting principles and standards.

2.1.1 Standardized Offset Crediting

A core objective of the Climate Action Reserve is to adopt "standardized" approaches to offset crediting. Standardized offset crediting has two main elements:[2]

1. Determining the eligibility and additionality of projects using standard criteria, rather than project-specific assessments.
2. Quantifying GHG emission reductions using standard baseline assumptions, emission factors, and monitoring methods.

The main goal of standardized offset crediting is to minimize the subjective judgment required in evaluating whether a project should receive credit for emission reductions, and in determining how much credit it should receive. Compared to project-specific assessment and analysis, standardized crediting reduces transaction costs for project developers, alleviates uncertainties for investors, and increases the transparency of project approval and verification decisions. Furthermore, the Reserve believes that appropriately designed standardized protocols can be as rigorous as project-specific approaches in ensuring additionality and environmental integrity (see Section 2.4.1 below for further discussion of standardized additionality tests).

Three challenges with standardized crediting are worth noting. First, developing standardized methods for determining additionality and estimating baselines requires significant upfront research and analysis. In order to avoid the need for extensive data collection and analysis on a project-by-project basis, the Reserve invests significant time and resources to establish credible benchmarks and emission factors that can be applied to similar projects throughout an entire industry or sector. The Reserve may frequently build off existing project-specific methodologies, but in general will augment these methodologies with further analysis to establish standardized tests and metrics.

Second, because "business as usual" activities can vary significantly across different geographic areas, standardized benchmarks and factors for one region will not necessarily be appropriate for other regions. Therefore, standardized protocols will almost always apply to a specific, limited geographic area. Every Reserve protocol specifies the geographic region(s) to

[2] For further reference, see Broekhoff, D., 2007. *Expanding Global Emissions Trading: Prospects for Standardized Carbon Offset Crediting*. International Emissions Trading Association, Geneva.

which it applies. In adapting protocols for other geographic regions, the Reserve engages in a full stakeholder process designed to assess and incorporate region-specific benchmarks and factors.

Third, not all possible offset project types are equally amenable to standardized crediting.[3] For some types of projects, determining additionality and estimating baseline emissions cannot be done credibly and accurately on a standardized basis. In general, the Reserve will avoid developing protocols for these project types. Alternatively, the Reserve may incorporate project-specific methods or variables into standardized protocols as appropriate, or limit the scope of protocols to address only activities and conditions for which standardized approaches are feasible.

2.1.2 Reference Standards

The Reserve's offset project protocols are designed to be consistent with the principles, requirements, and guidance of two overarching standards for project-based GHG accounting:[4]

- International Organization for Standardization (ISO) 14064, Part 2
- The World Resources Institute/World Business Council for Sustainable Development (WRI/WBCSD) Greenhouse Gas Protocol for Project Accounting

Both standards contain consistent general requirements for quantifying reductions in GHG emissions (or increases in carbon sequestration) that result from project-based activities, including requirements for:

1. Establishing GHG accounting boundaries
2. Estimating baseline emissions
3. Determining project-case emissions
4. Monitoring project activities

Although the ISO and WRI/WBCSD standards are largely consistent in their basic requirements, they have different terminologies and structures. Reserve protocols may utilize terminology from either or both standards depending on circumstances. The structure and general content of Reserve protocols are presented in the remainder of this section.

2.2 GHG Accounting Principles

There is now strong international consensus around a core standard set of overarching principles to guide decisions about the accounting, quantification, and reporting of project-based GHG reductions. These consensus principles are listed and defined in both the ISO and WRI/WBCSD standard referenced above. Definitions of these principles differ slightly between the two standards; the Reserve interprets the principles as follows in developing its protocols:

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[3] *Ibid*.
[4] International Organization for Standardization, 2019. *ISO 14064, Part 2*: *"Specification with guidance at the project level for quantification, monitoring, and reporting of greenhouse gas emission reductions or removal enhancements."* International Organization for Standardization, Geneva, Switzerland; World Resources Institute and World Business Council for Sustainable Development, 2005. *The GHG Protocol for Project Accounting*, World Resources Institute, Washington, DC.

- **Relevance:** Data, methods, criteria, assumptions, and accounting boundaries should be chosen based on their “intended use.” For the Reserve, this means protocols are designed around standardized, practical approaches to GHG accounting while still adhering to other core accounting principles.
- **Completeness:** All relevant information should be considered when developing criteria and procedures, and all relevant GHG emissions and removals should be accounted for. Reserve protocols comprehensively identify the GHG sources, sinks, and reservoirs affected by project activities and require accounting for all significant changes in GHG emissions or removals that may result from a project. Where there are multiple baseline possibilities, protocols must thoroughly address identification and quantification methods for each possibility.
- **Consistency:** Data, methods, criteria, and assumptions should allow meaningful and valid comparisons of the GHG reductions achieved by different projects. Reserve protocols are standardized to apply consistent GHG accounting and monitoring methods to all projects of the same type. Reserve protocols are also designed to reflect similarly rigorous and conservative accounting methods and assumptions for all project types.
- **Transparency:** Sufficient information should be disclosed to allow reviewers and stakeholders to make decisions about the credibility and reliability of GHG reduction claims with reasonable confidence. Access to sufficient and appropriate GHG-related information is critical for assuring users of the Reserve that a project’s GHG reduction claims are credible. To this end, the Reserve uses an open, consultative process for developing protocols; makes protocols publicly available; requires regular, rigorous, and complete reporting from registered projects; and provides a publicly accessible database detailing all relevant information used to quantify GHG reductions for each registered project. In addition, the Reserve’s standardized protocols reduce ambiguities associated with how project-related information is interpreted.
- **Accuracy:** Uncertainties and bias should be reduced as far as is practical. Greater accuracy in estimating GHG emissions and reductions will help ensure credibility of GHG reduction claims. Reserve protocols require that quantification of GHG reductions and monitoring of GHG emissions and other variables be conducted within acceptable levels of uncertainty. All GHG reduction estimates must pass rigorous review by an independent verification body. Where accuracy is difficult to achieve, Reserve protocols will err on the side of being conservative with GHG reduction estimates.
- **Conservativeness:** Conservative assumptions, values, and procedures should be used to ensure that GHG reductions are not over-estimated. Reserve protocols employ conservative estimation methods whenever data and assumptions are uncertain and measures to reduce uncertainty would be impractical.

2.3 Project Definition

A GHG project is a specific activity or set of activities intended to reduce GHG emissions, increase the storage of carbon or enhance GHG removals from the atmosphere.[5] A GHG project is considered to be a “carbon offset” project if the GHG reductions or removals it generates are used to compensate for GHG emissions occurring elsewhere.[6] Projects that meet

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[5] World Resources Institute (WRI), World Business Council for Sustainable Development (WBCSD), 2005. *The GHG Protocol for Project Accounting*. World Resources Institute, Washington, D.C.
[6] Offset Quality Initiative, 2008. *Ensuring Offset Quality: Integrating High Quality Greenhouse Gas Offsets Into North American Cap-and-Trade Policy*. Available at: http://www.offsetqualityinitiative.org/.

the Reserve's standards are issued emission reduction or removal credits, and those credits act as offsets when they are certified and retired in the Reserve's online registry. The Reserve's primary purpose is to certify GHG reductions as carbon offsets.

Every Reserve protocol clearly defines the type of activity (or activities) that constitute a GHG reduction project. A clear project definition ensures that GHG quantification methods prescribed by the protocol are applied only where they are relevant and appropriate. The "project definition" section of each protocol specifies the kinds of activities that must be undertaken to reduce GHG emissions (or increase removals), the required conditions that must be met for these activities, and the necessary elements of project design and implementation.

2.3.1 Project Types

The Reserve only registers GHG projects that follow project protocols that have been developed by the Reserve. In other words, only projects meeting the requirements of project protocols that have been approved and adopted by the Reserve's Board are eligible for registration on the Reserve. The Reserve may establish linkages with additional programs in the future to allow other projects to be registered.

Approved project protocols and information on additional project protocols in development are available for download at http://www.climateactionreserve.org/how/protocols/.

2.4 Project Eligibility Criteria

Eligibility criteria specify essential characteristics a project must have in order to register with the Reserve, as well as the conditions under which the Reserve will issue CRTs to a project. In Reserve protocols, eligibility criteria serve three main purposes:

1. To ensure that baseline estimation methods and emission factors prescribed by the protocol are relevant and appropriate. Reserve protocols use standardized baseline estimation methods that are calibrated to specific geographic regions; to be eligible, projects must be located in an appropriate geographic region.
2. To ensure that projects are "additional." To test for additionality, the Reserve employs objective criteria designed to distinguish additional projects from those that would have happened anyway (i.e., in the absence of an offset market). These criteria fall into two categories: (1) a legal requirement test, and (2) a performance standard test. These tests are explained and described further below.
3. To ensure that projects adhere to all applicable laws and do not cause adverse environmental, social or economic impacts.

Generally, the Reserve seeks to specify eligibility criteria that are as standardized and objective as possible. This means that criteria will be designed to require a minimum amount of subjective judgment in determining whether a project is eligible.

2.4.1 Additionality Determinations

Within existing carbon offset programs, there are two basic approaches to determining "additionality": project-specific and standardized. The Reserve applies a standardized approach to determining additionality, where performance standards and other conditions or criteria that projects must meet in order to be considered additional are determined by the Reserve. These standards and criteria are established separately for each project type and are designed to exclude non-additional (or "business as usual") projects from eligibility. In all cases, projects that are required by law or regulation are excluded. Other criteria and conditions are specified in each project protocol.

This approach differs from some other offset programs, where additionality is assessed using information and analysis specific to each project (see Box 1). It avoids the need to subjectively interpret individual project developers' assertions about additionality and sends a clear signal to market participants about which projects will be eligible and which ones will not. Like any testing method, however, it is potentially subject to error. The Reserve strives to establish rigorous standards for additionality that serve to exclude the vast majority of non-additional projects. At the same time, the Reserve acknowledges that no system of testing for additionality is perfect, and it reserves the right to update and modify additionality criteria over time in light of new data and information.

Box 1. Project-Specific vs. Standardized Additionality Tests

Project-specific approaches to determining additionality seek to assess, by weighing certain kinds of evidence, whether a project in fact differs from a hypothetical baseline scenario in which there is no carbon offset market. Generally, a project and its possible alternatives are subjected to a comparative analysis of their implementation barriers and/or expected benefits (e.g., financial returns). If an option other than the project itself is identified as the most likely alternative for the "business as usual" (or "baseline") scenario, the project is considered additional. The Kyoto Protocol's Clean Development Mechanism (CDM), a global carbon offset program for projects in developing countries, requires project-specific additionality tests.

Standardized, or performance-based, approaches to additionality evaluate projects against a consistent set of criteria designed to exclude non-additional projects and include additional ones on a sector-wide basis. For example, standardized tests could involve determinations that a project:

- Is not mandated by law
- Exceeds common practice
- Involves a particular type of high-performing technology
- Has an emission rate lower than most others in its class (e.g., relative to a performance standard)

From a regulatory perspective, standardized performance-based additionality tests are advantageous in that they are less subjective and administratively easier to implement than project-specific tests. Additionally, they can reduce transaction costs for project developers, alleviate uncertainties for investors, and increase the transparency and consistency of regulatory decisions. For further discussion of these two approaches, see Broekhoff, D., 2007. *Expanding Global Emissions Trading: Prospects for Standardized Carbon Offset Crediting*. International Emissions Trading Association, Geneva.

The Reserve incorporates standardized additionality tests in all of its protocols. These tests generally have two components: a legal requirement test and a performance standard test.

2.4.1.1 Legal Requirement Test

Projects are very likely to be non-additional if their implementation is required by law. A legal requirement test ensures that eligible projects (and/or the GHG reductions they achieve) would not have occurred anyway in order to comply with federal, state or local regulations, or other legally binding mandates. A project passes the legal requirement test when there are no laws, statutes, regulations, court orders, environmental mitigation agreements, permitting conditions or other legally binding mandates requiring its implementation, or requiring the implementation of similar measures that would achieve equivalent levels of GHG emission reductions.

In Reserve protocols, the specific provisions of the legal requirement test may differ depending on the project type. During protocol development, the Reserve performs a review of existing and pending regulations to identify any specific regulatory requirements that would mandate the implementation of project activities covered by the protocol. If such requirements are identified, then project activities in relevant jurisdictions may be categorically excluded from eligibility.

In addition, Reserve protocols require project developers to review and determine whether federal, state or local regulations and other legal requirements (including local agency ordinances or rulings) require the implementation of their project. This review is always required at the time a project is registered and may be required each verification period thereafter depending on the protocol. Generally, Reserve protocols will stipulate the following:

- Project monitoring plans must include procedures that the project developer will follow to periodically ascertain and demonstrate that the project passes the legal requirement test.
- Project developers must submit a signed Attestation of Voluntary Implementation form stipulating that the project is not required by law.

2.4.1.2 Performance Standard Test

Projects that are not legally required may still be non-additional if they would have been implemented for other reasons, e.g., because they are attractive investments irrespective of carbon offset revenues. Performance standard tests are intended to screen out this potential set of projects. In developing performance standards, the Reserve considers financial, economic, social, and technological drivers that may affect decisions to undertake a particular project activity. Standards are specified such that the large majority of projects that meet the standard are unlikely to have been implemented due to these other drivers. In other words, incentives created by the carbon market are likely to have played a critical role in decisions to implement projects that meet the performance standard.

Although performance standard tests do not require individual project assessments of financial returns and implementation barriers, they are designed to reflect these factors in determining which projects are additional. Projects that pass a performance standard test should be those that – in the absence of a carbon offset market – would have insufficient financial returns or would face other types of insurmountable implementation barriers.

In Reserve protocols, performance standards may be specified in several ways:

- *Emission rate thresholds*. For some project types, a performance standard may be specified in terms of a rate of GHG emissions (usually per unit of production of some product or service, e.g., tonnes of CO_2 per megawatt-hour). Generally, the threshold rate would be based on a level of performance that is significantly better than average for the industry or sector. Projects that have lower emission rates than the threshold, for example, would be considered additional.
- *Practice- or technology-based thresholds*. Performance standards may also be specified in terms of a specific practice or technology that is rarely or never implemented in the absence of a carbon offset market. Such standards are generally based on surveys of

the market penetration rates of candidate practices or technologies. Projects employing a qualifying technology or practice are automatically considered additional.

- *Other qualifying conditions or criteria*. Performance standards may also incorporate, or be based on, other specific qualifying conditions that a project must meet in order to be considered eligible. Conditions may include characteristics related to the project site, specifications for a particular eligible technology or practice, or other contextual factors. Projects meeting the conditions would be considered additional.

Several specifications may be combined in a single performance standard test. For example, a protocol may define a performance standard in terms of a specific type of technology that has an emission rate below a certain threshold and is implemented at an eligible project location.

Performance standard tests are developed through extensive analysis of standard practices and technology deployment in industry sectors related to a project type. They may also be based on an assessment of "typical" financial, implementation, and operating conditions facing a certain type of project. Most Reserve protocols contain an appendix explaining and summarizing the analyses undertaken to establish the protocol's performance standard.

The Reserve has no predefined threshold for determining an acceptable performance standard. Rather, establishing performance standards involves balancing the need to restrict eligibility for non-additional projects with the goal of allowing additional (and otherwise eligible) projects to participate. Setting a threshold always involves making tradeoffs between these two goals and may also involve considerations about the size of the market for carbon credits and the potential supply of reductions available from certain project types.[7] See Box 2 for further discussion and a hypothetical example.

[7] For further discussion of setting thresholds and establishing the parameters for additionality tests, see Trexler, M., D. Broekhoff, and L. Kosloff, 2006. "A Statistically-Driven Approach to Offset-Based GHG Additionality. Determinations: What Can We Learn?" in *Sustainable Development Law & Policy*, Volume VI, Issue 2, Winter 2006.

Box 2. Determining Acceptable Performance Standard Thresholds

A common rule of thumb for establishing performance standards is that they should make eligible only technologies or practices that are not "common practice." However, "common practice" is often difficult to define. Instead of adopting a simple rule for defining "common practice" (as a threshold market penetration rate, for example) the Reserve requires setting performance standards based on an overall assessment of the market for GHG reductions and the risk of crediting too many non-additional reductions.

For example, suppose a particular emission-reducing technology has a market penetration rate of five percent. Colloquially, such a technology would not be considered "common practice." However, if a threshold were established allowing all instances of this technology to be eligible for offset crediting, we could expect existing users of the technology to apply for credit despite the fact that they were employing it already, without any incentives from the carbon market. This will have consequences for the integrity of the carbon market. Whether such consequences are serious depends on the potential supply of reductions from this technology compared to overall demand for reductions. If five percent of the market would result in hundreds of millions of tonnes of GHG reductions, for example, then a simple technology-based threshold would be too lenient, and the Reserve would explore using additional criteria that could further exclude "business as usual" instances of the technology despite its relative rarity. If five percent of the market would result in only a few thousand tonnes of GHG reductions, then the Reserve may consider a simple technology-based threshold acceptable.

2.4.2 Project Location

Projects throughout the United States are eligible to be registered with the Reserve. Some project types are also eligible in Mexico. Project developers should check the project location eligibility requirements specified in each project protocol.

2.4.3 Project Start Date

In general, the start date for a project will correspond to the start of the activity that generates GHG reductions (sometimes referred to as "start of operations"). Specific requirements for determining the start date of a project are contained in each protocol.

The Reserve limits the eligibility of projects according to their start dates. Start date restrictions are intended to accommodate "early actors" for a period of time following the adoption of new protocols, but to otherwise restrict eligibility to new projects. The Reserve's general policy is as follows:

1. For qualifying projects that have not previously been listed or registered on a greenhouse gas registry or program:

    a. For a period of 12 months following the adoption by the Reserve Board of any new protocol, the Reserve will accept projects for listing with start dates (as defined in the protocol) that are no more than 24 months earlier than the date of the Reserve protocol's adoption. These are considered pre-existing projects.

    b. After the 12-month period following the date of the Reserve protocol's adoption, the Reserve will accept projects for listing with start dates (as defined in the protocol) that are no more than six months prior to the date on which they are submitted. A project submitted within six months of its start date is considered a "new" project.

2. For qualifying projects that have previously been listed or registered on a greenhouse gas registry or program:

    a. Projects with start dates (as defined in a relevant Reserve protocol) on or after January 1, 2001 but more than 24 months earlier than the date of adoption of a relevant new Reserve protocol – and which were listed or registered with another registry or program at least 24 months earlier than the date of adoption of the new Reserve protocol – may apply for transfer to the Reserve. These are considered pre-existing projects.

    b. Projects with start dates (as defined in a relevant Reserve protocol) that are no more than 24 months before and no more than 12 months after the date of adoption of a relevant new Reserve protocol – and that were listed or registered with another registry or program no more than 12 months after the date of adoption of the new Reserve protocol – may apply for transfer to the Reserve.

    c. Projects with start dates (as defined in a relevant Reserve protocol) that are more than 12 months after the date of adoption of a relevant new Reserve protocol, and that were listed or registered with another registry or program within six months of the project start date, may apply for transfer to the Reserve.

The Reserve considers a protocol to be "new" if it:

- Covers an entirely new project type not covered by any of the Reserve's existing protocols;
- Creates a wholly new category of eligible projects under an existing protocol (in which case only the new project category would qualify for a 12-month period of "early actor" eligibility); or
- Significantly expands the geographic coverage of the protocol (in which case only projects in newly covered geographic areas would qualify for a 12-month period of "early actor" eligibility).

If a new version of a protocol is adopted (e.g., updating from Version 1.0 to Version 2.0), this does not necessarily mean it will be considered a "new" protocol.

2.4.4 Project Crediting Period

The project "crediting period" defines the period of time over which a project's GHG reductions are eligible to be verified as CRTs. In general, the start of a project's crediting period will correspond to its start date.

The length of a project's crediting period is defined in each project protocol. For most non-sequestration projects registered with the Reserve, there is a 10-year crediting period that may be renewed one time for a maximum of two 10-year crediting periods. For sequestration projects, the crediting period may be up to 100 years. Refer to each project protocol for specific details on allowable crediting periods. A non-forest project may end its crediting period at any time prior to the limit specified in the protocol, but must abide by any monitoring requirements necessary to ensure permanence, if applicable.

If a project wishes to apply for eligibility under a renewed crediting period, it must do so by re-submitting project submittal forms no sooner than six months before the end of the project's ongoing crediting period and paying the project submittal fee. The project must meet all of the eligibility requirements of the most current version of the applicable protocol at the time of re-submittal to be eligible for a renewed crediting period.

Note that projects registered under early protocol versions that do not have provisions for a second crediting period can apply for one under the most current version of the protocol, if the most current version allows for a second crediting period.

Notwithstanding any pre-defined crediting period, projects that become required by law will not be eligible to receive CRTs for the reductions they generate, unless otherwise specified in the protocol. Thus, in most cases, if a project becomes subject to a regulation, ordinance or permitting condition that effectively requires its implementation, the project can no longer be considered additional and its crediting period will be terminated. The crediting period will likewise be terminated if the emission sources affected by a project are included under an emissions cap (e.g., under a state or federal cap-and-trade program) or GHG emissions from the project/project site are directly regulated by a local, state or federal agency. As specified in each protocol, emission reductions may be reported to the Reserve until the date that a regulation or emissions cap takes effect.

Details on the allowable crediting period as well as crediting period renewals for each type of project recognized by the Reserve are contained in each protocol.

Once a project has reached the end of its crediting period(s) and is no longer being issued CRTs, the project is considered "completed." Although the project is completed, project information remains publicly available through the Reserve software indefinitely.

2.4.5 Bundling of Projects

Only certain types of Reserve-recognized GHG projects may be bundled for registration and reporting purposes. Generally, each GHG project, as defined by the project definition and/or project boundary (described in each protocol), must register separately with the Reserve. However, protocols for certain project types may allow project boundaries to span multiple activities or locations. For example, the Livestock Project Protocol covers centralized manure digesters by allowing the project boundary to include all individual livestock operations that contribute manure to the centralized processing facility, as well as the centralized facility itself. The Reserve has also developed aggregation guidelines for U.S. and Mexico forest projects, which allow forest inventory and verification requirements to be streamlined for individual projects. Grassland projects may go through joint verification and reporting by participating in the cooperative option described in that protocol.

Project developers should check specific project protocols and associated guidance documents for direction on whether and how joint reporting and verification is allowed.

2.4.6 Regulatory Compliance and Environmental and Social Safeguards

The Reserve requires project developers to demonstrate that their GHG projects will not undermine progress on other environmental issues such as air and water quality, endangered species and natural resource protection, and environmental justice. When registering a project, the project developer must attest that the project was in material compliance with all applicable laws, including environmental regulations, during the verification period. The project developer is also required to disclose any and all instances of non-compliance – material or otherwise – of the project with any law to the Reserve and the verification body.

If a project or project activities have caused a material violation, then CRTs will not be issued for GHG reductions that occurred during the period(s) when the violation occurred. Individual violations due to "acts of nature" or due to administrative or reporting issues (such as an expired permit without any other associated violations or tardiness in filing documentation) are not considered material and will not affect CRT crediting. If it is determined that a project was out of compliance after CRTs have been issued, CRTs may be cancelled for the time period of non-compliance.

A violation is considered to be "caused" by a project or project activities if it can be reasonably argued that the violation would not have occurred in the absence of the project activities. If there is any question of causality, the project developer shall disclose the violation to the verifier.

In addition, individual protocols may contain requirements designed specifically to ensure environmental and social safeguards. Individual protocols may allow for project developers to report measures taken to avoid negative impacts. Individual protocols may also encourage project developers to report on the potential environmental co-benefits of their projects, such as reductions in other air pollutants, improvements in water quality, enhancement of wildlife habitat, etc.

In developing environmental and social safeguard criteria and requirements for specific protocols, the Reserve applies the following general principles:

Common Agency

Environmental and social harms will only be considered in determining project eligibility[8] to the extent that they can be attributed to the same agents (e.g., project developers, implementers or operators) in charge of implementing the project. Harms that may occur concurrently with a project, but are caused by other actors, will not be a factor in determining eligibility. The agents responsible, individually or collectively, for implementing projects will be determined during the protocol development process in consultation with stakeholders.

Proximity

Only environmental and social harms directly associated with a project activity (i.e., either physically or causally proximate) will be considered:

- Harms directly caused by project activities, regardless of where the harms physically occur, will be a factor in determining eligibility.
- Harms physically proximate to project activities but not directly caused by those activities may also be considered in determining eligibility if they are caused by agents responsible for project implementation. Such harms will be considered only if the agents are *required by the relevant protocol* to be involved in project implementation. Required agents will be specified in the Reserve's protocols, e.g., as part of the project definition or definition of eligible "project developers." If an agent is allowed, but not required, to be involved in project implementation, then physically proximate harms caused by that agent will not be considered (even if such an agent is directly involved with a particular project).

[8] Either initial eligibility or eligibility to receive credits.

- Harms caused by agents in charge of implementing a project that occur at sites or facilities not linked or co-located with the project will *not* be a factor in determining eligibility.

Both agency and proximity of effects will be considered in the protocol screening and development processes to identify and set clear standards for the application of this policy.

In determining whether environmental and social harms are occurring, the Reserve will use the following criteria:

Legal Obligation

The Reserve will rely first and foremost on legal requirements within the jurisdiction(s) where the project is implemented. Project agents that are found to be out of material compliance with applicable laws, regulations or other legal mandates that apply to the project itself or activities proximate to the project will be penalized.

"Do No Harm" Beyond Legal Requirements

In some cases, the Reserve may determine, in consultation with stakeholders, that existing legal requirements are insufficient to guarantee protection against important environmental and social harms. In these cases, the Reserve may include additional criteria in protocols to ensure that projects will not give rise to these harms, or may screen out certain project types or activities from eligibility under a protocol altogether.

The Reserve coordinates with government agencies and environmental representatives to ensure that its climate-oriented projects complement other environmental policies and programs.

2.5 Defining the GHG Assessment Boundary

The GHG Assessment Boundary delineates the GHG sources, sinks, and reservoirs (SSRs)[9] that must be assessed in order to determine the total net change in GHG emissions caused by a GHG reduction project.[10] GHG Assessment Boundaries are defined for each type of project activity addressed in a Reserve protocol.

The GHG Assessment Boundary is not a boundary related to a project's physical location. Instead, it encompasses all SSRs that could be significantly affected by a project activity, regardless of where such SSRs are located or who owns or controls them. A comprehensive and clearly defined GHG Assessment Boundary is required in order to provide a complete accounting of the net GHG reductions achieved by a project. All SSRs within the GHG Assessment Boundary are included in the calculation of GHG reductions.

SSRs are only included in the GHG Assessment Boundary if a project activity will have a *significant* effect on their associated GHG emissions or removals. The Reserve determines significance based on an assessment of the range of possible outcomes for a relevant SSR.

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[9] Terminology is from International Organization for Standardization, 2005. *ISO 14064, Part 2*: *"Specification with guidance at the project level for quantification, monitoring, and reporting of greenhouse gas emission reductions or removal enhancements."* International Organization for Standardization, Geneva, Switzerland.

[10] See World Resources Institute and World Business Council for Sustainable Development, 2005. *The GHG Protocol for Project Accounting*, World Resources Institute, Washington, DC.

There is no numerical threshold for significance. Inclusion or exclusion of SSRs is determined for each protocol based on the principles of completeness, accuracy, and conservativeness, and the need for practicality (e.g., related to measurement and monitoring costs). In general, relevant SSRs will only be excluded from the GHG Assessment Boundary if:

1. Projects are likely to reduce GHG emissions (or increase removals) at a SSR, so that excluding the SSR would be conservative (i.e., doing so would result in an underestimation of total net GHG reductions for the project); or
2. The total increase in GHG emissions from *all* excluded SSRs is likely to be less than five percent of the total GHG reductions achieved by a project.[11]

For each included SSR, the protocols:

- Identify whether the SSR is present in the baseline, project case or both
- Identify whether and how GHG emissions, removals or storage from the SSR will be measured, calculated or estimated
- If GHG emissions, removals or storage will be estimated, justify why values will be estimated rather than measured (or calculated from other measurements

Each protocol contains a table that:

- Lists all SSRs potentially affected by a project
- Explains or describes the SSR
- Indicates whether each SSR is included in the GHG Assessment Boundary
- Justifies instances where an SSR is excluded from the GHG Assessment Boundary
- Briefly describes how GHG emission values for the SSR will be determined, and justifies instances where such values will be estimated

Most protocols also contain a schematic diagram showing how different SSRs are related to each other and indicating which SSRs are included in or excluded from the GHG Assessment Boundary.

The Reserve does not restrict the GHGs that may be considered within the GHG Assessment Boundary. Any gas that has been determined by the IPCC to have a radiative forcing effect on the atmosphere may be considered for inclusion in a protocol. Reserve protocols may address gases other than the six GHGs regulated under the Kyoto Protocol (i.e., CO_2, CH_4, N_2O, SF_6, HFCs, and PFCs).

2.5.1 Physical Project Boundaries

For some types of projects, it is necessary to define a physical boundary for a project in addition to a GHG Assessment Boundary. Physical boundaries are defined in terms of the physical area affected by a project activity and possibly specific equipment or facilities involved. Protocols will only require identification of a physical boundary where a physical boundary is necessary to quantify the magnitude of GHG emissions, removals or storage associated with one or more SSRs included in the GHG Assessment Boundary. The primary example would be forest

[11] If excluding SSRs is unavoidable for practical reasons, then calculation and estimation methods related to included SSRs must be made suitably conservative in order to avoid overestimating total net GHG reductions.

projects, where the amount of carbon stored by a project depends on the area of land on which the project activity takes place.

2.5.2 Leakage Accounting

The term “leakage” is often used to refer to unintended increases in GHG emissions that may result from a GHG reduction project. Generally, leakage occurs at SSRs that are physically distant from the project itself or otherwise outside the project’s physical boundaries. Because the Reserve requires the definition of a comprehensive GHG Assessment Boundary – which must include any and all SSRs associated with significant GHG emissions, regardless of their physical location – Reserve protocols generally do not require an explicit and separate accounting for “leakage” effects. Instead, all effects of a GHG reduction project – both positive and negative – are accounted for without distinguishing one kind of effect from another. This does not mean that Reserve protocols neglect or ignore what other methodologies or protocols identify as “leakage.”

Where helpful for conceptual understanding, Reserve protocols may organize SSRs according to whether they are associated with a project’s “primary” or “secondary” effects. A project’s primary effect is its intended effect on GHG emissions (i.e., intended GHG reductions). Secondary effects are unintended effects on GHG emissions, often associated with leakage.[12]

2.6 Quantifying GHG Reductions

GHG emission reductions are quantified by comparing actual project GHG emissions to baseline GHG emissions. Baseline emissions are an estimate of the GHG emissions from sources within the GHG Assessment Boundary that would have occurred in the absence of the project (assuming the project is additional and would not have happened anyway). Project emissions are actual GHG emissions that occur at sources within the GHG Assessment Boundary. Project emissions must be subtracted from the baseline emissions to quantify the project’s total net GHG emission reductions. For sequestration projects, the formula is reversed: the baseline carbon sequestration rate is subtracted from the project carbon sequestration rate.

For most protocols, GHG emission reductions must be quantified and verified on at least an annual basis. Project developers may choose to quantify and verify GHG emission reductions on a more frequent basis if they desire and if the protocol allows it. The length of time over which GHG emission reductions are quantified is called a “reporting period.” The length of time over which GHG emission reductions are verified is called a “verification period.” Under some protocols, a verification period may cover multiple reporting periods (see Section 3.4.2).

2.6.1 Global Warming Potentials for Quantifying GHG Reductions

Under the Climate Action Reserve’s offset project protocols, projects convert quantities of non-CO_2 greenhouse gases (GHGs) into a quantity of CO_2-equivalent (CO_2e) using the 100-year global warming potential (GWP) values from the Intergovernmental Panel on Climate Change (IPCC).[13] Reserve project protocols currently reference the Fourth Assessment Report (AR4) of the IPCC, released in 2007. At the time that the Reserve was launched, the AR2 was the most

[12] The terms “primary effect” and “secondary effect” are from the World Resources Institute and World Business Council for Sustainable Development, 2005. *The GHG Protocol for Project Accounting*, World Resources Institute, Washington, DC.
[13] Assessment Reports of the IPCC may be accessed at: https://www.ipcc.ch/reports/

widely-used source for GWP values, underpinning activities under the Kyoto Protocol, as well as the U.S. EPA's GHG reporting and inventory efforts. At this time, the IPCC AR4 has become the industry standard for most applications relevant to the Reserve's voluntary offset protocols. All projects using Reserve protocols – regardless of version – shall use AR4 GWP values. While it is the Reserve's policy for protocols to take precedence over the Reserve Offset Program Manual in instances where the standards conflict, this policy is an exception to that rule. In future protocol updates, the Reserve will make clear that GWP values are not fixed and may be updated at a later date. Note that this policy may be superseded by a future policy memo as GHG accounting practices progress. It is anticipated that the program will move to application of the GWP values from the Fifth Assessment Report (AR5) in the near future, in accordance with industry best practice.

2.6.2 Estimating Baseline Emissions

Baseline emissions are always subject to uncertainty because they are counterfactual, i.e., they are an estimate of GHG emissions or removals that would have occurred in the absence of the project. Depending on the project type and SSRs involved, many methods can be used to try to estimate baseline emissions. The Reserve uses standardized baselines in its protocols to the extent possible, meaning that the same conservative assumptions, emission factors, and calculation methods are applied to all projects. Standardized baseline approaches seek to avoid case-by-case analysis of individual projects while maintaining overall levels of quantification accuracy and environmental integrity. Within Reserve protocols, however, project-specific calculations and emission factors may be used wherever necessary to ensure accuracy, or where standardized methods would result in estimates that are overly conservative in a large number of cases.

Standardized baselines are developed by considering broad trends (economic, technological, regulatory, and policy) in the industry or sector relevant to a project type and determining what future "business as usual" alternative activities are likely to be. To develop standardized baselines, the Reserve works with stakeholders to determine the most likely alternative technologies or practices. In many cases, a single practice, activity or technology is assumed to be the common baseline alternative for a class of project activities. In some cases, the performance threshold developed for additionality may also be used as an emissions baseline. After establishing a standard baseline alternative, the Reserve develops specific quantification steps, calculation methods, and formulas to estimate baseline emissions, incorporating site-specific data where appropriate. Depending on the project type, baseline emission estimates may either be fixed at the outset of a project, or they may be regularly updated using actual data collected during the project's operation (used to infer baseline conditions).

2.6.3 Quantifying Project Emissions

Project GHG emissions are quantified based as much as possible on actual measurements of project activity performance. GHG emissions for each SSR may be measured directly, or calculated from measurements of parameters from which GHG emissions can be derived. For SSRs where direct or indirect measurements are too costly or infeasible, project GHG emissions may be estimated using standard assumptions or models.

2.6.4 Quantification Methods

The Reserve develops methods to calculate baseline and project emissions that meet an acceptable level of accuracy. As a general rule, methods should ensure 95% confidence that actual emissions are within +/- 5% of measured or calculated values, although required levels of accuracy will often depend on the specific magnitudes involved and their materiality. Methods may employ one or more of the following approaches:

- **Emission factor** approaches use input data multiplied by specific emission factors that approximate emissions per unit of the input. The factors are derived from research or model simulations and they are typically categorized by variables such as geographic location, local climate data, tree species, equipment standards, etc.
- **Dynamic models** estimate processes that cause GHG emissions (or biological carbon sequestration). Model users input specific parameters and the model generates emission or removal estimates. Research studies identify the parameters as important drivers of emissions or removals. Sometimes the parameter may be chosen from data provided by the Reserve or they may need to be measured at the project location.
- **Direct emission measurement** uses special instruments that monitor the flow of GHGs from the source into the atmosphere. This involves instrumentation and monitoring of GHG emission sources onsite.

2.6.4.1 Quantification Uncertainty and Conservativeness

Where cost-effective methods for quantifying GHG emissions or carbon storage yield uncertain estimates (e.g., greater than a five percent range), it may not be possible to accurately quantify baseline or project emissions. In these cases, Reserve protocols must use conservative assumptions and/or parameter values that will tend to underestimate, rather than overestimate, total GHG reductions and removals.

2.6.5 Calculating GHG Reductions or Removals

GHG reductions are calculated by periodically comparing the baseline to the project over a certain time period, usually one year.

The general formula for calculating GHG reductions is:

GHG Reductions = Baseline Emissions – Project Emissions

Positive GHG reductions are achieved when the project results in lower GHG emissions to the atmosphere over a certain time period compared to what would have happened absent the project activity.

For biological carbon sequestration projects, the general formula for calculating GHG removals is:

GHG Removals = (Incremental Project Sequestration – Incremental Baseline Sequestration) + (Baseline Emissions – Project Emissions)

Positive GHG removals are achieved when the project results in more carbon sequestered in biological carbon stocks over a certain time period than would have been in the absence of the project activity.

2.6.6 Immediate Crediting for Future Avoided Emissions

In accordance with recognized principles for carbon offset quality, the Reserve has upheld a general policy against "forward crediting" of GHG emission reductions. Forward crediting occurs when credits are issued for GHG reductions before such reductions have occurred and before the activities that caused such reductions have been verified.[14] Subject to certain conditions, however, the Reserve does credit reductions upfront when a verified action results in the immediate avoidance of a future stream of GHG emissions. Please see the Reserve's policy memo on this subject, available at http://www.climateactionreserve.org/how/program/program-manual/.

Separate from its *ex post* offset crediting program, the Reserve has developed a program, Climate Forward, for the purpose of recognizing and crediting anticipated future streams of emission reductions. This program specifically issues GHG emission reduction credits (not offsets) on an *ex ante* basis. Climate Forward provides a practical solution to companies and organizations seeking cost-effective mitigation of anticipated (i.e., future) operational and/or project-related GHG emissions. Climate Forward facilitates investments in GHG reduction activities that are practical, scientifically-sound, transparent, and aligned with forward-looking mitigation needs. For more information, please visit the Climate Forward website at https://climateforward.org/.

2.7 Project Monitoring

Monitoring of GHG projects is required in order to determine project performance, quantify actual GHG emissions, and in some cases, calibrate baseline emissions estimates. Under all Reserve protocols, GHG reductions are quantified only based on actual project monitoring data. Monitoring requirements are specified in each protocol and include provisions for:

- Monitoring GHG emissions or removals associated with SSRs within the GHG Assessment Boundary
- Monitoring other data related to assumptions underlying GHG emissions and/or carbon stock estimates
- Documenting data storage and quality assurance/quality control (QA/QC) measures
- Ensuring all project components are operated in a manner consistent with the manufacturer's recommendations
- Ensuring all monitoring instruments are calibrated and maintained as specified by the manufacturer

The Reserve requires a monitoring plan to be established for all monitoring and reporting activities associated with a project. The monitoring plan serves as the basis for verification bodies to confirm that the monitoring and reporting requirements in each protocol have been met and that consistent, rigorous monitoring and record-keeping is ongoing at the project site. Monitoring plans must cover all aspects of monitoring and reporting contained in a protocol and must specify how data for all relevant parameters will be collected and recorded. Each protocol specifies in a table the parameters that must be monitored and how data for each parameter must be acquired (e.g., from measurement, calculation, approved references or operating records).

[14] Offset Quality Initiative, 2008. *Ensuring Offset Quality: Integrating High Quality Greenhouse Gas Offsets Into North American Cap-and-Trade Policy,* p. 10. Available at: http://www.offsetqualityinitiative.org/.

At a minimum, a monitoring plan must stipulate the frequency of data acquisition; a record keeping plan; the frequency of instrument field check and calibration activities; and the role of individuals performing each specific monitoring activity. Monitoring plans should include QA/QC provisions to ensure that data acquisition and meter calibration are carried out consistently and with precision.

Finally, monitoring plans for most protocols must include procedures that project developers will follow to ascertain and demonstrate that the project passes the legal requirement test for additionality.

2.8 Ensuring Permanence of GHG Reductions

Because CO_2 and other GHG emissions remain in the atmosphere for very long periods of time, offsetting reductions in GHG emissions must effectively be permanent. The Reserve defines "permanence" as being equivalent to the radiative forcing benefits of removing CO_2 from the atmosphere for 100 years. Some types of offset projects, however, cause GHG reductions by removing CO_2 from the atmosphere and storing it in a reservoir (e.g., in trees or other organic materials, or in geologic formations). In these cases, there is a risk that CO_2 may be re-emitted to the atmosphere, leading to a "reversal" of GHG reductions. A reversal occurs when the total amount of CO_2 stored by a project becomes less than the total number of CRTs issued to the project. This can happen, for example, if some or all of the trees associated with a forest project are destroyed by fire, disease or intentional harvesting.

The Reserve requires that reversals be compensated for in order to ensure the integrity of CRTs and to maintain their effectiveness at offsetting GHG emissions. Specific rules and conditions for reversal compensation are detailed in individual protocols. Generally, the Reserve requires that CRTs be retired in proportion to any reversals, such that the total number of issued CRTs does not exceed the total quantity of CO_2 stored by a project over a sufficiently long period of time.

In some individual protocols, the Reserve may offer the option of "Tonne-Year Accounting" as an alternative mechanism to ensure the permanence of CRTs related to reversible emission reductions. In those cases, the protocol will specify when a project is subject to reversal risk, and how any reversal is to be quantified and compensated.

2.8.1 Maintenance and Disposition of the Buffer Pool

The Reserve maintains a buffer pool composed of credits from project types with identified risk of unavoidable reversal. Credits within the buffer pool from different project types are functionally distinct, despite the buffer pool being administered in one comprehensive account in the Reserve registry. For example, grassland credits in the buffer pool will be used to compensate for reversals of grassland projects, while forest credits in the buffer pool will be used to compensate for reversals of forest projects. Similarly, credits that have been granted eligible status for use in programs outside of the Reserve, but for which the Reserve follows a formal eligibility or qualification process, will be used to compensate for reversals of credits with the same status. The Reserve will retire credits out of the buffer pool to compensate for reversals on a First In First Out (FIFO) basis, after identifying which credits meet the aforementioned criteria for reversal compensation.

Buffer pool contributions are established by each protocol, in accordance with the best available literature. In the highly unlikely event that the buffer pool does not contain sufficient supply of credits for a certain project type or program eligibility qualification to compensate for identified, unavoidable reversals for that same project type or program eligibility qualification, the Reserve may opt to retire buffer pool credits of another type. If the aggregate buffer pool still is not sufficient for addressing any identified unavoidable reversals, a situation the Reserve believes to be close to impossible (or indicative of an environmental catastrophe hard to imagine), the Reserve will assess the situation and pursue one or more of the following options depending on what is most suitable:

- Require an increased buffer pool contribution from existing projects
- Revise reversal risk ratings within relevant protocols upwards for future reporting to compensate for the unavoidable reversals
- Purchase and retire an adequate amount of similar credits through the Reserve's Blind Trust
- Consult with affected project developers to determine an appropriate course of action

2.9 Avoiding Double Counting of Emission Reductions

Double counting is "a situation in which a single greenhouse gas emission reduction or removal is counted more than once towards achieving climate change mitigation. Double counting can occur through double issuance, double use, and double claiming."[15] The Reserve program guards against each form of possible double counting in different ways. The combination of these safeguards should mitigate the risk of double counting in all its forms.

The first layer of safeguards to avoid double counting is applied at the level of project protocols. The initial safeguard is through the process for screening project protocols for development and adoption by the Reserve. Section 4.1 provides details regarding the selection of project types with low risk of double counting. The next safeguard to avoid double counting is via the act of protocol development. During this process, decisions are made regarding the determination of additionality and the defining of the GHG Assessment Boundary. Both of these processes can reduce the risk of double counting where project activities or GHG sources are covered by other programs.

The next layer of safeguards is implemented at the program level. When a project is submitted for listing with the Reserve, staff conduct a review of other carbon project registries to ensure that the project is not seeking GHG credits for a concurrent period of time. There are specific circumstances under which a project may be listed in multiple registries at the same time without risk of double counting. For example, a project may have transferred to the Reserve from another registry without any temporal overlap in crediting. When a project is submitted for registration, following review of the verification report, Reserve staff will once again conduct a review of other carbon project registries. Project developers also sign a legal Attestation of Title prior to each registration. Through this form they attest, and thus accept liability, that the relevant emission reductions are not registered in any other program, or in the Reserve under another project.

The registry itself is designed to mitigate the risk of double counting through transparency. Each CRT has a unique serial number, identifying, among other things, the location of the project, the relevant protocol, and the vintage year of the GHG reductions. All issuances and retirements

[15] *Guidelines on Avoiding Double Counting for the Carbon Offsetting and Reduction Scheme for International Aviation*. June 2019. Available online at: https://www.adc-wg.org/.

are immediately public. Cancellations for other programs are made public. Any user may review all CRT retirements and view the serial numbers, as well as the reason for retirement. In addition, verification reports are made public, providing an additional source of detailed information regarding the generation of the GHG reductions.

Additional guidance will be added to this document at a later date to address the risk of double claiming between international reporting mechanisms under the Paris Agreement and the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA), once the international community provides more details on how these commitments will be implemented.

3 Program Rules and Procedures

3.1 Reserve Offset Program Manual

This manual contains details on the Reserve's program, policies, and requirements. Users of the Reserve program, including verification bodies, are subject to the requirements and guidance specified in the most recent version of the Reserve Offset Program Manual. The Reserve Offset Program Manual is considered effective as of the date it is posted on the Reserve website. All account holders and verification bodies are notified when an update to the Reserve Offset Program Manual is released, and the manual is available on the Reserve's Program Manuals and Policies webpage at http://www.climateactionreserve.org/how/program/program-manual/.

3.1.1 Revisions to the Reserve Offset Program Manual

Between updates, the Reserve may release policy memos that update or replace guidance in the Reserve Offset Program Manual or protocols. These memos are considered effective on the date they are posted on the Reserve website; users of the Reserve program and verification bodies must follow the guidance specified in the memo from that date forward. All account holders and verification bodies are notified when a policy memo is released, and memos are posted on the Reserve's Program Manuals and Policies webpage at http://www.climateactionreserve.org/how/program/program-manual/.

In most cases, the contents of the memos are incorporated into the next update of the Reserve Offset Program Manual.

3.2 Start Date

In general, the start date for a project corresponds to the start of activity that generates GHG reductions or removals. Specific requirements for determining the start date of a project are contained in each protocol. Project start date is used in determining project eligibility and initiates a project's crediting period.

Although the project start date is defined by each protocol, the date that begins the project's initial verification period is not. A project must begin its initial verification period on the project start date. This ensures that all project emissions within the GHG Assessment Boundary are accounted for from the project start date until the end of its crediting period.

It is possible that a project developer may not have implemented the appropriate monitoring or QA/QC procedures per the protocol on the project start date. Regardless, the project developer must still begin the initial verification period on the project start date. The project developer shall claim no emission reductions for any time period that the project cannot meet the data, monitoring or QA/QC requirements of the protocol. The verification body must confirm with reasonable assurance that project emissions were not greater than baseline emissions during a verification period, including the time period from the project start date until the protocol requirements were met. Verification bodies shall perform a review of project documentation and calculations for such a time period and may use professional judgment when assessing available project documentation.

If the verifier cannot confirm with reasonable assurance that project emissions were less than or equal to baseline emissions for the verification period, the Reserve will make a determination of action on a case-by-case basis.

3.3 Project Registration

This section summarizes the administrative steps a project developer must follow to register a project with the Climate Action Reserve. The timing of project registration may be independent of its start date. In other words, projects may be submitted after they begin operation (subject to the eligibility restrictions on the project start date described above) or before they begin operation. However, the steps outlined in this section must be followed in order for the Reserve to issue CRTs to a project.

Detailed information on the Reserve's software operating procedures, including step-by-step instructions for creating accounts, entering information, receiving CRTs, and transferring CRTs among accounts can be found in the Reserve's User Guide: http://www.climateactionreserve.org/how/program/documents/.

3.3.1 Fee Structure Summary

The Reserve imposes required fees that are charged to account holders during the project registration process (Sections 3.3.2 to 3.3.13). A summary of those fees is below:

Reserve Account Fees (Effective July 1, 2017) [16]	
Account Setup Fee	$500
Account Maintenance Fee (annual per project)	$500
Account Re-activation Fee	$500
Project Owner Account Setup Fee (for aggregated projects/cooperatives only)	$200
Project Owner Account Maintenance Fee (annual, for aggregated projects/cooperatives only)	$80
Project Submittal Fee under a Reserve Project Protocol (per project)	$500
Project Variance Review Fee (per request)	$1350
Project Transfer Fee (per project transferred between account holders, paid by the transferee)	$500
Project Registration Extension (per request)	$200
CRT Issuance Fee (per CRT issued)	$0.19
CRT Transfer Fee (per CRT transferred between account holders, paid by the transferor)	$0.03
Retirement (per CRT retired)	no charge

3.3.2 Account Registration

As a first step, an account must be set up with the Reserve. Account registration only needs to occur once; any number of projects can be registered under the same account.

[16] All fees in this table are limited to the Reserve's voluntary offset program. Fees related to the Reserve's work as an Offset Project Registry (OPR) under the California Cap-and-Trade system can be found at http://www.climateactionreserve.org/how/program/program-fees/

Any person or organization may apply for a Reserve account regardless of location or affiliation. Account applications are completed through the Reserve software. Along with completing an online application, each user must also agree to the legal Terms of Use for the Reserve. The Terms of Use binds users of both the Reserve software and the program itself to the terms laid out in the protocols, the Reserve Offset Program and Verification Manuals, and the Operating Procedures as modified from time to time. The Terms of Use document can be downloaded at http://www.climateactionreserve.org/how/program/documents/.

When a new account is approved by the Reserve, the account holder will receive an invoice for the account maintenance fee. Payment is due within 30 days of approval to avoid cancellation of the new account.

Account management can be shared between the account owner and another party provided a Designation of Authority form has been completed (see Section 3.3.2.2).

3.3.2.1 Types of Accounts

There are six types of accounts in the Reserve:

1. **Project Developer**. An account type for organizations that wish to register projects that generate GHG reductions or removals. This account type can also be used to transfer and manage CRTs. Users of this account type are also able to function as project aggregators or cooperative developers, enabling the management of CRTs on behalf of multiple projects formally registered as part of an aggregation or cooperative, as allowed under certain protocols.
2. **Trader/Broker/Retailer**. This type of account allows the transfer and management of CRTs, but not registration of projects.
3. **Verifier**. An account type for verification bodies that have been trained and authorized by the Reserve to verify projects. There is no annual account fee for verification bodies.
4. **Reviewer**. This account type is only for those who have been asked by the Reserve to serve as a project reviewer. There is no annual account fee for reviewers.
5. **Client**. This type of account is for any individual or entity that wishes to retire CRTs but not develop its own projects.
6. **Project Owner (limited)**. This account type is designated for use by project participants participating in a cooperative or aggregate according to protocol-specific rules and procedures. This account type allows the registration of projects that are formally part of a cooperative or an aggregation. It is intended for use when the owner of the GHG reduction rights (the Project Owner) is not the entity carrying out project development activities in the registry system. This account type may also be used for limited transfers of CRTs under the terms and restrictions imposed by the relevant project protocol and/or aggregation guidance and does not include privileges for retiring CRTs.

The public also has the ability to view information on the Reserve, but an account is not needed to view publicly available information.

3.3.2.2 Designation of Authority

A project developer and trader/broker/retailer account holder may designate an agent to access the Reserve software on their behalf.

Account holders must complete the Designation of Authority form to specify agents besides themselves who will have access to all information contained in their account. An example of an account holder agent would be a technical consultant hired by the project developer to manage a project on their behalf.

An account holder agent will have all the rights and responsibilities of the account holder and will also be bound by the Reserve Terms of Use. The Designation of Authority form can be downloaded at http://www.climateactionreserve.org/how/program/documents/.

3.3.3 Project Submittal

Project developers must complete and upload the appropriate project submittal forms for the project type and pay a project submittal fee to the Reserve. Submittal forms are specific to the project type and include project descriptions and preliminary information used to assess eligibility. The submittal forms for each type of project are available for download at http://www.climateactionreserve.org/how/program/documents/. A project is considered "submitted" when all of the appropriate forms have been completed, uploaded and submitted through the Reserve software.

3.3.4 Requests for Variances from Protocol Requirements

The Reserve will allow variances from protocol requirements only where Reserve staff determines that such variances are acceptable. Variances are only granted for deviations from requirements related to monitoring or measuring of GHG reductions or removals. The Reserve will not consider variances related to project eligibility criteria, or to the general methodological approaches for quantifying GHG reductions or removals specified in a protocol.

Reserve protocols are standardized documents developed through a transparent, stakeholder-driven process during which public input is solicited and considered thoroughly. Through this process, a single set of requirements and methodologies is established for all projects. If a requested variance diverges significantly from the approved methodology in a protocol, in that it requires extensive analysis of site-specific features and/or employs concepts not fully vetted through public consultation, the variance will be denied.

Variance requests that affect eligibility rules or methodological approaches cannot be granted, but if a request appears to have merit and may have application beyond a single project, it may be a candidate for future work and inclusion in future protocol revisions. Therefore, while a variance may not be approved at the time of submittal, the Reserve may elect to initiate work to explore the issue further if the resolution may be extrapolated, standardized, and used to inform future protocol revisions. If a future version of a protocol addresses the request for variance in such a way that the project would meet the requirements of the revised protocol, the project may be re-submitted and will not be deemed ineligible because of start date requirements (i.e., that the project must be submitted within six months of the project start date – see Section 2.4.3).

To submit a variance request, the project developer must complete and submit a Request for Project Variance form and pay the associated fee. No variance request will be considered until the project in question has been formally submitted to the Reserve. Each variance request is only applicable to a single project. A project developer seeking a similar variance on multiple projects must still submit a variance request for each project.

Upon receipt of the appropriate documentation and payment of the invoice, the Reserve will review the variance and will provide explicit, written acceptance to the project developer if the variance is approved. Decisions on variances are considered *sui generis* and are not precedent-setting. The Reserve retains the right to reject a variance, request further documentation or impose additional constraints and/or discount factors on the proposed monitoring or measuring methods. There is no process to appeal the denial of a variance; the decision to approve or deny a variance request lies solely with the Reserve. If the Reserve approves a variance request, a letter describing the variance granted will be sent to the project developer and will be made publicly available.

The Reserve also maintains a publicly-accessible Variance Tracking Log, which provides a summary list of all variance requests approved by the Reserve. The variance log can be downloaded at http://www.climateactionreserve.org/how/program/documents/.

The Request for Project Variance form can be downloaded at http://www.climateactionreserve.org/how/program/documents/.

3.3.5 Project Listing

Once the project submittal fee has been received, the Reserve reviews the forms to determine whether they are complete and conducts a preliminary assessment of the project's eligibility according to the eligibility criteria set forth within the appropriate project protocol. Once this review is satisfactorily completed, the project is "listed" and made publicly available on the Reserve. Project verification activities cannot begin until a project is listed. Review of submitted forms will generally take no more than 10 business days.

Note that a project may be verified against the protocol version in place at the time of project submittal as long as the project is verified by its verification deadline (see Section 3.4.2). As long as a project meets it verification deadline, a project developer is not required to verify against a new protocol version, even if one becomes effective in between the time a project is submitted and registered. Project developers always have the option, however, of voluntarily choosing to verify against the most recent version of a protocol at any time.

Listing a project does not constitute a validation or verification of the project or its eligibility; it is a preliminary review of project information provided to the Reserve by the project developer. It is not a final determination of the eligibility of the project, nor does it guarantee CRT issuance or CRT ownership. Project registration and CRT issuance is contingent upon the submission and approval of all required forms and documents for a particular project type, including, but not limited to:

- Attestation of Title (see Section 3.3.6)
- Attestation of Voluntary Implementation (see Section 3.3.7)
- Attestation of Regulatory Compliance (see Section 3.3.8)
- NOVA/COI form (see Section 3.3.9)
- Verification Report, Verification Statement, and List of Findings

The required forms and documents for registration under each project type can be found at http://www.climateactionreserve.org/how/program/documents/.

3.3.6 Attestation of Title

All project developers must submit a signed Attestation of Title form indicating that they have exclusive ownership rights to the GHG reductions or removals associated with the project and for which the Reserve will issue CRTs. In addition, the project developer agrees that ownership of the GHG reductions or removals will not be sold or transferred except through the transfer of CRTs in accordance with the Reserve Terms of Use policies.

This form shall be signed and submitted after the conclusion of each verification period for a project, as specified in each protocol. Note that the entity/individual signing the Attestation of Title (and the other attestation forms) must be the account holder who submitted the project. Projects will not be registered unless the account holder and signatory to the attestation forms match.

The Attestation of Title form can be downloaded at http://www.climateactionreserve.org/how/program/documents/.

3.3.7 Attestation of Voluntary Implementation

All project developers must submit a signed Attestation of Voluntary Implementation form that confirms the project was implemented and established voluntarily and continues to operate as such. The project developer attests that at no time was the project required to be enacted by any law, statute, rule, regulation or other legally binding mandate by any federal, state, local or foreign governmental or regulatory agency having jurisdiction over the project.

This form is signed and submitted after the conclusion of each verification period (unless otherwise exempted by the protocol under which the project is registered). The Attestation of Voluntary Implementation, along with activities detailed in the project's monitoring plan, are the primary mechanisms by which the project passes the legal requirement test, as specified in each protocol.

The Attestation of Voluntary Implementation form can be downloaded at http://www.climateactionreserve.org/how/program/documents/.

3.3.8 Attestation of Regulatory Compliance

All project developers must sign and submit an Attestation of Regulatory Compliance form after the conclusion of each verification period, as specified in each protocol. By signing this form, the project developer attests to the project's compliance status throughout the project verification period. The form identifies specific dates during the verification period over which the project was in material compliance with all laws. In addition, the form confirms that the project developer has disclosed to its verification body in writing any and all instances of non-compliance of the project with any law. The Attestation of Regulatory Compliance form and the accompanying disclosure to the verification body of non-compliance events are the primary mechanisms by which the project passes the regulatory compliance eligibility criterion, as specified in each protocol.

The Attestation of Regulatory Compliance form can be downloaded at http://www.climateactionreserve.org/how/program/documents/.

3.3.9 Conflict of Interest Evaluation and Initiation of Project Verification

As described in Section 3.4, the Reserve requires third-party verification of all GHG reductions by an ISO-accredited and Reserve-approved verification body. Once the project developer has selected a verification body, the verification body must submit a Notice of Verification Activities and Conflict of Interest (NOVA/COI) evaluation form to the Reserve at least 10 business days prior to the commencement of verification activities. This form includes the scope of proposed verification activities and other required information used to assess the potential for conflict of interest between the verification body and the project developer. In order for verification activities to begin, the Reserve must determine that the potential for conflict of interest between the project developer and the verification body is low or can be mitigated. The conflict of interest evaluation must be completed before verification activities can begin. The NOVA/COI form is available for download at http://www.climateactionreserve.org/how/program/documents/.

Once the conflict of interest evaluation is complete, the project developer must upload the required attestations and enter project data into the Reserve software, and then submit the project for verification. Required data is described in each protocol, and can include project information, monitored GHG emissions data, estimated GHG emission reductions, and other data required by the project monitoring guidelines. Once the project has been submitted by the project developer, the Reserve software automatically notifies the verification body that the project is ready for verification.

The verification body then reviews the project data in the Reserve software, performs verification activities, conducts site visits as needed, and verifies that the listed project has fully complied with the appropriate project protocol and that the GHG reductions or removals have been appropriately quantified. The verification body then submits a Verification Report, Verification Statement, and List of Findings through the Reserve software.

3.3.10 Approval of Verification and Project Registration

Once the verification body completes the Verification Statement, Verification Report, and List of Findings, the project developer reviews the verification body's documents and then formally submits the project to the Reserve for final approval of the verification. The Reserve reviews the submission for completeness, reviews the Verification Statement, Verification Report, and List of Findings, and either approves the verification or requests a re-submittal of one or more components. Upon approval, the project developer receives an invoice for the issuance of CRTs generated by the project.

A project becomes "registered" the first time it is verified and accepted by the Reserve. The status of the project then changes from listed to registered in the Reserve software. See Section 3.4 below and the Reserve Verification Program Manual for further information about the project verification cycle.

3.3.11 Project Completion

A project is considered "completed" when it is no longer reporting to the Reserve. A project may be considered completed because it reaches the end of its crediting period(s), becomes ineligible or the project developer voluntarily chooses not to continue reporting. The reason for the completed status is noted in the Reserve system. Once a project is completed, project information remains publicly available indefinitely.

3.3.12 Record Keeping

According to the Terms of Use, the Reserve has the right to examine, audit, and obtain copies of users' records from the most recent 12-month period. The Reserve does not anticipate this being a routine need, but rather a rare event to verify the accuracy of any attestation, transfer or statement, or to review account holders' performance of obligations under the protocols, the Terms of Use or the Reserve's Operating Procedures.

Project developer account holders on the Reserve must also maintain copies of all relevant records related to their projects and associated account usage for the time period specified in each protocol.

3.3.13 Publicly Available Information

The Reserve is intended to serve both account holders and the interested public. To this end, information about each project registered with the Reserve is accessible to the public. This openness and transparency provides interested parties with valuable information and helps instill confidence in the Reserve and enhance the credibility of the offset credits it certifies.

The public and all account holders can access the following information online:

- **Participating companies.** Organizations that have an active Reserve account (address or contact information is not disclosed).
- **Projects.** Projects that are listed or registered with the Reserve. Rejected project submittals and projects that are de-listed prior to registration and/or CRT issuance are not displayed; however, information will be made publicly available indefinitely for any project to which CRTs have been issued, regardless of whether the project is completed, terminated or transferred to another program.
- **Project CRTs issued.** Projects for which CRTs have been issued along with the quantity of CRTs issued to each project. Current CRT balances in individual accounts are not automatically displayed.
- **Search of CRT serial numbers.** The Reserve software allows searching for a CRT serial number by batch number or block start or end numbers. This search feature is designed for someone who wants to see details about a given CRT batch (for example, a CRT buyer). It cannot be used to search every CRT issued for a company or project. Search results include whether the CRTs are active or retired and, if retired, the time and date of retirement.
- **Accounts disclosed to public.** Active or retired CRT balances that account holders have chosen to be shown to the general public.
- **Retired CRTs.** Displays the CRTs that have been retired by account holders.

Information that is never shared with the public includes:

- Company street addresses
- Company phone, fax or email addresses
- Internal company information, like billing addresses
- Any person's contact information

Account holders' contact information is not used by the Reserve except to notify users of important system occurrences and policy updates and is not shared with other parties.

3.4 Project Verification

The Reserve requires periodic third-party verification of all GHG projects, as specified in each project protocol. This provides an independent review of data and information used to register CRTs. For every project, a third-party verification body reviews documentation, monitoring data, and procedures used to estimate GHG reductions or removals. The verification body submits a Verification Statement and Verification Report that provide the basis for determining the quantity of CRTs that can be issued to the project. The Reserve makes these documents publicly available. Verifiers conducting verification activities for projects listed or registered on the Reserve must be trained by the Reserve or its approved designees and employed by or subcontracted to an accredited verification body. A list of accredited verification bodies is available at http://www.climateactionreserve.org/how/verification/connect-with-a-verification-body/.

Verification bodies follow guidelines set forth in the Reserve Offset Program Manual and Verification Program Manual, as well as rules and procedures described in the specific verification guidance that is included in each project protocol.

3.4.1 Validation

Validation involves determining the project methodology and a project's eligibility to generate GHG reductions or removals. Unlike some other offset programs, the Reserve does not require that validation be conducted. Eligibility criteria and methodologies for emission reduction calculations are built into the Reserve protocols. Because the Reserve's eligibility criteria are mostly standardized, determination of eligibility is usually straightforward and requires minimal interpretative judgment by verification bodies. The first time a project is verified, verification bodies are required to affirm the project's eligibility according to the rules defined in the relevant project protocol. Project developers may choose to have a project verified without verifying CRTs for issuance in order to establish its eligibility for registration and provide more certainty to potential CRT buyers or sellers. However, when a project developer is seeking to register CRTs, a full verification must be conducted. See the Verification Program Manual for more information.

3.4.2 Reporting Period and Verification Period

GHG emission reductions are generally quantified and verified on an annual basis. Some protocols allow project developers to verify GHG emission reductions on a more frequent or less frequent basis if they desire. The length of time over which GHG emission reductions are quantified and reported to the Reserve is called a "reporting period." The length of time over which GHG reductions are verified is called a "verification period." Under some protocols, the reporting period and the verification period are identical, and no distinction is made between these terms (the protocol may refer only to a "reporting period"). Other protocols distinguish between the two and the maximum period for each is specified. Note that some protocols may allow the verification period to cover multiple reporting periods. However, the end date of a verification period must always correspond to the end date of a reporting period.

CRTs are issued according to the quantity of verified reductions achieved during a verification period, regardless of the period's length.

Reporting periods must be contiguous; there can be no time gaps in reporting during the crediting period of a project once the initial reporting period has commenced.[17] Gaps in monitoring data or activity must be included in reporting periods and verified accordingly. The verification body must confirm that no reductions are claimed for any period for which a gap in monitoring data exists or for which a project was non-operational.

[17] There is an exception to this requirement for projects under the U.S., Article 5, and Mexico Ozone Depleting Substances Project Protocols. Under those protocols, reporting periods need not be contiguous.

3.4.3 Initial Verification and Registration

A project must complete verification within 12 months of the end of its initial reporting period. To satisfy this verification deadline, the project developer must submit a completed Verification Report and signed Verification Statement to the Reserve.

For project types that require annual verification at a minimum, the Verification Statement and Report may cover a maximum of 12 months of project activity, with the following exceptions. A pre-existing project (see Section 2.4.3) undergoing its initial verification and registration with the Reserve may submit a Verification Statement and Report that cover multiple years, back to the project's start date. This data is considered "historic data." Historic data may only be registered during a pre-existing project's initial verification with the Reserve. The Reserve also allows project developers to register more than 12 months of data during a project's initial verification period while still meeting the 12-month verification deadline (based on the maximum initial reporting period specified by each protocol), or register a project's initial verification period as a zero-credit reporting period (see Section 3.4.5).[18]

A project is considered "registered" when the project has been successfully verified by an approved third-party verification body, submitted by the project developer to the Reserve for final approval, and accepted by the Reserve.

A project that fails to meet its initial verification deadline must re-submit under the latest version of the applicable protocol. Projects that do so are not subject to the start date requirements in Section 2.4.3, provided that the project met all applicable requirements at the time of initial submittal.

If a project misses its initial verification deadline, the project is "de-listed"[19] in the Reserve software and is no longer viewable by the public. The Reserve will contact the project developer to inform them they must re-submit under the latest version of the protocol within 60 calendar days of notification.

If the project developer re-submits the project within 60 calendar days, the project is "re-listed"[20] under the same project ID and the project maintains its original start date. The project is given a new listing date.

If the project developer fails to re-submit within 60 calendar days, the project is cancelled. The project developer could still re-submit the same project at a later date, but it would be assigned a new project ID and would have to meet all the requirements of the applicable protocol, including start date requirements.

Projects that successfully re-list must submit either 1) a Verification Statement and Verification Report or 2) a Zero-Credit Reporting Period Acknowledgment and Election form within 12 months of re-submittal, with the following exceptions. Forest, urban forest, and nitrogen

[18] Forest and urban forest projects are not eligible for zero-credit reporting periods.
[19] "De-list" is not a phase in the Reserve software. De-listed projects will no longer appear to the public in the software.
[20] "Re-list" is not a phase in the Reserve software. Projects will be identified as "listed" in the software with the same project ID.

management projects are not eligible for zero-credit reporting periods and therefore must complete initial verification within 12 months of re-submittal.

If a re-listed project misses the deadline above, the project is cancelled. Again, the project developer could still re-submit the same project at a later date, but it would be assigned a new project ID and would have to meet all the requirements of the applicable protocol, including start date requirements.

3.4.4 Subsequent Verification

After a project is registered, a Verification Statement and Verification Report must be submitted within 12 months of the end of each subsequent verification period. The maximum allowed length of a verification period is specified in each protocol. For example, a Verification Statement and Report for GHG reductions achieved between January 1, 2015 and December 31, 2015 would have to be submitted by December 31, 2016. The only exception to the verification deadline is if the project developer has successfully applied for an extension or is taking a zero-credit reporting period (see Section 3.4.5 below).

The Reserve makes account holders aware of upcoming verification deadlines for projects in their account. Project developers that miss this verification deadline are notified and given the choice to:

A) cancel the project; or
B) continue the project by initiating verification using the latest version of the relevant protocol.

Once notified that the verification deadline has passed, a project developer has six months to choose one of the options above. If no choice is communicated to the Reserve within six months, the project is cancelled.

If a project developer chooses Option B, they are required to submit a Zero-Credit Reporting Period Acknowledgment and Election form and a monitoring report to retroactively cover the time period since the end date of the last successful verification period (see Section 3.4.5). Thus, the project developer acknowledges that CRTs will not be issued for any GHG reductions or removals achieved by the project since its last successful verification. They are also required to verify the project to the latest version of the relevant protocol.

A project utilizing Option B maintains its original project start date, and thus maintains the crediting period defined by that start date. This option may be used across two crediting periods should the project protocol allow for that.

If a verification period spans two crediting periods and there is a more recent version of the protocol that must be used for the renewed crediting period (see Section 2.4.4), the project developer can either be issued CRTs for two verification periods by completing separate verifications for each crediting period, or can be issued CRTs for one verification period that spans two crediting periods if they choose to verify the entire verification period to the more current protocol version.

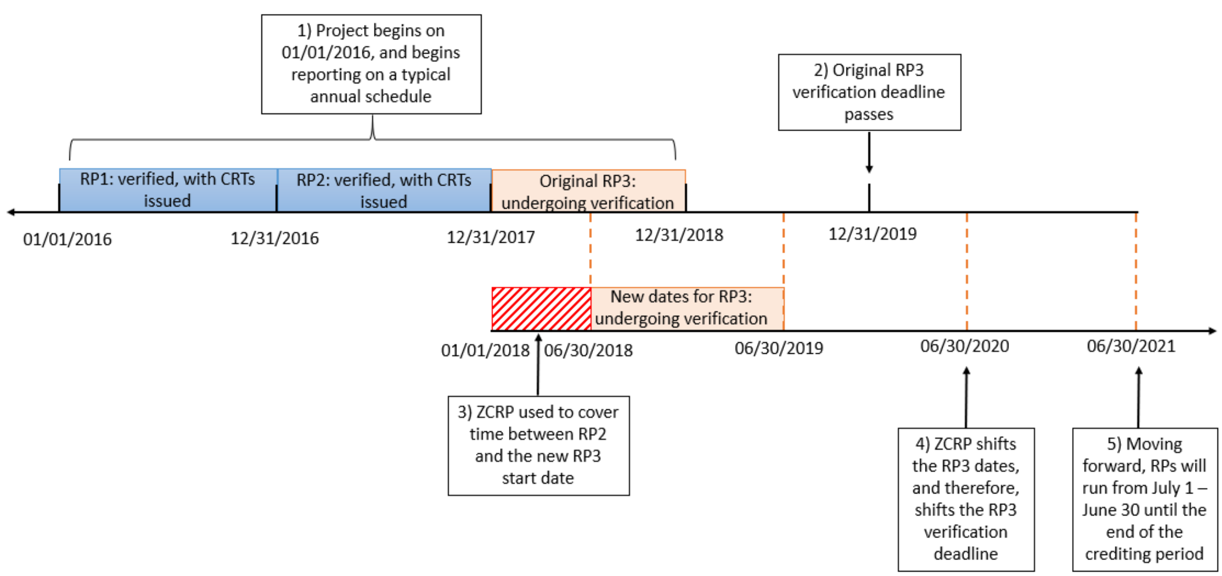
3.4.4.1 Subsequent Verification for Forest, Urban Forest, and Nitrogen Management Projects

The only exceptions to the options regarding a missed verification deadline detailed above are for forest, urban forest, and nitrogen management projects, as these project types are not eligible for a zero-credit reporting period. If a registered forest, urban forest, or nitrogen management project misses a subsequent verification deadline, project account activities will be suspended until the verification is complete. The project developer has 36 months from the end of the reporting period(s) being verified to complete verification. Otherwise, the project will be terminated.

3.4.5 Zero-Credit Reporting Period (ZCRP)

To provide flexibility for project developers in instances where verification is not practical or economical for a specific reporting period/verification period, developers of projects *other than forest, urban forest, and nitrogen management projects* may choose to delay verification on the condition that they acknowledge no CRTs will be issued for any period of time that falls outside the standard window for completing verification of project information and monitoring data. Such a period is referred to as a "zero-credit reporting period." In such cases, zero-credit reporting periods can be used to cover any time that falls between reporting periods that undergo verification. For most eligible project types, the maximum length of a verification period is 12 months, allowing CRTs to be issued only for GHG reductions achieved up to 24 months prior to submission of a Verification Report. See Figure 1 below for an example of a project using a ZCRP to cover time that falls between reporting periods, in order to extend the deadline for submission of a Verification Report.

Figure 1: Zero-Credit Reporting Period for a Project with a 12 Month Maximum Verification Period



For any zero-credit reporting period, the project developer must sign a Zero-Credit Reporting Period Acknowledgment and Election form (Acknowledgment and Election form) acknowledging that CRTs will not be issued for any GHG emission reductions or removals achieved by the project during the zero-credit reporting period. Along with the Acknowledgment and Election form, the project developer must also submit a monitoring report to the Reserve that covers data for the zero-credit reporting period.

The Acknowledgment and Election form and monitoring documents shall be submitted via the Reserve software within 12 months of the end date allowed for a verification period (i.e., by the verification deadline). The monitoring report is not a publicly available document. The Acknowledgment and Election form is made public. The Acknowledgment and Election form and monitoring report are required in order to meet the regular documentation requirements of the Reserve program and ensure the continuation of a project's crediting period. CRTs for subsequent verification periods will not be issued until these documentation requirements are met. The submission of the monitoring report for a zero-credit reporting period will satisfy the requirement for contiguous reporting in Section 3.4.2.

If neither a Verification Report nor an Acknowledgment and Election form is submitted within 12 months of the end date allowed for a verification period, the project is either de-listed or cancelled (see Section 3.4.3, 3.4.2, and 3.4.4). Under certain circumstances, after a project has been de-listed or cancelled, it may re-enter the program, using zero-credit reporting periods to cover the time period when the project was not actively reporting. This is also possible in cases where the failure to maintain contiguous reporting has extended through the end of the crediting period if allowed by the relevant project protocol. In these cases, the zero-credit reporting period may cover a period of time spanning two crediting periods, and the second crediting period will be considered to have begun on the day following the end date of the initial crediting period. There is no limit to the amount of time a zero-credit reporting period may cover, and a project may have contiguous zero-credit reporting periods. Project developers may also declare a project's initial verification period as a zero-credit reporting period.

The Acknowledgment and Election form and project-specific monitoring report templates can be downloaded at http://www.climateactionreserve.org/how/program/documents/.

3.4.6 Zero-Credit Reporting Period Verification

To ensure that project emissions were not greater than baseline emissions during a zero-credit reporting period, monitoring data collected during the zero-credit reporting period must be verified the next time the project undergoes verification. While the project is not required to conform to the protocol's monitoring and QA/QC procedures during a zero-credit reporting period, the verification body must be able to confirm with reasonable assurance that project emissions were less than baseline emissions during the zero-credit reporting period. Project developers shall provide project documentation and calculations for zero-credit reporting period emissions to the verifiers.

More information on the verification of zero-credit reporting periods can be found in the Verification Program Manual and the relevant project protocols. If the verifier cannot confirm with reasonable assurance that project emissions were less than or equal to baseline emissions, the Reserve will make a determination of action on a case by-case basis.

The Reserve views a zero-credit reporting period as a separate reporting period from the one undergoing verification for CRT issuance; to that end, the zero-credit reporting period should not be represented as part of the verification period that will be issued CRTs. For example, the dates of the verification period being issued CRTs shall not include the dates of the zero-credit reporting period. Similarly, for attestations that specify a beginning and end date, the time period should not include the zero-credit reporting period (i.e., Attestation of Regulatory Compliance, Attestation of Voluntary Implementation).

3.4.7 Verification Deadline Extension Request

The Reserve allows project developers to request a project verification deadline extension. No extension requests are granted unless the project has commenced verification and has undergone the site visit for the current verification period (if applicable)[21] and all outstanding invoices for the project and account holder have been paid. The following extensions may be granted:

- Forest (U.S. and Mexico), grassland (U.S. and Canada), and urban forest projects may be granted a 12-month extension.
- Livestock (U.S. and Mexico), landfill (U.S. and Mexico), and nitrogen management projects may be granted a six-month extension.
- All other project types may be granted a 30-day extension if the account holder can demonstrate to the Reserve's satisfaction that they will miss the deadline due to extraordinary circumstances. The Reserve holds the right to determine what rises to the level of an extraordinary circumstance.

To submit a request, account holders must submit a completed Request for Verification Deadline Extension form and requested documentation to the Reserve and pay a $200 review fee. The form must be received by the verification deadline.

The Request for Verification Deadline Extension form can be downloaded at http://www.climateactionreserve.org/how/program/documents/.

3.5 Stakeholder Input for Individual Projects

Direct and indirect stakeholder interaction is an integral part of the process for developing offset project protocols (see Sections 4.2 and 4.4). This includes comment periods that are open to the general public. At the project level, interactions generally involve those stakeholders with a commercial interest in the projects (e.g., facility owners, project developers, verifiers, consultants, CRT buyers, regulators, etc.). This section details avenues for non-commercial stakeholders to interact with the Reserve in relation to individual projects (rather than project protocols).

3.5.1 Local Stakeholder Consultations

Every Reserve protocol includes requirements to ensure that credits are only issued for emission reductions at projects that are in compliance with applicable regulations, and do no net environmental harm. In some cases, offset projects may have the potential to create social impacts on the local community, either positive or negative, which may not be appropriately handled by other, existing government structures. In those cases, the individual protocol may include additional requirements for local stakeholder consultations. In addition, every protocol development process, as well as every major protocol update, involves at least one public

[21] If the registration extension is being requested for a non-site visit year, evidence must be provided to show that the project developer has provided requested documentation to the verification team to allow them to commence the desk review.

comment period, with a public webinar. Local stakeholders are welcome to participate in any of these public events.

For example, the Mexico Forest Protocol provides social safeguards through prescriptive guidance about obtaining free, prior, and informed consent; meeting notification, participation, and documentation; and project governance. This ensures that the local community is able to participate in the offset project.

3.5.2 Feedback and Grievance Process

For any project type, it is possible that a stakeholder may want to contact the Reserve to provide feedback, either positive or negative. For general feedback or inquiries, stakeholders may contact the Reserve at reserve@climateactionreserve.org, or call the Reserve office at (213) 891-1444. For questions or comments related to a specific protocol, current points of contact are listed on our website at http://www.climateactionreserve.org/contact-us/.

The Reserve strives to avoid adopting protocols for activities that present a risk of negative environmental or social impacts. However, if a stakeholder has a grievance about a specific project, the initial point of contact would be the same as described above. The staff member receiving this initial contact will collect as much information as possible from the stakeholder about the specific project and grievance. This will then be communicated to the senior management at the Reserve, including the President. The specific action taken will depend on the nature of the grievance.

- For cases of a potential over-issuance, Reserve staff will conduct a thorough review and analysis, then ensure that the system is “made whole,” according to the process detailed in Section 3.6.2 below.
- For disputes related to ownership of the GHG emission reductions, the Reserve senior management and legal counsel will review the positions and documentation of the parties involved and determine the appropriate owner (based on existing Reserve guidance related to ownership of GHG emission reductions), as well as whether any additional action against the project or the project developer is warranted. The Reserve will not be party to any disputes where the involved parties pursue actions beyond the Reserve issuing a determination as previously described.
- For grievances related to potential negative social or environmental impacts related to a Reserve project, which are not in violation of existing regulations (and thus handled by the relevant government agency), the Reserve senior management will conduct a finding of facts and consider the stakeholder’s position. Such instances may be referred to the Board of Directors for a decision on project eligibility.

3.6 Climate Reserve Tonnes (CRTs)

In the Reserve, GHG reductions and removals are recognized as Climate Reserve Tonnes or CRTs, which are equal to one metric ton of carbon dioxide equivalent (CO_2e) reduced or sequestered. After projects are registered, CRTs are issued based on the GHG reduction or removal amount reported by the project developer and confirmed by an approved verification body. CRTs are issued only on an *ex post* basis (i.e., after verification that reduction activities have actually occurred) and only for GHG reductions or removals that occur within the project crediting period. For transparency, each CRT has a unique serial number with embedded information that identifies the project type, location, developer, and vintage. The unique serial number persists as CRTs are transferred between accounts or are retired and become offsets.

3.6.1 Issuance of CRTs

CRTs are issued by the Reserve for actual GHG reductions or removals achieved by a project, as determined in approved Verification Reports. Once a project is registered and the project's account holder pays the appropriate CRT Issuance Fee, CRTs for verified GHG reductions or removals are released into the account holder's primary CRT account. CRTs will not be issued until the CRT Issuance Fee is received by the Reserve. CRTs can then be transferred to another Reserve account holder's account, moved into one of the project account holder's other accounts or retired.

An account holder can only hold or retire CRTs in its account for which it is the sole holder of legal title and Beneficial Ownership Rights, except as permitted under Section 9 of the Terms of Use.

3.6.2 Over-Issuance of CRTs

In the event that the Reserve determines that GHG reductions or removals for a project were incorrectly quantified or reported, such that the number of CRTs issued to the project account holder was in excess of the correct number according to the requirements of the applicable protocol, it is primarily the project account holder's responsibility to compensate for the over-issuance of CRTs.

The Reserve will notify the project account holder of the over-issuance, including the basis for its determination, and the number of CRTs to be surrendered for cancellation or authorized to be withheld from issuance as further described below. The Reserve shall determine, at its sole discretion, which option or combination of options a project account holder may use; this will be determined on a case-by-case basis and detailed in the over-issuance notification.

Within 30 days, the project account holder must:

1. Surrender CRTs for cancellation; and/or
2. Provide written authorization to the Reserve to withhold CRTs from future issuances to the project.

If the project account holder fails to satisfy its obligations within 30 days, the Reserve may:

1. Cancel CRTs held by the project account holder;
2. Withhold from issuance CRTs otherwise issuable to the project account holder; and/or
3. Purchase CRTs from third parties at the project account holder's expense and cancel them.

The project account holder may dispute the over-issuance determination using the dispute resolution provisions set forth in Section 11(c) of the Climate Action Reserve Terms of Use.

3.6.3 Transfer of CRTs

In order to transfer CRTs to another party, that party must have an approved account with the Reserve. There is a transfer fee to transfer CRTs from one account holder to another ($0.03 per CRT charged to the transferor). The transfer is conducted via the software between the two account holders; the Reserve does not play a role in the transfer.

Note that the Reserve does not function as a trading system or commodity exchange. The sale or purchase of CRTs takes place outside of the Reserve. Account holders may record sales by using the Reserve to move CRTs from one account to another. However, the Reserve makes no warranties concerning, and has no control over, the legal ownership of CRTs that may be held in individual accounts.

3.6.4 Retirement of CRTs

CRTs may be "retired" to indicate that the emission reductions or removals they represent have been used to satisfy a voluntary GHG emission reduction claim or to offset other emissions. To support such claims, CRTs are taken out of circulation so that they cannot be used to support any further claims. The Reserve retires CRTs by transferring them to a locked retirement account where they remain permanently and in perpetuity, precluding further use or transfer to other parties. Each account holder has its own associated retirement account. Information about retired CRTs is publicly available and includes details like project type, location, serial number, date issued, reason for retirement, etc. to support the transparency of the offsets within the Reserve. There is no charge to retire CRTs.

For the greatest level of transparency, Account Holders are encouraged to provide complete details of the purpose of the CRT retirement in the "Retirement Reason Details" field.

3.6.5 Holding and Retirement of CRTs on Behalf of Other Parties

In some circumstances, an account holder may hold and retire CRTs on behalf of one or more third parties. See Section 9 of the Reserve Terms of Use for related requirements.

3.6.6 Transferring Credits from the Reserve

Offset credits may be transferred to other GHG registries and offset programs under processes that are specific to the receiving registry/program.

3.6.6.1 VCS

CRTs may be exported to a Verified Carbon Standard (VCS) registry and converted into Verified Carbon Units (VCUs). Transfers may be initiated by any account holder with active CRTs. The account holder initiates this process as they would a CRT transfer. Once the transfer is accepted by the VCS registry administrator, the Reserve processes the transfer and VCUs are issued on the VCS registry. The exported CRTs have "converted to VCUs" noted as the cancellation reason in the Reserve software and public reports.

3.6.6.2 The California Compliance Offset Program

The Reserve is an approved Offset Project Registry (OPR) under the California Compliance Offset Program. Projects wishing to receive credits under one of the ARB's approved Compliance Offset Protocols (COPs) may do so through the Reserve's project registry. Registry Offset Credits (ROCs) are issued to projects in the Reserve's registry that have been listed under a COP. Following the issuance of ROCs, project proponents may request issuance of ARB Offset Credits (ARBOCs) from the California Air Resources Board. Upon approval, the Reserve is notified, and ROCs are cancelled and then re-issued as ARBOCs in the Compliance Instrument Tracking System Service (CITSS). The exported ROCs have "ARB" noted as the cancellation reason in the Reserve software and public reports.

3.7 Transferring Projects into the Climate Action Reserve

Existing projects that have been registered with other carbon offset programs may be transferred to the Reserve if they meet, and are successfully verified against, the Reserve's protocol requirements, and if they meet the project start date requirements detailed in Section

2.4.3. Such projects must submit a Registry Project Transfer Form, available for download at http://www.climateactionreserve.org/how/program/documents/. The Registry Project Transfer Form requires additional information and documentation to determine the status of the project and any offset credits issued for it under other programs.

The project developer must also provide the Reserve with a signed Project Transfer Letter before CRTs for that project are issued by the Reserve. The letter must be sent to the administrator of the other program where the project was registered, confirming that no further emission reductions or removals for the project will be verified or registered under the other program.

Transferred projects are considered pre-existing projects and thus are able to register more than 12 months of data during their initial verification with the Reserve (see Section 3.4.2). Transfer projects are also subject to contiguous reporting, which means that a project's initial verification period with the Reserve must be contiguous with the end of the last verification period under the program from which the project is transferred.

The crediting period for a transferred project will be reduced by the length of time that has elapsed since the project start date, as defined by each protocol.

Note that while projects can be transferred from another program to the Reserve, previously issued credits from another program cannot be transferred to the Reserve. Furthermore, projects that generated offset credits in the past but were never registered on a carbon offset registry cannot be registered with the Reserve.

3.8 Transferring Projects from the Climate Action Reserve

Projects may be transferred from the Reserve to other GHG registries and offset programs. To transfer a project, the developer shall provide a signed Project Transfer Letter to the Reserve specifying the effective date of transfer and confirming that no further emission reductions or removals for the project will be verified or registered with the Reserve.

Once a project is transferred, no future reductions or removals from that project will be registered as CRTs. Project information and previously issued CRTs will remain in the Reserve system under their given serial numbers. Previously issued CRTs may be transferred to other accounts on the Reserve system and retired on the Reserve system, as long as the project developer maintains an account with the Reserve. Section 3.6.3 of this manual describes how to transfer CRTs to other Reserve accounts.

3.9 Transferring Projects between Account Holders in the Reserve

Projects may be transferred between project developer account holders within the Reserve program. The project developer transferee (the project developer who is acquiring the project) must submit an Account Holder Project Transfer form and pay $500 per project transfer. The Reserve will review this form and the project will then be transferred to the new account holder. The original account holder will no longer have access to restricted (non-public) project information.

The Account Holder Project Transfer form can be downloaded at http://www.climateactionreserve.org/how/program/documents/.

3.10 Relationships to Other GHG Programs

The Climate Action Reserve operates as a stand-alone voluntary offset registry. However, the Reserve program does interact with other GHG programs in various ways. Relationships with several, major programs are detailed in this section.

3.10.1 Voluntary Carbon Offset Programs

Registration of projects using project protocols developed by the Reserve is limited to the Reserve's voluntary offset program and other carbon offset programs that have pre-existing agreements in place with the Reserve. If a project developer is seeking crediting under a project protocol developed by the Reserve under a different program, it is the project developer's responsibility to notify the Reserve and to ensure that there is such a pre-existing agreement in place.

It may be possible for a voluntary Reserve offset project to be simultaneously listed under another voluntary offset program, provided that there is no overlap in the GHG Assessment Boundaries of the relevant protocol(s) or methodology. All project developers wishing to take advantage of any such opportunity should seek guidance from the Reserve, and staff of the other voluntary offset program, as early as possible in that process, to ensure best chances for approval and avoidance of any double counting. Reserve staff will work directly with the project developer, and likely also staff from the other voluntary program in question, to ensure there is no double counting in such circumstances. Generally speaking, where GHG accounting boundaries do not overlap, it may be possible for a project to enroll in multiple offset programs, undertake one set of activities, and receive crediting from those multiple programs. However, such a determination shall be made on a case-by-case basis for each combination of Reserve protocol and external protocol or methodology.

3.10.1.1 The Verified Carbon Standard

The Reserve is the first recognized independent GHG offset program under the Verified Carbon Standard, a global standard and program for approval of credible voluntary offsets. As an approved VCS program, offset projects that meet the Reserve's protocols can generate VCS credits, known as VCUs. CRTs issued by the Reserve can also be converted to VCUs and transferred to a VCS registry (see Section 3.6.6). However, VCUs cannot be converted to CRTs; only projects registered with the Reserve using Reserve protocols are able to generate CRTs.

For more information on Verra's VCS Program, visit https://verra.org/project/vcs-program/.

3.10.2 The California Compliance Offset Program

The California Air Resources Board (ARB) administers a Compliance Offset Program for use under the state's economywide cap and trade program for GHG emissions. The project registry functions for this program are administered by approved Offset Project Registries (OPRs). The Reserve is an approved OPR. Projects wishing to receive credits under one of the ARB's approved Compliance Offset Protocols (COPs) may do so through the Reserve's project registry. Reserve staff are experts in the OPR procedures, as well as the application of the COPs, most of which are adapted from the Reserve's voluntary offset protocols. The Reserve issues Registry Offset Credits (ROCs), which are ultimately canceled and then reissued by the ARB as ARB Offset Credits (ARBOCs). The Reserve does not issue ARBOCs and does not have a connection with the Compliance Instrument Tracking System Service (CITSS) (the registry used by the Western Climate Initiative for tracking compliance instruments). In instances where a project does not seek the issuance of ARBOCs for a given reporting period, the project may retire the ROCs for voluntary purposes (see Section 3.6.4) or seek the conversion of ROCs into CRTs.

For information on the Reserve's role as an Early Action Offset Program and Offset Project Registry for the California Compliance Offset Program, please see the following resources:

- Climate Action Reserve California Compliance Offset Program website http://www.climateactionreserve.org/how/california-compliance-projects/
- California Air Resources Board Compliance Offset Program website http://www.arb.ca.gov/cc/capandtrade/offsets/offsets.htm

3.10.3 The California Low Carbon Fuel Standard Program

The California Air Resources Board (ARB) administers a Low Carbon Fuel Standard (LCFS) Program for use under the state's plan for reducing GHG emissions. Certain project types that are eligible for CRTs and ROCs under the Reserve's voluntary and compliance offset project registry programs are also potentially eligible to receive LCFS credits for the generation and delivery of transport fuels (such as biogas) into California. This includes livestock anaerobic digestion projects and landfill gas capture and destruction projects. The Reserve does not issue or verify LCFS credits. Nor can CRTs or ROCs be directly converted into LCFS credits. However, in some cases the process of verifying and registering offsets through the Reserve may be a component of the project's process toward receiving and verifying LCFS credits. In cases where a Reserve offset project is also seeking LCFS credits, Reserve staff will work with ARB staff and the project developer to ensure that CRTs or ROCs are appropriately cancelled to reflect overlapping issuance in the LCFS program. In instances where a project cancels some, but not all ROCs from a given reporting period, in order to receive benefit in the LCFS program, the project may be able to retire the remaining ROCs or seek the conversion of those ROCs into CRTs.

In all cases, project developers must disclose to their verifiers the existence of any additional crediting or payment programs in which the project is participating concurrently with its registration through the Reserve.

3.10.4 The Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA)

The International Civil Aviation Organization, a special body of the United Nations, has resolved to mitigate the growth in GHG emissions from international aviation beyond 2020 through the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA). The offsets portion of this program is designed to be decentralized, allowing for airlines to comply with their offsets obligations via retirement of eligible emission units issued by approved GHG programs.

As of this writing, no GHG programs have been approved by ICAO, and details around qualification of eligible emission units are not settled. The Reserve has applied for its offsets program to be approved for use by airlines to comply with CORSIA. At a later date, this document will be updated to reflect the process by which CRTs may be qualified and retired for use in CORSIA, including procedures to avoid double claiming of emission reductions.

For more information on CORSIA, please visit https://www.icao.int/environmental-protection/CORSIA/Pages/default.aspx.

3.10.5 Green-e Climate

Green-e Climate is a “global third-party certification program for carbon offsets,” operated by the Center for Resource Solutions (CRS). This program could be viewed as a “meta” certification, applying its label to offsets issued by specific GHG programs it has decided to endorse. The Climate Action Reserve’s voluntary offsets program is one such endorsed program. Thus, CRTs may be certified as Green-e Climate carbon offsets. Regardless of this additional certification, CRTs remain within the Reserve’s registry, with the original serial numbers and no additional requirements from the Reserve program.

For more information on the CRS’s Green-e Climate program, visit https://www.green-e.org/programs/climate.

4 Project Protocol Development Process

The Reserve is committed to producing high quality GHG project accounting protocols, and to this end uses an intensive multi-stakeholder process to develop its project protocols. This approach integrates extensive data collection and analysis with review and input from a diverse range of experts and stakeholders. Reserve staff guides this process to ensure that final protocols adhere to the principles outlined in Section 1.2. This process produces high quality, well-vetted, and credible protocols based on best practices from national and international standards. This section details the Reserve's unique and rigorous project protocol development process.

4.1 Screening Process

The Reserve uses an internal screening process to identify candidate project types with good potential for offset protocol development. The Reserve takes into consideration a number of issues when assessing a project type for further development, including:

- Does the project type create direct or indirect emission reductions? All else equal, the Reserve will focus on project types that result in direct reductions. Direct emission reductions are generally easier to verify because the sites where they occur can be directly monitored. When emission reductions occur at sites or sources owned by the project developer, there is also less risk that an entity other than the project developer will claim ownership of the reductions. Thus, these projects are unlikely to be at risk for double counting or ownership issues.

- How amenable is the project type to standardized additionality and baseline determinations? For some types of projects, it is difficult to credibly and accurately determine additionality and estimate baseline emissions on a standardized basis. In general, the Reserve will avoid developing protocols for these project types. Alternatively, the Reserve may incorporate project-specific methods or variables into standardized protocols as appropriate, or limit the scope of protocols to address only activities and conditions for which standardized approaches are feasible.

- What is the likelihood that the sector where the project activity occurs will be covered under a future cap-and-trade system? Since issuing offset credits for reductions that occur at capped emission sources would result in double counting, the Reserve prefers to focus on projects affecting GHG emissions that are unlikely to be capped.

- What are the total potential GHG reductions that could result from this type of project? As it takes significant effort and resources to produce a standardized project protocol, there should be large and geographically diverse potential reduction opportunities.

- Are there potential positive or negative environmental or social impacts from this type of project activity or the operations, facilities or sectors with which this type of project may be associated? Negative effects should be avoided. All else equal, the Reserve will prioritize sectors and project types that can create significant co-benefits for the habitats and communities where projects take place. Where necessary, the Reserve will also consider developing additional criteria for ensuring environmental and social safeguards.

- Are there existing methodologies or protocols that could serve as a starting point? Standardized protocols are more easily developed where sound scientific methods already exist to determine baselines and quantify emission reductions.

- Are there high quality datasets to evaluate "business as usual" activities for the sector in which the project activity occurs? Setting performance thresholds and other standardized tests for additionality requires defensible data on the current state of the sector.

Once the internal screening process is complete, project types with good potential are either explored more fully through the development of an issue paper or the Reserve holds a scoping meeting to engage stakeholders in further evaluating what types of activities should be targets for protocol development.

4.1.1 Issue Paper

An issue paper evaluates the feasibility and desirability of developing a protocol (or set of protocols) for a particular project type. It assesses possible issues with developing a standardized protocol for the project type, including an evaluation of potential approaches to GHG emission quantification; exploration of options for defining eligible project activities; evaluation of approaches to setting project boundaries; and assessment of the availability of datasets and other pertinent information. It also assesses the environmental and social impacts associated with prospective project activities, as well as potential impacts from the operations, facilities or sectors with which project activities may be associated. Issue papers are prepared by researching existing sector methodologies and datasets and consulting sector experts. After completion, the issue paper may be sent to interested parties (industry experts, environmental groups, state agencies, academics) for review and comment.

4.1.2 Scoping Meeting

Interested parties may be invited to a scoping meeting to discuss protocol development options and challenges for the project type in question. At the scoping meeting stage, the Reserve will generally propose a series of activities within the project type category for which specific accounting and verification standards could be developed. Feedback from the scoping meeting is used to determine whether the Reserve will move forward in developing a protocol, and which activities the protocol should encompass.

4.2 Development Process

After a project type is identified, the Reserve follows a rigorous multi-stakeholder consultation process to develop an appropriate protocol.

4.2.1 Workgroup Assembly

To initiate the project protocol development process, the Reserve assembles a balanced multi-stakeholder voluntary workgroup, drawing from industry experts, state and federal agencies, environmental organizations, and other various stakeholders. Workgroups are assembled by invitation, but all parties are encouraged to express their interest in participating in the workgroup process. Throughout the protocol development process, the workgroup provides expert review and direct input into the development of the project protocol.

Interested stakeholders that are not on the workgroup can still participate in the workgroup process as "observers." Any individual is welcome to be an observer to a protocol development process. Observers can listen to workgroup meetings via conference call, but are not solicited for comments or feedback until the public review period.

4.2.2 Options Paper

Where appropriate, the Reserve may develop an options paper to further address and lay out different approaches for key elements of the protocol. A draft is shared with the workgroup and comments are incorporated into a final options paper that forms the basis of the draft protocol.

4.2.3 Draft Protocol for Workgroup Review

The Reserve develops a draft protocol based on expert input and insights from an issue paper or the final options paper. The draft protocol is released to the workgroup for review and revision and is also posted on the Reserve's website for review by observers and other interested members of the public. The draft protocol review process usually includes at least one or more in-person workgroup meetings in which members are invited to discuss issues at length. At this point in the process, the Reserve explicitly requests input on possible environmental and social harms associated with project activities and associated operations or facilities, and requests discussion of whether existing legal and regulatory safeguards are appropriate and adequate to mitigate any harms.

Written comments from the workgroup are incorporated into the draft protocol, which may go through multiple iterations of workgroup review before it is ready for public review. Note that observers and the public do not comment on the draft protocol at this stage.

4.2.4 Public Review Period and Public Workshop

The revised draft protocol is posted on the Reserve's website for a 30-day public comment period. The public is notified via the Reserve's listserv database and other venues, and reviewers are asked to submit written comments. During the 30-day public review period, the Reserve also hosts a public workshop to solicit feedback and address concerns regarding the draft protocol in an open forum. After receiving written feedback, all comments are recorded and addressed. A final protocol is produced, taking into account public comments and any further workgroup feedback.

4.2.5 Board Approval

The Reserve's Board of Directors must vote to adopt each project protocol. Protocols are presented at quarterly board meetings, which are open to the public, and issues raised throughout the development process are reviewed, giving workgroup members and interested stakeholders a chance to raise any last concerns or questions. After the Board adopts the protocol, it becomes an official Reserve protocol and is immediately available for use.

4.2.6 Ongoing Public Feedback and Comments

After Board approval, the Reserve continues to solicit, document, and respond to public feedback and comments on the current version of the project protocol. Comments and feedback on adopted protocols can be submitted to the Reserve at policy@climateactionreserve.org. The public is also welcome to contact Reserve staff directly to discuss their comments and concerns.

Public feedback and comments are assessed on an ongoing basis and may initiate a revision to a project protocol.

4.3 Revisions to Project Protocols

After Board approval, the protocols are periodically revised in light of public comments, on-the-ground experience, and technological, scientific, and regulatory developments. In addition, the Reserve may review and update performance standards and standardized baselines to ensure they continue to effectively screen projects for additionality and accurately represent “business as usual” emissions. There are two types of revisions to project protocols: policy revisions and program revisions.

4.3.1 Policy Revisions

Policy revisions are those that affect project definition or eligibility, or that involve significant changes or adjustments to baseline estimation and/or the quantification of emission reductions or removals. A policy revision is generally focused on specific elements of the protocol and is not necessarily an opportunity to revisit all decisions made in the initial protocol development process.

Depending on the extent of the revision, the Reserve may convene an expert stakeholder group or reach out to stakeholders involved in the initial protocol development process. This group may be asked to comment on a revised draft protocol or be convened to discuss key issues prior to changes being circulated for comment. All policy revisions require a 30-day public comment period and adoption by the Reserve’s Board. Policy revisions are brought for adoption at the quarterly board meetings or are brought to the executive committee of the Board for adoption if expedited action is required. When adopted, a policy revision creates a new version of the project protocol (e.g., Version 1.0 undergoes a policy revision to become Version 2.0).

4.3.2 Program Revisions

Program revisions are editorial or technical in nature and do not require a public comment period, nor do they require adoption by the Reserve’s Board. These revisions do not significantly change the policies or eligibility in the project protocol, but can change or revise quantification methodologies or monitoring requirements. Program revisions create a new sub-version of the protocol (e.g., Version 1.0 undergoes a program revision to become Version 1.1). Program revisions are considered adopted on the date they are posted on the Reserve website. A protocol revision notification is sent to the Reserve’s listserv and to Reserve account holders at that time.

4.3.3 Grace Period for Registration under Prior Protocol Versions

Project developers have 90 days from the date on which a revised protocol is adopted to submit a project to the Reserve using the previous version of the protocol. The project must still complete verification within 12 months of the end of its initial reporting period. Otherwise, the project must be resubmitted for registration under the most current version of the protocol.

Projects that have been registered using a previous version of the protocol are not required to have their projects verified under any updated versions. Instead, projects may continue being verified against the original protocol version for the duration of their crediting period. Project developers always have the option, however, of voluntarily choosing to verify against the most current version. Applying the most current protocol to a project does not change the project’s crediting period.

4.3.4 Errata and Clarifications

If typographical errors are found in a protocol after it is released, the Reserve may issue an "Errata" document indicating required corrections. Errata are issued to correct typographical errors in text, equations or figures. Similarly, if the Reserve discovers that certain protocol requirements are ambiguous or in need of further guidance, the Reserve may issue a "Clarifications" document. Clarifications are issued to ensure consistent interpretation and application of the protocol.

Errata and Clarifications documents become effective immediately for the version(s) of the protocol to which they apply (applicable versions are identified in each document). Project developers and verification bodies must refer to and follow the corrections and guidance presented in Errata and Clarifications documents once they are issued. Errata and clarifications are considered effective on the date they are first posted on the Reserve website. All listed and registered projects must follow the guidance specified in the Errata and Clarifications document. On a case-by-case basis, in order to ensure that the protocol is consistently applied and that the purpose of the protocol is achieved, the Reserve has sole discretion to apply current errata retroactively to a project for which CRTs have been issued prior to the release of the errata that may affect quantification of its GHG reductions and/or CRTs issued.

All account holders and verification bodies will be notified if an Errata and Clarifications document is released or updated. Errata and Clarifications documents will be appended to all applicable versions of the protocol and will also be available as stand-alone documents on the relevant protocol's webpage. The errata and clarifications identified in these documents will be incorporated into subsequent versions of the relevant protocol.

4.4 Communication with the Public

Current versions of each project protocol and information about protocols in development are available at http://www.climateactionreserve.org/how/protocols/. Each project protocol also has its own dedicated webpage that can be accessed from here.

Interested members of the public can receive protocol development announcements and program updates by joining the Reserve's mailing list at http://www.climateactionreserve.org/news-and-events/newsletter/.

5 Glossary

Business day	Any day except Saturday, Sunday or a Federal Reserve Bank holiday. A business day shall open at 8:00 a.m. and close at 5:00 p.m. Pacific Prevailing Time.
Client	In the Reserve software system, a “client” is an organization or individual who wishes to retire CRTs but does not develop its own projects.
Climate Action Reserve	The national offsets program that establishes standards for quantifying and verifying GHG emission reduction projects, issues carbon credits generated from such projects, and tracks the transfer and retirement of credits in a publicly-accessible online system.
Climate Reserve Tonne or CRT	The unit of offset credits used by the Climate Action Reserve. One Climate Reserve Tonne is equal to one metric ton of CO_2e reduced or sequestered.
Completed	A project is considered “completed” when it is no longer reporting to the Reserve. A project is completed if it reaches the end of its crediting period(s), becomes ineligible, or if the project developer chooses not to continue reporting. The “completed” designation is also used for certain early action projects to indicate that the monitoring, reporting, and verification (MRV) requirements under the Reserve’s Early Action Offset Program have been satisfied, and that the project will continue MRV requirements under the Compliance Offset Program. The reason for the completed status is noted in the Reserve’s public reports. Once a project is completed, project information remains publicly available indefinitely.
Group Retirement Subaccount	The subaccount for the retirement of CRTs that are held by an account holder on an omnibus basis on behalf of one or more third parties that hold legal title and/or beneficial ownership rights in those CRTs.
Listed	A project is considered “listed” once the Reserve has satisfactorily reviewed all project submittal forms. The project will then appear in the public interface of the Reserve system.
Offset	A reduction or removal of GHG emissions from the atmosphere that is used to compensate for an equivalent amount of emissions from another GHG emitting activity occurring elsewhere. For the purposes of the Reserve program, a CRT becomes an offset when it is retired.
Project developer	An organization or individual that registers projects for the purpose of generating emission reductions or removals. In the Reserve software system, project developers may be issued CRTs for the verified emission reductions or removals that their projects achieve. They can also transfer and manage CRTs.
Project owner (limited)	An organization or individual representing a landowner participating in a cooperative or aggregate according to protocol-specific rules and procedures. In the Reserve software system, project owners may register projects that are formally part of a cooperative or an

	aggregation. This account type may also be used for limited transfers of CRTs under the terms and restrictions imposed by the relevant project protocol and/or aggregation guidance and does not include privileges for retiring CRTs.
Project protocol	A Reserve-developed document that contains the eligibility rules, GHG Assessment Boundary, quantification methodologies, monitoring and reporting parameters, etc. for a specific project type. Project protocols are akin to “methodologies” in other offset programs.
Reduction	A verified decrease in GHG emissions caused by a project, as measured against an appropriate forward-looking estimate of baseline emissions for the project.
Registered	A project is considered “registered” when the project has been verified by an approved third-party verification body, submitted by the project developer to the Reserve for approval, and accepted by the Reserve.
Removal	A verified increase in carbon stocks caused by a forest project, as measured against an appropriate forward-looking estimate of baseline carbon stocks for the project.
Reporting period	A discrete period of time over which a project developer quantifies and reports GHG reductions to the Reserve.
Retired	When CRTs are transferred to a retirement account in the Reserve system, they are considered retired. Retirement accounts are permanent and locked, so that a retired CRT cannot be transferred again. CRTs are retired when they have been used to offset an equivalent tonne of emissions or have been removed from further transactions on behalf of the environment.
Submitted	A project is considered “submitted” when all of the appropriate forms have been completed, uploaded, and submitted to the Reserve software.
Trader/Broker/Retailer	An organization or individual that transfers and manages CRTs in the Reserve system, but does not develop its own projects.
Transitioned	An early action project is considered “transitioned” when the project has been listed and successfully completed a verification under the Compliance Offset Program, but has any number of early action-eligible CRTs remaining active or retired in the Reserve program. The project is no longer reporting or seeking credits under the requirements of the relevant Reserve protocol, but is required to meet the MRV requirements of the California Cap-and-Trade Regulation.
User	An individual or entity that holds an account with the Reserve and has agreed to the Terms of Use and shall include such representative as the entity shall appoint and designate by completing the Designation of Authority form.
Verified	A project is considered “verified” when the project verification body has submitted the project’s Verification Statement and the Verification Report in the Reserve system.
Verification body	An organization or company that has been ISO-accredited and

	approved by the Reserve to perform GHG verification activities for specific project protocols.
Verification period	A discrete period of time over which a project's GHG reductions are verified. Under some protocols, a verification period may cover multiple reporting periods. The end date of a verification period must correspond to the end date of a reporting period.
Verifier	An individual that is employed by or subcontracted to an ISO-accredited and Reserve-approved verification body and is qualified to provide verification services for specific project protocols.

A.2.2 Verification Program Manual

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Verification Program Manual

February 8, 2017

NOTE TO USERS:

From time to time, the Climate Action Reserve may update this manual. Please make sure you are using the latest version, available at www.climateactionreserve.org.

For information, comments, or questions, please email reserve@climateactionreserve.org.

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Climate Action Reserve
Verification Program Manual

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1 Introduction

Verification plays a vital role in upholding the integrity and quality of the data reported to both mandatory and voluntary GHG programs across the world. The Climate Action Reserve (Reserve) created this Verification Program Manual to detail the requirements of its verification program and provide approved verification bodies with a standardized approach to the independent and rigorous verification of GHG emissions reductions and removals reported by project developers into its offset program. Project developers should also use this document to help prepare them for the reporting and verification process.

This standardized approach to verification promotes the relevance, completeness, consistency, accuracy, transparency and conservativeness of emissions reductions data reported in the Reserve. This is an accompanying document to the Program Manual, which presents the Reserve's policies, processes and procedures for registering projects and generating offset credits with the Reserve.

Detailed information on the Reserve's general operating procedures and offset program can be found in the following documents:

- Climate Action Reserve Program Manual
  http://www.climateactionreserve.org/how/program/program-manual/
- Climate Action Reserve User Guide
  http://www.climateactionreserve.org/open-an-account/
- Climate Action Reserve Terms of Use
  http://www.climateactionreserve.org/open-an-account/

Verification is an integral part of the Reserve's voluntary offset program. The key objectives of the verification program and guidelines found in this manual are to:

- Ensure projects are real, additional, permanent, verifiable and enforceable
- Minimize the risk of erroneously crediting or double counting of Climate Reserve Tonnes (CRTs)
- Ensure projects meet minimum eligibility requirements
- Support the transparency and integrity of the data contained within Reserve
- Maintain that verifications are conducted in a consistent and comparable manner across projects
- Ensure projects' on-going compliance with the Reserve's protocols and program rules

The Reserve requires third-party verification of all GHG projects as specified in each project protocol. CRTs are issued only after a Verification Report and a Verification Statement attesting to the accuracy of reported emission reductions have been submitted by the verification body and accepted by the Reserve. The Reserve relies upon these documents to attest to the legitimacy of the CRTs issued. The verification body is held accountable to the Reserve for the quality and independence of the report and statement submitted to the Reserve.

Guidance in this Verification Program Manual is limited to the Reserve's program serving the voluntary carbon market. For information on the Reserve's role as an Offset Project Registry for the California Compliance Offset Program, please see the following resources:

- Climate Action Reserve California Compliance Offset Program website
  http://www.climateactionreserve.org/how/california-compliance-projects/

- California Air Resources Board Compliance Offset Program website http://www.arb.ca.gov/cc/capandtrade/offsets/offsets.htm

1.1 The Climate Action Reserve

The Climate Action Reserve is a pioneer in carbon accounting and the most experienced, trusted and efficient offset registry to serve the carbon markets. With deep roots in California and a reach across North America, the Reserve encourages actions to reduce greenhouse gas emissions and works to ensure environmental benefit, integrity and transparency in market-based solutions to address global climate change. For the voluntary market, the Reserve establishes high quality standards for carbon offset projects, oversees independent third-party verification bodies and issues and tracks the transaction of carbon credits (CRTs) generated from such projects.

At the heart of the Reserve is a publicly accessible web-based system where owners and developers of carbon offset projects can register project information along with verification reports demonstrating GHG emission reductions. Emission reductions are certified as CRTs (equal to one metric ton of GHG reduced/sequestered), which provide title assurance and unique serial number identifiers to ensure that each metric ton is counted and retired only once.

1.2 Disclaimer

This manual has been prepared for informational and procedural purposes only. Its contents are not intended to constitute legal advice and any person who requires legal advice should obtain it elsewhere. The Reserve maintains the right to amend or depart from any procedure or practice referred to in this guideline as deemed necessary. Where a departure is necessary, the Reserve will provide public notification of significant changes on its website and will notify verification bodies in writing. This guidance is subject to revisions as new information and industry best practices are identified.

This document is intended to be used in combination with project verification guidance that accompany each Reserve project protocol and the International Organization for Standardization (ISO) 14064 series on GHG emission reductions and removals. In the instance that the applicable protocol differs from guidance given in this document, the Reserve project protocols prevail. ISO standards are intended to be program neutral, ensuring that key rules and decisions are made and enforced by the GHG program itself. If differing procedures are noted, contact the Reserve staff for further clarification and interpretation.

1.3 Organization of Verification Program Manual

This manual is divided into six parts that outline the necessary steps for verification bodies to perform verification activities under the Climate Action Reserve.

Part 1, Introduction provides a brief overview of the Reserve, its principles and requirements of the verification process.

Part 2, Standard of Verification focuses on the Reserve's standards; describes the levels of assurance and materiality threshold required under the Reserve; and highlights important definitions.

Part 3, Requirements to Perform Verification focuses on how a verification body becomes accredited to perform verification under ISO 14065, outlines obligations and requirements of verification bodies under the Reserve, provides specific and detailed training requirements, and details required administrative activities prior to beginning verification activities, which include: roles and responsibilities, conflict of interest, providing required notifications, and designing appropriate verification activities.

Part 4, Project Verification Activities provides guidance on conducting verification activities, such as: assessing eligibility criteria, identifying sources, reviewing management systems and methodologies, and verifying emission reductions and removals.

Part 5, Documenting and Reporting Verification Activities covers procedures for successfully completing the verification process including: preparing the Verification Report, List of Findings and the Verification Statement, and submitting documentation.

Part 6, Administration and Reserve Intervention provides information on the Reserve's verification oversight and auditing process, its dispute resolution process and its record keeping requirements.

1.4 Reserve GHG Accounting Principles

Verification provides an independent third party review of project data and information being submitted to the Reserve. This process ensures project eligibility per the relevant project protocol and that reported emission reductions or removals meet the materiality threshold.

To fulfill this purpose, the independent verification process maintains the minimum criteria of relevance, completeness, consistency, accuracy, transparency and conservativeness. These underlying principles are laid out in ISO 14064-2:2006 and are interpreted below as Reserve accounting principles.

Relevance. Project eligibility and compliance status shall be measured in accordance with applicable reporting boundaries and performance standards.

Completeness. Verification shall identify and account for all emissions, reductions or removals within the GHG assessment boundary that may have occurred in the baseline and project scenarios.

Consistency. Methodologies shall be consistent and uniform. Measurements, source data, data sampling, and tests shall be applied equally so that performance can be compared over time and across similar projects.

Accuracy. Projects shall meet a minimum materiality threshold to ensure accuracy. See Section 2.3 from more information.

Transparency. Verification shall be conducted in a transparent manner. The data used for verification and the verification activities shall be clearly and thoroughly documented to allow replication and outside review by the Reserve or other oversight bodies.

Conservativeness. GHG reductions or removals should not be overstated. Calculations, values and procedures should always be applied in a conservative manner, particularly when there are limitations to certainty.

Implementing these standards in the verification process will help to ensure comparable and consistent reporting to the Reserve. These standards will also help verifiers make the reliable, dependable decisions discussed further in the core verification process (see Section 4.6).

1.5 Overview of Verification Process

The following steps must be taken to ensure that the obligations and responsibilities of both the verification body and the project developer are met.

1. **Verification body receives accreditation:** Verification body meets all accreditation requirements and two Lead Verifiers successfully complete required project verification training (see Section 3.4.2).
2. **Project developer selects approved verification body:** Project developer contacts one or more approved verification bodies listed on the Reserve to discuss verification activities. Project developer selects an organization to verify its GHG emissions reductions or removals and begins to negotiate contract terms. (The contract may not be finalized until a determination has been issued by the Reserve.)
3. **Verification body submits project-specific Notification of Verification Activities and Conflict of Interest (NOVA/COI) Form:** After a project developer chooses a verification body, the verification body must submit a NOVA/COI Form to the Reserve outlining the proposed scope of the planned verification. This document provides insight into the likelihood of a conflict of interest between parties (see Section 3.6).
4. **Reserve sends approval to proceed to verification body:** The Reserve reviews the NOVA/COI Form and supporting information to determine the level of risk associated with the proposed project developer/verifier relationship, then notifies the Lead Verifier of its determination.
5. **Verification body conducts verification activities:** Verification body develops a risk-based verification plan and conducts verification following the guidance in the Verification Program Manual and the applicable project verification guidance. The verification must evaluate a project's ongoing eligibility and the GHG emissions reductions or removals reported to the Reserve (see Section 4.6).
6. **Verification body shares List of Findings with the project developer:** A confidential list of material and immaterial findings is sent to the project developer. This gives the project developer the opportunity to correct any errors found (see Section 5.1).
7. **Verification body prepares the verification documentation for project developer:** Verification body prepares the final List of Findings Verification Report, and the Verification Statement for project developer's review prior to uploading electronically to the Reserve software (see Section 5).
8. **Project developer uploads documents to the Reserve:** Project developer then submits all final documentation to the Reserve - the List of Findings, the Verification Report and Verification Statement (see Section 5.6).

2 Standard of Verification

The Reserve requires that verification bodies use the following standards when conducting verification:

- The applicable Reserve project protocol and any relevant errata and clarifications
- The Reserve Program Manual and any relevant policy memos
- This Verification Program Manual
- ISO 14064-3:2006

Verification must adhere to each of these standards, but in instances where standards conflict, the Reserve protocols shall take precedence, followed by the Reserve Program Manual, the Verification Program Manual, and then ISO 14064-3:2006.

ISO 14064-1:2006 and ISO 14064-2:2006 cover both conformance with the standard and the criteria for establishing that the GHG assertion is reliable and correctly stated based on the agreed level of assurance, materiality, criteria, objectives and scope. The applicable verification standards must be stated in each Verification Report.

2.1 Principles of Verification

An essential element of project verification is to ensure that all verification bodies and verifiers conducting work under the Reserve uphold the basic verification principles laid out in ISO 14064-3:2006. Namely, verification bodies and verifiers shall demonstrate independence from the activity being verified (interpreted in Section 3.6 under Conflict of Interest). Verification bodies must also demonstrate ethical conduct and fair presentation of findings, conclusions and reports throughout the verification process. All projects undergoing verification must be treated equally, with all appropriate procedures followed. Finally, verification bodies must conduct verifications with due professional care, demonstrating the skill, diligence and competence necessary to perform the verification (see Section 3).

2.2 Level of Assurance

The concept of level of assurance is derived from financial auditing and corresponds to the likelihood that a material misstatement has gone undetected. With reasonable or “positive” assurance, the verification body provides a direct factual statement expressing the outcome of the verification. Providing a reasonable level of assurance confirms the accuracy of the GHG assertion. Absolute assurance is the highest form of assurance, but does not allow for professional judgment, sampling and inherent limitations. For reasonable assurance, the verification body must confirm the accuracy of reported data to a reasonable level. The Reserve requires reasonable assurance to uphold the integrity and high quality of verifications conducted under its program.

Under the ISO 14064 standards, the level of assurance determines the depth of detail and rigor that a verifier designs into the verification plan used to identify any material errors, omissions or misstatements. The level of assurance refers to the degree of confidence a verification body is able to provide regarding the accuracy of the asserted GHG removals or reductions. The Reserve requires that reasonable, but not absolute, assurance be obtained by the verification body prior to the execution of a positive Verification Statement, which ensures that the verification body is able to “verify without qualification” and attest to the accuracy of the number of CRTs being issued to the project developer.

2.3 Materiality Threshold

The concept of materiality is fundamental in executing GHG verification. Information is considered material if its omission or misstatement could be seen to influence any resulting decisions or actions. In order to reach a conclusion on the veracity of data used to support assertions, a verification body must form a view on the materiality of all identified errors or uncertainties.

Issues identified during verification must be classified by verification bodies as either material (significant) or immaterial (insignificant). To be verified successfully, all reported emissions reductions or removals submitted to the Reserve must be free of material misstatements or discrepancies.

A materiality threshold is used to assess any error, omission or misstatement that may impact the GHG assertion made by a project developer. This threshold is also known as the “minimum quality standard” and differentiates those errors, omissions or misstatements that are considered by the Reserve to be significant from those that are insignificant.

Materiality has both a quantitative and a qualitative aspect in relation to a project reporting to the Reserve.

2.3.1 Quantitative Materiality Threshold

The quantitative materiality threshold sets a numeric cap on the magnitude of cumulative error in stated reductions permissible under the Reserve as a percent of the verifier’s recalculated emission reductions. Error leading to misstatement may be introduced through incorrect application of protocol calculations, transcription errors, or the use of incorrect default values. Immaterial misstatements identified during verification may go uncorrected and the project may receive a positive Verification Statement from the verification body. All material errors must be corrected prior to a project receiving a positive Verification Statement.

A verification body must recalculate the total quantity of GHG emission reductions reported to the Reserve for any given reporting period in order to determine if the project meets the Reserve’s designated materiality threshold.[1]

In determining whether a material misstatement has occurred, the verification body must compare the aggregate total of misstatements against the materiality threshold for the total GHG emission reductions reported to the Reserve. Finding several small reporting errors, each of which might be immaterial on their own, may lead to a material misstatement when totaled against the final number of reported emission reductions. The materiality threshold shall be used to inform the design of a verification body’s sampling plan.

If errors are discovered, the verification body must determine if these errors result in a material misstatement using its risk-based review of materiality and a rigorous data sampling process.

In an effort to maintain a balance of diligence, accuracy and conservativeness, the Reserve defines the quantitative materiality threshold for all projects as follows:

[1] In GHG inventory reporting, the notion of *de minimis* threshold is in relation to a section of a reporter’s inventory that is allowed to be excluded from their reported total. The *de minimis* threshold does not apply to Reserve projects unless explicitly stated in the project protocol.

- Projects registering ≤25,000 CRTs over a 12-month period shall achieve a >95% level of accuracy (<5% error) relative to the verification body's calculated emission reductions
- Projects registering >25,000 CRTs but ≤100,000 CRTs over a 12-month period shall achieve a >97% level of accuracy (<3% error) relative to the verification body's calculated emission reductions
- Projects registering >100,000 CRTs over a 12-month period shall achieve a >99% level of accuracy (<1% error) relative to the verification body's calculated emission reductions

This materiality threshold is set on a 12-month basis to ensure that projects verifying sub-annually do not receive any advantage over those verifying annually. For sub-annual reporting, the quantity of CRTs must be pro-rated based on the verification period length in order to determine the appropriate materiality threshold. For example, if a project registers 20,000 CRTs for a 3-month verification period, then the materiality threshold is <3% error: (20,000 CRTs / 3 months) x 12 months = 80,000 CRTs; >97% accuracy required).

To determine the materiality threshold for projects with verification periods longer than 12 months, the quantity of reported CRTs must be pro-rated in the same fashion. For example, if a project reports 30,000 CRTs for an 18-month verification period, then the materiality threshold is <5% error relative to the verification body's calculated emission reductions: (30,000 CRTs / 18 months) x 12 months = 20,000 CRTs; >95% accuracy required.

The percent error is defined by the following:

$$\%Error = abs\left(\frac{Stated\ reductions - Verified\ reductions}{Verified\ reductions}\right) \times 100$$

The accuracy level is defined by the following:

$$Accuracy = 100\% - \%\ Error$$

The Reserve allows for under-reporting of total CRTs as that is considered conservative and in line with the Reserve's key principles. Under-reporting errors are not required to be corrected. The quantitative materiality threshold only applies to mistakes that result in over-reporting.

Example 1: A verification body, Verification Pro, recalculates a project's total emission reductions over a 12-month period and notes a quantitative error made by the project developer, LFG Unlimited.

- LFG Unlimited's reported emission reductions = 9,900 metric tons CO_2e
- Verification Pro's recalculated emission reductions = 10,000 metric tons CO_2e
- Percent Error = 1.00%

Given the above information, LFG Unlimited is not required to fix the error. The project is under-reporting its emission reductions and it meets the quantitative materiality threshold of >95% accuracy.

Example 2: Verification Pro recalculates a project's the total emission reductions over a 12-month period and notes two quantitative errors made by the project developer, Worldwide Dairy.

- Worldwide Dairy's reported emission reductions = 55,000 metric tons CO_2e
- Verification Pro's identified errors = -1,000 metric tons CO_2e due to monitoring, +2,000 metric tons CO_2e due to data processing
- Percent Error = 1.79%

Correction is not required as the errors result in a total discrepancy of 1,000 metric tons CO_2e. The project meets the quantitative materiality threshold of >97% accuracy.

Example 3: Verification Pro recalculates a project's total emission reductions over a 3-month period and identifies a quantitative error made by the project developer, ODS Destroyers.

- ODS Destroyers' reported emission reductions = 1,000,000 metric tons CO_2e
- Verification Pro's recalculated emission reductions = 980,000 metric tons CO_2e
- Percent Error = 2.04%

This error requires correction, as it does not meet the >99% materiality threshold and is therefore considered material.

2.3.2 Qualitative Materiality Threshold

A qualitative non-conformance occurs when a prescriptive protocol requirement (e.g., metering, monitoring, management systems, record-keeping, etc.) is not met. Every qualitative non-conformance identified by the verification body is considered material and must be corrected by the project developer before a positive Verification Statement can be issued. A prescriptive requirement is defined as any specific guidance mandated by the protocol that does not allow for deviation, variance or verifier professional judgment.

Take for instance a project developer who neglects to quantify a small source of project emissions. Leaving out that source does not result in a quantitative material misstatement, but the protocol states that all emission sources related to project activities must be accounted for in the emissions calculations. The omission of this source would be considered a qualitative non-conformance because of the protocol requirements and the emission reductions would therefore need to be recalculated.

Another example is the application of an incorrect emission factor – again, this would be considered material even if the difference in emission reductions does not exceed the quantitative materiality threshold. If a Reserve protocol prescribes that a specific emission factor be used and that emission factor is not correctly applied by the project developer, the result is a qualitative misstatement because the non-conformance directly defies a protocol requirement.

Any identified qualitative non-conformances must be documented by the verification body and presented to the project developer in the List of Findings prior to issuance of the Verification Statement and Report (see Section 5.1). All qualitative non-conformances must be corrected in order for the verification body to be able to issue a positive Verification Statement.

3 Requirements to Perform Verification Activities

3.1 Verification Body and Lead Verifier Requirements Overview

In order to conduct verification for the Reserve program, there are requirements for both verification bodies and individual verifiers that must be met. Table 3.1 summarizes the necessary criteria for both entities acting as verification bodies and individuals acting as lead verifiers. Additional information on these requirements can be found below.

Table 3.1: Verification Body and Lead Verifier Requirements

VERIFICATION BODY REQUIREMENTS
Accreditation under International Organization for Standardization (ISO) 14065: 2013 with conformance to all accreditation requirements under ISO 14065, ISO 14064-3: 2006, IAF MD 6: 2014 and all other accreditation requirements, or Acceptance in the American National Standards Institute (ANSI) accreditation program, having filed a full application for ISO 14065: 2013
Demonstration of a thorough understanding and competency with the Climate Action Reserve program manuals and project protocols
Employment of a minimum of two staff members (or contracted personnel) designated as Lead Verifiers who have successfully completed the training required by the Reserve
LEAD VERIFIER REQUIREMENTS
Employment or a contract with a verification body that is accredited under ISO 14065: 2013, ISO 14064-3: 2006, and IAF MD 6: 2014
Successful completion of Climate Action Reserve training(s) pertaining to each project type for which they wish to perform verifications
Successful completion of the General Project Verification training course
Fulfilment of internal training requirements, following proper processes and procedures under the ISO 14065: 2013, ISO 14064-3: 2006, and IAF MD 6: 2014 accredited verification body
Identification as a Lead Verifier in the Verification Staff Reporting Form submitted by the verification body to the Reserve

Trainings are scheduled as demand or need arises based on feedback from bi-annual surveys by the Reserve. When a new protocol is developed, an inaugural verification training will be provided after the adoption date in order to accommodate verification bodies seeking to practice in that sector.

A verifier can complete Reserve trainings prior to its verification body achieving ISO accreditation or during the accreditation process itself. However, priority for available spaces at the trainings will be given to individuals representing accredited companies, followed by individuals representing companies already enrolled in the accreditation process.

Once a verification body has achieved its ISO 14065 accreditation in accordance with the appropriate scoping policy and has personnel that have completed the training requirements, it may advertise that it is recognized and qualified as a verification body for the Climate Action Reserve and may use the Reserve logo to promote its services in accordance with the Reserve's style guide. All recognized verification bodies are listed on the Reserve's website along with all applicant entities currently undergoing the accreditation process.

Two of the steps in the ISO 14065 accreditation process are an on-site assessment at the verification body's main offices and a witness assessment performed by the accreditation body. The accreditation body must witness the verification activities in order to assess the competency of the verification team as well as the procedures and systems in place at the organizational level. The on-site assessment is designed to ensure that the verification body conforms to ISO 14065 and ISO 14064-3, displays the competency to act in the specific sector, and has the capacity to perform the activities related to the scopes of accreditation for which it has applied.

Over the course of the witness assessment, the accreditation body will observe the verification body performing the tasks related to the verification process for the scope (or group of sectoral scopes) of accreditation for which it has applied. The purpose of the witness assessment is to assess whether verification activities are in line with its documented quality procedures and to assess the capability to conform to the applicable sectoral scope(s).

Verification body applicants that are currently undergoing but have not yet completed the accreditation process are allowed to perform verification activities for Reserve projects if they have met the Reserve training and personnel requirements. A list of the applicant verification bodies that have successfully met the Reserve's training requirements and submitted the Verification Policies Acknowledgement and Agreement form are posted on the Reserve's website. However, CRTs generated by a project verified by a verification body applicant will not be issued to the project developer until the verification body receives its formal accreditation. The verification body should inform the project developer of the circumstances surrounding its expected accreditation, and the issue should be addressed in the verification contract.

Verification bodies that have met Reserve training requirements may conduct one additional verification in each appropriate sector for the purpose of accreditation renewal. There is no deadline for this requirement and CRTs will not be withheld for that verification. The additional verification shall be used for the purpose of obtaining the required witness assessment and finalizing a sector-specific group accreditation. If a verification body fails to obtain its sector-specific accreditation using this additional verification, no future CRTs can be verified in that sector until the verification body has obtained its sector-specific accreditation.

3.2 Obligations and Requirements to the Reserve

Verification bodies and verifiers must follow all applicable Reserve program rules and adhere to the guidance laid out in the Reserve project protocols and program manuals when performing verification activities. In addition, a verification body and its verifiers must always demonstrate ethical conduct and competence, exercise due professional care, and adhere to the remaining verification principles throughout the verification process.

In addition to Reserve rules, the verification bodies under the Reserve have certain duties and obligations. The Reserve also has the discretion to exercise certain powers.

Verification body obligations include (but are not limited to) the following:

- Compliance with any guidelines or policies notified to them by the Reserve in writing.
- A minimum of two Lead Verifiers on staff to enable the appropriate management of the verification program and the separation of powers and responsibilities between the role of Lead Verifier and the role of independent Senior Internal Reviewer. These roles may be filled by either employees or contracted personnel (see Section 3.8).
- Ensuring that all Lead Verifiers are competent and have successfully completed internal, general and protocol-specific training required by the Reserve.
- Ensuring that a Lead Verifier directs, supervises and leads the undertaking of the verification services, including signing all written reports and statements.
- Ensuring that the Senior Internal Reviewer is an active Lead Verifier as defined by the Reserve, has been trained on the relevant protocol and is able to demonstrate continued competence.
- Ensuring that all verification body personnel working on project verification activities have agreed to be bound by confidentiality obligations and understand that the verification body accepts liability for any breach of confidentiality by its employees, agents or contracted personnel.
- Submitting a signed and duly executed Verification Policies Acknowledgment and Agreement to the Reserve on an annual basis. As staff and roles fluctuate over time, the verification body must ensure that up-to-date information is provided to the Reserve.
- Submitting a Notification of Verification Activities and Conflict of Interest (NOVA/COI) Form a minimum of **10 business days** before the commencement of work so that the Reserve has an opportunity to review and address any potential conflicts and observe any part of the verification activities it chooses.
- Not entering into any agreement or participating in any activity that could create a conflict of interest with a verification client without first notifying the Reserve in writing in order to allow the Reserve to evaluate and mitigate any potential risks.
- Maintaining professional liability insurance with a reputable insurer to the level of at least $4 million for each claim and $4 million annual aggregate. This professional liability insurance must be held separately from general or umbrella liability policies. The policy must provide coverage of damages and defense costs for any actual or alleged error, omission, neglect, misstatement or misleading statement, or breach of duty relating to verification activities undertaken by the verification body and have the Reserve named as an additional insured. The coverage territory for the insurance must include all geographic regions where the verification body operates and does business under the Reserve's program. This insurance must be maintained for three years following the completion of verification services. Proof of insurance shall be provided to the Reserve within one month of the verification body's usual insurance renewal date.
- Retaining records in line with protocol requirements or for **at least seven years** from the date the Verification Report is accepted following the end of the verification period, whichever is longer. Records to be retained shall include all relevant evidence to support said Report.
- Providing full and free access to the Reserve to obtain all records, documents, accounting and other information maintained by the verification body that relate to Reserve projects.

The Reserve has certain powers that at any time and at its sole discretion it may employ, including (but not limited to):

- Directing the verification body and the project developer to refrain from entering into any agreement that may amount to a conflict of interest in relation to Reserve projects. The verification body must comply with any such direction.
- Determining that a verification of a Reserve project should not proceed or that a person should be removed and/or suspended as a Lead Verifier or key personnel.
- Conducting audit or oversight activities and sending its staff, partners or consultants to attend and oversee verification activities.
- Determining that a verification body should be suspended and/or requiring said verification body to purchase and retire CRTs.
- Compelling the project developer or the verification body to submit all project documents in relation to the GHG assertions made to the Reserve.
- Amending these rules as it deems necessary.

3.3 ISO 14065 Accreditation

The International Organization for Standardization is a recognized institution that developed GHG standards as various schemes emerging in international, national and voluntary sectors began using different sets of guidance or rules for GHG accounting. ISO created a series of standards intended to incorporate best practices and provide consistency and confidence in GHG assertions or claims.

ISO 14065 is the international standard that specifies processes and requirements for accrediting verification bodies to perform GHG validation and verification services. The accreditation process provides criteria for assessing and recognizing the competence of verification bodies, thereby allowing for a consistent and comparable scheme across GHG programs. Accreditation reduces the risk to GHG programs like the Reserve by providing assurance that verification bodies are competent, and it helps establish trust within the voluntary carbon market by ensuring impartiality in the verification process.

The objectives of the ISO 14064 series and ISO 14065 standards are to:

- Develop flexible, regime-neutral tools for use in voluntary or regulatory GHG schemes
- Promote and harmonize best practice
- Support the environmental integrity of GHG assertions
- Assist organizations to manage GHG-related opportunities and risks
- Support the development of GHG programs and markets[2]

The Reserve has partnered with the American National Standards Institute (ANSI) to accredit independent third party verification bodies to ISO 14065:2013 and the International Accreditation Forum, Inc. (IAF) guidance as well as their accompanying protocols. Verification bodies accredited by ANSI or those undergoing the ANSI accreditation process may provide verification services to Reserve project developers. The Reserve is also working with Entidad Mexicana de Acreditación, A.C. (EMA) in Mexico to accredit verification bodies to support the Mexico Forest Project Protocol. The Reserve may partner with other IAF national standards organizations to provide accreditation services in the future.

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[2] ISO Press Release on 14065:2007 (4/17/2007) Ref 1054: New Tool for International Efforts to Address Greenhouse Gas.

The accreditation process is very rigorous, and verification bodies should undertake it only after understanding and implementing all procedures required under the ISO standards. Verification bodies approved under IAF national standards organizations are granted accreditations that are recognized worldwide.

The following resources provide further information on the principles and standards governing GHG verification and accreditation.[3] Verification bodies should cross reference these documents with the rules detailed in each project protocol and accompanying verification guidance in order to ensure the GHG project meets all applicable rules for a specific project type.

Table 3.2: ISO Documents and References

REFERENCE	APPLICABLE TO
ISO 14064-3:2006 – Greenhouse Gases – Part 3: Specification with guidance for the validation and verification of greenhouse gas assertions	Verification body
ISO 14065:2013 – Greenhouse Gases – Requirements for greenhouse gas validation and Verification Bodies for use in accreditation or other forms of recognition	Verification body
ISO 17011:2004 – Conformity Assessment – General requirements for Accreditation Bodies accrediting conformity assessment bodies	Accreditation body
IAF MD 6: 2014 – IAF Mandatory Document on the Application of ISO14065:2013	Accreditation body
ISO 14064-2:2006 - Greenhouse Gases – Specification with guidance at the project level for quantification, monitoring and reporting of greenhouse gas emissions reductions or removals	Project developer, verification body

3.3.1 Obtaining Accreditation

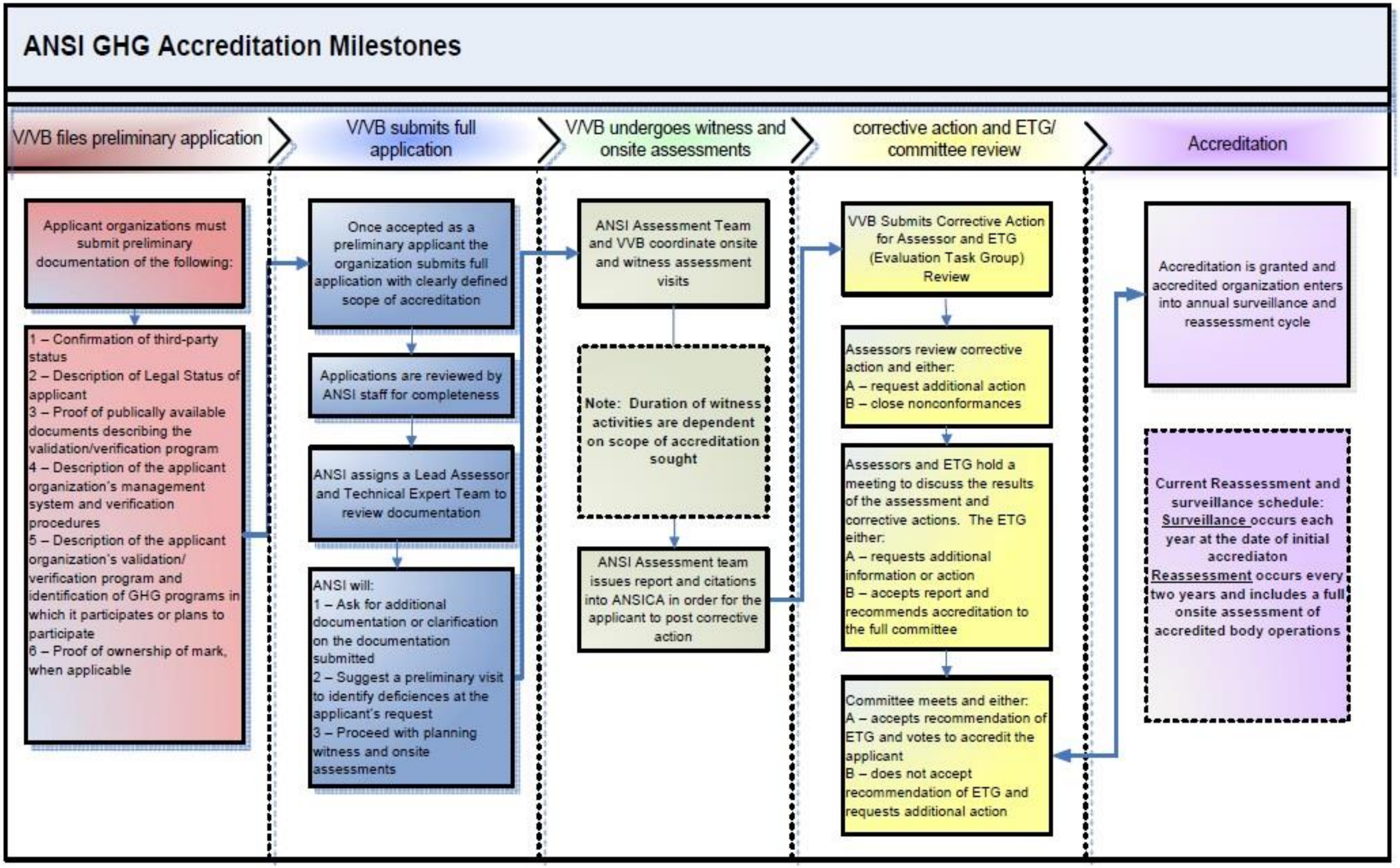
The full accreditation process under ISO 14065 entails:

- Submitting the preliminary application to an approved accreditation body (e.g., ANSI or EMA)
- Submitting the full application
- Preparing for assessment
- Undergoing initial onsite and witness assessments
- Addressing corrective actions identified
- Undergoing committee review
- Receiving accreditation
- Participating in annual surveillance
- Participating in the three-year cycle of reassessment (onsite and witness assessment)

The following diagram of GHG accreditation milestones courtesy of ANSI shows what the accreditation process might look like:

[3] Available at www.iso.org.

Figure 3.1: ANSI GHG Accreditation Milestones



3.3.2 Costs of Accreditation

The cost of accreditation is determined by the accreditation body and generally includes an initial non-refundable application fee, an assessment fee for the surveillance performed by the assessors, and an annual accreditation fee. There is also an additional fee to extend the scope of accreditation, which is collected when verification bodies seek eligibility to perform verifications for new sectors.

More information on the ANSI accreditation program is available here: https://www.ansi.org/Accreditation/environmental/greenhouse-gas-validation-verification/Default

More information on EMA accreditation is available here: ema.org.mx/portal/index.php/Acreditacion/conozca-el-proceso-de-acreditacion.html

3.3.3 ISO Conformance

The Reserve project protocols are generally consistent with international standards and best practice within the GHG offset industry.

Due to ISO copyrights, the text of the relevant sections of ISO standards cannot be reproduced in this document. Therefore, the Reserve has summarized its interpretation of key elements that verification bodies must address to comply with ISO standards and adhere to Reserve protocols, processes and procedures throughout this manual. This manual should not be used as a substitute for any of the ISO standards during accreditation or when planning for project verification activities.

There are some minor differences between the Reserve and ISO 14064 series that are program specific. In areas where other GHG program protocols or ISO standards differ from guidance provided in the Reserve project protocols or program manuals, the Reserve project protocols take precedence, followed by the program manuals.

The language in Reserve protocols is ISO conformant when possible. Where the Reserve protocols presently use non-ISO terminology, the Reserve will attempt to identify and detail its meaning in relation to both Reserve and ISO standards. The Reserve expects that verification bodies will comply with both ISO standards and Reserve requirements when undertaking verifications.

3.3.4 Validation

Under ISO 14065:2013 and IAF Mandatory Document guidance, validation is the process by which an independent validation body assesses a project plan for GHG reductions or removals and deals with the assessment of potential future outcomes. Validation is typically conducted on projects that do not follow standardized protocols. The validation process occurs prior to project implementation in order to establish the project developer’s methodology, scope and eligibility to create GHG reductions or removals.

The Reserve does not require that validation be conducted as a separate step in project development. Instead, when a project is first verified, the verifier must affirm the project’s eligibility according to the rules defined in the relevant project protocol. Under the Reserve, the project’s eligibility criteria are developed through a transparent, stakeholder-driven process that lays out the design and scope for each project type prior to project implementation through the application of performance-based standards and other standardized criteria. The project protocols provide eligibility rules, methods to calculate reductions, performance-monitoring instructions, and procedures for reporting project information to the Reserve. Further, the project developer completes a standard project submittal form and is reviewed by Reserve staff for compliance with the eligibility criteria prior to the project being publicly listed on the Reserve.

By reviewing project submittal forms, Reserve staff conduct an initial screening to check whether, on the basis of the information provided, the project meets the eligibility rules established in the project protocol. However, the Reserve performs no substantiation of claims made in the submittal forms; that task is left to the verifier. Because the Reserve's eligibility criteria are mostly standardized, determination of eligibility is usually straightforward and requires minimal interpretative judgment by verifiers. Verifiers must ensure that the project developer has provided sufficient evidence to prove that the project meets the eligibility criteria.

Project developers may choose to have a project verified during its initial reporting period without verifying total emission reductions in order to establish the project's eligibility for registration and provide more certainty to potential CRT buyers or sellers. This de-facto validation process is permitted. In addition, the Reserve does not consider validation services conducted under other GHG registries or programs to be a conflict of interest, as validations and verifications are both independent third-party assessments.

3.4 Training Requirements and Qualifications for Lead Verifiers

The Reserve recognizes the verification body as the responsible party under its program, rather than an individual verifier. Verification bodies are obligated to ensure that individual verifiers are qualified with the proper training and skills to conduct verification activities. For individual verifiers to be recognized as Lead Verifiers by the Reserve, they must have completed the training requirements as detailed below.

A Lead Verifier is any verifier from the accredited verification body who directs, supervises and leads verification services and has the authorization from the verification body to sign written reports or statements. A Lead Verifier is someone who has completed the verification body's internal training processes and procedures to achieve this designation, and passed the Reserve training course(s) on the appropriate project protocol(s) as well as the general project verification training.

Each verification body must employ a minimum of two Lead Verifiers for every approved sector accreditation. This policy ensures that the verification team for every project includes at least two Lead Verifiers, one to serve as the Lead Verifier and one to serve as the Senior Internal Reviewer. These Lead Verifiers may be employees of the verification body or contracted personnel.

A Senior Internal Reviewer is any Lead Verifier from the accredited verification body selected to perform a final quality assurance and quality control (QA/QC) review on the project data and verification documentation. The Senior Internal Reviewer must also sign the Verification Statement attesting to the accuracy of reported data. The Senior Internal Reviewer shall remain independent of all verification activities and shall not participate in site visits, as this could compromise his or her objectivity and independence in the final review. The Senior Internal Reviewer must be designated as such on the NOVA/COI Form and also be designated as a Lead Verifier on the annually submitted Verification Staff Reporting form, which is an exhibit to the Verification Policies Acknowledgement and Agreement form.

3.4.1 Internal Training

Qualification as a Lead Verifier begins with the verification body's internal training procedures and programs that instruct staff on how to conduct verifications and lead verification activities. Verification bodies must have a formal process in place for the initial qualification, training, and ongoing monitoring of all personnel verifying a Reserve project. The verification body is responsible for ensuring the verification team has the proper skills, competency and collective capability to conduct verification activities under the Reserve.

In order to be eligible to take the Reserve's Lead Verifier trainings, a verifier must have a basic understanding of GHG accounting and have completed either internal training or taken a recommended external course on GHG accounting and basic verification methods.

3.4.2 Reserve Training

In addition to internal training, Lead Verifiers must successfully complete a Reserve-administered General Project Verification Training course and one or more project protocol verification trainings. This requirement ensures that the individuals leading verification activities under the program have a high level of sector-specific knowledge and training.

At the completion of a Reserve training, verifiers must take a Reserve-administered exam that consists of multiple choice and short essay questions. To prepare for the test, the verifier should study the protocols and the ISO 14064 series, complete the homework assignment, and undertake the practical exercises provided within the training. After passing the general project verification exam and a protocol-specific exam (and meeting the criteria above), the individual becomes a Reserve-recognized Lead Verifier. Following the training, the Reserve provides the recognized verifiers with a notification and a certificate that allows them to act as Lead Verifiers under the Reserve.

Verifiers who do not pass the exam, choose not to take the exam, or are unable to complete the exam on the date it is given receive a certificate of training attendance but will not have met the Reserve's Lead Verifier training requirements. These verifiers have one year from the original date of the course to re-take the exam. There is an administrative fee to retake the exam. If more than one year has passed or a verifier does not pass the exam on the second attempt, the verifier must retake both the training and the exam. The Reserve encourages verifiers who fail the exam to assist on additional verifications in order to gain practical experience before retaking the exam. Please note that for confidentiality purposes, the Reserve does not distribute copies of the verification exam.

An individual's recognition as a Lead Verifier under a specific protocol is generally valid for three years after the date that the training certificate is issued, at which point the Lead Verifier must retake and pass the appropriate exam to demonstrate that he or she has sufficiently maintained knowledge of the protocol and is well-versed in any relevant protocol or programmatic updates made in the interim.

The certification(s) of Lead Verifiers can be extended beyond the three-year period indefinitely if the following requirements are met:

- The Lead Verifier has successfully passed the relevant exam at least twice
- For the general verification certification, the Lead Verifier serves as a Lead Verifier or Senior Internal Reviewer on at least two verifications per calendar year

- For protocol-specific certifications, the Lead Verifier serves as a Lead Verifier or Senior Internal Reviewer on at least two verifications under the relevant protocol per calendar year
- The relevant protocol has not undergone a policy revision since the Lead Verifier last passed the exam

A Lead Verifier is not required to re-take a training course in its entirety unless significant changes to the Reserve program or relevant protocol dictate that a full training is necessary. Verification Statements signed by Lead Verifiers or Senior Internal Reviewers with expired certifications will not be accepted by the Reserve. If a Lead Verifier's general or protocol-specific certification expires during verification services, he or she must pass the exam before the project can be registered.

The Reserve offers public certification exam dates throughout the year. Lead Verifiers seeking to renew their certification(s) are free to take any exams on these dates. Lead Verifiers may also schedule private certification exams through the Reserve Events webpage, but a 10 business day notification period is required. Note that the Lead Verifier certification is tied to the individual and will therefore be recognized regardless of which verification body provides employment.

Unlike the Lead Verifier and the Senior Internal Reviewer, other team members (verifiers, technical experts, administrative staff, etc.) are not required to complete Reserve training or exams.

3.4.3 ARB Training

For the purpose of verifying voluntary Reserve projects, the Reserve will accept the California Air Resources Board (ARB) verification trainings for the Coal Mine Methane, Forest, Livestock, Ozone Depleting Substances, and Urban Forest compliance protocols in lieu of the Reserve's project protocol verification trainings. However, the successful completion of the Reserve's General Project Verification Training is required for all Lead Verifiers, regardless of project type.

It is the responsibility of the Lead Verifier to demonstrate to the Reserve the successful completion of the ARB compliance offset protocol training.

3.5 Verification Policies Acknowledgment and Agreement Form

Verification bodies must have a duly authorized representative of its organization sign and submit the legally binding Verification Policies Acknowledgment and Agreement form to the Reserve on an annual basis. This required agreement between the Reserve and verification bodies ensures that personnel performing verification activities are aware of their roles, responsibilities and obligations under the program. It asserts that the verification body will follow proper processes and procedures as laid out in the project protocols, the Program Manual and Verification Program Manual. The agreement outlines requirements in relation to confidentiality provisions, insurance requirements, record-keeping requirements, liability, and conflict of interest. It also includes an authorization of potential oversight of verification activities.

The verification body must acknowledge that its duty of care is first and foremost to the Reserve. When a verification body is acting under the auspices of the Reserve's program, it is bound by this agreement to abide and adhere to the rules and procedures of the program itself. If, during the course of verification activities, a verification body suspects the occurrence of fraud, double-counting, or any other significant issue that could impact the quantity or quality of CRTs to be issued, the verification body agrees to immediately report the issue to the Reserve.

The agreement states that personnel conducting verification activities shall be trained and knowledgeable on Reserve procedures. It also asserts that the verification body will remain neutral and impartial. The verification body must acknowledge that potentially market-sensitive information may be encountered while conducting project verification activities and agree to strict confidentiality in its findings prior to the release of the Verification Report.

Further, the agreement asserts that the verification body will not engage in any business activities that would amount to a conflict of interest in relation to its Reserve clients. Specifically, the purchasing, selling, trading or retiring of any offset credits between a verification body and a project developer client in question is considered a high risk for conflict of interest and is strictly prohibited. Conflicting services of this type are addressed further in Section 3.6.3.

The agreement also requires that, in the instance where the Reserve determines an error made by the verification body resulted in the issuance of CRTs not in compliance with Reserve protocols or Reserve policy, the verification body deemed responsible will replace or replenish an equal value of CRTs up to the $4 million required amount of annual professional liability insurance. The same is true if gross negligence, willful misconduct or fraudulent activity on the part of the verification body has occurred.

Failure to submit the Verification Policies Acknowledgment and Agreement form could result in suspension from the Reserve program.

3.5.1 Verification Staff Reporting Form

Verification bodies must identify to the Reserve all staff members who are designated as verifiers and serve as key personnel in Exhibit A of the Verification Policies Acknowledgment and Agreement form, i.e., the Verification Staff Reporting form.[4] This form must to be updated and electronically submitted to reserve@climateactionreserve.org whenever new staff members are designated as verifiers on a NOVA/COI form or once per year, whichever is more frequent.

A verification body may add or delete staff to its roster at any time. To add or delete designated staff, the verification body should resubmit the form with the names and contact information for any personnel changing from the roster and note if said personnel are to be removed, added, or their status updated. For each individual identified on the form, the firm shall describe his or her job classifications, relevant experience, education, academic degrees, professional licenses (for technical staff), and role for the Reserve's records. Failure to submit the Verification Staff Reporting form could result in suspension from the Reserve program.

3.6 Conflict of Interest

When conducting verification activities for Reserve project developers, verification bodies must work in a credible, independent, nondiscriminatory and transparent manner that is in compliance with applicable legislation and relevant ISO standards. A conflict of interest (COI) is defined as any situation that compromises a verification body's ability to perform a wholly independent verification. In order to ensure the credibility of the emissions data reported to the Reserve, it is crucial that the verification process be completely independent from the influence of the project developer. The verification team must act objectively and exercise professional skepticism while conducting verification activities. Conflict of interest is a difficult and dynamic issue and is therefore assessed by Reserve staff on a case-by-case basis.

[4] Available at http://www.climateactionreserve.org/how/verification/verification-documents/.

The COI review process gives the verification body the ability to demonstrate that its organization is capable of identifying and mitigating situations that would impair its ability to render an impartial Verification Statement. Any pre-existing relationship between the verification body/verification team and project developer must be disclosed to the Reserve. The Reserve will then evaluate the potential for a real or perceived conflict of interest between the two entities.

3.6.1 Reserve COI Review

Each verification body must provide information to its accreditation body about its organizational relationships, internal structures, and management systems for identifying potential conflicts of interest (organizational COI). Then, on a case-by-case basis, the Reserve will review any pre-existing relationship between a verification body and project developer and assess the potential for conflict of interest in light of the individuals involved. The Reserve staff base the review on the verification body's self-reported information submitted against the criteria laid out below. The verification body must assess all potentially conflicting services it has provided to the project developer, specifying the nature, timing, location, financial value, etc. This information is evaluated and cross-checked against the Reserve's internal records.

If the Reserve finds that there is low risk of COI, a determination is made in writing and sent to the verification body allowing verification services to proceed. After that point, the project developer and verification body may finalize negotiations of their contract and begin verification activities. Following completion of the verification, the verification body must monitor for COI through the next 12 months, as any new business relationship could increase the potential for COI (known as emerging COI).

If the Reserve finds that there is a medium or high risk of COI, it may request further information or the development of a mitigation plan before a final determination is made. For these cases, the Reserve will convene a COI Committee comprised of three or more staff members (with a minimum of one management-level staff member) in order to discuss the issue. The determination will be communicated to the verification body, the project developer, and any relevant body performing oversight. If the verification body disagrees with the determination, it may appeal (the appeals process is detailed in Section 6.4).

In the event that a verification body violates COI procedures, the Reserve, in consultation with the accreditation body and at its discretion, may disqualify an approved verification body from providing services under the Reserve.

Note that this conflict of interest clause does not preclude a verification body from engaging in consulting services for other clients that participate in the Reserve for whom the verification body does not provide any verification activities.

3.6.2 Notification of Verification Activities and COI Form

To obtain an approval for verification activities to proceed, the verification body must submit a Notification of Verification Activities and Request for Evaluation of Potential for Conflict of Interest (NOVA/COI) form[5] detailing the specifics of its relationship with the project developer and the scope and plan for verification activities. The Reserve will determine the risk for COI

[5] Available at http://www.climateactionreserve.org/how/verification/verification-documents/.

and can seek further information from the verification body to satisfy itself that no conflict exists or will arise and the proposed services are appropriate.

The verification body must conduct an internal review of previous relationships and services provided to the proposed project developer in order to determine the potential for COI before submitting the NOVA/COI form. The form must be submitted to the Reserve a minimum of 10 business days prior to the beginning of verification activities and the finalization of the contract. This notification period is necessary to provide the Reserve time to assess the risk of COI, resolve or mitigate issues, and allow itself, its partners or its consultants the opportunity to conduct verification oversight. More information on the verification oversight process can be found in Section 6.1. If the Reserve approves verification activities to proceed without oversight, project verification may begin on the date that approval is received by the verification body. The verification body may need to revise and resubmit the NOVA/COI form to include a mitigation plan, correct errors, or include any additional information per the Reserve's request.
No verification activities may occur prior to NOVA/COI approval.

A verification body that does not provide proper notification to the Reserve could be denied the right to conduct verification services for the proposed verification and may be disqualified or suspended as a recognized verification body. Note that a NOVA/COI form must be submitted for each verification period, even if a verification body has verified a previous vintage for the project and is within the allowed verification cycle timeline.

3.6.3 Potentially Conflicting Services

A verification body will have a high risk of COI if it or one of its contracted personnel shares any management with the potential client or if any of the potential client's staff working on GHG-related activities were previously employed by the verification body within the last three years, or vice versa. A verification body will have a high risk of COI if it or its related companies (e.g., parent company, subsidiaries of a parent company, affiliates) has provided any GHG management, consulting or advocacy services (as identified on the list below) to the potential client within the last three years. Such services would indicate the verification body could be: 1) verifying their own work, 2) performing management functions for the client, and/or 3) acting as an advocate for the client.

Verification bodies may not conduct both GHG consultancy services and verification services for the same project. A verification body may offer both types of services in general, but for any particular project it must choose which of the two services it wishes to offer. A verification body is strictly prohibited from consulting on any project it wishes to verify and can never verify a project that it has designed, developed, implemented or consulted on, regardless of when it provided that service.

Validation of a project prior to verification is considered an independent third party assessment service, not consulting. All instances of work in relation to validation and consulting should be disclosed on the NOVA/COI form.

Where a high risk of COI is determined to exist and mitigation is not possible, the verification body will not be approved to conduct the verification.

The following lists contain services that are considered potentially conflicting and therefore incompatible with the provision of GHG verification activities. Services of this nature must be declared on the NOVA/COI form. Please note that this list is not exhaustive, as there are other services and conditions that could constitute a COI.

High risks for COI:

- Sharing senior management staff or Board of Director membership between the project developer and the verification body, or previous employment of the senior management staff by the verification body or vice versa within the previous three years.
- Designing, developing, implementing, internal auditing, consulting or maintaining a GHG emissions reduction or removal project
- Designing or developing GHG information systems for the project developer in the same sector
- Owning, buying, selling, trading or retiring shares, stocks or offset credits from the project in question
- Brokering in, advising on, or assisting in carbon or GHG-related markets
- Dealing in or being a promoter of credits on behalf of the project developer

Medium risks for COI:

- Developing GHG emissions factors or other related engineering analyses for the project developer
- Designing energy efficiency, renewable energy, or other projects for the project developer that explicitly identify GHG reductions as a benefit
- Providing appraisal services of carbon or GHG liabilities or assets
- Preparing or producing GHG-related manuals, handbooks, or procedures for the project developer
- Providing legal services
- Providing expert services for a legal purpose or advocating for the project developer
- Providing other GHG-related fee-paying services to the project developer during the course of project verification services
- Members of proposed verification team have a close personal or familial relationship with the project developer
- Any regulatory enforcement action, including citations and fines
- Other services as determined by the Reserve

Depending on the nature of the services provided, it is possible that a COI could be alleviated with a proper mitigation plan. If the verification body identifies a potential high or medium COI risk on the NOVA/COI form, the verification body must submit a plan to avoid, neutralize, or mitigate the COI. The Reserve will review the submitted documents to determine if sufficient information has been provided. If not, the Reserve will request additional information. Once the information is found to be sufficient, the Reserve will review the case and issue a written determination within 10 business days.

Potentially conflicting services could be mitigated by the following circumstances, including, but not limited to:

- **Time of service:** Any services delivered between the project developer and the verification body (past employee/employer or other relationships) that occurred more than three years before the date of the COI determination are viewed as a lower risk. However, any services rendered related to the design, development, implementation or maintenance of a GHG emissions project must be fully disclosed and are always considered conflicting, regardless of the time of delivery.

- **Location:** Services provided to a business unit, facility or office of the project developer located outside of North America are considered a lower risk for a conflict of interest.
- **Type of service:** Services that do not appear on the above lists of potentially conflicting services may be considered a lower risk.
- **Financial value of service:** The verification body's provision of other services with a small monetary value relative to the value of verification is viewed as a lower risk by the Reserve. Cases where the total value of services provided to the project developer is a very small percentage of the verification body's revenue over the same period may be less cause for concern as well. The size of the verification team is also a factor into the determination of financial value of services. The percentage of annual revenue of verification services conducted by the company's North American Greenhouse Gas Business Management Unit (GHG Business Unit)[6] for the project developer in question must be provided on the NOVA/COI form. This information will be treated confidentially by the Reserve.

3.7 Organizational COI and the Verification Cycle

There is no limit on the number of projects that a verification body may work on for a project developer. However, if the verification body has performed verification activities for more than 10 projects over a 12-month period for a single project developer, the Reserve may require further information to inform its COI determination.

A verification body may verify any number of reporting periods for a project for a maximum of six consecutive years. After the six-year period, the project developer must engage a different verification body to verify the project. The original verification body may continue to provide verification services for other projects developed by the same project developer, but it cannot provide verification services for the project in question for at least three years.

The cycling and rotation of verification bodies helps avoid COI situations that could arise from lengthy and ongoing business relationships. In addition, this process guarantees that another firm reviews previously verified reporting periods, thus providing another check on the consistency and appropriateness of protocol interpretation and professional judgment. The new verification body must re-check eligibility criteria per the protocol requirements, but it is not required to perform an additional verification of data that was verified in previous reporting periods (see Section 4.6.1).

The original verification body may again provide verification services to the project after a lapse of at least three years. This three-year suspension may be triggered earlier if the verification body has conducted a substantial amount of other services for the project, depending on their nature. These services must be disclosed in the NOVA/COI form and will be assessed by the Reserve on a case-by-case basis. The three-year suspension period begins the day after the project's most recent registration date.

The potential for COI between a project developer and a verifier who works for multiple verification bodies is reviewed on a case-by-case basis. Individual verifier relationships, non-project related consulting services or employment by the project developer or another verification body (also non-project related) may trigger the requirement for a verifier to wait at

[6] The term "GHG Business Unit" refers to the verification body's staff and offices within the corporate structure that offer climate change and greenhouse gas services (validation, verification, consulting, etc.) in North America.

least three years before performing verification for a particular project in order to mitigate the potential for COI. All personal and business relationships must be disclosed on the NOVA/COI. These cases proceed directly to a Reserve COI Committee for review.

The verification cycle applies to verification services performed during the entire life of the project, which includes verifications performed under another GHG registry or program.

If for any reason the Reserve determines that a relationship constitutes a conflict of interest that cannot be mitigated, the Reserve will require the project developer to select a new verification body. The Reserve may also require re-verification of any verification results from the time at which the conflict of interest arose and could not be mitigated.

Example 1: Verification Pro provided GHG inventory verification services for a Climate Registry member, MacDonald Dairy, from 2012-2015. MacDonald Dairy now has a Reserve livestock project in 2016 and would like to hire Verification Pro.

While Verification Pro has provided verification services for MacDonald Dairy in the recent past, it has never verified this specific project. Verification Pro may verify this project for up to six consecutive years.

Example 2: Verification Pro provided validation services for a LFG Unlimited landfill project under the Verified Carbon Standard from 2012 through 2015 (4 years). The project transferred to the Reserve in 2016.

LFG Unlimited may contract with Verification Pro for verification services for 2016 through 2018 (2 additional years), at which point LFG Unlimited must select a different verification body.

3.8 Technical Consultants and Contracted Verifiers

Technical consultants that are hired by the project developer to provide technical assistance in any capacity, including helping the project developer compile data or manage a project, are not required to complete training or become accredited under ISO 14065. However, a technical consultant that participated in the development of a project cannot provide verification services for that same project, as this is a clear COI. Development services include designing, implementing, or maintaining a GHG emissions reductions or removals project as well as setting up GHG management or information systems for the project. The history and relationships between the technical consultant(s) and the verification body must also be disclosed on the NOVA/COI form.

A verification body is allowed to use contracted verifiers to fill any role on the verification team. Contracted verifiers acting as the Lead Verifier or Senior Internal Reviewer are subject to all training requirements described in Section 3.4. Any contracted verifiers performing verification activities must be included on both the NOVA/COI form and the Verification Staff Reporting form, and per the requirements of ISO 14065, verification bodies must take full responsibility for verification activities performed by contracted verifiers.

Under ISO 14065, contracting is distinct from outsourcing[7]; outsourcing is described as the practice of an organization setting a contract arrangement with another organization to provide services tasked to the original organization. While verification bodies may not outsource the Lead Verifier or Senior Internal Reviewer roles to another organization, verification bodies are allowed to outsource other roles on the verification team, provided no COI exists between the

[7] ISO 14065:2013, Note under 6.4.

outsourced party and the project developer. Like contracted verifiers, individuals in outsourced positions must be included on both the NOVA/COI form and the Verification Staff Reporting form.

3.9 Confidentiality

Verification bodies must keep sensitive information encountered while conducting verification activities confidential in order to uphold the integrity of data reported within the Reserve. Verification bodies must not make use or take advantage of any confidential information and must take reasonable steps to protect the information from any unauthorized access. Due to the fact that market-sensitive information may be encountered while conducting project verification activities, the verification body must agree to maintain strict confidentiality in its findings prior to the public availability of the Verification Report. Confidentiality arrangements and requirements should be addressed in the contract between the project developer and the verification body.

The Reserve enters into confidentiality agreements with verification bodies and project developers as necessary. The Reserve may also, on occasion, request supporting information to supplement reported data. The Reserve follows standardized security and confidentiality procedures in order to protect all confidential business information. Any organization that must provide confidential information to support the NOVA/COI assessment should clearly mark which information is considered confidential in order for it to be treated as such.

Once a verification body is selected by a project developer, the two parties should negotiate contract terms. This contract should be between the project developer and the verification body exclusively, with the particulars of the contract at the discretion of the two parties. While the commercial arrangements surrounding the timing of the verification and the payment of fees are negotiated between the two parties, these details must be disclosed in the NOVA/COI form. As previously stated, the NOVA/COI form is not made public and no verification activities can take place until it has been approved.

4 Project Verification Activities and Expectations

4.1 Overview

The ultimate objective of verification is to provide assurance that GHG reductions or removals are real, additional, verifiable, permanent, and owned unambiguously. To do this, verification bodies must develop a risk-based verification plan that takes into account the size and complexity of the GHG project, the verification team's knowledge of the project, and the relevant sector, technology and processes. The verification plan must identify areas of key reporting risks to support to a reasonable level of assurance that the claimed GHG reductions or removals are materially correct.

Verification bodies must verify a project's GHG reductions or removals by:

- Implementing a risk-based approach to verification
- Ensuring verifications are conducted in a systematic and comparable way
- Ensuring Verification Reports, List of Findings and Verification Statements are independent and robust

Verification activities necessarily differ based on the complexity of a project's GHG emissions reductions or removals and the underlying data supporting them. However, the verification process must include, at a minimum, the following steps:

- Notification of verification activities and case-by-case evaluation of conflict of interest
- Scoping and planning of project verification activities
- Desk review and initial site visit to conduct project verification activities:
    - Confirmation of eligibility criteria
    - Identifying emissions sources, sinks and reservoirs and assessing risk of material misstatements
    - Reviewing methodologies and management systems
    - Verifying emission reduction calculations
- Preparing a Verification Report, List of Findings and Verification Statement and submitting them to the Reserve

Upon completion of the above steps, Reserve staff reviews the relevant documents and reported data before registering the project and issuing CRTs. The Reserve relies upon the Verification Report to attest to the accuracy and legitimacy of the CRTs issued and the verification body is held accountable to the Reserve for the quality and independence of the Verification Report and Statement. See Section 5 for further guidance on the materials Reserve staff reviews prior to CRT issuance.

4.2 Risk-Based Verification

Project verification is an iterative, risk-based activity in which the complexity of all project components are balanced and assessed in relation to one another using verifier professional judgment. Areas that display low complexity or have minimal bearing on the eligibility or quantification of project emission reductions should receive lower priority and attention relative to areas with high complexity and significant implications for project eligibility or emission reductions.

During the scoping and planning phases (Section 4.3), the verification team shall conduct a preliminary risk assessment in order to establish a verification approach based on areas of highest perceived risk. This assessment should include the project type, size, complexity, and length of verification period, and should not be considered final. Rather, an iterative approach must be used to re-assess risk and complexity in the context of the knowledge gained and information gathered during the verification process.

Identified areas of risk may include any aspect of the project. Where the verification team identifies significant risk, it shall review those project components with increased care exceeding the minimum requirements provided in this document and the appropriate project protocol.

Potential areas of risk may include, but are not limited to:

- Ownership of GHG rights
- Project conformance with the Legal Requirement Test
- Project conformance with the Performance Standard Test
- Project compliance with relevant regulations
- Maintenance and appropriate operation of project hardware
- Adequacy and QA/QC of data collection processes
- Training of project personnel
- Data transcription and handling
- Data calculations

4.3 Scoping and Planning Project Verification Activities

Prior to entering into an engagement to provide verification services for a Reserve project developer, the Reserve must review the composition of the verification team and the scope of verification activities. This information is submitted to the Reserve for its approval in the NOVA/COI form (see Section 3.6).

4.3.1 Verification Team

The verification body is responsible for assembling a competent and qualified verification team to undertake verification activities before beginning any verification work. It must consider the capabilities and capacities of its staff when building the team. The verification team must have sector-specific competency in relation to the type of project being verified, and all team members and their respective roles must be disclosed on the NOVA/COI form. The verification team shall consist of a minimum of two individuals with Lead Verifier qualifications: one to serve as the Lead Verifier and one to serve as the Senior Internal Reviewer.

The role of a Lead Verifier is to coordinate and lead the verification team and all underlying verification activities. The Senior Internal Reviewer's role is to perform a final quality control on the data checks, the List of Findings, the Verification Statement and Verification Report prior to its completion.

In order to perform an impartial evaluation of the verification process and results, the Senior Internal Reviewer must remain independent from decisions made by the rest of the verification team during verification activities. To that end, the Senior Internal Reviewer shall not participate in meetings, phone calls or site visits between the verification team and the project developer.

See Section 3.4 for more detailed information on individual verifier training requirements.

4.3.2 Developing a Verification Plan

Prior to the kick-off meeting, the verification team shall develop an initial verification plan outlining the scope and nature of verification activities to be conducted for the specific project. In developing this plan, it shall consider the key requirements and objectives of the project developer, compliance with the relevant Reserve project protocol, the information to be reported to the Reserve, and the verification team members' capabilities and sector competencies.

The verification plan must include a review of any previously reported information to the Reserve, a preliminary assessment of areas of high risk, identification of potential systemic weaknesses, a draft sampling plan to recalculate the emission reductions or removals data reported to the Reserve, and a site visit itinerary (if necessary). The data sampling plan should be created in line with the requirements of Section 4.3.3 of ISO 14064-3, which stipulates the different types of sampling and the typical conditions that apply to each sampling type. The verification plan should evolve as the verification progresses and the verification team obtains more information on potential areas of risk and supporting evidence to substantiate the GHG emission reductions assertion. The Reserve may request a copy of the verification plan at any time.

After the Reserve has been notified of planned verification activities and issued approval for verification to proceed, contract terms may be finalized. At that point, the verification team shall conduct a kick-off meeting with the project developer. This meeting can be held either in person or remotely. The agenda for the meeting should include:

- Introduction of the verification team, overview of roles and responsibilities
- Review of verification activities, plan and scope
- Transfer of background information and underlying activity data
- Review and confirmation of the verification process schedule

Based on the information provided during the kick off call, the verification team should determine the most effective, efficient, and credible verification approach tailored to the particular characteristics of the project. If a project has been selected by the Reserve for verification oversight, Reserve staff may participate in all or some of the verification activities.

4.4 Verification Cycle

A reporting period is a period of time over which a project developer quantifies and reports GHG reductions/removals for the project. The verification period is the period of time over which GHG reductions/removals from said reporting period(s) are verified. Reporting periods must be contiguous in the Reserve program; there can be no time gaps in reporting during the crediting period of a project once the initial reporting period has commenced. Gaps in recorded data or activity within the crediting period must be included within the reporting period and verified accordingly. The verification body must confirm that no reductions are claimed for any period that is missing data or is designated as a zero-credit reporting period by the project developer. See Section 3.4.6 of the Program Manual for details related to a zero-credit reporting period.

All projects must complete their initial verification within 12 months of the end of the initial reporting period. To satisfy this verification deadline, a completed Verification Report and signed Verification Statement must be submitted to the Reserve.

After a project is registered, a Verification Statement and Verification Report must be submitted within 12 months of the end of each subsequent verification period. The maximum allowed length of the verification period is specified in each protocol, but project developers may choose to verify more frequently than required. For example, a Verification Statement and Report for GHG reductions achieved between January 1, 2016 and December 31, 2016 would have to be submitted by December 31, 2017 if a project was required to verify annually. The only exception to the verification deadline is if the project developer is taking a zero-credit reporting period (see Section 3.4.6 of the Program Manual).

The following flow charts provide an overview of the NOVA/COI approval and verification processes.

Figure 4.1: NOVA/COI Approval

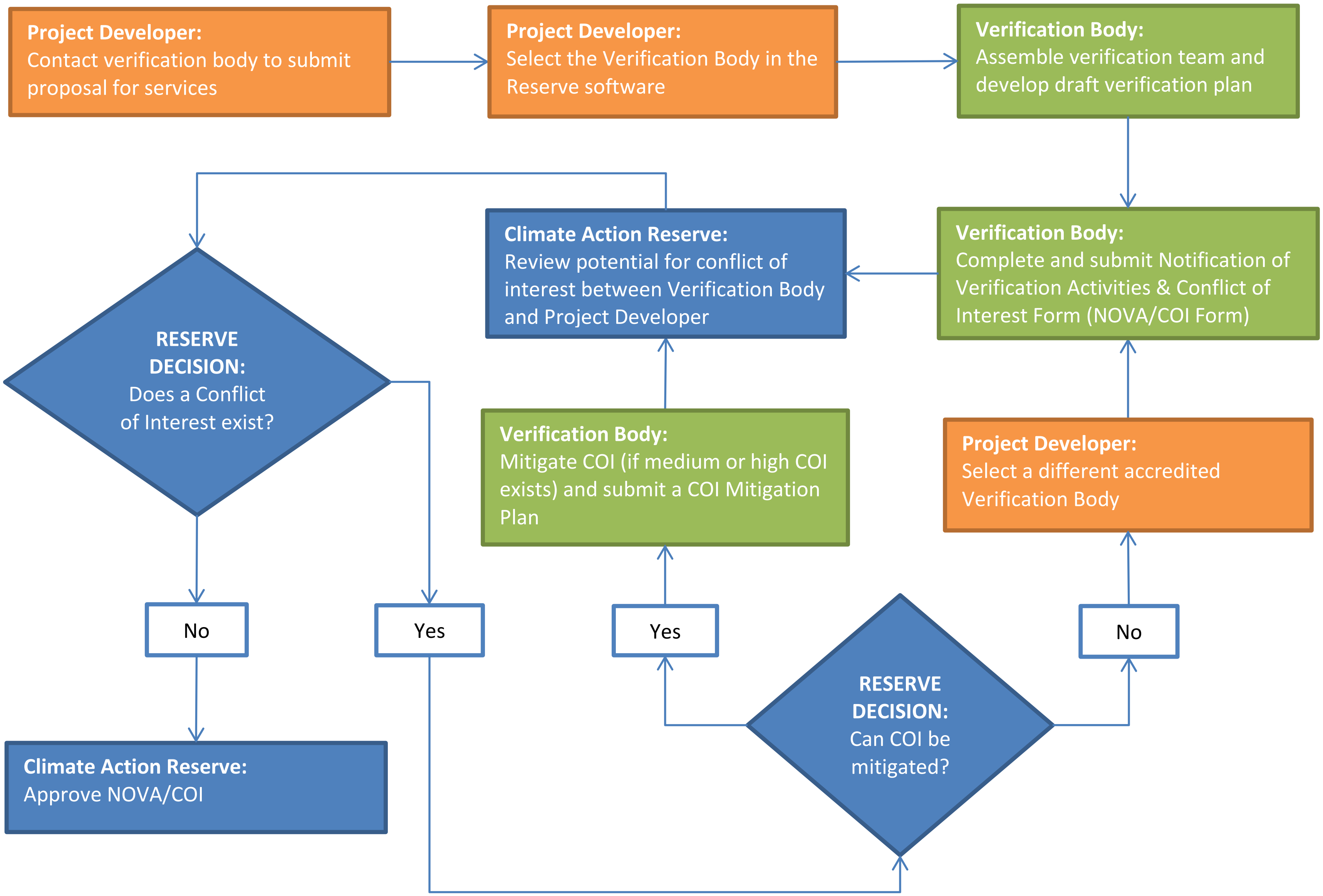
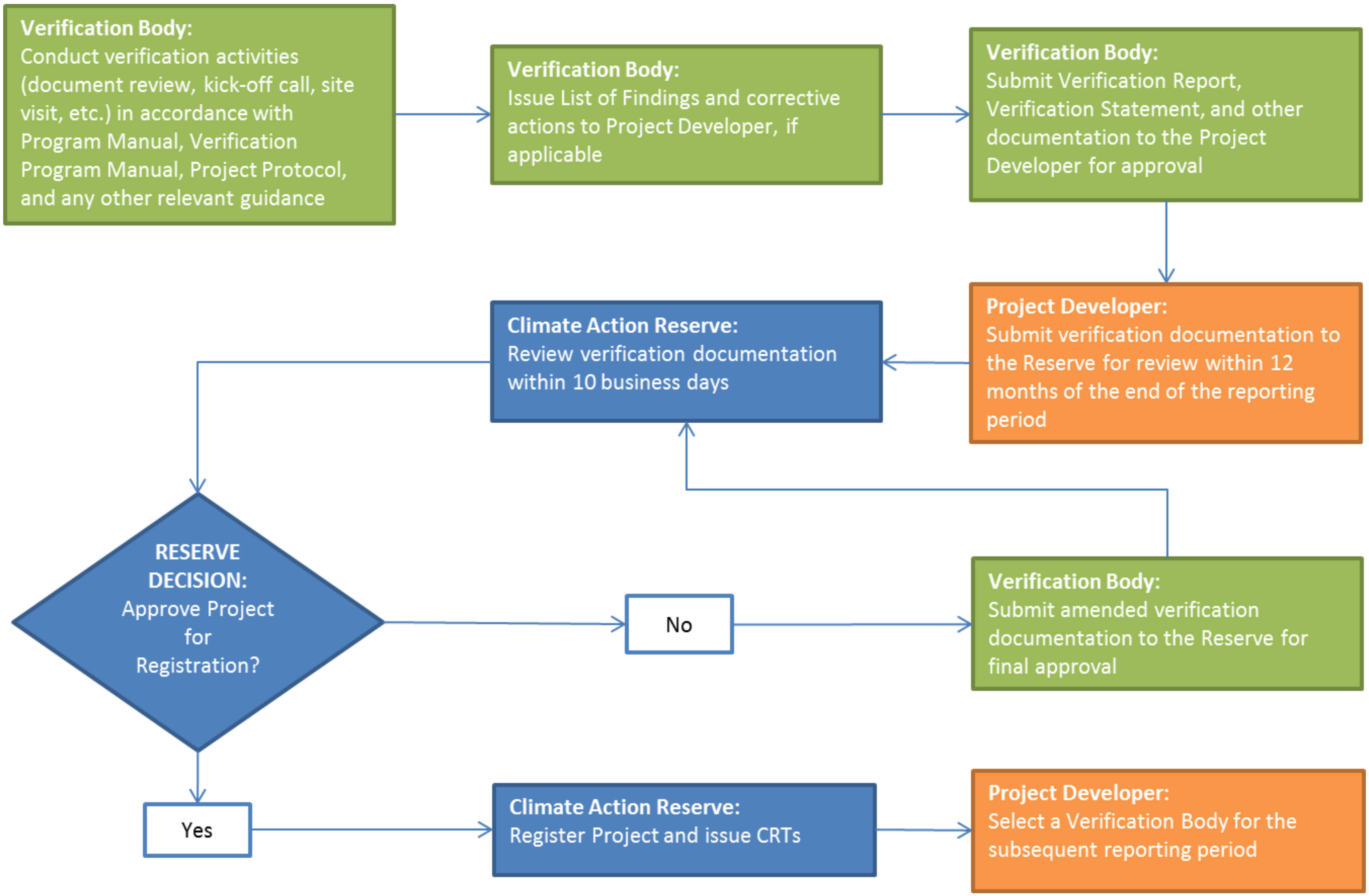


Figure 4.2: Project Verification and Registration



4.5 Desktop Verification vs. Full Verification

The following activities are expected to occur during a desktop verification and a full verification (desktop verification and a site visit), respectively. Please note that these lists are not comprehensive. Requirements differ by project type, and the project protocols note the exact requirements. The depth and breadth of verification activities shall also be guided by the project-specific risk assessment (see Section 4.2).

A desktop verification must, at minimum, consist of:

- Assessment of project eligibility criteria
- Review of required attestations
- Re-calculation and review of the data calculations and information presented in order to verify completeness
- Review of the monitoring plan and monitoring methodology for conformance with protocol requirements
- Evaluation of data management, QA/QC systems, and general procedures in the context of their influence on the generation and reporting of reductions or removals

A full verification must, at minimum, consist of the above-listed desktop verification activities as well as:

- Site visit(s) as required by the relevant protocol
- Assessment of the implementation and operation of the project activity
- Review of information flows for generating, aggregating and reporting the monitoring parameters
- Interviews with relevant personnel to confirm that they are properly trained and qualified for the duties they perform
- Interviews with relevant personnel to confirm that the operational and data collection procedures are implemented in accordance with the project monitoring plan and the protocol requirements
- A cross-check between information provided in the monitoring report and data from other sources such as plant log books, inventories, purchase records or similar data sources
- A check of the monitoring equipment including calibration performance and observations of monitoring practices against the applicable protocol requirements
- Identification of QA/QC procedures in place to prevent or identify the possibility of misstatements

4.5.1 Site Visits

A significant portion of the verification activities are conducted during the desktop review of calculations made by the project developer, GHG emissions data, and supporting documentation. However, a site visit can be critical to properly assess project operations, functionality, and data control systems; confirm the project boundaries and assessment area; and review measurement/monitoring techniques and onsite record-keeping practices.

Unless otherwise specified in a protocol, the verification body must conduct a site visit at least once for every 12 months of data verified. It is recommended, but not required, that the site visit occur after the conclusion of the reporting period under verification and that the Lead Verifier is present.

For sub-annual reporting and verification periods for which the same verification body has been on site within the last 12 months, site visits are not required unless significant changes to the project are identified during the desk review. The verification body may use professional judgment to determine if there have been significant changes to the project.

4.6 Core Verification Activities

The core verification activities of the Reserve program encompass a risk assessment and data sampling effort used to determine that the project is eligible, no relevant sources, sinks or reservoirs (SSRs) identified in the project protocol are excluded, data was properly collected and calculated, and the risk of error is low. Each of these areas must be assessed and addressed through appropriate sampling, testing and review.

All verification activities shall include the following core steps:

1. Confirm eligibility criteria
2. Review data and identify SSRs
3. Review management systems
4. Verify emissions estimates

4.6.1 Step 1: Confirm Eligibility Criteria

Every project must meet the eligibility criteria established in the Reserve Program Manual and relevant project protocol in order to qualify for project registration. There can be no deviation from these rules. The Reserve conducts a preliminary review of project information provided in the project submittal form to assess eligibility. This review is not a final determination of the eligibility of the project, nor does it guarantee CRT issuance or CRT ownership.

Upon initiation of verification activities, it is the responsibility of the verification body to assess these claims and confirm that a project meets the eligibility criteria in the initial verification period. For subsequent verification periods, the verification body must confirm that the project continues to meet eligibility requirements. The eligibility check includes, but is not limited to, reviewing the required attestations described in the following sections.

While the structure of the project eligibility criteria is shared amongst the Reserve protocols, the specific requirements can vary. Please refer to the relevant protocols and accompanying verification guidance for more information on the eligibility criteria and required frequency of verification for each criterion. Whenever a verification body verifies a registered project for the first time, it must review all applicable eligibility criteria rather than relying on the determination of the previous verification body.

The verification body must explicitly state in the Verification Report whether each eligibility requirement has been met and summarize the evidence that was reviewed to reach its determination. Please note that areas of high risk may necessitate investigation beyond the steps described below.

4.6.1.1 Location

Each project protocol limits project activities to an explicitly defined geographic boundary. Verification of project location shall be conducted through site visits, corroboration and review of appropriate documentation, and/or geographic searches confirming location and the project area.

4.6.1.2 Project Start Date

As defined in the Reserve Program Manual and project protocols, the project start date initiates the project crediting period. Verification bodies must verify that:

- The project start date reported in the Reserve software is correct
- The project start date is eligible per the applicable protocol and the policy laid out in the Reserve Program Manual

Verification bodies shall review supporting documentation to ensure the start date established by the project developer is correct (e.g., design plans, installation dates, operational dates, commissioning reports, service invoices, log books, staff interviews, etc.) and may use their discretion as to the adequacy and sufficiency of evidence provided. Supporting documentation should always be clear, traceable and directly correspond to the reported timeline. The exact start date must be explicitly stated in every Verification Report for the project.

4.6.1.3 Crediting Period

Verification bodies shall verify that the reporting period falls within the project's crediting period as defined in the applicable protocol. Verification bodies shall also confirm that the crediting period and the reporting period entered in the Reserve software are accurate and the underlying activity or source data supplied by the project developer directly corresponds to these dates.

It should be noted that all data must be contiguously reported and verified, even if no credits are being claimed for a given time within a particular reporting period (see Section 4.4).

Project transfers are allowed in accordance with the guidelines outlined in Sections 3.6, 3.7, and 3.8 of the Reserve Program Manual. Transfers from another GHG registry shall be reviewed by the verification team, and the verification body must ensure that no double-counting has occurred by cross-checking the previous registry's records with the Reserve software.

4.6.1.4 Additionality

The Reserve incorporates standardized additionality tests in all of its protocols. These tests generally have two components that must be confirmed by the verification body: a legal requirement test and a performance standard test.

The Legal Requirement Test

Projects are very likely to be non-additional if their implementation is required by law. The legal requirement test ensures that eligible projects (and/or the GHG reductions/removals they achieve) would not have occurred anyway in order to comply with federal, state or local regulations, or other legally binding mandates. A project passes the legal requirement test when there are no laws, statutes, regulations, court orders, environmental mitigation agreements, permitting conditions or other legally binding mandates requiring its implementation, or requiring the implementation of similar measures that would achieve equivalent levels of GHG emission reductions/removals.

Verification of the legal requirement test requires:

1. **Review of the Attestation of Voluntary Implementation form:** The Attestation of Voluntary Implementation states that the project was implemented, established, operated, and conducted voluntarily and for the carbon benefit. Verifiers must confirm

that this form has been properly executed by a qualified representative of the project developer.

2. **Risk-based review of relevant legal requirements:** The verification body must conduct a review of applicable local, state or federal regulations in order to reach reasonable assurance that there are no specific mandates for the project's implementation.

In addition, most protocols specify that the project's Monitoring Plan must include the procedures that the project developer must follow to ascertain and demonstrate that the project passes the legal requirement test at all times. If the verification risk assessment determines that there is a low risk of the project failing the legal requirement test, then the reviews of the Attestation of Voluntary Implementation and the evidence that the project's Monitoring Plan has been properly implemented may be sufficient.

However, if significant risk of failure is present, verification bodies shall use their professional judgment to determine the depth and scope of the review required to confirm that the project passes the legal requirement test. Project developers are expected to provide evidence if requested by the verifier.

The Performance Standard Test

Projects that are not legally required may still be non-additional if they would have been implemented for reasons other than generating revenue from the sale of carbon offsets or simply to reduce GHG emissions. Performance standards are designed to screen out this potential set of projects. In developing performance standards, the Reserve considers financial, economic, social, and technological drivers that may affect decisions to undertake a particular project activity. These standards are tailored such that the large majority of projects that meet them are unlikely to have been implemented due to other drivers. In other words, incentives created by the carbon market are likely to have played a critical role in decisions to implement each project in the Reserve program.

Verification bodies must verify that the project meets or exceeds the protocol-specific performance standard. This determination is not subjective.

The applicable performance standard is applied by the project developer at the time the project commences. In most protocols, projects that have been registered do not need to be evaluated against the performance standard in future verifications for the duration of the first crediting period.

4.6.1.5 Regulatory Compliance

The verification body shall confirm that the project being verified was in material compliance with all applicable laws, including environmental regulations, during the verification period; no CRTs may be issued for periods when a project was not in material compliance with all applicable laws. The protocol-specific regulatory compliance requirement is generally limited to project activities at the host site, but it may extend to the entire facility or additional holdings. This requirement is verified through a review of the Attestation of Regulatory Compliance, as well as a risk-based review of project documentation.

Project developers are required to disclose to the verifier all instances of non-compliance of the project with any law. To confirm regulatory compliance, the verifier must assess 1) whether a violation is related to the project or project activities, and 2) whether the violation is material.

Before assessing materiality, the verifier must first assess whether a violation is related to the project or project activities. A violation should be considered to be “caused” by project activities if it can be reasonably argued that the violation would not have occurred in the absence of the project activities. It is important to note that the scope of regulatory compliance may be different for different project types. For example, there are many activities and pieces of equipment at a dairy operation, in a forest or at a coal mine that are completely unrelated to project activities occurring at the same site. However, activities at a composting facility, nitric acid facility or ODS destruction facility are inherently more connected to the project.

It is also important to review the timing of the violation. Many facilities do not receive documentation of a violation until well after the violation has actually occurred. If a violation was to affect CRT crediting, it would be for the time period when the violation occurred, which is not necessarily when notice of the violation is received.

Once the verifier has determined that the violation is related to the project or project activities and the reporting period being verified, he/she shall then assess the materiality of the violation.

The concept of materiality is found throughout the Reserve’s program. Generally, the term is used to indicate something significant (material) as opposed to insignificant (immaterial). This manual discusses materiality with respect to verifying an emissions report in terms of a materiality threshold (Section 2.3), a quantitative materiality threshold (Section 2.3.1), and a qualitative materiality threshold (Section 2.3.2).

The materiality thresholds to assess an emissions report described in previous sections are not appropriate to use when assessing the materiality of regulatory violations. The Reserve introduced the concept of materiality to regulatory compliance in order to differentiate between violations that could bring into question the integrity of the project and violations that are strictly administrative or due to acts of nature. Violations that are administrative (such as an expired permit without any other associated violations or tardiness in filing documentation) are not considered material and do not affect CRT crediting. Any other type of violation that is project-related is generally considered material.

Any violation that is found by the verifier to be caused by the project or project activities shall be brought to the Reserve as soon as possible for assessment on a case-by-case basis. Verifiers should continue to use professional judgment to assess the violation and gather the necessary information and documentation they feel is required to make a determination of materiality. The Reserve shall utilize this information and the recommendation of the verifier to make such a determination.

4.6.1.6 Ownership

One of the fundamental principles of the Reserve program is the unambiguous ownership of GHG reductions/removals. Project developers must have exclusive ownership rights to the GHG reductions or removals associated with the project and for which the Reserve will issue CRTs. In addition, the project developer must agree that ownership of the GHG reductions or removals will not be sold or transferred except through the transfer of CRTs in accordance with the Reserve Terms of Use policies.

It is essential that the verification body determines the project developer is the proper owner of a project’s potential CRTs early in the verification process. The ownership requirement is verified through review of the Attestation of Title and an accompanying review of available ownership documentation. The owner of the CRTs must be the account holder in the Reserve software; the owner must also be the signatory to the Attestation of Title.

The verification body must confirm that the project developer has signed the Attestation of Title and is the owner of full, legal and beneficial title to the GHG reductions or removals generated within the Reserve. Although several parties may be involved in a single project, the party that signs the Attestation of Title must be the party that has beneficial ownership rights in relation to the CRTs registered in the Reserve

If the verification body determines a different organization has ownership of the CRTs, the verification body may proceed with verification activities as long as the rightful owner is clearly identified in the verification documentation, all involved organizations are informed, and a COI evaluation between that party and the verification body has been approved by the Reserve. The project could also be moved to a different account within the Reserve software.

In addition to the Attestation of Title, verification bodies should review relevant contracts, agreements, and/or supporting documentation between project developers, facility owners, utilities, and other parties that may have a claim to the CRTs generated by the project. Verification bodies must review these contracts in a risk-based context and use professional judgment to determine the depth and breadth of the review. In order to issue a positive Verification Statement, the verification body must conclude with reasonable assurance that the project developer has title of the GHG reductions/removals.

In some instances, ownership will be straightforward and easy to identify (see Example 1). In other instances, particularly those involving multiple parties, a more careful analysis will be required (see Example 2).

Example 1: A forest owner with complete title and beneficial rights in certain real property and its timber designs and implements an Improved Forest Management project to sequester carbon without any outside assistance. In this situation, the future owner of the CRTs is clear, absent any further documentation or assertions to the contrary.

Discussion: In this case, the verifier should be able to establish ownership through a site visit, geographic search mapping of the project boundary, and a thorough review of the deed and/or title to the land.

Example 2: A private company, X Co, pays for the installation of GHG emissions-capturing equipment at a landfill owned by the local county waste authority in exchange for rights to any GHG offset credits derived from such activities.

Discussion: In this case, the proper owner and appropriate Reserve account holder is not immediately clear without reviewing the underlying contractual arrangements between the two parties, since both are involved in the activities leading to the emission reductions.

Upon review of the underlying documents, the verification body should be able to reasonably conclude that X Co is the proper project developer and account holder to which any CRTs would be issued. Even though the waste authority could have potentially laid claim to the emission reductions, it most likely conceded such rights, often noted as "environmental attributes," to X Co via a contract prior to the implementation of the project.

Although the above examples require some review of contractual terms, the parties with potential interest in the project are still fairly straightforward. However, in some cases, a project developer may try to open an account for an affiliated entity or under a different name and have the CRTs issued directly into that account. In the Reserve program, CRTs can only be issued to the account of the legal entity that owns the rights to those CRTs. Thus, the account holder must be the same legal entity as the project developer in order to be issued the CRTs.

Separate legal entities may include limited liability companies (LLCs), corporations, and other business organizations, regardless of whether these entities are 100% related to the project developer (e.g., parent, subsidiary, affiliate, etc.). Even if a project developer is 100% owned by its parent company, its parent or any other related company cannot be considered the project developer or be designated as the account holder unless they are the same legal entity, e.g., the project developer is a division within the parent LLC or corporation. This is true regardless of the reasoning behind the creation of the organizational structure of the larger corporate family, whether it be for tax purposes, administrative convenience, efficiency, or any other purpose.

If there is any question as to whether the project developer is the same legal entity as the rightful owner of CRTs, then the verifier may ask for the formation documents of each entity, e.g., LLC operating agreement, certificate of incorporation, etc., and/or request each entity's tax identification number (TIN) issued by government authorities. If the entities have separate formation documents but the TIN is the same number for both, they are likely the same legal entity. If they both have separate formation documents and/or different TINs, then they are not the same legal entity.

Table 4.1 contains some examples of different corporate structures that can be considered when assessing legal entities:

Table 4.1: Corporate Structure of Legal Entities

Scenario	Likely Outcome
Names of X Co and Other Named Entity each end in "LLC", "Inc.", "Corp." or other legal entity designation	Separate legal entities
X Co is doing business as (DBA) Other Named Entity	Unclear → check formation docs and TINs
No clear relationship between X Co and Other Named Entity	Unclear → check formation docs and TINs
X Co is a division of Other Named Entity, not a separate LLC, corporation, or other legally formed entity and same TIN	Same legal entity

The Reserve recognizes that verification teams generally do not contain a legal expert. If any high-risk contractual and/or title issues remain unresolved following an exhaustive review, the verification body should contact the Reserve for further assistance. In these circumstances, the Reserve will help make an ownership determination.

4.6.2 Step 2: Review Reported Data and Identify Sources, Sinks and Reservoirs

Verification bodies shall review a project's reported SSRs to ensure that all are properly identified within the GHG Assessment Boundary as defined by the applicable protocol. The review must also include the reporting and monitoring parameters for the project.

The site visit shall be used to confirm the GHG Assessment Boundary, examine project equipment, identify any associated SSRs resulting from the project, and assess the operation of the project activity.

As part of this process, verification bodies shall review the project's Monitoring Plan to verify that all required SSRs and project activities are measured, modeled or calculated appropriately and with the correct frequency. Verification bodies must also review the project's GHG reduction assertions, data collection and storage methods, and QA/QC measures.

Once all reporting parameters and SSRs have been identified and any issues addressed, the verification body may proceed to Step 3 to review the project's calculation methodologies and management systems.

4.6.3 Step 3: Reviewing Management Systems and Methodologies

After the project SSRs have been confirmed, verification bodies shall review the methodologies and management systems used to generate, compile, transcribe, and store project data. This is principally a risk assessment exercise in which the verification body must weigh the relative complexity of the scope of the project's emissions operations and activities, the project developer's methodologies and management systems used to report GHG reductions, and the likelihood of calculation error as a result of reporting uncertainty or misstatement. The verification body must determine the presence and level of inherent and management type risks and focus its verification effort on the highest risk areas. This is an area which requires professional judgment, and it is likely that qualitative material non-conformances with the protocol could be identified.

Through this review, the verification body shall determine the appropriateness of the management systems, IT systems, staff competency, internal audits, record keeping arrangements, and documentation processes to understand the risk of systemic errors as a result of reporting uncertainty or misstatement. A review of records and management systems onsite helps to ascertain the adequacy of the management system relative to protocol requirements.

A verification body's general review of a project's GHG management systems should document whether methodologies/procedures are appropriate given the inherent uncertainty/risk; the likelihood that the data is correctly aggregated, monitored, and measured; and whether a qualified individual is responsible for managing and reporting GHG reductions or removals. The verification body shall also check that the correct metering equipment is used, inspected, cleaned and calibrated in accordance with the applicable project protocol. The verification body is responsible for ensuring that all metered and modeled (if applicable) data are accurate.

4.6.4 Step 4: Verify Emissions Estimates

Based on a project's SSRs, management systems, and corresponding risk profile, verification bodies must ensure that the calculations of GHG reductions or removals are accurate within the appropriate quantitative materiality threshold. This is achieved by re-calculating all emission estimates based on project activity data. All emission or efficiency factors used in the applicable protocol equations must also be checked. Cross-checking calculated emissions reductions and performing data reconciliation in line with the methodologies outlined in the applicable protocol is vital to ensure quantitative material misstatements are identified and resolved.

Verification bodies shall also trace activity and/or monitoring data compiled by the project developer back to the original source and perform re-calculations in accordance with a sampling plan that focuses on high-risk data. Verification bodies shall review all relevant physical and documentary evidence.

In order for verification bodies to verify the reductions or removals entered in the Reserve software, the sample of recalculated project data must be free of material misstatement. It is possible that the overall GHG reductions or removals calculated by the project developer will differ from those estimated by the verification body. A discrepancy is considered material if the difference between the reported GHG reductions and the verifier's estimate surpasses the materiality threshold defined in Section 2.3.1. Immaterial discrepancies are those that fall within the materiality threshold and are not required to be corrected.

Note that, per Section 2.3.1, the Reserve allows for under-reporting of emission reductions/removals as that is considered conservative. Under-reporting errors are not required to be corrected. The quantitative materiality threshold only applies to mistakes that result in over-reporting.

If the reported data is not free of material misstatement, the verification body shall include this information in the List of Findings and complete the sampling effort of other sources. Once the verification body has confirmed that the data sample is free of material misstatements, it is ready to complete verification activities.

Examples of directly monitored and measured data or supporting evidence that should be reviewed during verification include (but are not limited to):

- Flow meter, electricity meter, and continuous emissions monitoring system (CEMS) data
- Outputs from gas collection, destruction or abatement systems
- Electricity use or fossil fuel combustion records, invoices, purchases and sales orders
- Onsite fuel stocks
- Data recording devices and portable monitoring equipment
- Maintenance and calibration records, log books, and system operations manuals
- Laboratory test results or third party reports
- Manufacturer specifications and reports
- Raw material inputs, production output, and hours of operation
- Field check reports, sampling exercises, and analysis reports
- Emission factors (if not default), combustion efficiency, and oxidation factors
- Certificates of destruction, weight tickets, and customs documents
- Calculation spreadsheets and electronic files

It is a verification body's duty to identify errors during the verification process. Common errors include, but are not limited to:

- Calculation errors: equations used by project developer do not match those specified by the protocol
- Incompleteness: incorrect inclusion or exclusion of SSRs within the GHG Assessment Boundary, exclusion of significant sources and/or leakage effects
- Inaccuracy: manual data transfer and transcription errors, double counting, and use of incorrect emission or destruction efficiency factors

Any of the above errors could result in the project developer materially over-estimating GHG reductions or removals.

4.7 Professional Judgment

By design, Reserve protocols are not entirely prescriptive, which necessitates that verification bodies use their best professional judgment when executing certain verification activities. Verification bodies must demonstrate, through their staff's professional qualifications and relevant GHG experience, their ability to render sound professional judgment in relation to Reserve projects.

Application of professional judgment is expected in the following areas:

- Implementation of verification activities with appropriate rigor for the size and complexity of the project and the uncertainty of calculations associated with the project's SSRs
- Review of the capability of a project developer's GHG emissions tracking, monitoring, and management systems to provide accurate information
- Determination of the amount of data that constitutes a representative sample
- Assessment of methods used for calculations where the protocol does not provide prescriptive guidance
- Appraisal of assumptions, estimation methods and emission factors that are selected as alternatives to protocol guidance, where allowed

In areas where the Reserve project protocols are prescriptive, as with monitoring or calibration frequency, verification bodies are not permitted to use professional judgment. Projects must follow the prescriptive requirements of the protocols, where available. The verification section of each protocol provides guidance on areas where professional judgment is allowed/expected and areas where it is not.

The Reserve maintains the right to question any and all decisions made by the verification body. However, in areas where the project protocols explicitly state that professional judgment can be used, the Reserve expects that the verification body has the competency and knowledge to make these decisions, will err on the side of conservativeness, and will follow industry best practice.

4.8 Variances

The Reserve may, at its discretion, grant variances with regard to the manner in which specific projects meter, measure or monitor GHG reductions or removals where Reserve staff determines that such variances are acceptable. Only with explicit, written acceptance of the variance may a project developer apply alternate methods not contained in the applicable protocol. In most cases, a variance will be granted only for a specified time period or portion of the project data. Verification bodies must ensure that the project developer has met the Reserve's requirements and correctly applied the variance determination. Once a variance is granted, the variance determination is available publicly in the Reserve software.

4.8.1 Verification Body Application of Variance Determinations

Verification bodies must adhere to any instructions laid out within the variance determination and ensure that all other relevant criteria in the protocol have been met. Like the listing process, receiving a positive variance determination does not guarantee that a project will be successfully verified, nor that a project complies with other aspects of a given project protocol;

variance determinations do not qualify projects for registration prior to completing the verification process.

Projects continue to be subject to verification body review after a variance has been granted. The burden remains on the project developer to provide supporting evidence to the verification body that all aspects of its project are in compliance with the variance determination and the project protocol. Variance determinations allow for minor alterations to the protocol and are based on the initial information provided in the Variance Request Form. Verification bodies must confirm the underlying facts that were presented to the Reserve. Variances do not exempt the project from protocol requirements that are not specifically referenced in the variance determination.

A verification body shall not make specific recommendations to the project developer in relation to what could qualify for a variance. This would be considered consulting and is explicitly prohibited. Verification bodies shall not recommend that project developers seek variances from the Reserve, but can note sections or guidance of the protocol with which the project is not in conformance. The verification body can refer the project developer to seek assistance from the Reserve in determining how best to proceed with the project.

4.9 Errata and Clarifications

The Reserve utilizes Errata and Clarifications documents to correct and/or clarify issues in previously issued protocols. Errata are issued to correct typographical errors in text, equations or figures. Clarifications are issued to ensure consistent interpretation and application of the protocol.

Errata and Clarifications documents become effective on the date they are first posted on the Reserve website. Listed and registered projects must adhere to all errata and clarifications issued for the applicable protocol version when they undergo verification. Thus, verification bodies must refer to and follow the corrections and guidance presented in Errata and Clarifications documents as soon as they are effective, even if they are issued during an ongoing verification.

The Reserve does not require verification bodies to attend trainings specific to errata and clarifications. Rather, the Reserve expects that verification bodies refer to these documents immediately prior to uploading any Verification Statement to ensure all relevant guidance is properly addressed and incorporated into verification activities.

4.10 Joint Verification

Certain project protocols allow for “joint verification” when a project developer has multiple projects operating on a single site. In these instances, project developers have the option to hire a single verification body to assess the projects concurrently. This is intended to provide economies of scale for the project verifications and improve the efficiency of the verification process.

Under the joint project verification process, each project, as defined by the protocol and the project developer, must be submitted and registered separately in the Reserve software. However, the verification body may submit a single NOVA/COI form that details and applies to all of the projects at a site that it intends to verify.

Additionally, a verification body may conduct a single site visit and prepare a single Verification Report summarizing the verification results from multiple projects. However, the verification body must develop a separate verification plan, sampling plan, and Verification Statement for each project, i.e., each project is assessed by the verification body separately as if it were the only project at the site. In addition, a copy of the Verification Report must be uploaded to each project's Project Documents page in the Reserve software.

If, during joint project verification, the verification activities of one project are delaying the registration of other projects, the project developer may choose to forego joint project verification. There are no additional administrative requirements of the project developer or the verification body if a joint project verification is terminated.

At the time of publication, the following protocols have provisions allowing for joint project verification:

- Coal Mine Methane Project Protocol
- Mexico Boiler Efficiency Project Protocol
- Nitric Acid Production Project Protocol
- U.S. and Article 5 Ozone Depleting Substances Project Protocols

Please refer to the individual protocols for more information on specific processes and procedures for joint verification.

4.11 Aggregation and Cooperatives

Certain Reserve protocols allow projects to aggregate or form cooperatives for reporting and registration purposes. This can help reduce transaction costs for individual project developers. The requirements in relation to verification periods, desktop reviews and site-visit verifications may vary. See specific protocols for reporting and verification guidelines.

At the time of publication, the following protocols have provisions allowing for project aggregation:

- U.S. and Mexico Forest Project Protocol
- Grassland Project Protocol
- Livestock Project Protocol
- Nitrogen Management Project Protocol
- Rice Cultivation Project Protocol

5 Documenting and Reporting Verification Activities

After a verification body has completed its review of a project developer's estimated GHG reductions or removals, it must take the following steps to document the verification process:

1. Complete a detailed List of Findings containing both immaterial and material findings (if any) and deliver it to the project developer, allowing the opportunity for corrective actions (private document).
2. Complete a detailed Verification Report and deliver it to the project developer (public document).
3. Complete a Verification Statement detailing the vintage and the quantity of verified GHG reductions or removals and deliver it to the project developer (public document, standard form).
4. Conduct an exit meeting with the project developer to discuss the Verification Report, List of Findings, and Verification Statement and determine if material misstatements (if any) can be corrected. If so, the verification body must continue the verification after the project developer has made the necessary revisions.
5. If a reasonable level of assurance is successfully obtained, upload electronic copies of the Verification Report, List of Findings, and Verification Statement in the Reserve software.
6. Return important records and documents to the project developer for retention.

The List of Findings, Verification Report and Verification Statement shall be submitted at the conclusion of verification activities. If a project is deemed ineligible or non-compliant with a protocol to the extent that the verification body cannot reach reasonable assurance, the verification body shall submit only the adverse Verification Statement and List of Findings.

5.1 List of Findings

The List of Findings is a private document that details all material and immaterial findings identified by the verification team throughout the verification. These findings shall be distinguished by materiality and whether they were qualitative non-conformances or quantitative misstatements. The List of Findings shall be delivered first to the project developer in order to provide an opportunity to correct the issues that might impact CRT issuance. The List of Findings submitted to the Reserve should provide a summary of all findings and resolutions that arose during the verification process.

The List of Findings shall accompany the Verification Report and must include a record of all corrections or corrective actions made by the project developer to address the identified issues. A correction made by the project developer resolves an error and fixes the identified problem, while a corrective action fixes the cause of the problem in order to prevent its reoccurrence in future verifications. Each finding shall detail and list the identified issue and refer to the relevant section of the protocol, but shall not provide any solutions or potential remedies for resolution. Resolutions constitute consulting advice and thus create a conflict of interest.

The List of Findings should also include opportunities for improvement (OFIs) to help the project developer streamline future verifications. OFIs can consist of recommend improvements that cite sections of the protocol or reference public documents, but they may not provide advice on how to resolve the issues noted. A verification body may enumerate any shortcomings in a project developer's GHG tracking and management systems as related to the specific protocol requirements.

If no findings are issued for a reporting period, the List of Findings does not need to be submitted, but the lack of findings should be noted in the Verification Report. A standardized format for the List of Findings is not currently required - Table 5.1 contains a sample List of Findings. Detailed findings shall not be included in the Verification Report as that document is made public.

Table 5.1: Sample List of Findings

Category	Verification Findings	Correction/Corrective Action
Material Non-Conformance	The landfill protocol states the monitoring plan must include a mechanism to demonstrate that the project passes the Legal Requirement Test. The project's monitoring plan has no reference or application of this requirement.	Corrective action required. Project Developer (PD) updated its monitoring plan to include the current procedures used to demonstrate that the project is not required by federal, state, or local regulations or other legally binding mandates. PD will contact regulatory agencies, keep records and information surrounding its LFG system, and engage a consultant to perform a bi-annual review of applicable statutes.
Material Misstatement and Non-Conformance	GHG reduction calculations submitted to the Reserve do not apply the correct methane destruction efficiency. As prescribed by the landfill protocol, the default destruction efficiency for a lean-burn internal combustion engine is 0.936. An official source-tested destruction efficiency was not available, but PD used a factor of 0.995. This destruction efficiency increases the total reported CRTs to the Reserve by 4%, which is above the allowable materiality threshold (3%) for total reported CRTs.	Correction required. The protocol clearly states that the default factor must be applied if source data is not available. PD has now applied the appropriate factor.
Immaterial Misstatement	Indirect project emissions were calculated using electricity consumption billing history from the utility. Minor differences found in the total kWh purchased as listed in the billing history result in a slight discrepancy of 3%. This decreases the overall reported reductions by less than 0.01%.	Correction not required. PD chose not to fix the error for this reporting period as it has a minor impact on the reported CRTs. PD will ensure correct calculation of kWh consumed in future reporting periods.
Opportunity for Improvement	PD could strengthen its management and record keeping systems by automating the weekly logs and maintenance plans in order to reduce the risk of transcription error.	No corrective action required. Current system acceptable but could be improved for future verifications.

5.2 Verification Report

The Verification Report is a transparent, overarching document that is produced by the verification body for the project developer and is also made available to the Reserve and the general public. The Verification Report must contain a detailed summary and scope of verification activities undertaken. It is made public in order to uphold the integrity of the Reserve program and to establish the veracity of the CRTs issued. As such, the Verification Report must provide positive assertion that the project met all eligibility requirements, followed all monitoring requirements, applied the appropriate calculation methodologies, and is free of material errors for the reporting period in question. In addition, the Verification Report must include a discussion of how the perceived areas of risk were incorporated into verification activities and project data review.

Verification bodies have the ability to construct the Verification Report in a manner that they feel best communicates the activities undertaken and the results of the verification. However, all Verification Reports must incorporate the elements discussed below; otherwise, the Reserve will request revision and resubmittal. It is important to note that persistent spelling and grammatical errors may also trigger resubmittal. Verification Reports are public documents and should be treated as such.

The Reserve expects all Verification Reports to make explicit, positive assertions of the conclusions drawn. For example, it is insufficient for a Verification Report to simply indicate that no regulatory non-compliances were identified. The report must explicitly state that the verification body has concluded to a reasonable level of assurance that the project met regulatory compliance requirements and identify the evidence examined to reach that determination.

The following sections are not intended as an outline for Verification Reports. These elements may be presented in any fashion deemed appropriate by the verification body, but the report must include, at a minimum, the items indicated.

5.2.1 Verification Report Content

The Verification Report must clearly specify a detailed scope of the verification process and procedures undertaken. The scope includes the physical and temporal boundaries of the verification as well as the GHGs considered. The verification process must be fully documented, with particular focus on the risk-assessment and development of the verification plan. This documentation shall include a description of the verification activities based on the size and complexity of the project developer's operations. This section is expected to provide context for the remainder of the report.

In addition, the standard used to verify GHG emissions reductions or removals must be specified in the Verification Report. For all projects, the standard must include, at a minimum, this document, the Reserve Program Manual, the applicable version of the project protocol, the latest version of Errata and Clarifications, any approved variances, and ISO 14064-3. The quantitative materiality threshold for verification must also be included. Verification bodies are required to adhere to all rules and guidelines relevant to the protocol version under which the project is being verified.

5.2.2 Eligibility

For the majority of project types, the Verification Report must include a description of the eligibility criteria, i.e., start date, location, the legal requirement test, the performance standard test, and regulatory compliance. The report must make an explicit and positive assertion as to whether each eligibility criterion has been met and explain the basis of this determination. The supporting documentation should not be attached to the verification report, but the basis of the successful verification of the eligibility criteria must be explicitly stated.

The Verification Report must describe the project definition and scenario as well as indicate any review conducted to verify the project's asserted baseline status, as this impacts eligibility.

The report must indicate how the verifier's risk assessment was used to inform the project's conformance with eligibility criteria. While some criteria, such as project location, are relatively straightforward, others may require varying levels of review in order to positively verify. In particular, verifiers must indicate whether the risk assessment indicated that reliance on the Attestation of Voluntary Implementation, Attestation of Regulatory Compliance, and a risk-based regulatory review was sufficient or whether additional work was conducted. A simple narrative of work performed on the project is insufficient; verification body conclusions must be explicitly stated, e.g., "Based on the aforementioned review, we conclude that the project satisfies the legal requirement test".

5.2.3 Conformance with the Protocol

As prescribed by the applicable project protocol, all projects must adhere to certain operational, record-keeping, and methodological requirements. The Verification Report must explicitly and positively assert whether the project meets these requirements and provide the basis for the determination reached. Again, narratives of project activities must be accompanied by verification body conclusions.

In particular, the following areas must be reviewed (if applicable) and the project's conformance or non-conformance explicitly stated in the Verification Report:

- Existence of an appropriate monitoring plan
- Data was collected in accordance with monitoring plan (frequency, whether collection was continuous, any discounts applied, etc.)
- Equipment operation and QA/QC meets protocol requirements
- Meter and analyzer cleaning, maintenance, and calibration meets protocol requirements
- Data transcription, management, and QA/QC meets protocol requirements
- Calculations and equations applied in accordance with protocol requirements
- All individuals properly trained for the functions performed
- Accuracy of calculated GHG reductions

The Verification Report must contain explicit, conclusive, and unequivocal statements as to the project's conformance with relevant requirements.

5.2.4 Calculation Review and Sampling

The Verification Report must identify the SSRs contained within the project's GHG Assessment Boundary and make an explicit determination as to whether all necessary and appropriate SSRs have been included. The verification team must note the recalculation and verification of the total number of GHG reductions generated and reported to the Reserve within the given reporting period. It may utilize appropriate risk-based sampling techniques for underlying source data that factor into the final GHG reduction calculation.

The Verification Report must summarize the sampling techniques used, the verification plan, and the risk assessment methodologies employed for project calculations. The report must contain a discussion of the risk assessment and the manner in which this assessment informed the project data and calculation sampling techniques. Relevant input parameters such as destruction efficiency must also be disclosed, and the appropriateness of the chosen parameters must be asserted.

The Verification Report shall summarize the GHG reductions estimation in the following format:

Vintage	Baseline Emissions	Project Emissions	GHG Reductions/ Removals (CRTs)
20XX	A	B	Result of A - B

The report shall provide information regarding the comparison of the project's reported GHG reductions or removals with the verifier's recalculation.

5.2.5 Findings and Basis of Opinion

The Verification Report should support the Verification Statement by summarizing the results of the verification in a general conclusion. A positive Verification Report must contain, at a minimum, the following assertions:

- The project meets all eligibility requirements
- The project was conducted in accordance with all monitoring and record-keeping requirements
- There are no existing material non-conformances or misstatements in the reported data

5.3 Verification Statement

The Verification Statement presents the official results of the verification process. It details the amount of CRTs issued, their vintage(s), and the verification standard. The Verification Statement confirms the verification activities and outcomes for all stakeholders: project developers, verification bodies, the Reserve, and the public.

The Reserve relies on the Verification Statement provided by the verification body as the basis for issuing CRTs. A positive Verification Statement indicates that the project and its reported emission reductions meet the Reserve standards, including the verification standards contained in this manual.

Unlike other verification documentation, the Verification Statement is a standardized, mandatory form that is available on the Reserve website.[8]

5.3.1 Preparing a Verification Statement

The Verification Statement must be signed by the Lead Verifier and Senior Internal Reviewer designated in the NOVA/COI form on file with the Reserve. No deviations are allowed. Verification Statements may be positive or negative. Positive statements provide the required reasonable assurance to the Reserve that the amount of CRTs to be issued is materially correct and the project is in compliance with the appropriate protocol. A positive Verification Statement may only be issued if the verification body determines with a reasonable level of assurance that the stated emission reductions are materially accurate.

5.3.2 Negative Verification Statement

If a project cannot be successfully verified, a negative Verification Statement shall be issued. The verification body shall grant the project developer a reasonable amount of time to implement corrective actions prior to issuing a negative statement. If, after issuing the List of

[8] Available at http://www.climateactionreserve.org/how/verification/verification-documents/.

Findings and allowing a sufficient amount of time for corrective actions, a project remains unverifiable due to material misstatements or inability to meet the eligibility criteria, the verification body shall issue a negative Verification Statement to the Reserve. The issuance of a negative Verification Statement does not mean that the project is not eligible or that it cannot be successfully verified. A negative Verification Statement signifies that the engagement between verification body and the project developer has concluded without the issuance of a positive statement.

Different types of unresolvable issues may arise between the verification body and the project developer during the verification process. Any time an issue of this nature arises, the verification body shall notify the Reserve and follow the process outlined below:

- If a verification body is unable to confirm that the project meets the required eligibility criteria or if there are material non-conformances with the protocol that the project developer cannot or will not correct, then the verification body must submit a negative Verification Statement and List of Findings to the Reserve electronically. The verification body must state that it is unable to verify the project and therefore cannot meet the required level of reasonable assurance. It shall detail the issues noted in the List of Findings. Reserve staff will then conduct a review in order to make a determination. Both the verification body and project developer will be notified of the Reserve's determination.
    - If the Reserve determines that the project is ineligible, the project will be de-listed. The verification documents and supporting information will be archived but not made public.
    - If the Reserve determines that the project is eligible and that further actions could be taken to resolve the issues, then the project may remain listed on the Reserve and the project developer may proceed with further verification activities and corrective actions if it chooses. The project remains subject to all deadlines and must be registered within 12 months of the end of the reporting period. If that deadline is not met, the project will be de-listed per the Reserve Program Manual, Section 3.4.3.
- If a verification body has found that a project has not remedied material issues identified and communicated to the project developer in the List of Findings after a reasonable amount of time, it must notify the Reserve of the inaction and submit the List of Findings. The Reserve staff will then contact the project developer and attempt to address the issues noted.

Some verification activities are halted due to lack of knowledge on how to resolve non-conformances, insufficient funding, or inactivity on identified corrective actions. If issues cannot be resolved with Reserve assistance, the verification body may be given permission by the Reserve to cease verification activities rather than issuing a negative Verification Statement. The project remains subject to all Reserve deadlines and must be registered within 12 months of the end of the reporting period.

5.4 Senior Internal Review

The Verification Report, Verification Statement and the List of Findings must be reviewed by an independent Senior Internal Reviewer for a quality assurance check. As stated in previous sections, the Senior Internal Reviewer must conduct an objective and impartial review of the verification team's work, which should include a risk-based analysis of the project documentation and data. No Verification Report shall be forwarded to a project developer until it has undergone this internal review. The Senior Internal Reviewer is also a signatory to the Verification Statement.

5.5 Exit Meeting

Project developers should be allowed at least 30 days to review and comment on the Verification Report. At the end of that review, the Lead Verifier and the appropriate project developer representative should hold an exit meeting to discuss the nature of any material or immaterial misstatements and review any required corrective actions.

Verification bodies should prepare a brief summary presentation of the verification findings for the project developer's key personnel. At the exit meeting, verifiers and project developers are encouraged to exchange lessons learned about the verification process and share thoughts for improving the process with the Reserve.

The goals of this meeting should be:

- Acceptance of the Verification Report, List of Findings, and Verification Statement (unless material misstatements still exist but can be remediated, in which case the verification contract may need to be revised and additional verification services scheduled)
    - If the project developer does not wish to retain the verification body for the additional verification services, the verification body should return all relevant project documentation to the project developer within 30 days and submit a negative Verification Statement to the Reserve
- Authorization for the verification body to complete the verification and upload the necessary documents to the Reserve

If the verification body is under contract for verification activities in the future, the verification body and project developer may wish to establish a schedule for the upcoming verification activities.

5.6 Submitting the Verification Documentation to the Reserve

Once the Verification Statement, the List of Findings and the Verification Report are complete, the verification body must electronically submit these documents into the Reserve software. The project developer will then submit the project for final approval and Reserve staff will receive an email notification that triggers a review of the documents by the Reserve.

Reserve staff will also review the data entered in the Reserve software and compare it to the uploaded Verification Report, Verification Statement and List of Findings to ensure that all proper procedures were undertaken by both the project developer and the verification body.

In this review process, Reserve staff will ensure consistency between projects and verification bodies as well as compliance with Reserve protocols, processes and procedures. Reserve staff may request corrections or clarifications from either the verification body or the project developer. The Reserve staff aim to be as timely as possible with their requests and responses to verifiers and project developers.

If all outstanding issues can successfully be resolved, the project will be registered, CRTs will be issued to the project developer, and the Verification Report and Verification Statement will be made public.

6 Administration and Reserve Intervention

6.1 Verification Oversight and Audits

Oversight is conducted by the Reserve to provide quality assurance and control on verification activities performed by accredited verification bodies. Oversight consists of a comprehensive examination and evaluation of project verification activities in order to assess verification body performance. It also serves as an opportunity for the Reserve to identify potential improvements to the program's processes and guidance. Oversight is not intended to hold a project or project developer to a different level of scrutiny or subject it to additional requirements. Oversight is an important element of the Reserve program and provides an extra level of assurance and transparency to bolster the validity of the credits issued.

The Reserve staff member or representative conducting oversight must be provided access to all project documentation and data reviewed by the verification body as well as participate in certain stages of the verification. The verification body will be notified that it has been selected for oversight upon the approval of the NOVA/COI form. Reserve attendance in the following activities must be accommodated:

- Kick-off meeting between the verification team and the project developer – in-person or conference call
- Project site visit
- Closing meeting between the verification team and the project developer – in-person or conference call

In addition, the Reserve must review or observe all issues and findings-related discussions between the verification body and project developer during the verification. This can be achieved through conference calls, copying the Reserve staff member or representative on emails, or, if necessary, forwarding all correspondence at the conclusion of verification activities. Including the Reserve in calls and emails allows for real-time review and will decrease the duration of the oversight process.

Oversight can be triggered at random; however, a verification body can expect oversight to occur in the following instances:

- The first verification of a newly released project type
- A verification body's first verification under a specific protocol
- The first verification managed by a newly-approved Lead Verifier
- When issues, warnings or complaints regarding the verification body or project developer arise

Audits are also conducted by the Reserve and may be initiated under similar circumstances. They are limited to a desktop review and are performed upon the completion of verification activities. While oversight covers the entirety of a verification body's processes and qualifications, an audit consists solely of an investigative review of the project data and documentation, as well as the verification body's analysis. The Reserve auditor must be granted the same degree of access that would be afforded to staff conducting an oversight, but participation in verification milestones will not occur.

The Reserve maintains the right to conduct oversight or audits at any time, and such activities will be conducted by a Reserve staff member, partner or Reserve consultant. Entities that may perform or participate in oversight activities or audits on behalf of the Reserve include regulatory agencies, accreditation bodies, third-party observers (for learning or educational purposes), or contractors hired by the Reserve. The Reserve staff or representative will make every effort to not impede the verification process.

Proprietary information will be handled confidentially. The Reserve, as well as any partners or consultants, are willing to enter into a Non-Disclosure Agreement (NDA) should the verification body or project developer require.

Travel and time costs for Reserve staff conducting oversight are covered by the Reserve. To minimize costs associated with reproduction or shipping, records should be shared electronically when possible. If electronic document sharing is not possible, the project developer may incur costs associated with providing requested documentation.

A staff member, partner or consultant performing oversight for the Reserve will observe and evaluate:

- The overall performance of the verification body by reviewing its processes and procedures while conducting verification activities
- Whether the project activities meet the protocol requirements
- Whether the GHG reductions data reported to the Reserve can be verified to a reasonable level of assurance

The Reserve representative performing oversight or conducting an audit may discuss preliminary observations with the verification body and project developer before reporting the findings to the Reserve. Information requests should be addressed promptly. The oversight or audit process shall close with the issuance of a letter detailing the findings and overall evaluation to the verification body, usually upon conclusion of verification activities.

The Reserve will make an effort to clearly coordinate and communicate planned oversight activities to verification bodies and project developers, but it reserves the right to adjust verification activity dates in order to accommodate the schedules of all relevant parties.

6.2 Warnings, Suspensions, Notices to Correct

If the Reserve finds that a verification body has failed to meet the Reserve's standards, it may require the verification body to undertake specified corrective actions. The Reserve may, at its own discretion, issue warnings, temporary suspensions, and notices to correct. It may also disqualify verification bodies or individual verifiers from future verification activities.

In instances where a verification body and a project developer find themselves in disagreement, the two parties should attempt to reach a resolution, relying first on the verification body's internal dispute resolution process (as required by ISO 14065). Either party may contact the Reserve for assistance in resolving issues that require guidance on the project protocols, COI determinations, or verification findings.

If a resolution cannot be reached in a disagreement related to project activities, the verification must be completed prior to the initiation of any dispute resolution process detailed in Section 6.4. The verification body must issue the List of Findings, Verification Statement and Verification

Report to the project developer and upload the documents in the Reserve software. The Reserve staff will conduct an internal review of the verification documentation as well as any additional supporting documentation, claims and information related to the disagreement that substantiate the opinions of the verification body or the assertions of the project developer. The Reserve will interview both parties and make a final determination in a committee comprised of no less than three staff members, two of which will be manager level or higher. The Reserve's determination will be issued in writing to all relevant parties.

6.3 Rescission of Verifier or Verification Body Approval

The Reserve maintains the right to rescind or suspend its recognition of an individual verifier or verification body for any period of time deemed appropriate. The Reserve will make every effort to accommodate the implementation of corrective actions prior to rescinding approval.

Suspensions could occur if the Reserve determines that a verification body or individual verifier intentionally violated the COI policies, committed willful misconduct, displayed negligence, proved unable to uphold obligations to the Reserve, or was responsible for any other significant non-conformance with Reserve rules, protocols or procedures.

The Reserve will make public any suspensions of verification bodies on its website. However, suspensions of individual verifiers, including Lead Verifiers, will not be publicly noticed.

Verification bodies could also be subject to suspension of their ISO 14065 accreditation issued by the accrediting body and must adhere to the rules and procedures surrounding that process.

6.4 Dispute Resolution Process

Verification bodies and project developers have a right to appeal Reserve determinations, including COI determinations, through the Reserve's formal dispute resolution process. An appeal to a specific determination, including a detailed explanation of the issue and any supporting evidence, must be electronically submitted to the Reserve. The Reserve will then convene a Dispute Resolution Committee to review the appeal.

The Dispute Resolution Committee will consist of an odd number of individuals, including at least one Reserve staff member not directly involved in the case, and one Reserve Board member, all of whom are knowledgeable of Reserve policies and procedures. The committee will be convened either in person or via conference call.

The Dispute Resolution Committee may consult outside experts for assistance, but these experts will not have a vote in the committee's final decision. All information reviewed will be kept confidential and should be uploaded to the Reserve software as restricted, private documents by either the project developer or the verification body. Each committee member must declare his or her freedom from any conflict of interest and will have an equal vote. The Dispute Resolution Committee will consider the original finding, the detailed explanation, and any supporting documents. The final determination will be based on a majority vote. The decision will be binding and will be notified to all parties in writing. The Dispute Resolution Committee has the power to suspend a verification body from conducting verification activities under the Reserve Program.

6.5 Record Keeping and Retention

The verification body must retain sufficient records to enable an ex-post verification of the project's emissions. The Reserve requires that the following Reserve project-related records be retained by the verification body in line with the time period specified in the relevant protocol or for a minimum of seven years after the end of the reporting period, whichever is longer. It should be noted that some records may be subject to fiscal or other legal requirements that are longer than the Reserve's mandated period.

Verification bodies shall retain electronic copies, as applicable, of:

- The project developer's Monitoring Plan
- The project developer's SSR and/or project activity data as well as evidence cited
- The verification plan
- The sampling plan
- The Verification Report
- The List of Findings
- The Verification Statement

Each verification body must have an easily accessible record-keeping system, preferably electronic, that provides readily available access to project information. Copies of the original activity and source data records shall be maintained within said record-keeping system, as these records are necessary to perform an ex-post verification or audit. The Reserve may at any time request access to the record-keeping system or any supporting documentation for oversight, monitoring, and auditing purposes.

Glossary

Accreditation body	Under ISO 14065, this is the authoritative body that assesses a verification body's competence to perform GHG verification activities.
Aggregation	Where smaller projects can register jointly as a group. Does not apply to all project types.
Climate Action Reserve	A North American offsets program that establishes standards for quantifying and verifying GHG emission reduction projects, issues carbon credits generated by said projects, and tracks the transfer and retirement of credits in a publicly-accessible online system.
Climate Reserve Tonne (CRT)	The unit of offset credits used by the Climate Action Reserve. One Climate Reserve Tonne is equal to one metric ton of CO_2e reduced or sequestered.
Conflict of interest (COI)	A situation in which, due to other activities or relationships with other persons or organizations, a person or firm is unable to render an impartial Verification Statement of a potential client's GHG reductions or the person or firm's objectivity in performing verification activities is otherwise compromised.
Continuous Emissions Monitoring System (CEMS)	The monitoring system required for all projects under the Nitric Acid Project Protocol for the direct measurement of the N_2O concentration and flow rate of the stack gas.
Contracted verifier	Under ISO 14065, this is a verifier who is independently contracted to operate as part of a verification team under the supervision of a verification body on specific verification activities. The contracted verifier is not a full-time employee of said verification body, but acts as the verification body's agent and representative while under contract. The use of contracted verifiers under such agreements does not constitute outsourcing.
Inherent uncertainty	Scientific uncertainty associated with measuring GHG emissions due to limitations on monitoring equipment or methodologies.
Joint verification	In cases where a project developer has multiple projects operating on a single site, the project developer has the option to hire a single verification body to assess the projects concurrently. Does not apply to all project types.
Lead Verifier	Employee or contracted verifier to a verification body who is primarily responsible for directing, supervising and the quality of verification activities undertaken on behalf of the Reserve. Each Lead Verifier must be designated as such on the COI Form and the Verification Policies Acknowledgment and Agreement form, and he or she must successfully

	complete sector-specific project verifier training. Each verification body operating within the Reserve program must employ or have under contract a minimum of two Lead Verifiers for each project type in which it conducts verification services.
Listed	A project moves from “new” status to “listed” status once the Reserve has satisfactorily reviewed the project submittal form and any other required documentation. Listed projects appear in the public interface of the Reserve software.
Material misstatement	An error that results in a significant difference between the reported and the true quantity or quality of project information to an extent that will influence performance or decisions.
Onsite assessment	A two- to three- day assessment at the site of the verification body's main office(s) that is conducted by the accreditation body (ANSI). The purpose of the onsite assessment is to confirm whether the operational capability of the verification body conforms to ISO 14065, ISO 14064-3, IAF MD 6, and other accreditation requirements, including those for specific GHG programs/registries and/or activities in specific sectors. This assessment provides assurance that the verification body has the capacity to perform the activities related to the scopes of accreditation for which it has applied.
Outsourcing	Under ISO 14065, this is the practice of an organization setting a contract arrangement with another organization to provide services tasked to the original organization. The Reserve allows verification bodies to outsource verification services with the exception of the Lead Verifier and Senior Internal Reviewer roles.
Project	A specific activity or set of activities intended to reduce GHG emissions, increase the storage of carbon, or enhance GHG removals from the atmosphere. Each project and its accompanying project boundary are defined in the relevant Reserve project protocol.
Project developer	An organization or individual that registers projects for the purpose of generating GHG emission reductions or removals. Under the Reserve program, project developers may be issued CRTs for the verified emission reductions/removals achieved through project activities. They can also transfer and manage CRTs in the Reserve software.
Project protocol	Document developed by the Reserve that contains the eligibility rules, GHG Assessment Boundary, quantification methodologies, monitoring and reporting parameters, and other guidelines for a specific project type. Project protocols are akin to the “methodologies” developed by other offset programs.

Reduction	A verified decrease in GHG emissions caused by project activity, as measured against an appropriate forward-looking estimate of baseline emissions for the project.
Reporting uncertainty	Errors made in the identification of emission sources and the management and calculation of GHG emissions. This arises due to incomplete understanding of climate science or a lack of ability to measure greenhouse gas emissions.
Registered	A project is “registered” once the project has been verified by an approved third-party verification body, submitted by the project developer to the Reserve for final approval, and accepted by the Reserve.
Removal	A verified increase in carbon stocks caused by a forest or urban forest project, as measured against an appropriate forward-looking estimate of baseline carbon stocks for the project.
Retired	CRTs transferred to a retirement account in the Reserve software are considered retired. Retirement accounts are permanent and locked in order to prevent the transfer of a retired CRT. Each retired CRT represents the offset of an equivalent tonne of CO_2 emissions, and is removed from further transactions on behalf of the environment.
Senior Internal Reviewer (SIR)	The Senior Internal Reviewer must be an active Lead Verifier who is designated on the NOVA/COI Form, is listed in the Verifier Acknowledgement and Agreement form, and has successfully completed project-specific verifier training. The Senior Internal Reviewer must remain independent of all verification activities; perform a final quality assurance review on the project data, the Verification Report, and the List of Findings; and sign the Verification Statement attesting to the accuracy of reported data.
Submitted	A project has been “submitted” once the submittal form and any other required documentation have been completed and uploaded to the Reserve software.
Tax Identification Number (TIN)	Number used to assess ownership and the corporate structure of any legal entities involved in a given project.
Trader/Broker/Retailer	Organization or individual that transfers and manages CRTs in the Reserve software but does not develop its own projects. The trader/broker/retailer holds legal title and all beneficial ownership rights to the CRTs in its account or, with respect to CRTs that will be retired in a Group Retirement Subaccount, the trader/broker/retailer must be granted the authority to act on behalf of the holder of the legal title and/or the beneficial ownership rights of the CRTs.
Validation	The process by which an independent validation body assesses a project plan for GHG reductions or removals as well as potential future outcomes. Validation is typically required for projects that do not follow established protocols,

	and occurs prior to project implementation in order to establish the project's methodologies, scope and eligibility to create GHG reductions or removals.
Verification	The process used to ensure that a given project developer's reported GHG emissions reductions or removals have met a minimum quality standard and complied with the Reserve's procedures and protocols.
Verification body	An ISO-accredited organization that has been approved by the Reserve to perform GHG verification activities for specific project protocols.
Verified	A project is considered "verified" once the project verifier has submitted the project's Verification Statement and the Verification Report in the Reserve software.
Verifier	An individual that is employed by or under contract to an ISO-accredited and Reserve-approved verification body and is qualified to provide verification services for specific project protocols.
Witness assessment	Observation of the verification body by the accrediting body in the performance of tasks related to the verification process for the scope (or group of sectoral scopes) of accreditation for which the verification body has applied. The purpose of the witness assessment is to determine whether verification activities are in line with the verification body's documented quality procedures and to assess its capability to conform to the applicable sectoral scope(s).

A.2.2 Coal Mine Methane Project Protocol v1.1

CLIMATE ACTION RESERVE

Version 1.1 | October 26, 2012

Coal Mine Methane

Project Protocol

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Abbreviations and Acronyms

ACM	Approved consolidated baseline and monitoring methodology under CDM
CAA	Clean Air Act
CDM	Clean Development Mechanism
CH_4	Methane
CMG	Coal mine gas
CMM	Coal mine methane
CNG	Compressed natural gas
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
CRT	Climate Reserve Tonne
EIA	Energy Information Administration
GHG	Greenhouse gas
HMM	Coal mine methane from horizontal pre-mining
ISO	International Organization for Standardization
IPCC	Intergovernmental Panel on Climate Change
LNG	Liquid natural gas
MSHA	Mine Safety and Health Administration
NMHC	Non-methane hydrocarbon
NOV	Notice of Violation
NOVA/COI	Notification of Verification Activities/Conflict of Interest
PMM	Coal mine methane from post-mining (gob wells)
QA/QC	Quality assurance/quality control
SMM	Coal mine methane from surface pre-mining
SSR	Sources, sinks and reservoirs
UNFCCC	United Nations Framework Convention on Climate Change
U.S. EPA	United States Environmental Protection Agency
VAM	Ventilation air methane
WBCSD	World Business Council for Sustainable Development
WRI	World Resources Institute

1 Introduction

The Climate Action Reserve (Reserve) Coal Mine Methane Project Protocol provides guidance to account for, report and verify greenhouse gas (GHG) emission reductions associated with destroying methane from active underground coal mines that would have otherwise been vented to the atmosphere from degasification systems, including drainage systems and ventilation systems. The protocol focuses on quantifying the change in methane emissions, but also accounts for effects on carbon dioxide emissions.

As the premier carbon offset registry for the North American carbon market, the Climate Action Reserve works to ensure environmental benefit, integrity, and transparency in market-based solutions that reduce GHG emissions. It establishes high quality standards for carbon offset projects, oversees independent third-party verification bodies, issues carbon credits generated from such projects and tracks the transaction of credits over time in a transparent, publicly-accessible system. By facilitating and encouraging the creation of GHG emission reduction projects, the Climate Action Reserve program promotes immediate environmental and health benefits to local communities, allows project developers access to additional revenues and brings credibility and value to the carbon market. The Climate Action Reserve is a private 501c(3) nonprofit organization based in Los Angeles, California.

Project developers that install coal mine methane destruction technologies use this document to register GHG reductions with the Reserve. The protocol provides eligibility rules, methods to calculate reductions, performance-monitoring instructions, and procedures for reporting project information to the Reserve. Additionally, all project reports receive independent verification by ISO-accredited and Reserve-approved verification bodies. Guidance for verification bodies to verify reductions is provided in the Reserve's Verification Program Manual and Section 8 of this protocol.

This protocol is designed to ensure the complete, consistent, transparent, accurate, and conservative quantification and verification of GHG emission reductions associated with a coal mine methane project.[1]

[1] See the WRI/WBCSD GHG Protocol for Project Accounting (Part I, Chapter 4) for a description of GHG reduction project accounting principles.

2 The GHG Reduction Project

2.1 Background

Methane is formed during the same geologic process that converts vegetative matter to coal; coal mining and post-mining processes release this methane from the coal and surrounding rock to the atmosphere. The amount of methane contained in and around a coal seam tends to be correlated with the amount of geologic pressure on the seam, which in turn depends on the seam depth.

When combined with air in concentrations of 5 to 15 percent, methane released by mining activity is explosive within the mine atmosphere. All underground coal mines in the United States are required to establish and maintain ventilation systems meeting detailed specifications set forth in federal regulations; these regulations are enforced by the Mine Safety and Health Administration (MSHA). Under the MSHA regulations, methane concentrations must be kept below 1 percent at the working face. Degasification is therefore an integral and critically important component of the underground mining process. Two primary degasification techniques are available to the operator: ventilation and methane drainage. Methane emissions are vented through mine ventilation shafts or methane drainage wells designed for the express purpose of removing the methane from the mine and venting it to the atmosphere.

Ventilation

The primary purpose of ventilation systems is to (1) dilute the methane in the mine air, and (2) remove the methane from the mine. Clean intake air is drawn into the mine from above ground through intake air shafts and/or horizontal drift entries, where it is channeled through the intake airways to the face, and then through the "returns" to a return air shaft(s) and/or drift entry(ies). The energy needed to move the large quantities of air required under the MSHA regulations through the ventilation system is provided by high-powered exhaust mine fans located on the surface at the return air shaft(s). Upon passing up the return air shaft(s) and through the fan, the mine air, including diluted methane, is vented to the atmosphere.

The ventilation systems emit highly dilute concentrations of the methane; typically the mine air vented from return air shafts is less than 1 percent methane. In this protocol, coal mine methane in mine air emitted through ventilation systems is referred to as ventilation air methane or "VAM."

Methane Drainage

At very gassy mines, ventilation is typically supplemented with methane drainage systems designed to remove methane either in advance of, or behind, the working face. These systems involve drilling boreholes, either from the surface or inside the mine, to drain methane from the coal seam, surrounding strata, or underground workings, thereby reducing the amount of methane that has to be handled by the ventilation system.

There are three main types of drainage systems, which may be employed in isolation or in combination with one another:

- Surface pre-mining boreholes
- Horizontal pre-mining boreholes
- Post-mining (or gob) boreholes

Each of these three system types are described in more detail below. Note that the protocol distinguishes between *coal mine gas* (CMG), which is the gas that comes out of the boreholes before any processing or enrichment and often contains various levels of other compounds (e.g. nitrogen, oxygen, carbon dioxide, hydrogen sulfide, NMHC, etc.) and *coal mine methane* (CMM), which represents only the methane portion of CMG.

Surface Pre-Mining Boreholes

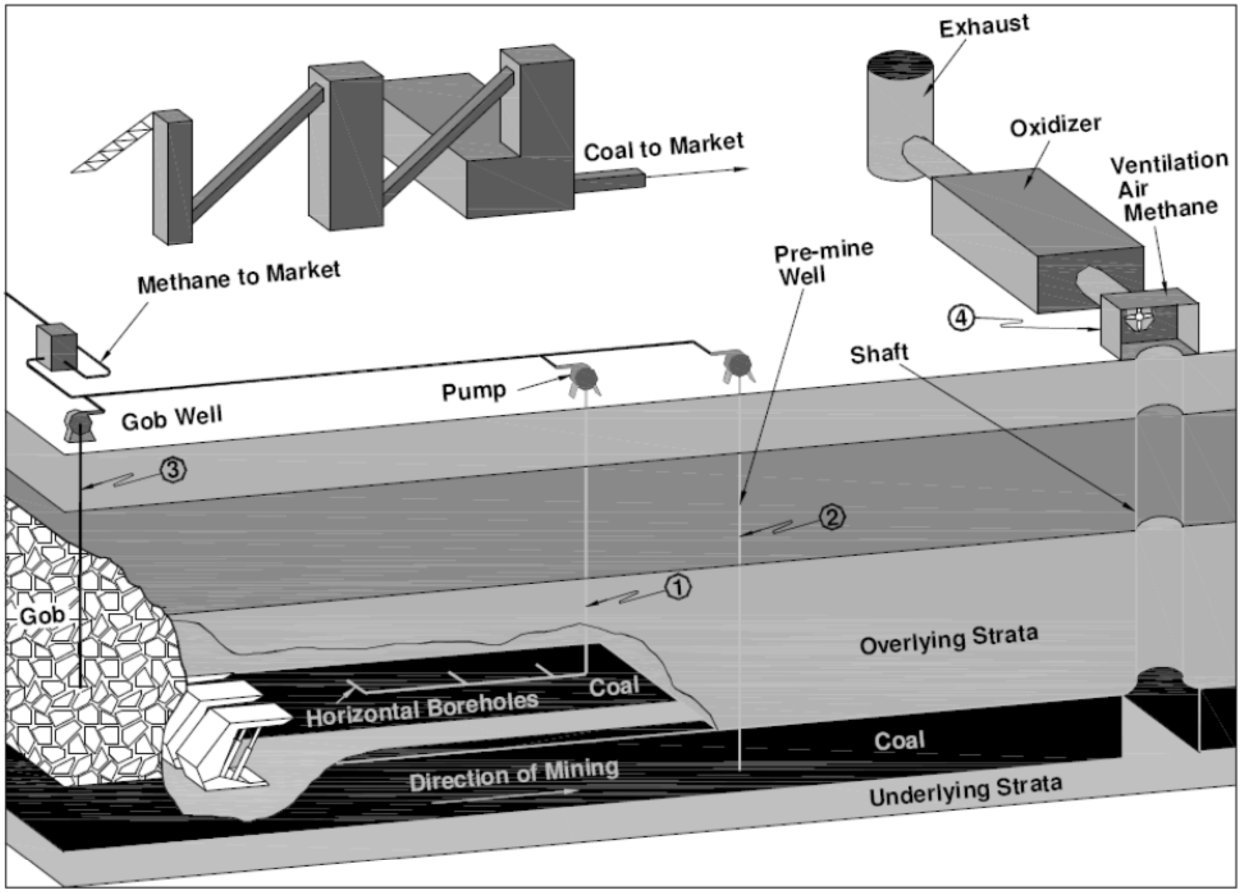
Surface pre-mining boreholes, or wells, are drilled from the surface to unmined portions of the coal seam in advance of mining (see Figure 2.1). They may be vertical, vertical to lateral, or even close to horizontal in their orientation. Surface-to-seam boreholes (otherwise known as surface-drilled directional boreholes) fall into this category. All of these surface pre-mining boreholes collect methane both from the seam itself, as well as from strata lying above the seam. Surface pre-mining wells may be drilled in locations that are not scheduled to be mined through for months or years; sometimes surface pre-mining wells are drilled before the associated mine even opens. Because they are drilled into virgin coal instead of the underground workings, pre-mining surface wells produce a high quality gas that is uncontaminated with mine air. Typically gas from these wells is at least 90 percent pure methane. In this protocol, the acronym “SMM” refers to coal mine methane drained from surface pre-mining boreholes.

Horizontal Pre-Mining Boreholes

Horizontal pre-mining boreholes, also referred to as “in-mine” boreholes, are drilled from within the mine (rather than from the surface) into unmined blocks of coal (see Figure 2.1). They are generally 400 to 800 feet in length, and are drilled shortly (as opposed to years) before mining occurs. Methane is drained from the boreholes by an in-mine vacuum piping system, which transports the methane to the surface where it may be either vented or captured and utilized. Because horizontal boreholes are drilled directly into the coal seam from the mine, drainage is limited to the methane contained within the seam; methane in the surrounding strata is unaffected. Hence recovery rates tend to be low (10 to 18 percent of the methane that would otherwise have been emitted from the ventilation system), although the gas recovered from horizontal boreholes is generally comparable in purity to methane drained from surface pre-mining boreholes. In this protocol, the acronym “HMM” refers to coal mine methane from horizontal pre-mining boreholes.

Post-Mining Boreholes

Post-mining, or gob, boreholes are drilled from the surface to a point 10 to 50 feet above the coal seam in advance of mining (see Figure 2.1). As mining advances under and past the well, the strata above the coal seam fractures and eventually collapses into the mined out area creating a de-pressurized zone extending up to the well; this zone is called the gob. Methane and other gases from the gob are collected via the gob well. The gob is exposed to the mine air, and hence the methane drained by gob wells is typically less pure than gas recovered by pre-mining boreholes, although it can be high quality early on in the life of the well. In many cases vacuum pumps are used in conjunction with gob wells to enhance gas recovery and to prevent methane from entering the mine’s ventilation circuit. However, these pumps may draw in mine air as well as methane, thus exacerbating the contamination of the recovered methane. Gob gas typically has a heating value ranging from 300 to 800 Btus per cubic feet (as compared with approximately 1,000 Btus per cubic foot for pipeline quality natural gas). In this protocol, the acronym “PMM” refers to coal mine methane from post-mining boreholes.



1) Horizontal Pre-Mining 2) Surface Pre-Mining 3) Post-Mining and 4) VAM
Source: U.S. EPA *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002 – 2006*, EPA -430-K-04-003, January 2009, p 2-5.

Figure 2.1. Schematic of Degasification Types

2.2 Project Definition

For the purpose of this protocol, a GHG reduction project (project) is defined as the installation and operation of any device, or set of devices, that result in the destruction of methane gas that would otherwise have been vented to the atmosphere from an active underground mine. Eligible mines include coal mines as well as trona mines that are classified by MSHA as Category III gassy underground metal and non-metal mines. While the protocol document refers to "coal mine methane" throughout, it may be applied to methane released through mining at Category III gassy underground trona mines.

A project must consist of either:

1. Installation and operation of a methane destruction device (or multiple devices) that destroys methane from a methane drainage system
2. Installation and operation of a methane destruction device (or multiple devices) that destroys ventilation air methane

A single project may not combine destruction of both drainage system and ventilation air methane, except under limited circumstances.[2] However, both drainage projects and VAM projects may be implemented and registered separately at the same mine. In addition, project developers may register multiple projects of the same type at the same mine, e.g. if separate destruction devices are installed at different times.

The protocol does not apply to projects that:

- Operate in surface mines
- Destroy methane from abandoned mines
- Destroy virgin coal bed methane (e.g. methane of high quality extracted from coal seams independently of any mining activities)
- Use CO_2 or any other fluid/gas to enhance CMM drainage before mining takes place

Under the terms of this protocol, the Reserve will issue CRTs only for the destruction of methane that would otherwise have been emitted to the atmosphere. Some projects may put captured CMM to beneficial use by using it to generate energy. Projects that use CMM for energy production are eligible under this protocol (since they destroy methane in the process). However, such projects will not receive credit for displacing GHG emissions associated with other fossil fuels that might have been used to produce energy. Although the Reserve does not issue CRTs for fossil fuel displacement, it strongly supports using CMM for energy production.

2.2.1 Drainage Projects

A drainage project is one that destroys methane that would otherwise be vented to the atmosphere from a methane drainage system. The methane drainage system may use any of the following extraction activities:

- Surface boreholes, including vertical and surface-to-seam directional drilling, located within the boundary of the mine to capture pre-mining CMM
- In-mine underground horizontal boreholes located within the boundary of the mine to capture pre-mining CMM
- Surface gob wells, underground boreholes, gas drainage galleries or other gob gas capture techniques located within the boundary of the mine, including gas from sealed areas, to capture post mining CMM

The borehole(s) that make up each project's drainage system must be defined by the project developer at the time of project submittal. The project developer must also specify what destruction device(s) is/are part of the drainage project. A single project must be explicitly defined and associated with specific boreholes and destruction devices. Multiple drainage projects may be implemented at a single mine, each with its own start date, crediting period, registration, and verification cycle. Each project's drainage system and destruction devices shall be detailed in the project diagram.

If additional boreholes are drilled and/or connected to an existing qualifying project destruction device, this is considered a project expansion. Similarly, if a new or additional destruction device is added to boreholes that are already connected to an existing project destruction device, this is considered a project expansion. If a new borehole or a borehole that is currently venting CMM

[2] In some cases, CMM from a drainage system is allowed to supplement a VAM project (see Section 3.4.1.1). In this case, a single project can consist of both drainage system and VAM methane destruction, as long as the drainage system contribution is limited to supplemental CMM.

is connected to a new destruction device, this may be considered a new project or a project expansion. If the project developer chooses to define it as a project expansion, the project start date and crediting period remain the same as the original project, and a single verification will cover all activities. If the project developer chooses to define it as a new project, the project will have a new start date and crediting period, and the new project will require separate verification.

2.2.2 Ventilation Air Methane Projects

A ventilation air methane project is one that destroys methane that would otherwise be vented from a ventilation shaft (or multiple shafts). The ventilation shaft(s) and VAM destruction device(s) that make up each VAM project must be defined by the project developer at the time of project submittal. A single project must be explicitly defined and associated with a specific shaft (or multiple shafts that are operating concurrently). Multiple projects may be implemented at a single mine, each with its own start date, crediting period, registration, and verification cycle. Each project's ventilation shaft(s) and VAM destruction device(s) shall be detailed in the project diagram.

If additional VAM destruction equipment is added to a shaft that is part of an existing project, this is considered a project expansion. If VAM destruction equipment is installed at a shaft that is not part of an existing project, this new shaft may be considered a new project or a project expansion. If the project developer chooses to define it as a project expansion, the project start date and crediting period remain the same, and a single verification will cover activities at both shafts. If the project developer chooses to define it as a new project, activities at the new shaft will have a new start date and crediting period, and will require separate verification. For a new VAM project, the VAM destruction equipment does not need to be new; it is only the ventilation shaft that must be new.

2.2.3 Non-Qualifying Devices

Non-qualifying devices are devices that destroy CMM but do not meet one or more of the eligibility rules as described in Section 3 and are located at the same mine where eligible project activities are taking place.[3] If there are any non-qualifying devices in operation at a mine, the project developer must include the non-qualifying device(s) in the project's GHG Assessment Boundary (see Section 0) and in the project diagram (see Section 7.1). Subsequent projects implemented at the same mine may exclude the same non-qualifying device(s) from their GHG assessment boundaries. In other words, if methane destruction at a non-qualifying device is accounted for by one project at a mine, it does not need to be accounted for by other projects at the same mine.

If any new non-qualifying devices become operational at the mine, these devices must be assigned to a specific project. In the case where a project developer has more than one registered project at a mine, the project developer may choose which project will account for the new non-qualifying device.

In the case where there are multiple projects with different crediting periods at a mine, when the crediting period for a project that includes a non-qualifying device expires, the non-qualifying device must be added to the GHG Assessment Boundary of a project that is still active. Thus, all non-qualifying devices must be properly accounted for in the GHG Assessment Boundary of an active project at the mine over time.

[3] Coal mine methane sent off-site through a pipeline is not eligible, but is also outside of the GHG Assessment Boundary. Because CMM sent to a pipeline is outside of the GHG Assessment Boundary, sources of emissions associated with pipelines are not included in the project diagram.

2.3 The Project Developer

The “project developer” is an entity that has an active account on the Reserve, submits a project for listing and registration with the Reserve, and is ultimately responsible for all project reporting and verification. Project developers may be mine owners, mine operators, GHG project financiers, utilities, independent energy companies, or other entities. The project developer must have clear ownership of the project’s GHG reductions. Ownership of the GHG reductions must be established by clear and explicit title, and the project developer must attest to such ownership by signing the Reserve’s Attestation of Title form.[4]

Under this protocol, the project developer is the only party required to be involved with project implementation.

[4] Attestation of Title form available at http://www.climateactionreserve.org/how/program/documents/.

3 Eligibility Rules

Projects that meet the definition of a GHG reduction project in Section 2.2 must fully satisfy the following eligibility rules in order to register with the Reserve.

Eligibility Rule I:	Location	⟶	*U.S. and its territories*
Eligibility Rule II:	Project Start Date	⟶	*No more than six months prior to project submission*
Eligibility Rule III:	Additionality	⟶	*Exceed legal requirements*
		⟶	*Meet performance standard*
Eligibility Rule IV:	Regulatory Compliance	⟶	*Compliance with all applicable laws*

3.1 Location

Under this protocol, only projects located at a single mine in the United States and its territories are eligible to register with the Reserve.[5]

3.2 Project Start Date

The project start date shall be defined by the project developer, but must be no more than three months after coal mine methane is first destroyed by the project, regardless of whether sufficient monitoring data is available to report reductions. The start date is defined in relation to the commencement of methane destruction, not other activities that may be associated with project initiation or development. For projects that involve pre-mine drainage, for example, well-drilling may commence in advance of any methane destruction; in such cases, the start date would be linked to the commencement of methane destruction, not drilling activities.

To be eligible, the project must be submitted to the Reserve no more than six months after the project start date.[6] Projects may always be submitted for listing by the Reserve prior to their start date.

3.3 Project Crediting Period

The crediting period for coal mine methane projects under this protocol is ten years. At the end of a project's first crediting period, a project developer may apply for eligibility under a second crediting period. However, the Reserve will cease to issue CRTs for GHG reductions if at any point in the future CMM destruction becomes legally required at the project site. Thus, the Reserve will issue CRTs for GHG reductions quantified and verified according to this protocol for a maximum of two ten year crediting periods after the project start date, or until the project activity is required by law, whichever comes first. Section 3.4.1 defines the conditions under which a project is considered legally required, and Section 3.4.1.1 describes the requirements to qualify for a second crediting period. If a project developer wishes to apply for eligibility under a

[5] The Reserve anticipates that this protocol could be applied throughout North America and internationally. To expand its applicability, data and analysis supporting an appropriate performance standard for other countries would have to be conducted accordingly. Refer to Appendix A for information on the performance standard analysis supporting application of this protocol in the United States.

[6] Projects are considered submitted when the project developer has fully completed and filed the appropriate project submittal documentation, available on the Reserve's website.

second crediting period, they must do so within the final six months of the initial crediting period. Deadlines and requirements for reporting and verification, as laid out in this protocol and the Verification Program Manual, will continue to apply without interruption.

The crediting period will also end if the mine where a project is located is declared abandoned; the Reserve will issue CRTs for GHG reductions quantified and verified according to this protocol only up until the date the mine was declared abandoned (i.e. the date when ventilation is discontinued).

3.4 Additionality

The Reserve strives to register only projects that yield surplus GHG reductions that are additional to what would have occurred in the absence of a carbon offset market.

Projects must satisfy the following tests to be considered additional:

1. The Legal Requirement Test
2. The Performance Standard Test

3.4.1 The Legal Requirement Test

All projects are subject to a Legal Requirement Test to ensure that the GHG reductions achieved by a project would not otherwise have occurred due to federal, state, or local regulations, or other legally binding mandates. A project passes the Legal Requirement Test when there are no laws, statutes, regulations, court orders, environmental mitigation agreements, permitting conditions, or other legally binding mandates requiring the destruction of coal mine methane at the project site. To satisfy the Legal Requirement Test, project developers must submit a signed Attestation of Voluntary Implementation form[7] prior to the commencement of verification activities each time the project is verified (see Section 8). In addition, the project's Monitoring Plan (Section 6) must include procedures that the project developer will follow to ascertain and demonstrate that the project at all times passes the Legal Requirement Test.

The Reserve did not identify any existing federal, state or local regulations that obligate mines to destroy coal mine methane.[8] If an eligible project begins operation at a mine that later becomes subject to a regulation, ordinance or permitting condition that calls for the destruction of coal mine methane, emission reductions may be reported to the Reserve up until the date that the coal mine methane is legally required to be destroyed. If the mine's methane emissions are included under an emissions cap (e.g. under a state or federal cap-and-trade program), emission reductions may likewise be reported to the Reserve until the date that the emissions cap takes effect.

[7] Attestation of Voluntary Implementation form available at http://www.climateactionreserve.org/how/program/documents/.

[8] To ensure that methane remains well below the concentrations at which it becomes explosive, the Federal Coal Mine Health and Safety Act of 1969 requires that methane levels be kept below 1 percent at the working face of the mine. To ensure that this requirement is met, all underground mines (gassy and non-gassy) are required under the same Act to develop ventilation systems that meet detailed specifications laid out in the federal regulations. The methane concentration limits and ventilation requirements are enforced by MSHA. The Act does not require, however, that CMM be destroyed.

3.4.1.1 U.S. EPA GHG Permitting Requirements under the Clean Air Act

Since January 2, 2011, the United States Environmental Protection Agency (U.S. EPA) has been phasing in[9] regulation of GHG emissions from major stationary sources under the Clean Air Act (CAA).[10]

Under this rule, commonly referred to as the "Tailoring Rule," all existing stationary sources emitting more than 100,000 tons (approximately 90,719 MT) of CO_2e emissions per year are required to obtain Title V operating permits for GHG emissions. Historically, underground mines have not been a source category subject to Title V operating permits. However, the Tailoring Rule also requires Prevention of Significant Deterioration (PSD) permits that address GHG emissions for (1) new source construction with emissions of 100,000 tons CO_2e per year or more and (2) major facility modifications resulting in GHG emission increases of 75,000 tons (approximately 68,000 MT) of CO_2e per year or more.[11] An assessment of "best available control technology" (BACT) for GHGs is required as part of the PSD permitting process; the permitting authority will ultimately mandate installation of a selected BACT. It is possible that future PSD permits may require installation of the same abatement technologies that are currently being voluntarily deployed as part of a carbon offset project at a mine. By legally mandating these technologies, PSD permit requirements may make them ineligible for carbon offsets because implementation of these projects would no longer be voluntary.

According to the Reserve's understanding of the EPA Tailoring Rule requirements, new mines or mines that undertake significant expansion may be subject to the new PSD requirements. If a mine triggers the PSD requirements and an official BACT review results in the mandatory installation of a technology that reduces CMM emissions, this activity will not be eligible for carbon offsets. Verification bodies will need to review these permits to ensure that projects are able to pass the Legal Requirement Test.

The Reserve continues to track these developments under the CAA. BACT determinations made at the state level will inform updates to the protocol's tests for additionality over time.

3.4.2 The Performance Standard Test

Projects pass the Performance Standard Test by meeting a performance threshold, i.e. a standard of performance applicable to all coal mine methane destruction projects, established on an ex-ante basis by this protocol.

There are numerous possible management options and end uses for coal mine methane, ranging from venting, to destruction by flares, to injection of the methane into natural gas pipelines. The Performance Standard Test employed by this protocol is based on a national

[9] All major sources already subject to PSD and/or Title V under the Clean Air Act for other pollutants have been subject to EPA's GHG permitting rules since January 2, 2011. All sources *not* previously subject to the Clean Air Act came under the GHG permitting rules on July 1, 2011, if they triggered the thresholds noted herein.

[10] U.S. EPA published the final rulemaking, "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule; Final Rule," in the Federal Register on June 3, 2010. The rulemaking is commonly referred to as the "Tailoring Rule," and amended 40 CFR Parts 51, 52, 70, and 71. http://www.gpo.gov/fdsys/pkg/FR-2010-06-03/pdf/2010-11974.pdf#page=1. In the final rulemaking in June 2010, the EPA also committed to undertake another rulemaking to conclude no later than July 1, 2012, which would phase in GHG permitting for smaller sources. However, in July 2012, EPA issued another rulemaking for the Tailoring Rule which continues to focus GHG permitting on the largest emitters, deferring GHG permitting for smaller sources to a later date. http://www.gpo.gov/fdsys/pkg/FR-2012-07-12/pdf/2012-16704.pdf

[11] "PSD and Title V Permitting Guidance for Greenhouse Gases" available at http://www.epa.gov/nsr/ghgdocs/epa-hq-oar-2010-0841-0001.pdf.

assessment of "common practice" for managing coal mine methane. The performance standard defines those end uses that the Reserve has determined will exceed common practice and therefore generates additional GHG reductions.[12]

Drainage projects pass the Performance Standard Test if they destroy CMM through any end-use management option other than injection into a natural gas pipeline for off-site consumption (e.g. flare, power generation, heat generation, producing CNG/LNG for vehicle use, etc.).

All VAM projects pass the Performance Standard Test. Such projects may include, but are not limited to, the following end uses for VAM:

- Thermal flow reversal reactors with or without catalysts
- Volatile organic compound concentrators
- Carbureted gas turbines
- Lean-fueled turbines with catalytic combustors that compress the air/methane mixture and then combust it in a catalytic combustor
- Hybrid coal- and ventilation air-fueled gas turbine technology
- Lean-fueled catalytic microturbine technology
- Combustion air for commercial engine and turbine technologies or a coal-fired steam power plant

In some cases, VAM projects may need to supplement VAM with CMM from drainage boreholes, either to increase the concentration of methane flowing into the combustion/oxidation device or to help balance the concentration of methane flowing into the combustion/oxidation device. This supplemental CMM is also eligible as part of a VAM project, as long as the supplemental CMM would not have been used for energy purposes.

The Performance Standard Test is applied at the time a project applies for registration with the Reserve. Once a project is registered, it does not need to be evaluated against future versions of the protocol or the Performance Standard Test for the duration of its first crediting period.

If a project developer wishes to apply for a second crediting period, the project must meet the requirements of the most current version of this protocol, including any updates to the Performance Standard Test.

3.5 Regulatory Compliance

As a final eligibility requirement, project developers must attest that project activities do not cause material violations of applicable laws (e.g. air, water quality, safety, etc.). To satisfy this requirement, project developers must submit a signed Attestation of Regulatory Compliance form prior to the commencement of verification activities each time the project is verified.[13] Project developers are also required to disclose in writing to the verifier any and all instances of legal violations – material or otherwise – caused by the project or project activities.

A violation should be considered to be "caused" by project activities if it can be reasonably argued that the violation would not have occurred in the absence of the project activities. If there is any question of causality, the project developer shall disclose the violation to the verifier.

[12] A summary of the study and analysis used to establish the Performance Standard Test is provided in Appendix A.
[13] Attestation of Regulatory Compliance form available at http://www.climateactionreserve.org/how/program/documents/.

If a verifier finds that project activities have caused a material violation, then CRTs will not be issued for GHG reductions that occurred during the period(s) when the violation occurred. Individual violations due to administrative or reporting issues, or due to "acts of nature," are not considered material and will not affect CRT crediting. However, recurrent administrative violations directly related to project activities may affect crediting. Verifiers must determine if recurrent violations rise to the level of materiality. If the verifier is unable to assess the materiality of the violation, then the verifier shall consult with the Reserve.

4 GHG Assessment Boundary

The GHG Assessment Boundary delineates the GHG sources, sinks, and reservoirs (SSRs) that shall be assessed by project developers in order to determine the total net change in GHG emissions caused by a coal mine methane project.

This protocol does not account for carbon dioxide emission reductions associated with displacing grid-delivered electricity or fossil fuel use.

Figure 4.1 provides a general illustration of the GHG Assessment Boundary for VAM projects, indicating which SSRs are included or excluded from the boundary.

Figure 4.2 provides a general illustration of the GHG Assessment Boundary for drainage projects, indicating which SSRs are included or excluded from the boundary.

Table 4.1 provides greater detail on each SSR and provides justification for all SSRs and gases that are excluded from the GHG Assessment Boundary. The GHG Assessment Boundary diagram and table presented here apply to both drainage and VAM projects; individual SSRs may or may not be relevant depending on the project type.

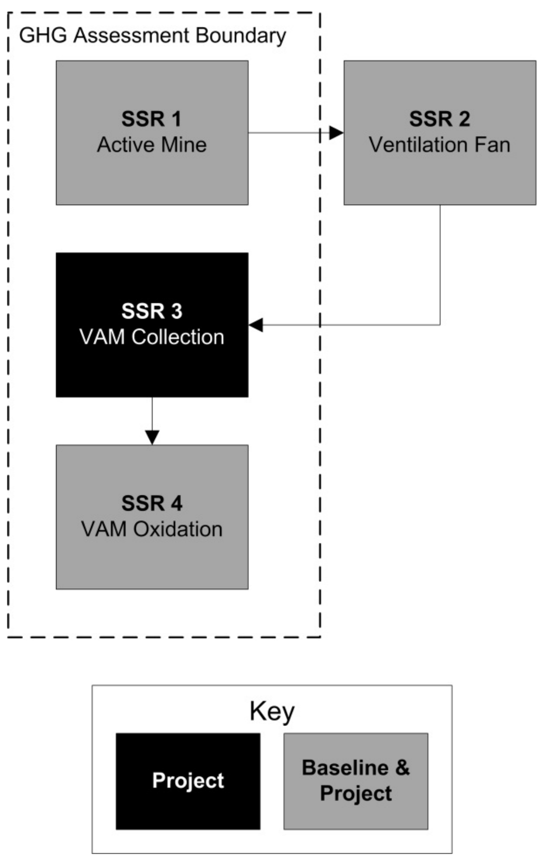


Figure 4.1. Illustration of the GHG Assessment Boundary for VAM Projects

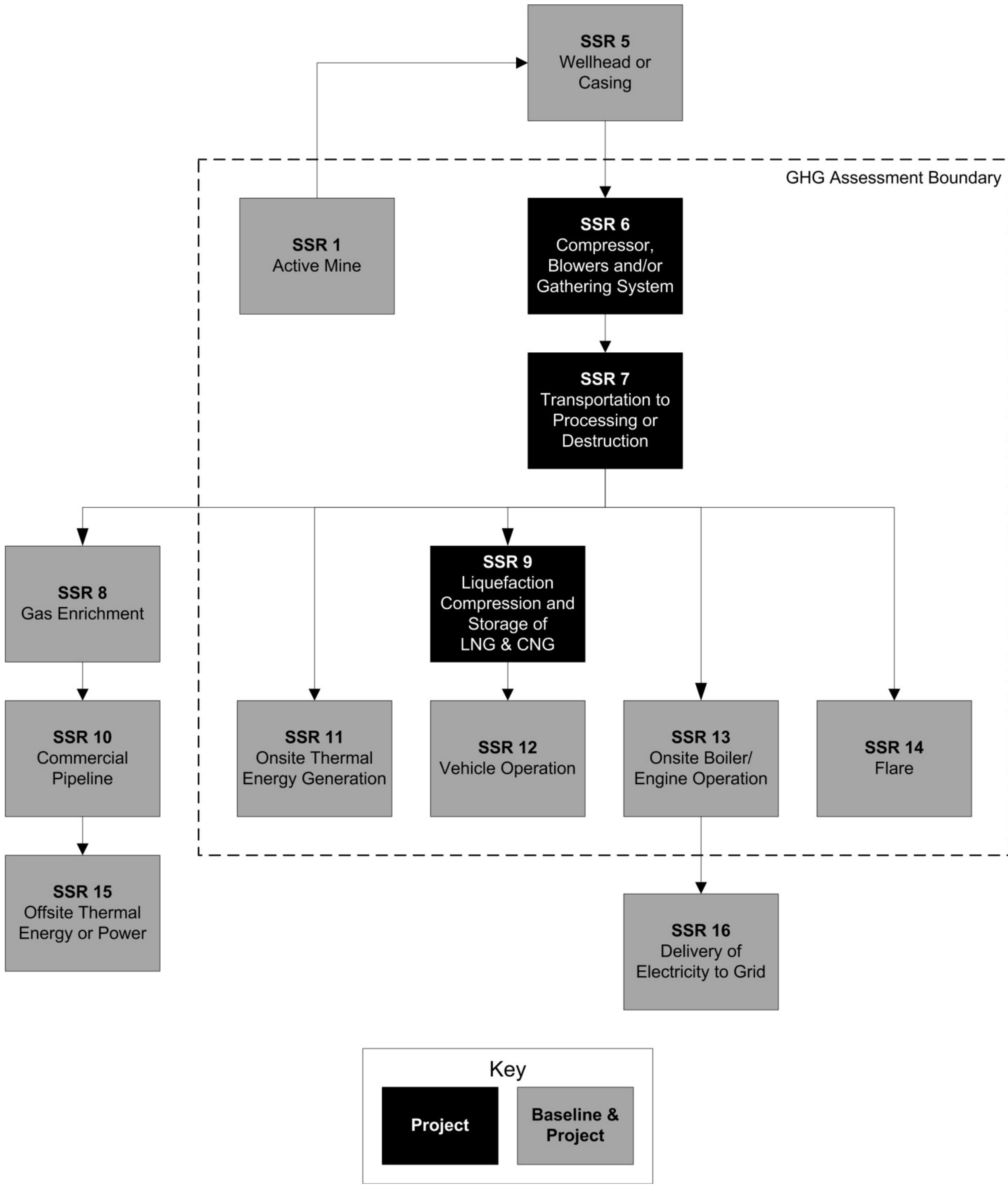


Figure 4.2. Illustration of the GHG Assessment Boundary for Drainage Projects

Table 4.1. Summary of Identified Sources, Sinks, and Reservoirs

SSR	Source	Gas	Relevant to Baseline (B) or Project (P)	Included/ Excluded	Justification/Explanation
1	Active mine – emissions as a result of venting	CH_4	B, P	Included	Main emission source of methane from active mines. A GHG project will directly affect these emissions. Only the change in CMM emissions release will be taken into account, by monitoring the methane used or destroyed by the project.
2	Ventilation fan	CO_2	n/a	Excluded	Ventilation fan operation will not be affected by the project.
3	VAM collection system	CO_2	P	Included	The VAM collection system will result in increased combustion emissions due to energy consumption from equipment used to drain, compress, blow, and gather VAM.
3	VAM collection system	CH_4	P	Excluded	Excluded for simplification. This emission source is assumed to be very small.
3	VAM collection system	N_2O	P	Excluded	Excluded for simplification. This emission source is assumed to be very small.
4	VAM oxidation	CO_2	B, P	Included	VAM project will result in increased CO_2 emissions from the oxidation of methane in ventilation air.
4	VAM oxidation	CH_4	P	Included	VAM project will result in CH_4 emissions from non-oxidized CH_4 from the ventilation air stream.
4	VAM oxidation	N_2O	n/a	Excluded	Excluded for simplification. This emission source is assumed to be very small.
4	Emissions from NMHC destruction	CO_2	P	Included if >3,500 mg/m^3	VAM project will result in increased CO_2 emissions from the combustion of NMHC in oxidizer (only included if NMHC accounts for more than 3,500 mg/m^3 (wet basis) of extracted ventilation air).
5	Fugitive emissions resulting from casing or wellhead	CH_4	n/a	Excluded	The project is unlikely to affect quantities of methane from this source.
6	Emissions resulting from energy used by compressors, blowers, and/or gathering system	CO_2	P	Included	If any additional equipment is required by the project beyond what is required in the baseline, energy consumption from additional equipment shall be accounted for. Energy used by equipment installed for the safety of the mine shall be excluded.
6	Emissions resulting from energy used by compressors, blowers, and/or gathering system	CH_4	P	Excluded	Excluded for simplification. This emission source is assumed to be very small.
6	Emissions resulting from energy used by compressors, blowers, and/or gathering system	N_2O	P	Excluded	Excluded for simplification. This emission source is assumed to be very small.
6	Fugitive emissions resulting from compressors, blowers, and/or gathering system	CH_4	n/a	Excluded	Excluded for simplification. This emission source is assumed to be very small.
7	Fuel consumption for transport of CMG to processing or destruction equipment	CO_2	P	Included	If any additional equipment is required by the project beyond what is required in the baseline, energy consumption from additional equipment shall be accounted for.
7	Fuel consumption for transport of CMG to processing or destruction equipment	CH_4	P	Excluded	Excluded for simplification. This emission source is assumed to be very small.
7	Fuel consumption for transport of CMG to processing or destruction equipment	N_2O	P	Excluded	Excluded for simplification. This emission source is assumed to be very small.
7	Fugitive emissions from transport of CMG to processing or destruction equipment	CH_4	n/a	Excluded	Excluded for simplification. This emission source is assumed to be very small.
8	Emissions resulting from gas enrichment	CO_2	n/a	Excluded	The project is unlikely to affect quantities of methane sent to gas enrichment systems, and will
8	Emissions resulting from gas enrichment	CH_4	n/a	Excluded	The project is unlikely to affect quantities of methane sent to gas enrichment systems, and will

SSR	Source	Gas	Relevant to Baseline (B) or Project (P)	Included/ Excluded	Justification/Explanation
	system	N_2O		Excluded	therefore not affect energy consumption or fugitive emissions from gas enrichment systems.
9	Emissions resulting from liquefaction, compression, or storage of methane for vehicle fuel	CO_2	P	Included	If any additional equipment is required by the project beyond what is required in the baseline, energy consumption from additional equipment shall be accounted for.
		CH_4		Excluded	Excluded for simplification. This emission source is assumed to be very small.
		N_2O		Excluded	Excluded for simplification. This emission source is assumed to be very small.
10	Fugitive emissions from commercial pipelines	CH_4	n/a	Excluded	The project is unlikely to affect quantities of methane delivered to commercial pipelines, and will therefore not affect fugitive pipeline emissions.
11	Emissions resulting from combustion during on-site thermal energy generation	CO_2	B, P	Included	If CMM is used for on-site thermal energy generation, project will result in increased CO_2 emissions from the destruction of methane to generate energy. This source is also included where CMM is sent to a non-qualifying device to generate energy.
		N_2O		Excluded	Excluded for simplification. This emission source is assumed to be very small.
	Emissions resulting from incomplete combustion during onsite thermal energy generation	CH_4	P	Included	If CMM is used for on-site thermal energy generation, project will result in increased CH_4 emissions from incomplete combustion. This source is also included where CMM is sent to a non-qualifying device to generate energy.
	Emissions from NMHC destruction	CO_2	P	Included if >35,000 mg/m^3	If CMM is used for on-site thermal energy generation, project will result in increased CO_2 emissions from the combustion of NMHC during energy generation (only included if NMHC accounts for more than 35,000 mg/m^3 of CMG). This source is also included where CMM is sent to a non-qualifying device to generate energy.
12	Emissions resulting from combustion during vehicle operation	CO_2	B, P	Included	If CMM is used to produce CNG/LNG to fuel vehicle operation, project will result in increased CO_2 emissions from the destruction of methane in CNG/LNG vehicles. This source is also included where CMM is used for non-qualifying vehicle operation.
		N_2O		Excluded	Excluded for simplification. This emission source is assumed to be very small.
	Emissions resulting from incomplete combustion during vehicle operation	CH_4	P	Included	If CMM is used to produce CNG/LNG to fuel vehicle operation, project will result in increased CH_4 emissions from incomplete combustion. This source is also included where CMM is used for non-qualifying vehicle operation.
	Emissions from NMHC destruction	CO_2	P	Included if >35,000 mg/m^3	If CMM is to produce CNG/LNG to fuel vehicle operation, project will result in increased CO_2 emissions from the combustion of NMHC during vehicle operation (only included if NMHC accounts for more than 35,000 mg/m^3 of CMG). This source is also included where CMM is used for non-qualifying vehicle operation.
13	Emissions resulting from combustion during on-site electricity generation	CO_2	B, P	Included	If CMM is used for on-site power generation, project will result in increased CO_2 emissions from the destruction of methane to generate power. This source is also included where CMM is sent to a non-qualifying device for electricity generation.

SSR	Source	Gas	Relevant to Baseline (B) or Project (P)	Included/ Excluded	Justification/Explanation
		N_2O		Excluded	Excluded for simplification. This emission source is assumed to be very small.
	Emissions resulting from incomplete combustion during on-site electricity generation	CH_4	P	Included	If CMM is used for on-site power generation, project will result in increased CH_4 emissions from incomplete combustion. This source is also included where CMM is sent to a non-qualifying device for electricity generation.
	Emissions from NMHC destruction	CO_2	P	Included if >35,000 mg/m^3	If CMM is used for on-site power generation, project will result in increased CO_2 emissions from the combustion of NMHC during power generation (only included if NMHC accounts for more than 35,000 mg/m^3 of CMG). This source is also included where CMM is sent to a non-qualifying device for electricity generation.
14	Emissions resulting from combustion during flaring	CO_2	B, P	Included	If CMM is sent to a flare, project will result in increased CO_2 emissions from the destruction of methane in flare. This source is also included where CMM is sent to a non-qualifying device for flaring.
		N_2O		Excluded	Excluded for simplification. This emission source is assumed to be very small.
	Emissions resulting from incomplete combustion during flaring	CH_4	P	Included	If CMM is sent to a flare, project will result in increased CH_4 emissions from incomplete combustion. This source is also included where CMM is sent to a non-qualifying device for flaring.
	Emissions from NMHC destruction	CO_2	P	Included if >35,000 mg/m^3	If CMM is sent to a flare, project will result in increased CO_2 emissions from the combustion of NMHC in flare (only included if NMHC accounts for more than 35,000 mg/m^3 of CMG).
15	Emissions resulting from offsite thermal or power generation	CO_2 N_2O	n/a	Excluded	The project is unlikely to affect quantities of methane delivered through pipelines to offsite thermal or power generation equipment, and will therefore not affect emissions from such equipment.
	Emissions resulting from incomplete combustion during off-site thermal energy or power generation	CH_4			
16	Delivery of electricity to grid	CO_2 CH_4 N_2O	n/a	Excluded	This protocol does not cover displacement of GHG emissions from the use of CMM for grid-connected electricity generation.
	Project construction and decommissioning emissions	CO_2 CH_4 N_2O	n/a	Excluded	Excluded for simplification. This emission source is assumed to be very small.

5 Quantifying GHG Emission Reductions

Figure 5.1. Organizational Chart for Equations in Section 5

GHG emission reductions from a coal mine methane project are quantified by comparing actual project emissions to baseline emissions at the mine. Baseline emissions are an estimate of the GHG emissions from sources within the GHG Assessment Boundary (see Section 0) that would have occurred in the absence of the coal mine methane project. Project emissions are actual

GHG emissions that occur at sources within the GHG Assessment Boundary. Project emissions must be subtracted from the baseline emissions to quantify the project's total net GHG emission reductions (Equation 5.1).

GHG emission reductions must be quantified and verified on at least an annual basis. Project developers may choose to quantify and verify GHG emission reductions on a more frequent basis if they desire. The length of time over which GHG emission reductions are quantified and verified is called the "reporting period."

Equation 5.1. GHG Emission Reductions

$$ER = BE - PE$$

Where,			Units
ER	=	GHG emission reductions of the project activity during the reporting period	tCO_2e
BE	=	Baseline emissions during the reporting period	tCO_2e
PE	=	Project emissions during the reporting period	tCO_2e

The calculations provided in this protocol are derived from internationally accepted methodologies.[14] Project developers shall use the calculation methods provided in this protocol to determine baseline and project GHG emissions in order to quantify GHG emission reductions.

Equation 5.2 provides guidance for calculating the mass of methane from the independently measured parameters of gas volume and methane concentration. Note that Equation 5.2 distinguishes between *coal mine gas* (CMG), which is the gas that comes out of the boreholes before any processing or enrichment and often contains various levels of other compounds (e.g. nitrogen, oxygen, carbon dioxide, hydrogen sulfide, NMHC, etc.) and *coal mine methane* (CMM), which represents only the methane portion of CMG.

Throughout the protocol, it is assumed that measured quantities of coal mine gas are converted to metric tons of methane using the following three parameters:

- Measured methane concentration of the coal mine gas
- Volume of gas, corrected to standard conditions (60°F and 1 atm)
- Density of methane at standard conditions (60°F and 1 atm)

[14] The Reserve's GHG reduction calculation method for CMM projects is derived from the UNFCCC approved consolidated methodology under the Kyoto Protocol's Clean Development Mechanism (ACM0008/Version 6), and also draws from Greenhouse Gas Services Methodology for Coal Mine Methane and Abandoned Mine Methane Capture and Destruction Projects (Version 1.1), the U.S. EPA Inventory of U.S. GHG Emissions and Sinks 1990-2007, and the 2006 IPCC Guidelines for National GHG Inventories.

Equation 5.2. Converting CMG Volumes to Metric Tons of CMM

$$tCH_4 = (0.0423 \times 0.000454) \times \sum_t scfCMG_t \times \%CH_{4t}$$

Where,			Units
tCH_4	=	Total quantity of CMM	tCH_4
t	=	Time interval for which flow and concentration measurements are aggregated (daily)	
$\%CH_{4t}$	=	The average methane fraction of the CMG in time interval t as measured	scf CH_4/scf
$scfCMG_t$	=	Total volume of coal mine gas in time interval t, as measured (see Equation 5.12 for additional guidance on adjusting the CMG flow for temperature and pressure)	scf CMG
0.0423	=	Density of methane	lb CH_4/scf CH_4
0.000454	=	tCH_4/lb CH_4	t/lb

5.1 Quantifying Baseline Emissions

Total baseline emissions must be estimated by calculating and summing the expected baseline emissions for all relevant SSRs (as indicated in Table 4.1) using Equation 5.3 and the supporting equations presented below.

Equation 5.3. Baseline Emissions

$$BE = BE_{MD} + BE_{MR}$$

Where,			Units
BE	=	Baseline emissions during the reporting period	tCO_2e
BE_{MD}	=	Baseline emissions from destruction of methane during the reporting period	tCO_2e
BE_{MR}	=	Baseline emissions from release of methane into the atmosphere during the reporting period	tCO_2e

Baseline emissions from CMM release or destruction may be associated with four different stages of mining activity:

1. Surface pre-mining: boreholes are drilled from the surface to unmined portions of the coal seam in advance of mining. CMM drained from surface pre-mining boreholes is represented as SMM in the equations below.

2. Horizontal pre-mining: boreholes are drilled horizontally from within the mine into unmined blocks of coal shortly before mining occurs (also referred to as in-mine boreholes). CMM drained from horizontal pre-mining boreholes is represented as HMM in the equations below.

3. Ventilation during mining through required ventilation systems. CMM collected from ventilation systems is represented as VAM in the equations below.

4. Post-mining: boreholes are drilled from the surface to a point 10 to 50 feet above the coal seam in advance of mining. As mining advances under and past the well, the strata above the coal seam collapses into the mined out area creating a de-pressurized zone extending up to the well; this zone is called the gob. CMM drained from post-mining boreholes is represented as PMM in the equations below.

5.1.1 Calculating Baseline Carbon Dioxide Emissions from Methane Destruction

Depending on the mine, some CMM may be destroyed in the baseline through flaring, oxidation, power generation, heat generation, etc., in non-qualifying destruction devices (see Section 2.2.3). Baseline emissions estimates must include the estimated CO_2 emissions from the destruction of CMM in non-qualifying devices, calculated using Equation 5.4.

The amount of CMM destroyed in the baseline by a non-qualifying destruction device (variables $SMM_{BL,i}$, $HMM_{BL,i}$, $PMM_{BL,i}$ and $VAM_{BL,i}$ in Equation 5.4) is established by calculating and comparing:

1. The actual amount of SMM, HMM, PMM and VAM destroyed by the non-qualifying destruction device during the reporting period; and
2. The amount of SMM, HMM, PMM and VAM destroyed by the non-qualifying destruction device over the three year period prior to the implementation of the project (or however long the non-qualifying destruction device has been operational, whichever is shorter), averaged according to the length of the reporting period. For example, if the reporting period is three months, then the three-year historical amount must be divided by 12 to derive the average amount of destruction in a three-month period.

The higher of either (1) or (2) must be used for $SMM_{BL,i}$, $HMM_{BL,i}$, $PMM_{BL,i}$ and $VAM_{BL,i}$ in Equation 5.4 (and Equation 5.5 in the next section).

Baseline emissions estimates must also include the CO_2 emissions from the destruction of non-methane hydrocarbons (NMHC) in non-qualifying devices, if NMHC comprise more than 35,000 mg/m^3 (measured on a wet basis at standard conditions) of extracted CMG or more than 3,500 mg/m^3 (measured on a wet basis at standard conditions) of extracted ventilation air.

If a non-qualifying destruction device in operation at the mine that was shut down less than one year prior to the project start date – or if a non-qualifying device is shut down at any point during the project's crediting period – the project developer must still account for the device in the baseline calculations, using the historical destruction amount calculated in (2), above. If the device was shut down more than one year before the project start date, it does not need to be accounted for in the baseline calculations.

If there is no destruction of methane in the baseline, then $BE_{MD} = 0$.

5.1.1.1 Treatment of CMM Sent to Pipeline

At some mines, the baseline may involve sending some CMM to a natural gas pipeline for off-site consumption/destruction. The pipeline could therefore be considered a "non-qualifying device." However, because on-site CMM destruction projects are unlikely to affect the quantity of CMM delivered to pipelines (due to the likely physical and temporal separation of these activities), emissions associated with pipelines are excluded from the GHG Assessment Boundary, and do not need to be accounted for in the baseline or the project emission calculations.

If a mine that has historically sent CMM to a pipeline ceases to do so, CMM from that drainage system (i.e. SMM, HMM or PMM) is not eligible for emission reductions, even if CMM is sent to an otherwise eligible destruction device. Furthermore, if a project mine begins to send CMM to a pipeline while a CMM project is still ongoing, CMM from that drainage system will also be deemed ineligible from that point in time forward.

Equation 5.4. Baseline CO_2 Emissions from CH_4 Destruction by Non-Qualifying Devices

$$BE_{MD} = \left(2.75 + r \times CEF_{NMHC}\right) \times \sum_i \left(SMM_{BL,i} + VAM_{BL,i} + HMM_{BL,i} + PMM_{BL,i}\right)$$

Where,			Units
BE_{MD}	=	Baseline emissions from destruction of methane in the reporting period	tCO_2e
i	=	Use of methane (flaring, power generation, heat generation, etc.). Uses must include all non-qualifying devices	
$SMM_{BL,i}$	=	CMM from surface pre-mining that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period	tCH_4
$VAM_{BL,i}$	=	VAM that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period	tCH_4
$HMM_{BL,i}$	=	CMM from horizontal pre-mining that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period	tCH_4
$PMM_{BL,i}$	=	Post-mining CMM that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period	tCH_4
2.75	=	CO_2 emission factor for combusted methane[15]	tCO_2e/tCH_4
CEF_{NMHC}	=	CO_2 emission factor for combusted non methane hydrocarbons	$tCO_2e/tNMHC$
r	=	Relative mass proportion of NMHC compared to methane	

With:

$$r = PC_{NMHC} / PC_{CH_4}$$

Where,			Units
r	=	Relative mass proportion of NMHC compared to methane	
PC_{NMHC}	=	NMHC concentration (in mass) in extracted CMG or ventilation air, measured on a wet basis	mg/m^3
PC_{CH4}	=	Concentration (in mass) of methane in extracted CMG or ventilation air, measured on wet basis at standard conditions (60°F and 1 atm)	mg/m^3

[15] Use the molar mass of CO_2 and CH_4 to calculate tCO_2e/tCH_4 (44/16 = 2.75).

5.1.2 Calculating Baseline Methane Emissions

Baseline emissions must include the methane that would have been emitted to the atmosphere in the absence of the project activity. Baseline emissions of methane are calculated by summing the total amount of methane *actually destroyed* by all qualifying and non-qualifying devices during the reporting period, and subtracting the amount that would have been destroyed in the baseline, as determined in Section 5.1.1. The difference between the actual amount of methane destroyed and what would have been destroyed determines how much methane would have been released. Baseline methane emissions must be calculated using Equation 5.5.

In Equation 5.5, actual methane destruction at all qualifying devices (those installed as part of the project to destroy methane) and non-qualifying devices must be accounted for. For qualifying devices, baseline values for methane destruction (i.e. $SMM_{BL,i}$, $HMM_{BL,i}$, $PMM_{BL,I}$, and $VAM_{BL,i}$) will be zero.

Baseline methane emissions from surface pre-mining (SMM) are quantified only during reporting periods in which the emissions *would have occurred* (i.e. when the borehole is mined through). Thus, baseline methane emissions from SMM must be determined according to the amount of *eligible* CMM that has been destroyed, as defined in Section 5.1.2.1.

If a qualifying device for a VAM project uses CMM to supplement the flow of VAM, the supplemental CMM must be accounted for in Equation 5.5 according to its source (SMM, HMM or PMM) if VAM flow and supplemental CMM flow are monitored separately, or directly through $VAM_{PJ,i}$ if only the resulting enriched flow is monitored.

Any methane that is still vented in the project scenario is not accounted for in the project emissions or baseline emissions, since it is vented in both scenarios. Similarly, the methane that is injected into natural gas pipeline in the project scenario is not accounted for in the project emissions or baseline emissions, since it is injected in both scenarios.

Equation 5.5. Baseline CH_4 Released to the Atmosphere

$$BE_{MR} = GWP_{CH_4} \times \left[\begin{array}{l} \sum_i \left(SMMe_i - SMM_{BL,i}\right) + \sum_i \left(HMM_{PJ,i} - HMM_{BL,i}\right) \\ + \sum_i \left(PMM_{PJ,i} - PMM_{BL,i}\right) + \sum_i \left(VAM_{PJ,i} - VAM_{BL,i}\right) \end{array} \right]$$

Where,			Units
BE_{MR}	=	Baseline methane emissions avoided by the project activity in the reporting period	tCO_2e
i	=	Use of methane (flaring, power generation, heat generation, etc.). *Uses must include all qualifying and non-qualifying devices*	
$SMMe_i$	=	*Actual* amount of CMM from surface pre-mining captured, sent to and destroyed by use i for the reporting period. For qualifying devices, only the *eligible* amount shall be quantified (see Section 5.1.2.1)	tCH_4
$SMM_{BL,i}$	=	CMM from surface pre-mining that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period, as determined in Section 5.1.1	tCH_4
$HMM_{PJ,i}$	=	*Actual* amount of CMM from horizontal pre-mining captured, sent to and destroyed by use i in the reporting period	tCH_4
$HMM_{BL,i}$	=	CMM from horizontal pre-mining that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period, as determined in Section 5.1.1	tCH_4
$PMM_{PJ,i}$	=	*Actual* amount of post-mining CMM captured, sent to and destroyed by use i in the project activity in the reporting period	tCH_4
$PMM_{BL,i}$	=	Post-mining CMM that would have been captured, sent to and destroyed by use I in the baseline scenario in the reporting period, as determined in Section 5.1.1	tCH_4
$VAM_{PJ,i}$	=	*Actual* amount of VAM sent to and destroyed by use i in the project activity in the reporting period. In the case of oxidation, $VAM_{PJ,i}$ is equivalent to MM_{OX} defined in Section 5.2.2	tCH_4
$VAM_{BL,i}$	=	VAM that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period, as determined in Section 5.1.1	tCH_4
GWP_{CH4}	=	Global warming potential of methane (21)	tCO_2e/tCH_4

5.1.2.1 Determining Eligible SMM

To determine the amount of baseline SMM that is eligible to be quantified in a given reporting period, project developers shall identify what boreholes within the bounds of active coal extraction were "mined through" during the reporting period. The most current mine plan shall be used to identify these boreholes.

Baseline SMM emissions are quantified only when the endpoint of the borehole is mined through. If the mine plan calls for mining past rather than through the borehole, then quantification is allowed once the linear distance between the endpoint of the borehole and the working face that will pass nearest the endpoint of the borehole has reached an absolute minimum.

For the purposes of this protocol, mined through is defined as any of the following:

- The working face intersects the endpoint of the borehole
- The working face passes directly underneath the bottom of the borehole, as long as the endpoint of the borehole is within a -50 meter to +150 meter vertical range of the mined coal seam
- The working face intersects the plane of the borehole
- The working face passes both underneath and to the side of the borehole (which will happen when the bottom of the borehole lies above a block of coal that will be left unmined as a pillar)

Once a borehole is mined through, SMM from that borehole that was captured and destroyed by a qualifying device in previous reporting periods may be reported and quantified for the current reporting period (as a component of $SMMe_i$ in Equation 5.5). $SMMe_i$ is calculated as the sum of SMM captured and destroyed by qualifying devices from wells mined through in the current reporting period ($SMMpre_e$), plus SMM captured and destroyed by qualifying devices from wells that were mined through in previous reporting periods ($SMMpost_e$) – see Equation 5.6.

Equation 5.6. Eligible CMM from Surface Pre-mining Boreholes

$$SMMe_i = SMMpre_e + SMMpost_e$$

Where,			Units
$SMMe_i$	=	Actual amount of CMM from surface pre-mining captured, sent to and destroyed by use i that is *eligible* for quantification in the reporting period	tCH_4
$SMMpre_e$	=	Actual amount of CMM destroyed by qualifying devices from surface pre-mining boreholes that were mined through during the current reporting period	tCH_4
$SMMpost_e$	=	Actual amount of CMM destroyed by qualifying devices in the current reporting period from surface pre-mining boreholes that were previously mined through	tCH_4

And:

$$SMMpre_e = \sum_{w_1} \left(SMM_{w_1} \right)$$

Where,			Units
$SMMw_1$	=	Total actual amount of CMM captured and destroyed from well w_1 from the project start date through the end of the current reporting period	tCH_4
w_1	=	The set of wells mined through during the current reporting period	

And:

$$SMMpost_e = \sum_{w_2} \left(SMM_{w_2} \right)$$

Where,			Units
$SMMw_2$	=	Actual amount of CMM captured and destroyed from well w_2 during the current reporting period	tCH_4
w_2	=	The set of wells mined through prior to the current reporting period	

For example, at a mine in which five surface pre-mining wells had been drilled and whose reporting period is 12 months long, if all five wells are mined through in year 4, then in years 1 to 3 the eligible CMM from surface pre-mining would be zero. In year 4 it would be the cumulative volume for the previous three years plus the volume extracted in year 4. In year 5, it would only be the volume extracted in year 5.

5.2 Quantifying Project Emissions

Project emissions must be quantified at a minimum on an annual, *ex-post* basis. As shown in Equation 5.7, project emissions equal the sum of:

- CO_2 emissions from energy used to collect, process, transport and destroy CMM/VAM
- CO_2 emissions from CMM/VAM destroyed in qualifying and non-qualifying destruction devices
- Uncombusted CH_4 emissions from qualifying and non-qualifying destruction devices

Equation 5.7. Project Emissions

$$PE = PE_{ME} + PE_{MD} + PE_{UM}$$

Where,			Units
PE	=	Project emissions during the reporting period	tCO_2e
PE_{ME}	=	Project emissions from energy required for methane collection, transport, and combustion during the reporting period	tCO_2e
PE_{MD}	=	Project emissions from methane destroyed during the reporting period	tCO_2e
PE_{UM}	=	Project emissions from uncombusted methane during the reporting period	tCO_2e

5.2.1 Project Emissions from Energy Required for Methane Collection, Transport, and Combustion

Included in the GHG Assessment Boundary are carbon dioxide emissions resulting from fossil fuel combustion and/or use of grid-delivered electricity for on-site equipment that is used for:

- VAM collection
- Compressors, blowers and/or CMM gathering systems
- Transporting CMM to on-site combustion
- Liquefaction, compression and storage of liquid natural gas (LNG) or compressed natural gas (CNG) created from CMM
- Transporting CMM to boilers/engines for power generation
- Transporting CMM to a flare

If the project utilizes fossil fuel or grid electricity to power equipment necessary for performing the above processes, the resulting project carbon dioxide emissions shall be calculated per Equation 5.8 below. Note that fossil fuel or grid electricity to power equipment installed for the safety of the mine shall be excluded, as that equipment is not within the GHG Assessment Boundary of the project.

Equation 5.8. CO_2 Emissions from Fossil Fuel and Grid Electricity

$$PE_{ME} = \left(CONS_{ELEC,PJ} \times CEF_{ELEC}\right) + \frac{\left(CONS_{HEAT,PJ} \times CEF_{HEAT} + CONS_{FossFuel,PJ} \times CEF_{FossFuel}\right)}{1000}$$

Where,			Units
PE_{ME}	=	Project emissions from energy required for methane collection, transport, and combustion during the reporting period	tCO_2e
$CONS_{ELEC,PJ}$*	=	Additional electricity consumption for destruction of methane during the reporting period, if any	MWh
CEF_{ELEC}	=	CO_2 emission factor of electricity used by mine during the reporting period [16]	tCO_2/MWh
$CONS_{HEAT,PJ}$	=	Additional heat consumption for destruction of methane during the reporting period, if any	volume
CEF_{HEAT}	=	CO_2 emissions factor of heat used by mine during the reporting period; see Appendix B for guidance on deriving emission factor	kg CO_2/ volume
$CONS_{FossFuel,PJ}$	=	Additional fossil fuel consumption for destruction of methane during the reporting period, if any	volume
$CEF_{FossFuel}$	=	CO_2 emission factor of fossil fuel used by mine during the reporting period; see Appendix B for emission factors by fuel type	kg CO_2/ volume
1/1000	=	Conversion of kg to metric tons	

* If total electricity being generated by project activities is $\geq$ the additional electricity consumption, then $CONS_{ELEC,PJ}$ shall not be accounted for in the project emissions and shall be omitted from the equation above.

5.2.2 Project Emissions from Destruction of Captured Methane

When CMM/VAM is burned in a flare, heat or power plant, or oxidized in an oxidation unit, carbon dioxide emissions are released and must be accounted for. In addition, if NMHC comprise more than 35,000 mg/m^3 (measured on a wet basis at standard conditions) of extracted CMG or more than 3,500 mg/m^3 (measured on a wet basis at standard conditions) of extracted ventilation air, carbon dioxide emissions from combustion of NMHC must also be accounted for.

Equation 5.9 must be used to calculate carbon dioxide emissions from destruction of captured methane at qualifying and non-qualifying devices.

Note: Although baseline methane emissions from surface pre-mining are accounted for only when they are eligible (i.e. after the borehole is mined through), carbon dioxide emissions

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[16] Refer to the version of the U.S. EPA eGRID that most closely corresponds to the time period during which the electricity was used. The project shall use the annual total output emission rates for the subregion where the project is located, not the non-baseload output emission rates. The eGRID tables are available from the U.S. EPA website: http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

resulting from the destruction of surface pre-mining CMM must be accounted for in the period during which the destruction occurs, using Equation 5.9.

Equation 5.9. CO_2 Emissions from Destruction of Captured CH_4

$$PE_{MD} = \left(MD_{OX} + MD_i\right) \times \left(2.75 + r \times CEF_{NMHC}\right)$$

With:

$$r = PC_{NMHC} \big/ PC_{CH_4}$$

Where,			Units
PE_{MD}	=	Project emissions from methane destroyed during the reporting period	tCO_2e
MD_i[17]	=	Methane destroyed by all qualifying and non-qualifying devices during the reporting period	tCH_4
MD_{OX}	=	Methane destroyed through oxidation during the reporting period	tCH_4
2.75	=	CO_2 emission factor for combusted methane	tCO_2/tCH_4
CEF_{NMHC}	=	CO_2 emission factor for combusted NMHC[18]	$tCO_2/tNMHC$
r	=	Relative mass proportion of NMHC compared to methane	
PC_{NMHC}	=	NMHC concentration (in mass) in extracted CMG or ventilation air, measured on a wet basis at standard conditions (60°F and 1 atm)	mg/m^3
PC_{CH4}	=	Concentration (in mass) of methane in extracted CMG or ventilation air, measured on wet basis at standard conditions	mg/m^3

For each end-use destruction device (qualifying and non-qualifying), the amount of gas destroyed depends on the efficiency of combustion for that destruction device. For VAM project destruction devices, Equation 5.10 must be used to quantify the methane destroyed by oxidation, which accounts for the destruction efficiency of the oxidation unit on a continuous basis. For drainage project destruction devices, Equation 5.11 must be used to quantify the methane destroyed for each qualifying and non-qualifying device.

Using Equation 5.11, project developers have the option to use either the default methane destruction efficiencies provided in Appendix B, or site-specific methane destruction efficiencies. Site specific destruction efficiencies for each qualifying or non-qualifying device must be determined by a source-test service provider accredited by a state or local agency. If the project developer chooses to use site-specific destruction efficiencies, the destruction device shall be source tested at least annually and the destruction efficiency updated accordingly.

[17] MD_i includes methane from all SMM sent to qualifying devices, not just eligible SMM.
[18] Because concentrations of different NMHC components may vary over time, the appropriate emission factor shall be obtained through annual analysis of captured gas from each drainage system type.

Equation 5.10. CH_4 Destroyed by VAM Oxidation

$$MD_{OX} = MM_{OX} - PE_{OX}$$

Where,			Units
MD_{OX}	=	Methane destroyed through oxidation during the reporting period	tCH_4
MM_{OX}	=	Methane measured sent to oxidizer during the reporting period	tCH_4
PE_{OX}	=	Project emissions of non-oxidized CH_4 from oxidation of the VAM stream during the reporting period	tCH_4

And:

$$MM_{OX} = VAM_{flow.rate,y} \times time_y \times PC_{CH_4.VAM} \times D_{CH_4}$$

Where,			Units
$VAM_{flow.rate,y}$	=	Average flow rate of ventilation air entering the oxidation unit during period y corrected if needed for inlet flow gas pressure and temperature ($P_{VAMinflow}$ and $T_{VAMinflow}$ respectively) per Equation 5.12	scfm
$time_y$	=	Time during which VAM unit is operational during period y	m
$PC_{CH4.VAM}$	=	Concentration of methane in the ventilation air entering the oxidation unit corrected if needed for pressure and temperature in the vicinity of the methane analyzer	scf/scf
D_{CH4}	=	Density of methane under standard conditions	tCH_4/scf

And:

$$PE_{OX} = VAM_{flow.rate,y} \times time_y \times PC_{CH_4.exhaust} \times D_{CH_4}$$

Where,			Units
$PC_{CH4.exhaust}$	=	Concentration of methane in the ventilation air exhaust corrected if needed for pressure and temperature in the vicinity of the methane analyzer ($P_{VAManalyzerinflow}$, $T_{VAManalyzerinflow}$, $P_{VAMnalyzerexhaust}$, and $T_{VAManalyzerexhaust}$)	scf/scf
D_{CH4}	=	Density of methane under standard conditions	tCH_4/scf

Equation 5.11. CH_4 Destroyed by Other (Non-VAM) Destruction Devices

$$MD_i = \sum_i MM_i \times DE_i$$

Where,			Units
MD_i	=	Methane destroyed by all qualifying and non-qualifying devices i during the reporting period	tCH_4
MM_i	=	Methane measured sent to use i during the reporting period	tCH_4
DE_i	=	Efficiency of methane destruction device i; see Appendix B for default destruction efficiencies by destruction device[19]	%

Equation 5.12. Adjusting CMG Flow for Temperature and Pressure

Important: Apply the following equation only if the CMG flow metering equipment does not internally correct for temperature and pressure.

$$MM_{adjusted,i} = MM_{unadjusted,i} \times \frac{520}{T} \times \frac{P}{1}$$

Where,			Units
$MM_{adjusted,i}$	=	Adjusted volume of CMG collected for the given time interval at utilization type i, adjusted to 60°F and 1 atm	scf/unit time
$MM_{unadjusted,i}$	=	Unadjusted volume of CMG collected for the given time interval at utilization type i	scf/unit time
T	=	Measured temperature of the CMG for the given time period (°R = °F + 460)	°R
P	=	Measured pressure of the CMM for the given time interval	atm

[19] Project developers have the option to use either the default methane destruction efficiencies provided, or site specific methane destruction efficiencies as provided by a state or local agency accredited source test service provider, for each of the combustion devices used in the project.

5.2.3 Project Emissions from Uncombusted Methane

Not all of the methane sent to the flare, to the oxidizer or used to generate heat and power will be combusted; a small amount will escape to the atmosphere. These emissions are calculated using Equation 5.13.

As in Equation 5.11, project developers again have the option to use either the default methane destruction efficiencies provided in Appendix B, or site specific methane destruction efficiencies in Equation 5.13. If the project developer chooses to use site specific destruction efficiencies in Equation 5.11, they must use the same destruction efficiencies in Equation 5.13.

Equation 5.13. Uncombusted CH_4 Emissions

$$PE_{UM} = \left[GWP_{CH_4} \times \sum_i MM_i \times (1 - DE_i) \right] + PE_{OX} \times GWP_{CH_4}$$

Where,

			Units
PE_{UM}	=	Project emissions from uncombusted methane during the reporting period	tCO_2e
GWP_{CH4}	=	Global warming potential of methane (21)	tCO_2e/tCH_4
i	=	The set of all qualifying and non-qualifying devices	
MM_i	=	Methane measured sent to use i during the reporting period	tCH_4
DE_i	=	Efficiency of methane destruction in use i; see Appendix B for default destruction efficiencies by destruction device[20]	%
PE_{OX}	=	Project emissions of non oxidized methane from oxidation of the VAM stream during the reporting period	tCH_4

[20] Project developers have the option to use either the default methane destruction efficiencies provided, or site specific methane destruction efficiencies as provided by a state or local agency accredited source test service provider, for each of the combustion devices used in the project.

6 Project Monitoring

The Reserve requires a Monitoring Plan to be established for all monitoring and reporting activities associated with the project. The Monitoring Plan will serve as the basis for verification bodies to confirm that the monitoring and reporting requirements in this section and Section 7 have been and will continue to be met, and that consistent, rigorous monitoring and record-keeping is ongoing at the project site. The Monitoring Plan must cover all aspects of monitoring and reporting contained in this protocol and must specify how data for all relevant parameters in Table 6.1 (below) will be collected and recorded.

At a minimum the Monitoring Plan shall stipulate the frequency of data acquisition; a record keeping plan (see Section 7.3 for minimum record keeping requirements); the frequency of instrument cleaning, inspection, field check and calibration activities; and the role of individuals performing each specific monitoring activity. The Monitoring Plan should include QA/QC provisions to ensure that data acquisition and meter calibration are carried out consistently and with precision. The Monitoring Plan shall also contain a detailed diagram of the coal mine gas collection and destruction system, including the placement of all meters and equipment that affect SSRs within the GHG Assessment Boundary (see Figure 4.1 and Figure 4.2).

Finally, the Monitoring Plan must include procedures that the project developer will follow to ascertain and demonstrate that the project at all times passes the Legal Requirement Test (Section 3.4.1).

Project developers are responsible for monitoring the performance of the project and ensuring that the operation of CMM destruction devices is consistent with the manufacturer's recommendations for each piece of equipment.

6.1 Monitoring Requirements

For drainage projects, the drainage systems and methane destruction devices must be monitored with measurement equipment that directly meters:

- The total flow of CMG from each drainage system defined as part of a project, measured continuously and recorded every 15 minutes or totalized and recorded at least daily, adjusted for temperature and pressure

- The flow of CMG delivered to each destruction device (unless otherwise allowed by Section 6.1.1), measured continuously and recorded every 15 minutes or totalized and recorded at least daily, adjusted for temperature and pressure

- The fraction of methane in the CMG from each drainage system, measured continuously and recorded every 15 minutes and averaged at least daily

For VAM projects, monitoring requirements include:

- The total inlet flow entering the oxidation unit, measured continuously and recorded every two minutes to calculate average flow per hour

- The fraction of methane in the ventilation air entering the oxidation unit and in the exhaust gas, measured continuously and recorded every two minutes to calculate average methane concentration per hour

- If required in order to standardize the flow rate, the temperature and pressure in the vicinity of the flow meter, measured continuously and recorded at least every hour to calculate hourly pressure and temperature.

- If required in order to correct methane concentration readings, the temperature and pressure in the vicinity of the methane analyzer, measured continuously and recorded at least every hour to calculate hourly pressure and temperature.

All flow data collected must be corrected for temperature and pressure at standard conditions (60°F and 1 atm). Equation 5.12 must be applied if flow metering equipment does not make this correction automatically. Depending on the methane analyzer technology used, methane concentration data may or may not need to be corrected for temperature and pressure. If the methane analyzer technology used requires adjustment for temperature and pressure, then concentration data must also be corrected to 60°F and 1 atm.

For both VAM projects and drainage projects, NMHC content of the CMG shall be determined on an annual basis by a full gas analysis using a gas chromatograph at an ISO 17025 accredited lab or a lab that has been certified by an accreditation body conformant with ISO 17025[21] to perform test methods appropriate for NMHC content analysis.[22] Separate gas samples shall be collected by a third-party technician prior to each destruction device within the project definition.

Operational activity of the CMM drainage systems and the destruction devices shall be monitored and documented at least hourly to ensure actual methane destruction. GHG reductions will not be accounted for during periods in which the destruction device is not operational. For flares, operation is defined as thermocouple readings above 500°F. For all other destruction devices, the means of demonstration shall be determined by the project developer and subject to verifier review and professional judgment.

6.1.1 Arrangement of CMG Metering Equipment

For drainage projects, the CMG from each drainage system (i.e. surface pre-mining boreholes, horizontal pre-mining boreholes, or post-mining boreholes) must be monitored separately prior to interconnection with other CMG sources. The volumetric gas flow, methane concentration, temperature, and pressure shall be monitored and recorded separately for each drainage system.

In addition, the flow of gas to each destruction device must be monitored separately for each destruction device, except under certain conditions. Specifically, if all destruction devices are of identical efficiency and verified to be operational throughout the reporting period, a single flow meter may be used to monitor gas flow to all destruction devices. Otherwise, the destruction efficiency of the least efficient destruction device shall be used as the destruction efficiency for all destruction devices monitored by this meter.

If a project using a single meter to monitor gas flow to multiple destruction devices has any periods when not all destruction devices downstream of a single flow meter are operational, methane destruction from the set of downstream devices during these periods will only be

[21] Such as the American Industrial Hygiene Association (AIHA), the American Association for Laboratory Accreditation (A2LA) and the National Environmental Laboratory Accreditation Program (NELAP).
[22] For example, NIOSH method number 1550 for portable gas chromatography.

eligible provided that the verifier can confirm all of the following requirements and conditions are met:

a. The destruction efficiency of the least efficient downstream destruction device in operation shall be used as the destruction efficiency for all destruction devices downstream of the single meter; and
b. All devices are either equipped with valves on the input gas line that close automatically if the device becomes non-operational (requiring no manual intervention), or designed in such a manner that it is physically impossible for gas to pass through while the device is non-operational; and
c. For any period during which one or more downstream destruction devices are not operational, it must be documented that the remaining operational devices have the capacity to destroy the maximum gas flow recorded during the period.

6.2 Instrument QA/QC

Monitoring instruments[23] shall be inspected, cleaned, and calibrated according to the following schedule.

All gas flow meters[24] and continuous methane analyzers must be:

- Cleaned and inspected on a regular basis, as specified in the project's Monitoring Plan, with the activities and results documented by site personnel. Cleaning and inspection frequency must, at a minimum, follow the manufacturer's recommendations.

- Field checked for calibration accuracy by an appropriately trained individual or a third-party technician with the percent drift documented, using either a portable instrument or manufacturer specified guidance, at the end of – but no more than two months prior to or after – the end date of the reporting period.[25] If a portable calibration instrument is used for field checks, the portable instrument shall be maintained and calibrated per the manufacturer's specifications, and calibrated at least annually by the manufacturer or at an ISO 17025 accredited laboratory. For portable methane analyzers, the portable instrument must be field calibrated to a known sample gas prior to each use.

- Calibrated by the manufacturer or a third-party calibration service at the frequency recommended by the manufacturer. If the manufacturer does not specify a recommended calibration schedule, then no calibrations are required, unless a field check reveals a difference of +/- 5% or more.

    - Flow meter calibrations shall be documented to show that the meter was calibrated to a range of flow rates corresponding to the flow rates expected at the mine.
    - Methane analyzer calibrations shall be documented to show that the calibration was carried out to the range of conditions (temperature and pressure) corresponding to the range of conditions as measured at the mine.

[23] If separate instruments are used for monitoring temperature and pressure, these instruments must also meet the specified QA/QC guidelines.
[24] Field checks and calibrations of flow meters shall assess the volumetric output of the flow meter.
[25] Instead of performing field checks, the project developer may have equipment calibrated by the manufacturer or a third-party calibration service per manufacturer's guidance, at the end of, but no more than two months prior to or after, the end date of the reporting period to meet this requirement.

If the field check on a piece of equipment reveals a difference of +/- 5% or more between the value measured by the portable calibration instrument and the value measured by the monitoring instrument, calibration by the manufacturer or a third-party calibration service is required for that piece of equipment.

For the interval between the last successful field check/calibration and any field check/calibration event revealing accuracy outside the +/- 5% threshold, all data from that meter or analyzer must be scaled according to the following procedure based on the results of the calibration report from the manufacturer or third-party service provider. These adjustments must be made for the entire period from the last successful field check/calibration until such time as the meter is properly calibrated and in place.

1. For calibrations that indicate an underestimation of emission reductions, the metered values must be used without correction.

2. For calibrations that indicate an overestimation of emission reductions, the metered values must be adjusted based on the greatest calibration drift recorded at the time of calibration.

For example, if a project conducts field checks quarterly during a year-long reporting period, then only three months of data will be subject at any one time to the penalties above. However, if the project developer feels confident that the meter does not require field checks or calibration more than annually, then failed events will accordingly require the adjustments above to be applied to the entire year's data. Further, frequent calibration may minimize the total accrued drift (by zeroing out any error identified), and result in smaller overall deductions.

In order to provide flexibility in verification, data monitored up to two months after a field check may be verified. As such, the end date of the reporting period must be no more than two months after the latest successful field check. A field check conducted up to two months after the end date of a reporting period is also acceptable to confirm the accuracy of the equipment during the reporting period. Note that while a field check completed outside of the 12 month reporting period may be used, only the 12 months of data specified as the reporting period can be verified.

Project developers have the option to use either the default methane destruction efficiencies provided in the protocol, or the site-specific methane destruction efficiencies as provided by a state- or local agency-accredited source test service provider, for any of the destruction devices used in the project, performed on an annual basis. Device-specific source testing shall include at least three test runs, with the accepted final value being one standard deviation below the mean of the measured efficiencies.

6.3 Missing Data

In situations where the flow rate or methane concentration monitoring equipment is missing data, the project developer shall apply the data substitution methodology provided in Appendix C. If for any reason the destruction device monitoring equipment is inoperable (for example, the thermocouple on the flare), then no emission reductions can be credited for the period of inoperability.

6.4 Monitoring Parameters

Prescribed monitoring parameters necessary to calculate baseline and project emissions are provided in Table 6.1.

Table 6.1. Coal Mine Methane Project Monitoring Parameters

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
5.4 5.5	$SMM_{BL,i}$	CMM from surface pre-mining that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period	tCH_4	Estimated at start of project and calculated annually, if non-qualifying destruction device is still in place	c, m	The higher of the two calculated values is used
5.4 5.5	$HMM_{BL,i}$	CMM from horizontal pre-mining that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period	tCH_4	Estimated at start of project and calculated annually, if non-qualifying destruction device is still in place	c, m	The higher of the two calculated values is used
5.4 5.5	$PMM_{BL,i}$	Post-mining CMM that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period	tCH_4	Estimated at start of project and calculated annually, if non-qualifying destruction device is still in place	c, m	The higher of the two calculated values is used
5.4 5.5	$VAM_{BL,i}$	VAM that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period	tCH_4	Estimated at start of project and calculated annually, if non-qualifying destruction device is still in place	c, m	The higher of the two calculated values is used
5.4 5.9	CEF_{NMHC}	CO_2 emission factor for combusted non methane hydrocarbons (various)	tCO_2e/ tNMHC	Annually	m	To be obtained through analysis of the fractional composition of captured gas
5.4 5.9	PC_{CH4}	Concentration (in mass) of methane in extracted CMG or ventilation air , measured on wet basis	mg/m^3	Continuous	m	To be measured on wet basis
5.4 5.9	PC_{NMHC}	NMHC concentration (in mass) in extracted CMG or ventilation air	mg/m^3	Annually	m	Based on full gas analysis by a certified gas lab using a gas chromatograph
5.5 5.6	$SMMe_i$	CMM from surface pre-mining captured, sent to and destroyed by use i for the reporting period. For qualifying devices, only the *eligible* amount may be quantified	tCH_4	Every reporting period	c, m	Only includes SMM from boreholes that have been "mined through" and SMM destroyed by non-qualifying devices (excluding SMM sent to pipeline)

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
5.5	$HMM_{PJ,i}$	CMM from horizontal pre-mining captured, sent to and destroyed by use i in the reporting period	tCH_4	Continuous	m	Includes metered HMM destroyed by both eligible and non-qualifying devices
5.5	$VAM_{PJ,i}$	VAM sent to and destroyed by use i in the project activity in the reporting period. In the case of oxidation, $VAM_{PJ,i}$ is equivalent to MM_{OX} defined in Section 5.2.2	tCH_4	Continuous	m	Includes metered VAM destroyed by both eligible and non-qualifying devices
5.5	$PMM_{PJ,i}$	CMM from post-mining captured, sent to and destroyed by use i in the project activity in the reporting period	tCH_4	Continuous	m	Includes metered PMM destroyed by both eligible and non-qualifying devices
5.5 5.13	GWP_{CH4}	Global warming potential of methane	tCO_2e/ tCH_4		r	21
5.6	$SMMpre_e$	CMM destroyed by qualifying devices in the current reporting period from surface pre-mining boreholes that were mined through during the current reporting period	tCH_4	Every reporting period	m	
5.6	$SMMpost_e$	CMM destroyed by qualifying devices in the current reporting period from surface pre-mining boreholes that were previously mined through	tCH_4	Every reporting period	m	
5.6	$SMMw_1$	CMM captured and destroyed from well w_1 from the project start date through the end of the current reporting period	tCH_4	Every reporting period	m	
5.6	w_1	The set of wells mined through in current reporting period		Every reporting period	o	
5.6	$SMMw_2$	CMM captured from well w_2 during the current reporting period	tCH_4	Every reporting period	m	
5.6	w_2	The set of wells mined through prior to the current reporting period		Every reporting period	o	
5.8	$CONS_{ELEC,PJ}$	Additional electricity consumption for destruction of methane, if any	MWh	Every reporting period	o	From electricity use records
5.8	$CONS_{HEAT,PJ}$	Additional heat consumption destruction of methane	volume	Every reporting period	o	From purchased heat records

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
5.8	$CONS_{FossFuel,PJ}$	Additional fossil fuel consumption for destruction of methane	volume	Every reporting period	o	From fuel use records
5.8	CEF_{ELEC}	CO_2 emissions factor of electricity used by mine	tCO_2/ MWh	Every reporting period	r	See eGRID
5.8	CEF_{HEAT}	CO_2 emissions factor of heat used by mine	kg CO_2/ volume	Every reporting period	c	See Appendix B
5.8	$CEF_{FossFuel}$	CO_2 emissions factor of fossil fuel used by mine	kg CO_2/ volume	Every reporting period	r	See Appendix B
5.9	MD_i	Methane destroyed by all qualifying and non-qualifying devices	tCH_4	Every reporting period	c	
5.10	$VAM_{flow.rate,y}$	Average flow rate of ventilation air entering the oxidation unit during period y	scfm	Continuous	m, c	Readings taken every two minutes to calculate average hourly flow
5.10	$time_y$	Time during which VAM unit is operational during period y	m	Continuous		Readings taken every two minutes to calculate average hourly flow
5.10	D_{CH4}	Density of methane under standard conditions	tCH_4/scf		r	Density of methane under standard conditions (60ºF and 1 atm) = 0.0423 lb/scf
5.10	D_{CH4}	Density of methane under standard conditions	tCH_4/scf		r	Density of methane under standard conditions (60ºF and 1 atm) = 0.0423 lb/scf
5.10	$P_{VAMinflow}$	Pressure of ventilation air entering the oxidation unit	atm	Continuous	m	Readings taken at least every hour to calculate hourly pressure
5.10	$T_{VAMinflow}$	Temperature of ventilation air entering the oxidation unit (ºR = ºF + 460)	ºR	Continuous	m	Readings taken at least every hour to calculate hourly temperature
5.10	$PC_{CH4,VAM}$	Concentration of methane in the ventilation air entering the oxidation unit	scf/scf	Continuous	m	Readings taken at least every two minutes and used to calculate average methane concentration per hour
5.10	$PC_{CH4,exhaust}$	Concentration of methane in the ventilation air exhaust	scf/scf	Continuous	m	Readings taken at least every two minutes (either average over two minutes or instantaneous) and used to calculate average methane concentration per hour

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
5.10	$P_{VAManalyzerinflow}$	Pressure of ventilation air in the vicinity of the VAM methane analyzer at inlet	atm	Continuous	m	If methane analyzer technology requires adjustment for pressure and temperature and the use of $P_{VAMinflow}$ is inappropriate, readings shall be taken in the vicinity of the inlet VAM methane analyzer at least every hour to calculate hourly pressure
5.10	$T_{VAManalyzerinflow}$	Temperature of ventilation air entering the oxidation unit in the vicinity of the VAM methane analyzer	ºR	Continuous	m	If methane analyzer technology requires adjustment for pressure and temperature and the use of $T_{VAMinflow}$ is inappropriate, readings shall be taken in the vicinity of the inlet VAM methane analyzer at least every hour to calculate hourly temperature
5.10	$P_{VAManalyzerexhaust}$	Pressure of exhaust gases in the vicinity of the VAM methane analyzer at inlet	atm	Continuous	m	If methane analyzer technology requires adjustment for pressure and temperature, readings shall be taken in the vicinity of the exhaust VAM methane analyzer at least every hour to calculate hourly pressure
5.10	$T_{VAManalyzerexhaust}$	Temperature of exhaust gases exiting the oxidation unit in the vicinity of the VAM methane analyzer	ºR	Continuous	m	If methane analyzer technology requires adjustment for pressure and temperature, readings shall be taken in the vicinity of the exhaust VAM methane analyzer at least every hour to calculate hourly temperature
5.11 5.13	MM_i	Methane measured sent to use i	tCH_4	Continuous	m	Flow meters will record gas volumes, pressure and temperature
5.11 5.13	Eff_i	Efficiency of methane destruction through use i		Annually	m or r	See Appendix B
5.12	MMadjusted,i	Adjusted volume of CMG collected for the given time interval at use i	scf/unit time	Every reporting period	c	Adjusted to standard conditions (60°F and 1 atm)

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
5.12	MMunadjusted,i	Unadjusted volume of CMG collected for the given time interval at use i	scf/unit time	Continuously	m	If flow meters do not internally correct for temperature and pressure
5.12	T	Measured temperature of CMG for the given time period (ºR = ºF + 460)	ºR	Continuously	m	Measured to adjust the flow of CMG. No separate monitoring of temperature is necessary when using flow meters that automatically adjust flow volumes for temperature and pressure
5.12	P	Measured pressure of the CMG for the given time interval	atm	Continuously	m	Measured to adjust the flow of CMG. No separate monitoring of pressure is necessary when using flow meters that automatically adjust flow volumes for temperature and pressure

7 Reporting Parameters

This section provides requirements and guidance on reporting rules and procedures. A priority of the Reserve is to facilitate consistent and transparent information disclosure by project developers. Project developers must submit verified emission reduction reports to the Reserve annually at a minimum.

7.1 Project Documentation

Project developers must provide the following documentation to the Reserve in order to register a coal mine methane project.

- Project Submittal form
- Project diagram: diagram that illustrates how the project is defined and includes the location, quantity and type of boreholes, ventilation shafts, eligible destruction devices and non-qualifying destruction devices within the project GHG Assessment Boundary, as well as placement of monitoring equipment
- Signed Attestation of Title form
- Signed Attestation of Voluntary Implementation form
- Signed Attestation of Regulatory Compliance form
- Verification Report
- Verification Statement

Project developers must provide the following documentation each reporting period in order for the Reserve to issue CRTs for quantified GHG reductions:

- Verification Report
- Verification Statement
- Signed Attestation of Title form
- Signed Attestation of Voluntary Implementation form
- Signed Attestation of Regulatory Compliance form

At a minimum, the above project documentation (except for the project diagram) will be available to the public via the Reserve's online registry. Further disclosure and other documentation may be made available by the project developer on a voluntary basis. Project submittal forms can be found at http://www.climateactionreserve.org/how/projects/register/project-submittal-forms/.

7.1.1 Documentation of Project Expansions

If a project expands to include boreholes, ventilation shafts or destruction devices beyond what was included in the project as defined by the project developer at the time of listing (see Section 2.2), the project developer must submit an updated project diagram to the Reserve.

Similarly, if any new non-qualifying device becomes operational at the mine – or if an existing non-qualifying device at a mine is assigned to a different active project (see Section 2.2.3) – the project developer must submit an updated project diagram for the project to which the device is assigned.

7.2 Joint Project Verification

Because the protocol allows for multiple projects at a single mine site, project developers have the option to hire a single verification body to verify multiple projects at a mine through a "joint project verification." This may provide economies of scale for the project verifications and improve the efficiency of the verification process.

Under joint project verification, each project, as defined by the protocol and the project developer, is submitted, listed and registered separately in the Reserve system. Furthermore, each project requires its own separate verification process and Verification Statement (i.e. each project is assessed by the verification body separately as if it were the only project at the mine). However, all projects may be verified together by a single site visit to the mine. Furthermore, a single Verification Report may be filed with the Reserve that summarizes the findings from multiple project verifications.

Regardless of whether the project developer chooses to verify multiple projects through a joint project verification or pursue verification of each project separately, the documents and records for each project must be retained according to this section.

7.3 Record Keeping

For purposes of independent verification and historical documentation, project developers are required to keep all information outlined in this protocol for a period of 10 years after the information is generated or 7 years after the last verification. This information will not be publicly available, but may be requested by the verifier or the Reserve.

System information the project developer should retain includes:

- All data inputs for the calculation of GHG reductions, including all required sampled data
- Copies of mine operating permits, air, water, and land use permits; Notices of Violations (NOVs); and any administrative or legal consent orders related to project activities dating back at least three years prior to the project start date; and for each subsequent year of project operation[26]
- Copies of mine plans and mine ventilation plans submitted to MSHA throughout the crediting period
- Executed Attestation of Regulatory Compliance related to the project
- Flow meter information (model number, serial number, manufacturer's calibration procedures)
- Methane monitor information (model number, serial number, calibration procedures)
- Destruction device monitor information (model number, serial number, calibration procedures)
- Field checks and calibration results for all meters
- Corrective measures taken if meter does not meet performance specifications
- Destruction device monitoring data (for each destruction device)
- Project flow and methane concentration data
- Emission reduction calculations
- Verification records and results from each verification
- All maintenance records relevant to the project monitoring equipment and destruction devices

[26] Note that these documentation requirements are for activities and equipment related to the project and the mine where the project is located.

7.4 Reporting Period & Verification Cycle

Project developers must report GHG reductions resulting from project activities during each reporting period. Although projects must be verified annually at a minimum, the Reserve will accept verified emission reduction reports on a sub-annual basis, should the project developer choose to have a sub-annual reporting period and verification schedule (e.g. quarterly or semi-annually). A reporting period cannot exceed 12 months, and no more than 12 months of emission reductions can be verified at once, except during a project's first verification. A project's initial reporting period must begin on the project's start date. Reporting periods must be contiguous; there can be no time gaps in reporting during the crediting period of a project once the initial reporting period has commenced. Project developers may register their project's initial reporting period as a zero-credit reporting period (see Reserve Program Manual, Section 3.3.3 for more details).

8 Verification Guidance

This section provides verification bodies with guidance on verifying GHG emission reductions from coal mine methane projects developed to the standards of this protocol. This verification guidance supplements the Reserve's Verification Program Manual and describes verification activities in the context of coal mine methane destruction projects.

Verification bodies trained to verify coal mine methane projects must conduct verifications to the standards of the following documents:

- Climate Action Reserve Program Manual
- Climate Action Reserve Verification Program Manual
- Climate Action Reserve Coal Mine Methane Project Protocol
- Any applicable errata and clarifications to the Coal Mine Methane Project Protocol
- Any applicable policy memos issued by the Reserve

The Reserve's Program Manual, Verification Program Manual, and project protocols are designed to be compatible with each other and are available on the Reserve's website at http://www.climateactionreserve.org.

In cases where the Program Manual and/or Verification Program Manual differ from the guidance in this protocol, this protocol takes precedent.

Only ISO-accredited verification bodies trained by the Reserve for this project type are eligible to verify coal mine methane project reports. Verification bodies approved under other project protocol types are not permitted to verify coal mine methane projects. Information about verification body accreditation and Reserve project verification training can be found in the Verification Program Manual.

8.1 Verification of Multiple Projects at a Single Mine

Because the protocol allows for multiple projects at a single mine site, project developers have the option to hire a single verification body to verify multiple projects under a joint project verification. This may provide economies of scale for the project verifications and improve the efficiency of the verification process. Joint project verification is only available as an option for a single project developer; joint project verification cannot be applied to multiple projects registered by different project developers at the same mine.

Under joint project verification, each project, as defined by the protocol and the project developer, must still be registered separately in the Reserve system and each project requires its own verification process and Verification Statement (i.e. each project is assessed by the verification body separately as if it were the only project at the mine). However, all projects may be verified together by a single site visit to the mine. Furthermore, a single Verification Report may be filed with the Reserve that summarizes the findings from multiple project verifications.

Finally, the verification body may submit one Notification of Verification Activities/Conflict of Interest (NOVA/COI) Assessment form that details and applies to all of the projects at a single mine that it intends to verify.

If, during joint project verification, the verification activities of one project are delaying the registration of another project, the project developer can choose to forego joint project verification. There are no additional administrative requirements of the project developer or the verification body if a joint project verification is terminated.

8.2 Standard of Verification

The Reserve's standard of verification for coal mine methane projects is the Coal Mine Methane Project Protocol (this document), the Reserve Program Manual, and the Verification Program Manual. To verify a coal mine methane project developer's project report, verification bodies apply the guidance in the Verification Program Manual and this section of the protocol to the standards described in Section 2 through 7 of this protocol. Sections 2 through 7 provide eligibility rules, methods to calculate emission reductions, performance monitoring instructions and requirements, and procedures for reporting project information to the Reserve.

8.3 Monitoring Plan

The Monitoring Plan serves as the basis for verification bodies to confirm that the monitoring and reporting requirements in Section 6 and Section 7 have been met, and that consistent, rigorous monitoring and record-keeping is ongoing at the project site. Verification bodies shall confirm that the Monitoring Plan covers all aspects of monitoring and reporting contained in this protocol and specifies how data for all relevant parameters in Table 6.1 are collected and recorded.

8.4 Verifying Project Eligibility

Verification bodies must affirm a coal mine methane project's eligibility according to the rules described in this protocol. The table below outlines the eligibility criteria for a coal mine methane project. This table does not represent all criteria for determining eligibility comprehensively; verification bodies must also look to Section 3 and the verification items list in Table 8.2.

Table 8.1. Summary of Eligibility Criteria

Eligibility Rule	Eligibility Criteria	Frequency of Rule Application
Start Date	Projects must be submitted for listing no more than 6 months after the project start date	Once during initial verification
Location	United States and its territories	Once during initial verification
Performance Standard	▪ Drainage projects: the project destroys CMM through any end use destruction system other than injection into a natural gas pipeline for off-site consumption ▪ All VAM projects	During initial verification of each crediting period
Legal Requirement Test	Signed Attestation of Voluntary Implementation form and monitoring procedures that lay out procedures for ascertaining and demonstrating that the project passes the Legal Requirement Test	Every verification
Regulatory Compliance	Project must be in material compliance with all applicable laws, and submit a signed Attestation of Regulatory Compliance form	Every verification
Exclusions	▪ Surface coal mines ▪ Abandoned coal mines ▪ Coal bed methane destruction ▪ Use of CO_2 or other fluid/gas to enhance methane drainage before mining takes place	Every verification

8.5 Core Verification Activities

The Coal Mine Methane Project Protocol provides explicit requirements and guidance for quantifying GHG reductions associated with the destruction of coal mine methane. The Verification Program Manual describes the core verification activities that shall be performed by verification bodies for all project verifications. They are summarized below in the context of a coal mine methane project, but verification bodies shall also follow the general guidance in the Verification Program Manual.

Verification is a risk assessment and data sampling effort designed to ensure that the risk of reporting error is assessed and addressed through appropriate sampling, testing, and review. The three core verification activities are:

1. Identifying emissions sources, sinks and reservoirs
2. Reviewing GHG management systems and estimation methodologies
3. Verifying emission reduction estimates

Identifying emission sources, sinks, and reservoirs
The verification body reviews for completeness the sources, sinks, and reservoirs identified for a project, such as VAM and CMM destruction system energy use, fuel consumption from transport of the gas, combustion and destruction from various qualifying and non-qualifying destruction devices, and emissions from the incomplete combustion of methane.

Reviewing GHG management systems and estimation methodologies
The verification body reviews and assesses the appropriateness of the methodologies and management systems that the mine operator uses to gather data on methane collected and destroyed and to calculate baseline and project emissions.

Verifying emission reduction estimates
The verification body further investigates areas that have the greatest potential for material misstatements and then confirms whether or not material misstatements have occurred. This involves site visits to the project to ensure the systems on the ground correspond to and are consistent with data provided to the verification body. In addition, the verification body recalculates a representative sample of the performance or emissions data for comparison with data reported by the project developer in order to double-check the calculations of GHG emission reductions.

8.6 Coal Mine Methane Verification Items

The following tables provide lists of items that a verification body needs to address while verifying a coal mine methane project. The tables include references to the section in the protocol where requirements are further described. The table also identifies items for which a verification body is expected to apply professional judgment during the verification process. Verification bodies are expected to use their professional judgment to confirm that protocol requirements have been met in instances where the protocol does not provide (sufficiently) prescriptive guidance. For more information on the Reserve's verification process and professional judgment, please see the Verification Program Manual.

Note: These tables shall not be viewed as a comprehensive list or plan for verification activities, but rather guidance on areas specific to coal mine methane projects that must be addressed during verification.

8.6.1 Project Eligibility and CRT Issuance

Table 8.2 lists the criteria for reasonable assurance with respect to eligibility and CRT issuance for coal mine methane projects. These requirements determine if a project is eligible to register with the Reserve and/or have CRTs issued for the reporting period. If any one requirement is not met, either the project may be determined ineligible or the GHG reductions from the reporting period (or sub-set of the reporting period) may be ineligible for issuance of CRTs, as specified in Sections 2, 3, and 6.

Table 8.2. Eligibility Verification Items

Protocol Section	Eligibility Qualification Item	Apply Professional Judgment?
2.2 - 2.2.2	Verify that the project meets the definition of a CMM project and is properly defined as either drainage project or VAM project	No
2.2.3	Confirm all non-qualifying devices have been properly accounted for within project's GHG Assessment Boundary	No
2.3	Verify ownership of the reductions by reviewing Attestation of Title	No
2.2.1 - 2.2.3, 7.1.1	If there are new destruction devices, boreholes, shafts or a project crediting period expiration at the mine, verify that project expansions have been completed, properly defined and documented to account for these changes	No
3.1	Verify that the project only consists of activities at a single coal mine or Category III gassy underground trona mine operating within the U.S. or its territories	No
3.2	Verify eligibility of project start date	No
3.2	Verify accuracy of project start date based on operational records	Yes
3.3	Verify that project is within its 10-year crediting period	No
3.4.1	Confirm execution of the Attestation of Voluntary Implementation form to demonstrate eligibility under the Legal Requirement Test	No
3.4.1	Verify that the project monitoring plan contains procedures for ascertaining and demonstrating that the project passes the Legal Requirement Test at all times	Yes
3.4.1.1	Verify that the project meets the appropriate Performance Standard Test for the project type	No
3.4.1.1	If VAM project uses supplemental CMM, verify that supplemental CMM is eligible	No
3.5	Verify that project activities comply with applicable laws by reviewing any instances of non-compliance provided by the project developer and performing a risk-based assessment to confirm the statements made by the project developer in the Attestation of Regulatory Compliance form	Yes

8.6.2 Quantification of GHG Emission Reductions

Table 8.3 lists the items that verification bodies shall include in their risk assessment and re-calculation of the project's GHG emission reductions. These quantification items inform any determination as to whether there are material and/or immaterial misstatements in the project's GHG emission reduction calculations. If there are material misstatements, the calculations must be revised before CRTs are issued.

Table 8.3. Quantification Verification Items

Protocol Section	Quantification Item	Apply Professional Judgment?
0	Verify that SSRs included in the GHG Assessment Boundary correspond to those required by the protocol and those represented in the project diagram for the reporting period	No
5.1	Verify that the project developer correctly accounted for methane destruction in the baseline scenario	No
5.1	Verify that baseline emissions for non-qualifying devices were calculated according to the protocol	No
5.1.2.1	Verify definition of mined through was properly applied to SMM boreholes	No
5.2.2	Verify NMHC concentration of CMG is either below project-specific threshold or, if above, CO_2 emissions from NMHC combustion are accounted for in project emissions	No
5.2.1	Verify that the project developer correctly quantified and aggregated electricity use	Yes
5.2.1	Verify that the project developer correctly quantified and aggregated fossil fuel use	Yes
5.2.1	Verify that the project developer correctly quantified and aggregated heat consumption	Yes
Equation 5.8, Appendix B	Verify that the project developer applied the correct emission factors for fossil fuel combustion and grid-delivered electricity	No
Equation 5.11, Appendix B	Verify that the project developer applied the correct methane destruction efficiencies	No
Equation 5.11	If the project developer used source test data in place of the default destruction efficiencies (Appendix B), verify accuracy and appropriateness of data and calculations	Yes
6.1	Verify that monitoring meets the requirements of the protocol; if it does not, verify that a variance has been approved for monitoring variations	No
6.1	Verify that NMHC samples were properly collected and analyzed	No
6.1, 6.1.1	Verify that destruction devices were operational during the reporting period, or that guidance in Section 6.1.1 was properly applied	Yes
6.2	Verify that all gas flow meters and continuous methane analyzers adhered to the inspection, cleaning, and calibration schedule specified in the protocol; if they do not, verify that a variance has been approved for monitoring variations or that adjustments have been made to data per the protocol requirements	No
6.2	Verify that any portable calibration instruments were calibrated at least annually by the manufacturer or at an ISO 17025 accredited lab	No
6.2	If any piece of equipment failed a calibration check, verify that data from that equipment was scaled according to the failed calibration procedure for the appropriate time period	No
6.3, Appendix C	If used, verify that data substitution methodology was properly applied	No
n/a	If any variances were granted, verify that variance requirements were met and properly applied	Yes

8.6.3 Risk Assessment

Verification bodies will review the following items in Table 8.4 to guide and prioritize their assessment of data used in determining eligibility and quantifying GHG emission reductions.

Table 8.4. Risk Assessment Verification Items

Protocol Section	Item that Informs Risk Assessment	Apply Professional Judgment?
6	Verify that the project monitoring plan is sufficiently rigorous to support the requirements of the protocol and proper operation of the project	Yes
6	Verify that the methane destruction equipment was operated and maintained according to manufacturer specifications	Yes
6	Verify that appropriate monitoring equipment is in place to meet the requirements of the protocol	No
6	Verify that the individual or team responsible for managing and reporting project activities are qualified to perform this function	Yes
6	Verify that appropriate training was provided to personnel assigned to project-related duties	Yes
6	Verify that all contractors are qualified for project-related duties if relied upon by the project developer. Verify that there is internal oversight to assure the quality of the contractor's work	Yes
6	If field checks are performed by an individual that is not a third-party technician, verify the competency of the individual to perform the field check and the accuracy of the field check procedure	Yes
7.3	Verify that all required records have been retained by the project developer	No

8.7 Completing Verification

The Verification Program Manual provides detailed information and instructions for verification bodies to finalize the verification process. It describes completing a Verification Report, preparing a Verification Statement, submitting the necessary documents to the Reserve, and notifying the Reserve of the project's verified status.

As stated in Section 8.1, project developers may choose to have a verification body conduct multiple project verifications at a single mine under a joint project verification. The verification body must verify the emission reductions entered into the Reserve system for each project and upload a unique Verification Statement for each project within the joint verification. The verification body can prepare a single Verification Report that contains information on all of the projects, but this must also be uploaded to every project under the joint verification.

9 Glossary of Terms

Active mine	Active mines include mine works that are actively ventilated by the mine operator. For the purposes of this protocol, MSHA designated "intermittent" mines are also considered active mines.
Abandoned mine	A mine where all mining activity including mine development and mineral production have ceased, mine personnel are not present in the mine workings, and mine ventilation fans are no longer operative.[27] In the U.S., mines are declared "abandoned" from the date when ventilation is discontinued.[28] This mine type is not eligible under this protocol.
Baseline emissions	Baseline emissions represent the GHG emissions within the GHG Assessment Boundary that would have occurred in the absence of the GHG reduction project.
Coal bed methane (CBM)	A generic term for methane originating in coal seams that is drained from virgin coal seams and surrounding strata. CBM is unrelated to mining activities.
Coal mine gas (CMG)	Gas from drainage systems before any processing or enrichment that often contains various levels of other components (e.g. nitrogen, oxygen carbon dioxide, hydrogen sulfide, NMHC, etc.).
Coal mine methane (CMM)	Methane contained in coal and surrounding strata that is released because of mining activity. For the purposes of this protocol, CMM also refers to the methane gas that is released because of mining activity at Category III gassy underground trona mines.
Drainage system	A term used to encompass the entirety of the equipment that is used to drain the gas from underground and collect it at a common point, such as a vacuum pumping station. In this protocol, methane drainage systems include surface pre-mining, horizontal pre-mining, and post-mining.
Eligible end use	For the purposes of this protocol, all end uses that result in the destruction/oxidation of methane except for injection into natural gas pipeline.
Gob	Also referred to as goaf, it is the collapsed area of strata produced by the removal of coal and artificial supports behind a working coalface. Strata above and below the gob are de-stressed and fractured by the mining activity.
Intermittent	Mines placed in intermittent status by MSHA, as a result of being seasonally idled for more than 90 days, are not considered abandoned. To maintain intermittent status, facilities and equipment such as the mine office, surface and underground power systems, the main mine

[27] UN Economic and Social Council, Economic Commission for Europe, Committee on Sustainable Energy, Glossary of Coal Mine Methane Terms and Definitions, July 2008.
[28] MSHA Program Policy Manual Volume V, January 2006, p.120.

	fan, and underground coal haulage systems must remain intact.[29] Under this protocol, intermittent mines are considered active mines and are eligible.
Joint project verification	Project verification option where a project developer hires a verification body to verify multiple projects at a mine.
Longwall mine	An underground mining type that uses at least one longwall panel during coal excavation.
Mine Safety and Health Administration (MSHA)	Federal enforcement agency responsible for protecting the health and safety of U.S. miners.
Mined through	When the linear distance between the endpoint of the borehole and the working face that will pass nearest the endpoint of the borehole has reached an absolute minimum. Coal mine methane from surface pre-mining boreholes shall not be quantified in the baseline until the endpoint of the borehole is mined through.
Mine	An area of land and all structures, facilities, machinery tools, equipment, shafts, slopes, tunnels, excavations, and other property, real or personal, placed upon, under, or above the surface of such land by any person, used in, or to be used in, or resulting from, the work of extracting minerals. The mine boundaries are defined by the mine area as permitted by the state in which the mine is located.
Non-qualifying destruction device	A methane destruction device that does not meet one or more of the eligibility rules as described in Section 3 (e.g. operational start date, regulatory requirement, injection into natural gas pipeline) and is located at the same mine where eligible project activities are taking place.
Oxidizer	For the purposes of this protocol, the term oxidizer refers to technology for destruction of ventilation air methane with or without utilization of thermal energy and/or with or without a catalyst.
Project diagram	A diagram of the mine that illustrates the location, quantity, and type of boreholes, ventilations shafts, eligible destruction devices and non-qualifying destruction devices within a project's GHG Assessment Boundary. The project diagram must be updated and submitted to the Reserve whenever a project expansion occurs.
Project emissions	Project emissions are actual GHG emissions that occur within the GHG Assessment Boundary as a result of project activities. Project emissions are calculated at a minimum on an annual, *ex-post* basis.
Qualifying destruction device	A methane destruction device that meets the eligibility rules for a CMM project as described in Section 3.
Room and pillar mine	An underground mining type that uses square or rectangular pillars of coal during excavation, laid out in a checkerboard fashion. Pillars typically range in size from 60 feet by 60 feet to 100 feet by 100 feet and rooms are typically 20 feet wide and a few thousand feet long

[29] MSHA Program Policy Manual, p.138.

Reporting period	Specific time period of project operation for which the project developer has calculated and reported emission reductions and is seeking verification and registration. The reporting period must be no longer than 12 months.
Standard conditions	Under this protocol, standard conditions are defined as 60ºF and 1 atm.
Ventilation air methane (VAM)	Coal mine methane that is mixed with the ventilation air in the mine that is circulated in sufficient quantity to dilute methane to low concentrations for safety reasons (typically below 1 percent).
Ventilation system	A system that is used to control the concentration of methane and other deleterious gases within mine working areas. Ventilation systems consist of powerful fans that move large volumes of air through the mine workings to dilute methane concentrations. All underground coal mines in the U.S. are required to develop and maintain ventilation systems.
Verification cycle	The Reserve requires verification of coal mine methane projects annually, but does not require verifications to be completed on specific dates. Project developers select the reporting period to be verified. Thus, each project has a unique verification cycle that begins the first time a project is verified, occurs at least annually, and ends once the crediting period expires or the project is no longer eligible, whichever happens first.
Year	For the purposes of this protocol, year refers to a 12 month period of the project's crediting period, not a calendar year.

10 References

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Appendix A Summary of Performance Standard Development

The analysis to develop the performance standard for the Coal Mine Methane Project Protocol was conducted by Science Applications International Corporation (SAIC) and was completed in May 2009. The analysis culminated in a paper that provided a performance standard recommendation to support the coal mine methane protocol development process, which the Reserve has incorporated into the protocol's eligibility rules (see Section 3).

The purpose of a performance standard is to establish a standard of performance applicable to all coal mine methane management projects that is significantly better than average greenhouse gas production for a specified service, which, if met or exceeded by a project developer, satisfies one of the criterion of "additionality."

The performance standard analysis contained an in-depth study of the following areas:

- Coal mine data trends and regional variations across the U.S.
- Degasification techniques including ventilation, surface pre-mining drainage, horizontal pre-mining drainage, and post-mining gob drainage currently used in coal mines
- Ventilation air methane utilization technologies
- Review of current, pending and anticipated regulations that could affect coal mine methane projects
- Data analysis to establish common practice for coal mine methane management at underground coal mines in the U.S.

A.1 Overview of Data Collection

The primary database used for the SAIC analysis was a coal mine methane emissions database provided by the U.S. EPA.[30] This database provided annual emissions-related data for underground mines classified as gassy by MSHA; the data cover the period 1990 through 2007. For the purposes of this analysis, the annual data for the 2000 to 2007 timeframe was used, covering a total of 295 gassy underground mines. The database provides the following data:

- Company name, mine name, and MSHA ID number
- State and county in which each mine is located
- Daily average and total methane emissions from the ventilation system, as well as the total amount of methane liberated by the mine (equal to the sum of the ventilation emissions and the drainage emissions or capture)
- An indication of whether the mine utilizes a degasification system, and if so, a brief description of the system and the total amount of methane drained through the system
- An indication as to whether the drained methane is captured, and a brief description of how the captured methane is utilized
- Detailed information on the subset of mines using methane capture

To supplement this primary data set, EPA provided a second database containing annual coal production data for the gassy mines for the years 2002 through 2006, along with an indication of

[30] This database is used as the basis for the coal mine methane emissions estimated published in EPA's annual *Inventory of U.S. Greenhouse Gas Emissions and Sinks* reports.

the mine's production status.[31] SAIC also used mine-level production data for 2000, 2001, and 2007, obtained from the Energy Information Administration (EIA).[32] SAIC merged the production data with the emissions database using each mine's MSHA identification number. The final merged dataset included 241 mines for which emissions data for at least one of the eight years in the 2000 to 2007 time frame was available.

EPA also provided a list of longwall mines in the United States that produced in excess of 750,000 tons of coal from January through September 2007, published by CoalUSA magazine. This list was supplemented by SAIC with similar CoalUSA lists for production from 2001 through 2006[33] and a table detailing the production of top non-longwall mines in 2007.[34] SAIC also consulted the mining method information contained in two EPA reports on methane recovery opportunities at gassy mines.[35] They combined the mines on these lists to create a master list of longwall mines in operation during the 2000 to 2007 time period. The master list represents a comprehensive list of longwall mines operating in and around 2007 with the following assumptions:

- The individual lists provide a comprehensive identification of all longwall mines falling above the production cutoff
- Most, if not all, longwall mines would meet the production cutoff when operating at full capacity
- Most, if not all, longwall mines would have operated at full capacity at least in one year during the 2000 to 2007 time period

All remaining mines were assigned to the room and pillar method (the other main underground coal mining method). In keeping with the industry standard definition, a longwall mine is defined as any mine that has at least one longwall face or that opened a longwall face at some point during the 2000 to 2007 period.

In combining and using the data for eight separate years into a single dataset, SAIC characterized each mine according to the furthest development of its drainage system. For example, if a mine used gob boreholes only in some years, but gob boreholes with horizontal pre-mining boreholes in other years, SAIC treated the mine as using both drainage system types during the 2000 to 2007 time frame. Similarly, mines that utilized methane in some years but not in others were treated as having utilization projects in operation in the 2000 to 2007 time frame. The decision to use and combine data for the past eight years into a single dataset was based on a trend analyses which indicated that industry practice with respect to drainage systems and utilization projects has remained fairly stable since 2000 (see Table A.1). Given

[31] EIA was the original source of the production data.
[32] EIA, http://www.eia.doe.gov/cneaf/coal/page/database.html.
[33] Weir International, Inc. 2008. "U.S. Longwall Mines – Production and Productivity: September 2007 Year to Date (Mines Producing in Excess of 750,000 tons through September)." *CoalUSA*, March 2008; Weir International, Inc. 2006. "United States Longwall Mining Statistics: 1996-July 2006." Table 2: 2006 June Year to Date U.S. Longwall Mine Production and Productivity; "Table: U.S. Longwall Production 2005," *International Longwall News*, 27 March, 2006. At: http://www.longwalls.com/sectionstory.asp?SourceID=s50; NIOSH, 2005. "Table: U.S. Longwall production 2004." *International Longwall News*, 23 March 2005; NIOSH, 2004. "Table: U.S. Longwall output 2003 now working." *International Longwall News*, 7 April 2004; NIOSH, 2003. "Table: U.S. Longwall output 2002." *International Longwall News*, 21 July 2003.
[34] Weir International, Inc. 2008. "Top 50 U.S. Underground Mines (non-longwall) – Production and Productivity: September 2007 Year to Date." *CoalUSA*, March 2008. *CoalUSA*, March 2008.
[35] U.S. EPA, *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 1999-2003* and *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006*.

this relative stability in coal industry practices, it appeared safe to combine recent data with older data for the purpose of ascertaining current common practice.

Table A.1. Historical Trends in Mines Using Methane Drainage and Capture/Utilization

	Year							
	1990	1995	2000	2003	2004	2005	2006	2007
Mines with Drainage Systems	**33**	**25**	**21**	**18**	**21**	**24**	**21**	**20**
Mines with Gob Wells	n/a	n/a	n/a	8	11	15	12	12
Mines with Gob and Horizontal Pre-Mining Wells	n/a	n/a	n/a	3	3	3	3	3
Mines with All Three Drainage System Types	n/a	n/a	n/a	7	7	6	6	5
Mines with Capture/Use Projects	**7**	**12**	**13**	**12**	**12**	**15**	**15**	**15**
Pipeline	6	12	10	11	10	13	13	13
Electricity Generation	0	0	0	1*	1	1	1	1
Vent. Air Heating	0	0	0	1	1	1	1	1
Thermal Coal Drying	0	1*	1*	1*	1*	1*	1*	1*
Unspecified	1	0	3	0	0	0	0	0
*Mine also sells a portion of its recovered methane to a pipeline.								

Source: Developed using data in U.S. EPA, Coal 07 draft.xls file.

Trona Mines

Data on trona mines operating in the United States was also collected and examined.[36] There are four Category III gassy underground trona mines in the United States, of which two are room and pillar and two are longwall mines. The two longwall mines currently have gob wells, but neither is capturing the coal mine methane for destruction.

A.2 Summary of Analysis

Should the Performance Standard Include the Drainage System?

In order to establish the definition of a coal mine methane project, it was necessary to explore if the installation of a drainage system should be tested using a performance standard, or if the performance standard test could be limited to the installation of coal mine methane destruction devices.

The hypothesis was that federal health and safety regulations influence a coal mine operator's decision to install methane drainage systems. As stated in Section 3.4.1, there currently exists no federal, state, or local regulations requiring coal mines to reduce, limit, or control their methane emissions. Hence, based solely on a consideration of emissions regulations, all coal mine methane projects would appear to pass the regulatory test screen.

However, the situation for coal mines is complicated by the existence of federal safety regulations that govern methane concentration levels inside the mine. These safety regulations may effectively necessitate the utilization of methane drainage systems under certain gassy conditions. While there is no requirement to capture the methane emitted from such systems, to the extent that these systems may be necessitated by the safety regulations, they should not be considered a part of an additional coal mine methane project. In other words, the safety

[36] Coal Age *U.S. Longwall Census*, February 2009. MSHA ID numbers and liberation rates provided by Steven Pilling, MSHA Green River, Wyoming Field Office, June 2009. Information on drainage systems provided by Jeff Liebert, Verdeo Group, July 2009.

regulations may have important implications for determining the project definition and eligibility rules. Specifically, the methane drainage system may need to be excluded from the project definition if the system was developed as a response to the safety regulations. If this is the case, the methane drainage system does not pass the regulatory test but the methane destruction system may; the project definition should thus include only the destruction system.

To test this hypothesis, SAIC therefore conducted an analysis to determine the common practices utilized by coal mine operators to dilute methane concentrations as a function of methane liberation rates. As a first step in their data analysis, they computed arithmetic averages of the annual methane liberation data for each mine in the merged emissions dataset. However, a mine's methane emissions depend heavily on its production rate, as it is the process of removing the coal from the seam that relieves the pressure on the nearby unmined coal and surrounding strata, thereby releasing much of the gas. For this reason, the use of arithmetic average emissions data can lead to distorted results, particularly for mines that were underutilized during all or part of the 2000 to 2008 timeframe.

To correct for this possibility, SAIC developed normalized methane liberation rate estimates for the mines in the merged database for which both liberation and production data were available. Specifically, for each mine SAIC divided the sum of the 2000 through 2007 methane liberation data by the sum of the mine's 2000 through 2007 production to derive average methane liberation per ton of coal produced. They then multiplied this methane liberation rate by the largest of the eight annual production data points in the 2000 to 2007 timeframe to obtain their estimate of normalized methane liberation for the period. The year with the largest production value was used in the calculation in order to increase the likelihood that the resulting methane liberation estimate represents the mine's annual liberation rate when it is operating at full capacity. A mine operator will decide on whether or not methane drainage must be used to meet the regulatory requirements based on the expected methane liberation rate under full capacity operations.[37] Hence it is the methane liberation rate at full capacity that governs the mine operator's decision process; by computing a weighted average methane liberation value for the year in which production reaches its maximum they likewise sought to base their analysis on full capacity conditions. They used a production-normalized average rather than the actual methane liberation observed in the selected "maximum production year" because, as previously noted, the amount of methane liberated can fluctuate significantly from year to year depending on the geologic conditions encountered in each year. By using an average rather than an actual methane liberation value they reduced the potential for distortions introduced by abnormally low or high methane liberation rates in any given year.

It should be noted that production data was lacking for seven of the mines in the merged database; these mines were deleted from the database prior to proceeding with further analysis. Six of the deleted mines were room and pillar operations and hence were not a primary focus of the analysis. The single longwall mine lacking production data does not employ a drainage system.

Figure A.1 below presents a histogram of drainage system usage for the longwall mines, based on the production-normalized annual methane liberation rates for the 2000 to 2007 timeframe. This histogram indicates that the use of methane drainage is highly correlated with the quantity

[37] If the operator were to use a methane liberation estimate based on anything less than full capacity production for the purposes of deciding on the need for a drainage system, the mine would run the risk of being unable to meet the regulatory requirements when operating at full capacity.

of methane produced by a longwall mine. From these results, methane drainage can be considered a common practice for gassy longwall mines.

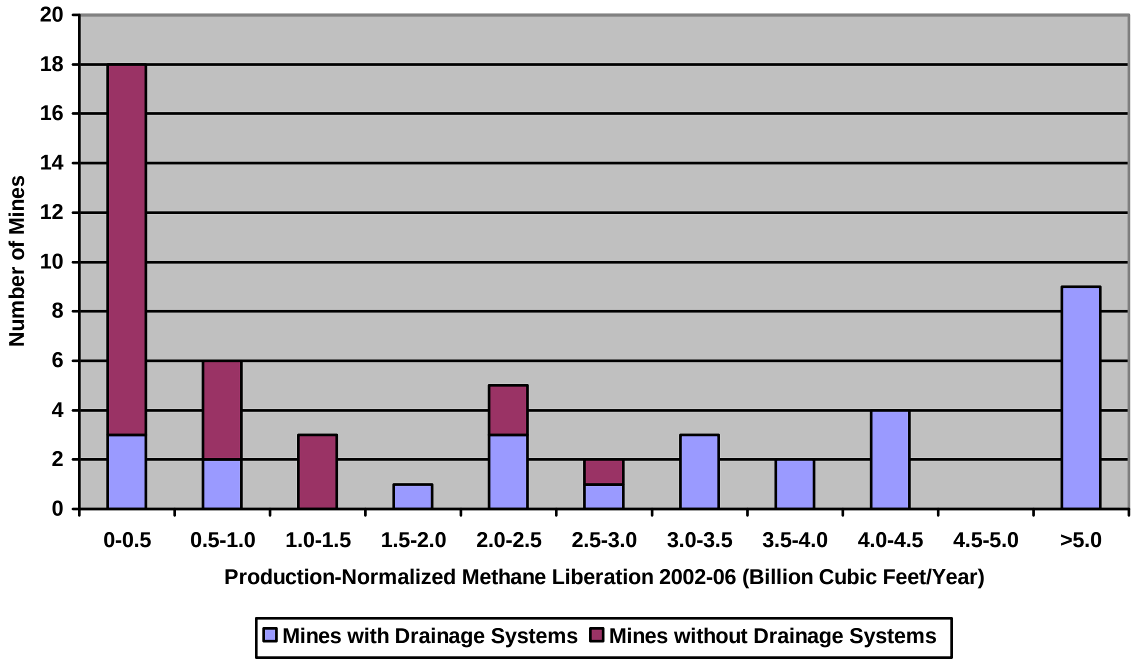

Figure A.1. Histogram of Drainage System Usage by Longwall Mines

There are currently no room and pillar mines with drainage systems in place; there are also no room and pillar mines with either arithmetic average or production-normalized methane liberation quantities in excess of two billion cubic feet.

Conclusion

This analysis strongly supports the hypothesis that the drainage systems currently in place are a response to the regulations. Given these results, we assume that all drainage systems are a response to health and safety regulations. Thus, the installation of a drainage system is not included in the definition of a coal mine methane project and is not tested for by a performance standard.

Recommendation to Use a Common Practice Standard

With the conclusion that the performance standard test must only test the additionality of the installation of a destruction device, it was necessary to determine what type of performance standard test was most suitable for coal mine methane projects.

Coal mine methane projects do not lend themselves to rate- or technology-based comparisons. In general, all coal mine methane projects are characterized by a very high rate of capture, making it difficult to distinguish projects on the basis of a metric such as methane destroyed as a percentage of methane entering the destruction device. Other potential metrics that might be used to establish a performance threshold for coal mine methane projects, such as the total quantity of methane captured on an annual basis, are fraught with difficulties. Specifically, the quantity of methane captured at any given mine is more a measure of the mine's geologic conditions than the performance of the methane capture equipment.

In general, there are no current requirements – federal, state, or local – that should influence a mine operator's choice between venting and utilizing the methane drained from drainage systems. This choice is driven by economic considerations, not regulatory requirements. A common practice standard is well-suited for these projects, in so far as common practice can help us infer whether the decision to install a methane destruction device was influenced by the availability of funding from carbon credits. Specifically, by identifying the conditions under which methane destruction is currently common practice, we can infer that projects operating under those conditions are likely undertaken to use the gas as a valuable byproduct of the mining process, and thus not additional.

Drainage Project Analysis

A strong argument can be made for determining additionality by assessing common practice of coal mine methane destruction by utilization type. As previously noted in Table A.1, only a small number of the mines with known utilization projects use the captured methane for purposes other than for sales to pipelines.

To test this hypothesis, SAIC analyzed a subset of the merged emissions/production database they created. Because the interest here is in mines that already utilize methane drainage systems, they eliminated all mines from the merged dataset that did not employ methane drainage at any time during the 2000 to 2007 timeframe. Following this elimination, they were left with a new data subset covering the 28 mines (all longwall) that employed methane drainage for at least one year during 2000 to 2007. In addition to data on the total annual amount of methane liberated in 2000 to 2007, this new database included 2000 to 2007 data on the annual amount of methane drained and vented at each of the 28 mines. The data set also provided a year-by-year indication as to whether or not all or a portion of the drained methane was captured, and the type of use to which the captured methane was applied (e.g. sales to a pipeline, electricity generation, etc.).

A close review of the database revealed anomalous methane capture indications for five of the 28 mines. Specifically, the data indicated that methane was captured at these five mines in 2002, but not in any of the subsequent years. SAIC reviewed the original EPA data file for these five mines, and found that for 1998 through 2001 the data indicated the mines were not capturing and utilizing methane. Thus the year 2002 was identified as the only year, in a ten-year period, during which methane was being captured at these five mines. In contrast, most of the other mines that practice methane capture are identified as using their capture systems in multiple years. Because of this anomaly, they treated these five mines as *not* utilizing methane capture techniques during the 2000 to 2007 timeframe, since, even if the 2002 data is correct, it appears that the mines' use of methane capture in this one year was atypical and not representative of normal practice at the five mines. In all other cases a mine identified as having employed methane capture at any time during the 2000 to 2007 timeframe was treated as a mine with a utilization project for the purposes of the analysis. See Table A.2 for a summary of this database.

Table A.2. Summary of Drainage System Type and Utilization at Longwall Coal Mines

MSHA ID	State Location	Utilization*	Drainage System Type(s)**
100851	AL	P	GHS
101247	AL	P	GHS
101322	AL	P	GHS
101401	AL	P	GHS
102901	AL	P	GH
503672	CO	H	GH
504452	CO	N	G
504591	CO	N	G
504758	CO	N	G
1514492	KY	N	U
2902170	NM	P	GH
3604281	PA	N	U
3605018	PA	P	G
3605466	PA	P	G
3605466	CO	N	G
3607230	PA	E	G
3607416	PA	N	G
4201890	UT	N	G
4202028	UT	P	G
4403795	VA	P	GHS
4404856	VA	P & TD	GHS
4601318	WV	N	GH
4601433	WV	P	GH
4601436	WV	N	GH
4601437	WV	N	G
4601456	WV	P & E	GH
4601816	WV	P	GHS
4601968	WV	P	GH

*P = Pipeline injection
E = Electricity generation
TD = Thermal coal drying
H = Mine ventilation air heating
N = None

**G = Gob wells
H = Horizontal pre-mine wells
S = Vertical pre-mine wells
U = Unknown

Results

Analysis of the new database found that:

- Use of methane for pipeline sales is common practice, in so far as it is used at 88 percent (15 of 17) of the mines that capture methane, and 53 percent (15 of 28) of the mines that drain methane
- Use of captured methane for electricity generation is uncommon, in so far as it is limited to 12 percent of the mines that capture methane, and 7 percent of the mines that drain methane
- Use of captured methane for heating ventilation air or fueling thermal coal dryers is uncommon (limited to only 6 percent of the mines that capture methane, and 4 percent of the mines that drain methane)

- Application of captured methane to any use other than the above three is not only uncommon but non-existent

There are two possible explanations for the general lack of end-use projects other than those involving sales to pipelines. First, these projects may be generally uneconomic under current conditions. Alternatively, such projects may be economically viable, but *less so* than pipeline sales projects. Under this second interpretation, on-site projects to generate electricity, heat, etc., would be more numerous than actually observed were it not for the fact that they must compete with a generally more preferable end use—i.e. selling the CMM to a pipeline. In other words, one might hypothesize that pipeline projects are in effect distorting the analysis of common practice with respect to other end use project types, by dominating the competition between the various end use options. If true, this hypothesis would suggest that other end use project types are not generally additional, despite their rarity.

To test this hypothesis, SAIC eliminated all of the mines with pipeline sales projects from the database, and considered whether or not other end use projects are common practice within the remaining group of mines – a group for which competition from pipeline projects is not a barrier to the application of other end uses. However, before performing this analysis, it was necessary to first consider that two of the four non-pipeline projects currently in operation (an electricity generation project and a thermal coal drying project) are located at mines that *also* sell a portion of their CMM to pipelines. It appears that these two projects are not being adversely affected by competition from pipeline projects, as they co-exist with the latter. The existence of these co-located projects suggests that there may be other opportunities for the application of on-site end uses at mines that currently sell their CMM - the fact that such co-located on-site projects are uncommon indicates that these on-site applications may be sub-economic, rather than merely less economic than pipeline sales projects. It was determined that the two co-located on-site projects should be excluded from the analysis, because competition from pipeline sales projects did not prevent these two projects from being undertaken.

Focusing then on the two remaining on-site end use projects – projects which *may* not have been undertaken had pipeline sales projects been feasible at these two mines – and on the mines that are currently venting their CMM, SAIC drew the following conclusions with respect to common practice:

- Only one of the 12 mines (8 percent) that utilize drainage systems *not* connected to natural gas pipelines currently captures methane to generate electricity
- Only one of the 12 mines (8 percent) that utilize drainage systems *not* connected to natural gas pipelines currently captures methane to heat the mine ventilation air

Based on the above analysis SAIC concluded that on-site end use projects are uncommon even at mines that do not sell their CMM to pipelines. In fact, CMM end use project types other than electricity generation, ventilation air heating, and thermal coal drying are non-existent. This finding suggests that such project types are generally uneconomic under current conditions, rather than simply less economic than pipeline sales projects. Thus, even if the current pipeline sales projects did not exist, it is not clear that other project types would take their place.

The Reserve believes it is appropriate to consider the entire population of mines with drainage systems, and not just those mines that do not sell CMM to pipelines, when assessing common practice with respect to non-pipeline end use projects.

Regional Analysis

An additional analysis was conducted to assess whether common practice with respect to utilization varies across regions. Whereas common practice with respect to methane drainage is unlikely to exhibit much regional variation, given that the decision to utilize drainage techniques is often driven by *federal* regulations, the same cannot be presumed for methane utilization. On the contrary, given that the decision to initiate a capture and utilization project will generally be driven by economic criteria rather than regulations, regional variations in common practice, reflecting regional variations in the underlying economic criteria, are a real possibility that must be investigated.

Table A.3. Regional Analysis of Methane Utilization among Mines with Drainage Systems

State/Region	Mines with Normalized Methane Drainage >0.25 Billion ft^3			Mines with Normalized Methane Liberation ≤0.25 Billion ft^3		
	Mines with Drainage Systems	Mines with Utilization	Percent with Utilization	Mines with Drainage Systems	Mines with Utilization	Percent with Utilization
Pennsylvania	3	3	100	1	0	0
W. Virginia	6	4	67	1	0	0
Virginia	2	2	100	0	0	n/a
Kentucky	0	0	n/a	1	0	0
Alabama	5	5	100	0	0	n/a
Eastern U.S.	**16**	**14**	**87**	**3**	**0**	**0**
Colorado	3	1	33	2	0	0
Utah	1	1	100	1	0	0
New Mexico	1	1	100	0	0	n/a
Western U.S.	**5**	**3**	**60**	**3**	**0**	**0**
Total U.S.	**21**	**17**	**81**	**6**	**0**	**0**

Table A.3 presents the results of the regional analysis. It indicates little regional variation in common practice amongst mines with production-normalized methane drainage in excess of 0.25 billion cubic feet per year. Regardless of their regional location, the majority of the mines in this category captures and utilizes methane (87 percent of the eastern mines and 60 percent of the western mines). None of the six mines draining less than 0.25 billion cubic feet per year capture and utilize their CMM, regardless of mine location. Thus SAIC recommended against establishing regional variations in the common practice standards for coal mine methane projects.

Conclusion

Based on the above analysis of current utilization project types, the Reserve concluded that all projects designed to utilize the methane for any purpose other than pipeline sales shall be eligible as additional under the common practice standard. Depending on the specific utilization project type, such non-pipeline projects are rare to non-existent at present. Projects that include both pipeline sales and other uses (e.g. electricity generation) are to be treated as two separate projects for the purposes of applying the common practice standard, and the project involving uses other than pipeline sales are to be eligible under the common practice standard.
Because of similarities between the regulatory requirements, operating conditions, mining methods, and methane management of gassy underground trona mines and coal mines, the Reserve concluded the same common practice standard also applies to trona mines categorized as MSHA Category III gassy underground metal and non-metal mines.

Ventilation Air Methane Projects

There is opportunity for achieving significant reductions in coal mine methane emissions from ventilation. In 2007, the methane emissions from ventilation systems were more than 10 times greater than drainage system emissions (78.9 million cubic feet versus 7.3 million cubic feet; see Figure A.2). However, the technology available to tap into this potential market is as yet unproven commercially, at least in the U.S.

The technical barrier to the commercialization of methane destruction or utilization technology capable of being used in conjunction with ventilation systems has been the highly dilute character of the methane emitted by these systems. Typically the mine air vented from return air shafts is less than 1 percent methane. The utilization technologies considered thus far require gas with much higher methane content.

There are at present no commercial projects using ventilation air methane destruction or oxidation technology at active coal or trona mines in the United States.[38] Since commercial VAM projects are non-existent at present, the Reserve concludes that all commercial VAM projects be eligible under a common practice standard.

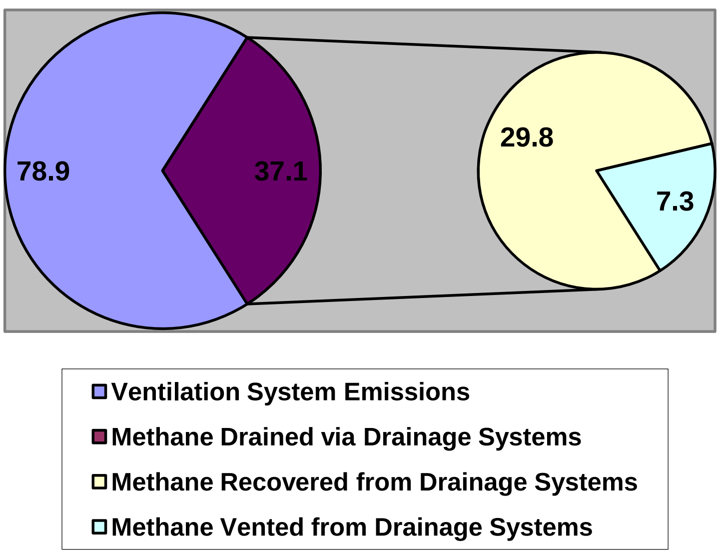

Figure A.2. Ventilation and Drainage System Emissions, 2007 (million cubic feet)

A.3 Evaluation of the Common Practice Standards

The common practice standards summarized above are based on a relatively small number of observations. However, it is important to recognize that this is not a “small sample” problem; rather it is the population of mines that uses drainage, with or without CMM utilization, which is small. With the exception of a very small number of mines with missing data that were deleted from the database, the Reserve believes the analysis covers the entire population of gassy U.S. underground mines. Although we cannot be certain that the original MSHA and EPA databases used as our primary sources provide comprehensive coverage of all gassy mines, all mines with

[38] There is one demonstration project that received approval from the Mine Health and Safety Administration (MSHA) in April 2008.

drainage, and all mines with utilization, this is the intent of these databases and we have no reason to believe that there are significant deficiencies in their coverage.

Thus, while the analysis necessarily rests on a small set of observations, it is nonetheless representative of the population. By pooling the data across eight years (2000 to 2007), SAIC was able to increase the number of mines covered in the analysis, as well as reduce the impact of short-term fluctuations in a mine's methane liberation, drainage and/or production rate on our analysis. Beyond pooling the data, there are few if any viable means of increasing the number of observations used in this analysis. We did consider the possibility of adding data from other countries, but ruled this approach out because we believe that the geologic conditions, mining methods, and economics of mining and CMM recovery are too variable across national borders to enable the application of non-U.S. data to an analysis of common practice within the U.S.

A.4 Updating the Performance Standard

The common practice standards developed for coal mine methane projects reflect operating practices under current economic, regulatory, and technological conditions. SAIC's analysis of sector trends indicated that common practice has been relatively stable or slow to evolve, at least over the past decade. If and when these conditions change in the future, the common practice standard will be affected. Therefore, the performance standard analyses will be updated on a periodic basis to either confirm that common practice has not changed or to develop new standards reflecting changed conditions.

Appendix B Emission Factor Tables

Table B.1. CO_2 Emission Factors for Fossil Fuel Use

Fuel Type	Heat Content	Carbon Content (Per Unit Energy)	Fraction Oxidized	CO_2 Emission Factor (Per Unit Energy)	CO_2 Emission Factor (Per Unit Mass or Volume)
Coal and Coke	**MMBtu / short ton**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / short ton**
Anthracite Coal	25.09	28.26	1.00	103.62	2,599.83
Bituminous Coal	24.93	25.49	1.00	93.46	2,330.04
Sub-bituminous Coal	17.25	26.48	1.00	97.09	1,674.86
Lignite	14.21	26.30	1.00	96.43	1,370.32
Unspecified (Residential/ Commercial)	22.05	26.00	1.00	95.33	2,102.29
Unspecified (Industrial Coking)	26.27	25.56	1.00	93.72	2,462.12
Unspecified (Other Industrial)	22.05	25.63	1.00	93.98	2,072.19
Unspecified (Electric Utility)	19.95	25.76	1.00	94.45	1,884.53
Coke	24.80	31.00	1.00	113.67	2,818.93
Natural Gas (By Heat Content)	**Btu / scf**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / scf**
975 to 1,000 Btu / scf	975 – 1,000	14.73	1.00	54.01	Varies
1,000 to 1,025 Btu / scf	1,000 – 1,025	14.43	1.00	52.91	Varies
1,025 to 1,050 Btu / scf	1,025 – 1,050	14.47	1.00	53.06	Varies
1,050 to 1,075 Btu / scf	1,050 – 1,075	14.58	1.00	53.46	Varies
1,075 to 1,100 Btu / scf	1,075 – 1,100	14.65	1.00	53.72	Varies
Greater than 1,100 Btu / scf	> 1,100	14.92	1.00	54.71	Varies
Weighted U.S. Average	1,029	14.47	1.00	53.06	0.0546
Petroleum Products	**MMBtu / barrel**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / gallon**
Asphalt and Road Oil	6.636	20.62	1.00	75.61	11.95
Aviation Gasoline	5.048	18.87	1.00	69.19	8.32
Distillate Fuel Oil (#1, 2, and 4)	5.825	19.95	1.00	73.15	10.15
Jet Fuel	5.670	19.33	1.00	70.88	9.57
Kerosene	5.670	19.72	1.00	72.31	9.76
LPG (average for fuel use)	3.849	17.23	1.00	63.16	5.79
Propane	3.824	17.20	1.00	63.07	5.74
Ethane	2.916	16.25	1.00	59.58	4.14
Isobutene	4.162	17.75	1.00	65.08	6.45
n-Butane	4.328	17.72	1.00	64.97	6.70
Lubricants	6.065	20.24	1.00	74.21	10.72
Motor Gasoline	5.218	19.33	1.00	70.88	8.81
Residual Fuel Oil (#5 and 6)	6.287	21.49	1.00	78.80	11.80
Crude Oil	5.800	20.33	1.00	74.54	10.29
Naphtha (<401°F)	5.248	18.14	1.00	66.51	8.31
Natural Gasoline	4.620	18.24	1.00	66.88	7.36
Other Oil (>401°F)	5.825	19.95	1.00	73.15	10.15
Pentanes Plus	4.620	18.24	1.00	66.88	7.36
Petrochemical Feedstocks	5.428	19.37	1.00	71.02	9.18
Petroleum Coke	6.024	27.85	1.00	102.12	14.65
Still Gas	6.000	17.51	1.00	64.20	9.17
Special Naphtha	5.248	19.86	1.00	72.82	9.10
Unfinished Oils	5.825	20.33	1.00	74.54	10.34
Waxes	5.537	19.81	1.00	72.64	9.58

Source: EPA Climate Leaders, Stationary Combustion Guidance (2007), Table B-2 except:
Default CO_2 emission factors (per unit energy) are calculated as: Carbon Content × Fraction Oxidized × 44/12.
Default CO_2 emission factors (per unit mass or volume) are calculated as: Heat Content x Carbon Content × Fraction Oxidized × 44/12× Conversion Factor (if applicable).
Heat content factors are based on higher heating values (HHV).

If available, the official source tested methane destruction efficiency shall be used in place of the default methane destruction efficiency. Project developers have the option to use either the default methane destruction efficiencies provided, or the site specific methane destruction efficiencies as provided by a state or local agency accredited source test service provider, for each of the combustion devices used in the project, performed on an annual basis.

Table B.2. Default Destruction Efficiencies for Combustion Devices

Destruction Device	Destruction Efficiency
Open Flare	0.96
Enclosed Flare	0.995
Lean-burn Internal Combustion Engine	0.936
Rich-burn Internal Combustion Engine	0.995
Boiler	0.98
Microturbine or Large Gas Turbine	0.995
Upgrade and Use of Gas as CNG/LNG Fuel	0.95
Upgrade and Injection into Natural Gas Pipeline	0.98**

Source: The default destruction efficiencies for enclosed flares and electricity generation devices are based on a preliminary set of actual source test data provided by the Bay Area Air Quality Management District. The default destruction efficiency values are the lesser of the twenty fifth percentile of the data provided or 0.995. These default destruction efficiencies may be updated as more source test data is made available to the Reserve.

****** The Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories gives a standard value for the fraction of carbon oxidized for gas destroyed of 99.5% (Reference Manual, Table 1.6, page 1.29). It also gives a value for emissions from processing, transmission and distribution of gas which would be a very conservative estimate for losses in the pipeline and for leakage at the end user (Reference Manual, Table 1.58, page 1.121). These emissions are given as 118,000kgCH_4/PJ on the basis of gas consumption, which is 0.6%. Leakage in the residential and commercial sectors is stated to be 0 to 87,000kgCH_4/PJ, which equates to 0.4%, and in industrial plants and power station the losses are 0 to 175,000kg/CH_4/PJ, which is 0.8%. These leakage estimates are compounded and multiplied. The methane destruction efficiency for landfill gas injected into the natural gas transmission and distribution system can now be calculated as the product of these three efficiency factors, giving a total efficiency of (99.5% * 99.4% * 99.6%) 98.5% for residential and commercial sector users, and (99.5% * 99.4% * 99.2%) 98.1% for industrial plants and power stations. [39]

Equation B.1. Calculating Heat Generation Emission Factor ($EF_{heat,y}$)

$$EF_{heat,y} = \frac{EF_{CO_2,i}}{Eff_{heat}} \times \frac{44}{12}$$

Where,			Units
$EF_{heat,y}$	=	Emission factor for heat generation	kg CO_2/volume
$EF_{CO2,i}$	=	CO_2 emission factor of fuel used in heat generation (see Table B.1)	kg C/volume
Eff_{heat}	=	Boiler efficiency of the heat generation (either measured efficiency, manufacturer nameplate data for efficiency, or 100%)	%
44/12	=	Carbon to carbon dioxide conversion factor	

[39] GE AES Greenhouse Gas Services, Landfill Gas Methodology, Version 1.0 (July 2007).

Appendix C Data Substitution Guidelines

This appendix provides guidance on calculating emission reductions when data integrity has been compromised due to missing data points. No data substitution is permissible for equipment such as thermocouples which monitor the proper functioning of destruction devices. Rather, the methodologies presented below are to be used only for the methane concentration and flow metering parameters, including temperature and pressure data.

The Reserve expects that projects will have continuous, uninterrupted data for the entire reporting period. However, the Reserve recognizes that unexpected events or occurrences may result in brief data gaps.

The following data substitution methodology may be used only for flow and methane concentration data gaps that are discrete, limited, non-chronic, and due to unforeseen circumstances. Data substitution can only be applied to methane concentration *or* flow readings, but not both simultaneously. If data is missing for both parameters, no reductions can be credited. The methodology may also be used for missing temperature and pressure data (which is used to adjust flow rate). However, the methodology must be applied to both parameters simultaneously, regardless of if data is available for one or the other. In other words: if either temperature or pressure data is missing, the project developer must use the following methodology to substitute data for both parameters over the same time interval.

Further, substitution may only occur when two other monitored parameters corroborate proper functioning of the destruction device and system operation within normal ranges. These two parameters must be demonstrated as follows:

1. Proper functioning can be evidenced by thermocouple readings for flares, energy output for engines, etc.
2. For methane concentration substitution, flow rates during the data gap must be consistent with normal operation.
3. For flow substitution, methane concentration rates during the data gap must be consistent with normal operations.

If corroborating parameters fail to demonstrate any of these requirements, no substitution may be employed. If the requirements above can be met, the following substitution methodology maybe applied:

Duration of Missing Data	Substitution Methodology
Less than six hours	Use the average of the four hours of normal operations immediately before and following the outage
Six to 24 hours	Use the 90% lower or upper confidence limit of the 24 hours of normal operations prior to and after the outage, whichever results in greater conservativeness
One to seven days	Use the 95% lower or upper confidence limit of the 72 hours of normal operations prior to and after the outage, whichever results in greater conservativeness
Greater than one week	No data may be substituted and no credits may be generated

The lower confidence limit should be used for both methane concentration and flow readings, as this will provide the greatest conservativeness.

Coal Mine Methane Project Protocol
Version 1.1
ERRATA AND CLARIFICATIONS

The Climate Action Reserve (Reserve) published its Coal Mine Methane (CMM) Project Protocol Version 1.1 in October 2011. While the Reserve intends for the CMM Project Protocol V1.1 to be a complete, transparent document, it recognizes that correction of errors and clarifications will be necessary as the protocol is implemented and issues are identified. This document is an official record of all errata and clarifications applicable to the CMM Project Protocol V1.1.[1]

Per the Reserve's Program Manual, both errata and clarifications are considered effective on the date they are first posted on the Reserve website. The effective date of each erratum or clarification is clearly designated below. All listed and registered coal mine methane projects must incorporate and adhere to these errata and clarifications when they undergo verification. The Reserve will incorporate both errata and clarifications into future versions of the protocol.

All project developers and verification bodies must refer to this document to ensure that the most current guidance is adhered to in project design and verification. Verification bodies shall refer to this document immediately prior to uploading any Verification Statement to assure all issues are properly addressed and incorporated into verification activities.

If you have any questions about the updates or clarifications in this document, please contact Policy at policy@climateactionreserve.org or (213) 891-1444 x3.

[1] See Section 4.3.4 of the Climate Action Reserve Program Manual for an explanation of the Reserve's policies on protocol errata and clarifications. "Errata" are issued to correct typographical errors. "Clarifications" are issued to ensure consistent interpretation and application of the protocol. For document management and program implementation purposes, both errata and clarifications are contained in this single document.

Please ensure that you are using the latest version of this document

Errata and Clarifications (arranged by protocol section)

Section 5

1. Accounting for Additional Non-Methane Cooling Air Volume in VAM Oxidation Projects (CLARIFICATION – October 22, 2013)

Section: 5.2.2, Equation 5.10

Context: Due to the high temperatures which may result from high methane concentrations of VAM entering destruction devices at a project, additional non-methane fresh air (either occasionally or continuous) may be added to the system to prevent overheating of the destruction device. The protocol assumes a closed system, in which the flow rate of the input and exhaust are the same. However, in the case of destruction devices in which additional non-methane fresh air is added after the point at which VAM input flow is metered, the flow of the exhaust would be greater than the metered flow of the input. Without accounting for this additional flow, the methane destruction will be overestimated due to the dilution of methane in the exhaust gas. It is not clear how projects should account for this situation in the quantification methodology.

Clarification: Destruction devices requiring an additional cooling air intake component are permissible under this protocol. To account for the additional non-methane air, Equation 5.10 shall be replaced with the revised Equation 5.10 below. If destruction devices include a cooling air intake, the flow of additional non-methane air entering the destruction device should be metered and the actual flow data shall be used in the equation. However, if the cooling air intake is not metered, the project developer must instead use the maximum flow rate (e.g. the full capacity) of the cooling air intake system for the full duration of time when it is operating. If the operational status of the cooling air system is not monitored, the project developer shall assume that the system is always operational.

Revised Equation 5.10. CH_4 Destroyed by VAM Oxidation

$$\boldsymbol{MD_{OX} = MM_{OX} - PE_{OX}}$$

Where, <u>Units</u>

MD_{OX}	=	Methane destroyed through oxidation during the reporting period	tCH_4
MM_{OX}	=	Methane measured sent to oxidizer during the reporting period	tCH_4
PE_{OX}	=	Project emissions of non-oxidized CH_4 from oxidation of the VAM stream during the reporting period	tCH_4

And,

$$\boldsymbol{MM_{OX} = VAM_{flow\,rate,y} \times time_y \times PC_{CH_4\,VAM} \times D_{CH_4}}$$

Where, <u>Units</u>

$VAM_{flow\ rate,y}$	=	Average flow rate of ventilation air entering the oxidation unit during period y corrected if needed for inlet flow gas pressure and temperature ($P_{VAM\ inflow}$ and $T_{VAM\ inflow}$ respectively) per Equation 5.12	scfm
$time_y$	=	Time during which VAM unit is operational during period y	m
$PC_{CH4\ VAM}$	=	Concentration of methane in the ventilation air entering the oxidation unit, corrected if needed for pressure and temperature in the vicinity of the methane analyzer	scf/scf
D_{CH4}	=	Density of methane under standard conditions	tCH_4/scf

And,

$$PE_{OX} = VAM_{exhaust\ volume,y} \times PC_{CH_4\ exhaust} \times D_{CH_4}$$

Where, Units

$VAM_{exhaust\ volume,y}$	=	Total volume of methane leaving the oxidation unit during period y	scf
$PC_{CH4\ exhaust}$	=	Concentration of methane in the ventilation air exhaust, corrected if needed for pressure and temperature in the vicinity of the methane analyzer ($P_{VAM\ analyzer\ inflow}$, $T_{VAM\ analyzer\ inflow}$, $P_{VAM\ analyzer\ exhaust}$, and $T_{VAM\ analyzer\ exhaust}$)	scf/scf
D_{CH4}	=	Density of methane under standard conditions	tCH_4/scf

And either,

$$VAM_{exhaust\ volume,y} = VAM_{exhaust\ flow\ rate,y} \times time_y$$

Or,

$$VAM_{exhaust\ volume,y} = \left(VAM_{flow\ rate,y} \times time_y\right) + \left(CA_{flow\ rate,z} \times time_z\right)$$

Where, Units

$VAM_{exhaust\ flow\ rate,y}$	=	Average metered flow rate of the ventilation air exhaust leaving the oxidation unit during period y, corrected if needed for inlet flow gas pressure and temperature ($P_{VAM\ inflow}$ and $T_{VAM\ inflow}$ respectively) per Equation 5.12	scfm
$CA_{flow\ rate,z}$	=	Flow rate[a] of additional cooling air added to VAM destruction system after metering point for $VAM_{flow\ rate}$ (equal to zero, if the project is a closed system in which VAM intake flow is equal to exhaust gas flow)	scfm
$time_z$	=	Subset of time, z, during which the air intake system is operational within the time period y[b]	m

[a] If the project is metering the cooling air intake flow volume, then the average metered data flow rate shall be used. If the flow is not metered, then the maximum capacity of the air intake system shall be used for the flow rate.

[b] If the operational status of the air intake system is not monitored, then the system shall be assumed to be operational at all times (i.e. $time_y = time_z$).

Section 6

2. NMHC Sampling Requirements (CLARIFICATION – March 10, 2014)

Section: 6.1

Context: The protocol requires the non-methane hydrocarbon (NMHC) content of coal mine gas (CMG) to be determined on an annual basis by a full gas analysis using a gas chromatograph for both VAM projects and drainage projects. The protocol goes on to state that these gas samples shall be collected “prior to each destruction device.” While the protocol’s intent is that the NMHC gas sample be taken upstream of each destruction device, it is not necessary to take multiple NMHC samples of CMG from a single drainage system or ventilation shaft if multiple destruction devices are being used. Rather, the protocol’s intent is to require that a separate NMHC sample be taken upstream of the destruction device for each CMG source within the project definition.

Clarification: The last sentence in the relevant paragraph shall be replaced with:

"Separate gas samples shall be collected from each drainage system or ventilation shaft within the project definition by a third-party technician. The sample shall be taken upstream of the destruction device(s)."

A.2.3 Forest Project Protocol v5.0

CLIMATE
ACTION
RESERVE

Version 5.0 | October 16, 2019

Forest

Project Protocol

Climate Action Reserve
www.climateactionreserve.org

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Abbreviations and Acronyms

C	Carbon
CH_4	Methane
CO_2	Carbon dioxide
CRT	Climate Reserve Tonne
FIA	USFS Forest Inventory and Analysis[1]
FPP	Forest Project Protocol
GHG	Greenhouse gas
lb	Pound
IFM	Improved Forest Management
N_2O	Nitrous oxide
PF	Professional Forester, in the case of California, a “Registered Professional Forester”
PIA	Project Implementation Agreement
Reserve	Climate Action Reserve
RPF	Registered Professional Forester, a person registered to practice professional forestry in California
USFS	United States Forest Service

[1] http://fia.fs.fed.us/program-features/rpa/

1 Introduction

The Forest Project Protocol (FPP) provides requirements and guidance for quantifying the net climate benefits of activities that sequester carbon on forestland in the United States. The protocol provides project eligibility rules; methods to calculate a project's net effects on greenhouse gas (GHG) emissions and removals of CO_2 from the atmosphere ("removals"); procedures for assessing the risk that carbon sequestered by a project may be reversed (i.e., released back to the atmosphere); and approaches for long term project monitoring and reporting. The goal of this protocol is to ensure that the net GHG reductions and removals caused by a project are accounted for in a complete, consistent, transparent, accurate, and conservative manner and may therefore be reported to the Climate Action Reserve (Reserve) as the basis for issuing carbon offset credits (called Climate Reserve Tonnes, or CRTs).

The Reserve is a national offsets program working to ensure integrity, transparency and financial value in the North American carbon market. It does this by establishing regulatory-quality standards for the development, quantification and verification of GHG emissions reduction projects in North America; issuing carbon offset credits known as CRTs generated from such projects; and tracking the transaction of credits over time in a transparent, publicly-accessible system. Adherence to the Reserve's high standards ensures that emissions reductions associated with projects are real, permanent and additional, thereby instilling confidence in the environmental benefit, credibility and efficiency of the U.S. carbon market.

Only those Forest Projects that are eligible under and comply with the FPP may be registered with the Reserve. Section 9 of this protocol provides requirements and guidance for verifying the performance of project activities and their associated GHG reductions and removals reported to the Reserve.

1.1 About Forests, Carbon Dioxide, and Climate Change

Forests have the capacity to both emit and sequester carbon dioxide (CO_2), a leading greenhouse gas that contributes to climate change. Trees, through the process of photosynthesis, naturally absorb CO_2 from the atmosphere and store the gas as carbon in their biomass, i.e., trunk (bole), leaves, branches, and roots. Carbon is also stored in the soils that support the forest, as well as the understory plants and litter on the forest floor. Wood products that are harvested from forests can also provide long term storage of carbon.

When trees are disturbed, through events like fire, disease, pests or harvest, some of their stored carbon may oxidize or decay over time releasing CO_2 into the atmosphere. The quantity and rate of CO_2 that is emitted may vary, depending on the circumstances of the disturbance. Forests function as reservoirs in storing CO_2.Depending on how forests are managed or impacted by natural events, they can be a net source of emissions, resulting in a decrease to the reservoir, or a net sink, resulting in an increase of CO_2 to the reservoir. In other words, forests may have a net negative or net positive impact on the climate.

Through sustainable management and protection, forests can also play a positive and significant role to help address global climate change. The Reserve's FPP is designed to address the forest sector's unique capacity to sequester, store, and emit CO_2 and to facilitate the positive role that forests can play to address climate change.

2 Forest Project Definitions and Requirements

For the purposes of the FPP, a Forest Project is a planned set of activities designed to increase removals of CO_2 from the atmosphere or reduce or prevent emissions of CO_2 to the atmosphere, through increasing and/or conserving forest carbon stocks.

A glossary of terms related to Forest Projects is provided in Section 10 of this protocol. Throughout the protocol, important defined terms are capitalized (e.g., “Avoided Conversion Project”).

2.1 Project Types

The Reserve will register the following types of Forest Project activities.[2]

2.1.1 Improved Forest Management

An Improved Forest Management Project involves management activities that maintain or increase carbon stocks on forested land relative to baseline levels of carbon stocks, as defined in Section 6.1 of this protocol. An Improved Forest Management Project is only eligible if:

1. The project takes place on land that has greater than ten percent tree canopy cover.
2. The project employs natural forest management practices, as defined in Section 3.9.2 of this protocol.
3. The project does *not* employ broadcast fertilization.
4. The project does not take place on land that was part of a previously registered Forest Project, unless the previous Forest Project was terminated due to an Unavoidable Reversal (see Section 7).

Eligible management activities may include, but are not limited to:

- Increasing the overall age of the forest by increasing rotation ages
- Increasing the forest productivity by thinning diseased and suppressed trees
- Managing competing brush and short-lived forest species
- Increasing the stocking of trees on understocked areas
- Maintaining stocks at a high level

Improved Forest Management Projects may be eligible on both private and public lands.

2.1.2 Avoided Conversion

An Avoided Conversion Project involves preventing the conversion of forestland to a non-forest land use by dedicating the land to continuous forest cover at existing or increased stocking levels through conservation easement recordation or transfer to public ownership. An Avoided Conversion Project is only eligible if:

[2] Reforestation Projects were previously included within the FPP. Please refer to the Reserve’s website for information about that project type.

1. The Project Operator can demonstrate that there is a significant threat of conversion of project land to a non-forest land use by following the requirements for establishing the project's baseline in Section 6.2 of this protocol.
2. The project does *not* employ broadcast fertilization.
3. The project does not take place on land that was part of a previously registered Forest Project, unless the previous Forest Project was terminated due to an Unavoidable Reversal (see Section 7).

An Avoided Conversion Project may involve tree planting, harvesting, and other silvicultural activities as part of the project activity.

Avoided Conversion Projects are eligible only on lands that are privately owned prior to the project start date.

2.2 Forest Owners and Project Operators

A Forest Owner is an individual or a corporation or other legally constituted entity, city, county, state agency, or a combination thereof that has legal control of any amount of forest carbon[3] within the Project Area. Control of forest carbon means the Forest Owner has the legal authority to effect changes to forest carbon quantities, e.g., through timber rights or other forest management or land-use rights. Control of forest carbon occurs, for purposes of satisfying this protocol, through fee ownership and/or deeded encumbrances, such as conservation easements.

Multiple Forest Owners may exist with respect to a single Forest Project, since control of forest carbon may be associated with fee ownership or through one or more deeded encumbrances that exist within a Project Area, any one of which may convey partial control of the project's forest carbon. However, only one fee owner may exist with respect to a single Forest Project. Any unencumbered forest carbon is assumed to be controlled by the fee owner. Individuals or entities holding mineral, gas, oil, or similar *de minimis*[4] interests in the forest carbon, are precluded from the definition of Forest Owner. Where any Forest Owner chooses to exclude the forest carbon it controls from becoming part of the Forest Project, the project's baseline must demonstrate the exclusion as a legal constraint.

The Project Operator is responsible for undertaking a Forest Project and registering it with the Reserve, and is ultimately responsible for all Forest Project reporting and attestations. The Project Operator has an account with the Reserve and executes the Project Implementation Agreement (see Section 3.6). A Project Operator must be one of the Forest Owners or must have an explicit legal agreement granting the right to operate the project from all other Forest Owners. In the latter case, the Project Operator must at least have fee ownership of the Project Area. The legal agreement granting the right to operate the project on behalf of the Forest Owner(s) will be subject to review and approval by the Reserve.

In all cases, the Project Operator must secure an agreement from all other Forest Owners that (1) assigns authority to the Project Operator to undertake a Forest Project, subject to any conditions imposed by any of the other Forest Owners to include or disallow any carbon they control; and (2) waives any right on the part of the Forest Owners to seek damages, penalties,

[3] See definition of Forest Carbon in glossary.
[4] *de minimis* control includes access right or ways and residential power line right of ways.

costs, losses, expenses, or judgments from the Reserve arising from or in any way connected with the Forest Project, except as explicitly provided for in the PIA.

The Reserve maintains the right to determine which individuals or entities meet the definition of “Forest Owner.”

The Project Operator may engage an independent third-party project developer to assist or consult with the Project Operator and to implement the Forest Project. All information submitted to the Reserve on behalf of the Project Operator shall reference the Project Operator, who is responsible for the accuracy and completeness of the information submitted, and for ensuring compliance with this Forest Project Protocol.

2.3 Forest Project Aggregation

Eligible Forest Projects[5] may be aggregated to improve cost-effectiveness while maintaining rigor in overall carbon inventory accounting. Individual Forest Projects can benefit through participation in an aggregate by meeting carbon inventory confidence standards across an aggregate, rather than within each project. This reduces the sampling intensity required within each project to meet statistical confidence requirements. Similarly, verification of aggregated projects is considered across the broader population, which reduces the verification costs to individual Project Operators participating in an aggregate. An aggregate consists of two or more individual Forest Projects enrolled with an Aggregator. For more information, please refer to the Guidelines for Aggregating Forest Projects.

[5] As described in the Guidelines for Aggregating Forest Projects available on the Reserve website.

3 Eligibility Rules and Other Requirements

In addition to the definitions and requirements described in Section 2, Forest Projects must meet several other criteria and conditions to be eligible for registration with the Reserve, and must adhere to certain requirements related to their duration, crediting period, and management activities.

Section 3.1	Project Location	→	*U.S., U.S. Territories (avoided conversion only), and tribal areas*
Section 3.2	Project Start Date	→	*No more than twelve months prior to project submission*
Section 3.3	Additionality	→	*Exceed legal requirements*
		→	*Meet performance standard*
Section 3.4	Project Crediting Period	→	*One hundred year crediting period*
Section 3.5	Permanence	→	*One hundred years following the issuance of CRTs*
Section 3.6	Project Implementation Agreement	→	*Project Operator executes PIA with the Reserve*
Section 3.7	Qualified Conservation Easement	→	*Optional*
Section 3.8	Regulatory Compliance	→	*Compliance with all applicable laws*
Section 3.9	Sustainable Harvesting and Natural Forest Management	→	*Ongoing compliance with the requirements for the project's assessment area(s)*

3.1 Project Location

All Forest Projects located in the United States of America are eligible to register with the Reserve provided they meet all other eligibility requirements described in this protocol. Improved Forest Management Projects may be located on private land or on state or municipal public land. Avoided Conversion Projects must be implemented on private land, unless the land is transferred to public ownership as part of the project. All projects can be transferred from private to public lands, whereby the public entity acquires all terms and conditions described in this protocol.

All Improved Forest Management Projects that are on public lands as of the project's start date must be approved by the government agency or agencies responsible for management activities on the land. This approval must include an explicit approval of the project's baseline, as determined in Section 6, and must involve any public vetting processes necessary to evaluate management and policy decisions concerning the project activity.

Forest Projects on federal lands may be eligible if and when their eligibility is approved through a federal legislative or regulatory/rulemaking process. Forest Projects in tribal areas must demonstrate that the land within the Project Area is owned by a tribe or private entities.

Companion documents to the Forest Project Protocol contain data tables, equations, and benchmark data applicable to projects located in the United States. The Reserve may add approved equations and models as they are developed in future versions of the Forest Project Protocol.

The methods required by this protocol for estimating baseline carbon stocks for Forest Projects cannot currently be applied outside the United States, as they rely on U.S.-specific data sets and models, particularly for Improved Forest Management Projects. Avoided Conversion Projects are eligible in U.S. Territories, as they do not depend on the U.S.-specific data sets mentioned above.

3.2 Project Start Date

The start date of a Forest Project is the date on which an activity is initiated that will lead to increased GHG reductions or removals relative to the Forest Project's baseline. All forest projects must be submitted to the Reserve within 12 months of their project start date.[6]

The following sections detail actions that identify the project start date for each project type.

3.2.1 Improved Forest Management Project Start Date

For an Improved Forest Management Project, the action is initiating forest management activities that increase sequestration and/or decrease emissions relative to the baseline. The start date must be linked to a discrete, verifiable action that delineates a change in practice relative to the project's baseline. Project Operators may choose to identify one of the following actions:

- Recordation of a conservation easement on the Project Area. The project start date is the date the easement was recorded.
- Transferring of property ownership (to a public or private entity). The project start date is the date of property transfer.
- Submitting the project to the Reserve.[7] The project start date is the date of submittal, provided that the project completes verification within 30 months of being submitted. If the project does not meet this deadline, it must be resubmitted under the latest version of the protocol; it will not retain the initial submittal date and will be subject to any new project start date requirements.

Project Operators must affirm the action denoting the project start date by providing documentation. Adequate documentation could include deeds of trust, title reports, conservation easement documentation, dated forest management plans, and/or contracts or agreements.

3.2.2 Avoided Conversion Project Start Date

For an Avoided Conversion Project, the action is committing the Project Area to continued forest management and protection through conservation easement recordation with a provision to maintain the Project Area in forest cover or transferring the Project Area to public ownership where the Project Area will be maintained in forest cover.

[6] See the Reserve's Program Manual for requirements for listing a project with the Reserve, available at http://www.climateactionreserve.org/how-it-works/program/program-manual/.

[7] Submitting a project to the Reserve is considered an initiation of a commitment to employ practices that will maintain or grow net carbon stocks for the duration of the FPP's commitment period, per the requirements of the FPP and signing the Project Implementation Agreement (PIA).

Where recordation of a conservation easement is used to signal the project start date, multiple conservation easements may be used to cover a single Project Area. Where transfer of the Project Area to public ownership is used to signal the project start date, multiple transfers may be used to cover a single Project Area. In either case, the following provisions must be met, as applicable:

- The Project Area being placed under easements has one fee owner, as required by Section 2.2, or the Project Area is being transferred to a single public entity;
- The easements must all have been recorded within the span of 12 months, or the transfers all take place within the span of 12 months;
- The alternative non-forest land use being avoided must be identical for all portions of the project and the default rate of conversion must be used (see Table 6.3); and,
- The Conversion Risk Adjustment Factor must be the same for all portions of the project (see Equation 6.11).

In these cases, the project start date will be the date of the last recorded easement, or the date of the final transfer of land.

3.3 Additionality

The Reserve strives to register only projects that yield surplus GHG emission reductions and removals that are additional to what would have occurred in the absence of a carbon offset market (i.e., under "Business As Usual"). For a general discussion of the Reserve's approach to determining additionality, see the Reserve's Program Manual (available at http://www.climateactionreserve.org/how/program/program-manual/).

The approach to additionality for Forest Projects recognizes increases in the amount of CO_2 removed from the atmosphere relative to Business As Usual management. It also considers the long-term risks to carbon sequestered in the Project Area presented by Business As Usual management and the potential emissions of such carbon into the atmosphere. Under such an approach, it takes into account the following:

- On-site carbon stocks are at risk on a 100-year time scale.
- Land ownership and management direction are not permanent, except in cases where binding commitments limit management options, such as conservation easements.
- Management goals and objectives are likely to change over time, especially as ownership of a forest changes hands, as often happens between generations of family forest owners[8] or between entities owning forests as a financial investment.[9]
- Over the length of a project lifetime and in the absence of a long-term commitment to a Forest Project, emissions may have resulted from the clearing of trees to convert a forest to another land cover type (for avoided conversion projects) or from harvest activities that reduce average on-site carbon stocking (for improved forest management projects).
- Committing a site to a Forest Project for at least 100 years and the long-term requirements specified in this protocol (e.g., monitoring, reporting, and verification; compensation for reversals; buffer pool contributions) removes such risks to emissions.

[8] Butler, B. J., *et al*. 2016. "Family Forest Ownerships of the United States, 2013: Findings from the USDA Forest Service's National Woodland Owner Survey." *Journal of Forestry* 114 (6): 638–47. doi:10.5849/jof.15-099.
[9] Bliss, J. C., *et al*. 2010. "Disintegration of the U. S. Industrial Forest Estate: Dynamics, Trajectories, and Questions." *Small-Scale Forestry* 9 (1): 53–66. doi:10.1007/s11842-009-9101-7.

Furthermore, this protocol acknowledges that the project's baseline, as the way Business As Usual management is represented for quantification purposes, is a counterfactual scenario, i.e., a representation of what may have actually occurred if the project had never happened. Additionality is assured over 100-year crediting period, during which project activities ensure forest carbon stocks are maintained or increase compared to the baseline, since the precise timing of potential outcomes within the counterfactual scenario are impossible to pinpoint. This and other assumptions incorporated into the quantification of a project's baseline and GHG reductions, as described below in Section 6, are used to create more consistency and simplicity in crediting while maintaining conservativeness.

Forest Projects must satisfy the following tests to be considered additional:

1. *Legal Requirement Test*. Forest Projects must achieve GHG reductions or removals above and beyond any GHG reductions or removals that would result from compliance with any federal, state, or local law, statute, rule, regulation, or ordinance. Forest Projects must also achieve GHG reductions and removals above and beyond any GHG reductions or removals that would result from compliance with any court order or other legally binding mandates including management plans (such as Timber Harvest Plans) that are required for government agency approval of harvest activities.

   Deeded encumbrances, such as timber deeds or conservation easements, may effectively control forest carbon, such that there may be multiple Forest Owners within the Project Area. Deeded encumbrances are considered legally binding mandates for the purposes of the legal requirement test, unless they are recorded within a year of the Forest Project's start date with clear agreement from all Forest Owners.

   Deeded encumbrances may contain terms that do not directly refer to forest carbon, but that nevertheless restrict the effect the ability of any one Forest Owner to change forest carbon stocks. These terms must be interpreted with respect to their effect on forest carbon for the purposes of the legal requirement test and baseline determinations. Where the terms of deeded encumbrances are not explicit with regards to forest carbon, the following assumptions shall be made:

   a. Restrictions or references related to canopy cover, basal area, density, volume, carbon or biomass apply to standing live and dead trees of all species.
   b. Carbon in other pools (soil, litter, duff, shrubs, etc.) is assumed to be associated with the other defined terms, such as trees.
   c. Terms related to forest (tree) growth apply to growth in all tree species.

2. *Performance Test*. Forest Projects must achieve GHG reductions or removals above and beyond any GHG reductions or removals that would result from engaging in Business As Usual activities, as defined by the requirements described below (Section 3.3.2).

   Project quantification (Section 6) further ensures that forest projects are additional via checks on financial feasibility.

3.3.1 Legal Requirement Test

The legal requirement test is satisfied if the following requirements are met, depending on the type of Forest Project.

3.3.1.1 Improved Forest Management Projects

At the Forest Project's initial verification, the Project Operator must sign the Reserve's Attestation of Voluntary Implementation form indicating that the Forest Project is not legally required (as defined above) and was not legally required at the time of the project's start date. For the purposes of the attestation, the "Project" is defined as maintaining onsite carbon stocks at or above their current levels (at the time the attestation is signed) for at least 100 years.

A project's final baseline must reflect all legal constraints in effect at the time of the project's start date, as required in Section 6.1 of this protocol.

3.3.1.2 Avoided Conversion Projects

At the Forest Project's initial verification, the Project Operator must sign the Reserve's Attestation of Voluntary Implementation form indicating that the Forest Project's planned forest conservation activities are not legally required (as defined above) and were not legally required at the time of the project's start date.

A project's final baseline must reflect all legal constraints, as required in Section 6.2 of this protocol.

3.3.2 Performance Test

The performance test is satisfied if the following requirements are met, depending on the type of Forest Project.

3.3.2.1 Improved Forest Management Projects

An Improved Forest Management Project automatically satisfies the performance test. Project activities are considered additional to the extent they produce GHG reductions and/or removals in excess of those that would have occurred under a Business As Usual scenario, as defined by the baseline estimation requirements in Section 6.1.

3.3.2.2 Avoided Conversion Projects

An Avoided Conversion Project satisfies the performance test if the Project Operator provides a real estate appraisal (or real estate appraisals) for the Project Area (as defined in Section 4) indicating the following:

1. *The Project Area is suitable for conversion*. The appraisal(s) must clearly identify the highest value alternative land use for the Project Area and indicate how the physical characteristics of the Project Area are suitable for the alternative land use.
2. The appraisal(s) must conform with the following minimum standards[10]:
    a. Appraisal reports shall be prepared and signed by a Licensed or Certified Real Estate Appraiser in good standing.
    b. Appraisal reports shall include descriptive photographs and maps of sufficient quality and detail to depict the subject property and any market data relied upon, including the relationship between the location of the subject property and the market data.

[10] Adapted from Sections 5096.501 and 5096.517, Public Resources Code, State of California.

c. Appraisal reports shall include a complete description of the subject property land, site characteristics and improvements. Valuations based on a property's development potential shall include:

   i. Verifiable data on the development potential of the land (e.g., Certificates of Compliance, Tentative Map, Final Map).
   ii. A description of what would be required for a development project to proceed (e.g., legal entitlements, infrastructure).
   iii. Presentation of evidence that sufficient demand exists, or is likely to exist in the future, to provide market support for the development.
   iv. Where conversion to commercial, residential, or agricultural land uses is identified as the highest value alternative land use, the appraisal(s) must demonstrate that the slope of Project Area land is compatible with the alternative land use by identifying two areas with similar average slope conditions to the Project Area that have been converted within the past ten years in the project's Assessment Area. Alternatively, the Project Area must have an average slope less than 40 percent.
   v. Where conversion to agricultural land use is anticipated, the appraisal(s) must provide:

      1) Evidence of soil suitability for the type of expected agricultural land use.
      2) Evidence of water availability for the type of expected agricultural land use.
      3) Where conversion to mining land use is anticipated, the appraisal(s) must provide evidence of the extent and amount of mineral resources existing in the Project Area.

   vi. Where conversion to residential, commercial, or recreational land uses is anticipated, the appraisal(s) must also describe the following information:

      1) The proximity of the Project Area to metropolitan areas
      2) The proximity of the Project Area to grocery and fuel services and accessibility of those services
      3) Population growth within 180 miles of the Project Area

d. Appraisal reports shall include a statement by the appraiser indicating to what extent land title conditions were investigated and considered in the analysis and value conclusion.
e. Appraisal reports shall include a discussion of implied dedication, prescriptive rights or other unrecorded rights that may affect value, indicating the extent of investigation, knowledge, or observation of conditions that might indicate evidence of public use.
f. Appraisal reports shall include a separate valuation for ongoing forest management prepared and signed by a certified or registered professional qualified in the field of specialty interest. This valuation shall be reviewed and approved by a second qualified, certified or registered professional, considered by the appraiser, and appended to the appraisal report(s). The valuation must identify and incorporate all legal constraints that could affect the valuation of both the ongoing forest management.
g. The appraisal(s) must provide a map that displays specific portions of the Project Area that are suitable for the identified alternative land use. (For example, an appraisal that identified a golf course as an alternative land use must specify the

approximate acres suitable for fairways, greens, clubhouses, and outbuildings.). The smaller of the two areas identified in the appraisals must be used.

3. *The alternative land use for the Project Area has a higher market value than maintaining the Project Area for sustainable forest management.* The appraisal(s) for the property must provide a value for the current forest land use condition of the Project Area and a fair market value of the anticipated alternative land use for the Project Area. The anticipated alternative land use for the Project Area must be at least 40 percent greater than the value of the current forested land use.

The appraisal(s) must be conducted in accordance with the Uniform Standards of Professional Appraisal Practice[11] and the appraiser must meet the qualification standards outlined in the Internal Revenue Code, Section 170 (f)(11)(E)(ii).[12]

3.3.3 Enhancement Payments

Enhancement payments provide financial assistance to landowners in order to implement discrete practices that address natural resource concerns and deliver environmental benefits. Examples of relevant enhancement payments include:

- California Climate Investments (CCI), formerly called Greenhouse Gas Reduction Funds (GGRF)
- USFS grants and agreements

Forest Owner(s) may pursue enhancement payments that support forest carbon project activities. Because every available enhancement payment is not comprehensively addressed by the protocol at this time, the Forest Owner(s) must still disclose any such payments to the verifier and the Reserve on an ongoing basis. The Reserve maintains the right to determine if payment stacking has occurred and whether or not it would impact project eligibility.

3.4 Project Crediting Period

The baseline for any Forest Project registered with the Reserve under this version of the Forest Project Protocol is assumed to be valid for 100 years. This means that a registered Forest Project will be eligible to receive CRTs for GHG reductions and/or removals quantified using this protocol, and verified by Reserve-approved verification bodies, for a period of 100 years following the project's start date. Projects may not end their crediting period early without penalty, as all quantification performed in this protocol assumes reporting and verification will continue for 100 years.

3.5 Permanence

Project Operators must monitor and verify a Forest Project for a period of 100 years following the issuance of any CRT for GHG reductions or removals achieved by the project. For example, if CRTs are issued to a Forest Project in year 99 following its start date, monitoring and

[11] The Uniform Standards of Professional Appraisal Practice may be accessed at: http://commerce.appraisalfoundation.org/html/2006%20USPAP/toc.htm
[12] Section 170 (f)(11)(E) of the Internal Revenue Code defines a qualified appraiser as
"an individual who:
(I) has earned an appraisal designation from a recognized professional appraiser organization or has otherwise met minimum education and experience requirements set forth in regulations prescribed by the Secretary,
(II) regularly performs appraisals for which the individual receives compensation, and
(III) meets such other requirements as may be prescribed by the Secretary in regulations or other guidance."

verification activities must be maintained until year 199. All Forest Projects must undergo an initial site visit verification to register with the Reserve. After the initial verification, all Forest Projects must undergo a site visit verification at the interval required in Section 8.3.2.1.

There are three possible exceptions to this minimum time commitment:

1. A Forest Project automatically terminates if a Significant Disturbance occurs,[13] leading to an Unavoidable Reversal that reduces the project's standing live tree carbon stocks below the project's baseline standing live tree carbon stocks. Once a Forest Project terminates in this manner, the Project Operator has no further obligations to the Reserve.
2. A Forest Project may be voluntarily terminated prior to the end of its minimum time commitment if the Project Operator surrenders a quantity of CRTs, as specified under 'Retiring CRTs Following Project Termination' below.
3. A Forest Project may be automatically terminated if there is a breach of certain terms described within the Project Implementation Agreement. Such a termination will require the Project Operator to retire a quantity of CRTs, as specified under 'Retiring CRTs Following Project Termination' below.

Retiring CRTs Following Project Termination

1. For an Avoided Conversion Project, the Project Operator must surrender a quantity of CRTs from its Reserve account equal to the total number of CRTs issued to the project over the preceding 100 years.
2. For an Improved Forest Management Project, the Project Operator must surrender a quantity of CRTs from its Reserve account equal to the total number of CRTs issued to the project over the preceding 100 years, multiplied by the appropriate compensation rate indicated in Table 3.1.
3. For any project seeking to terminate project activities on only a portion of the project area, the change must be treated as a potential Avoidable Reversal. If it is determined that the revision to the project area would lead to an Avoidable Reversal, then credits must be cancelled as described in Section 7.3.2. Improved Forest Management projects must also apply the early termination compensation rate in Table 3.1 below. If the revision to the project area would lower standing live carbon stocks below baseline levels, then this will be considered a complete project termination.
4. In addition:
    a. The cancelled CRTs must be those that were issued to the Forest Project, or that were issued to other Forest Projects registered with the Reserve. If neither of those options is available, CRTs from other land use projects will be given preference. If those are not available, then any other CRT is acceptable.
    b. The cancelled CRTs must be designated in the Reserve's software system as compensating for an Avoidable Reversal.

Table 3.1. Compensation Rate for Terminated Improved Forest Management Projects

[13] The natural disturbance shall not be the result of intentional or grossly negligent acts of any of the Forest Owners.

Number of Years that have Elapsed Between the Start Date and the Date of Termination	Compensation Rate
0-5	1.40
6-10	1.20
11-20	1.15
21-30	1.10
31-50	1.05
>50	1.00

3.6 Project Implementation Agreement

For a Forest Project to be eligible for registration with the Reserve, the Project Operator is required to enter into a Project Implementation Agreement (PIA) with the Reserve. The PIA is an agreement between the Reserve and a Project Operator setting forth: (i) the Project Operator's obligation (and the obligation of its successors and assigns) to comply with the Forest Project Protocol, and (ii) the rights and remedies of the Reserve in the event of any failure of the Project Operator to comply with its obligations. The PIA must be signed by the Project Operator before a project can be registered with the Reserve. It must be signed by all entities that are fee simple owners of the Project Area property. The PIA is recorded and submitted after the Reserve has reviewed the verification documents and is about to register the project.

3.7 Use of Qualified Conservation Easements or Qualified Deed Restrictions

A Qualified Conservation Easement is a conservation easement that explicitly (1) refers to, and incorporates by reference, the terms and conditions of the PIA agreed to by the Project Operator, thereby binding both the grantor and grantee – as well as their subsequent assignees – to the terms of the PIA for the full duration of the Forest Project's minimum time commitment, as defined in Section 3.5 of this protocol; (2) makes all future encumbrances and deeds subject to the PIA; and (3) makes the Reserve a third party beneficiary of the conservation easement.

A Qualified Deed Restriction is a deed restriction that ensures that the Project Implementation Agreement runs with the land and explicitly (1) refers to, and incorporates by reference, the terms and conditions of the PIA agreed to by the Project Operator, thereby Project Operator—as well as their subsequent assignees to the terms of the PIA for the full duration of the Forest Project's minimum time commitment, as defined in Section 3.5 of this protocol; (2) makes all future encumbrances and deeds subject to the PIA; and (3) makes the Reserve a third party beneficiary of the deed restriction. A deed restriction is not "qualified" if it merely consists of a recording of the Project Implementation Agreement or a notice of the Project Implementation Agreement, as such a recording is already required by the Project Implementation Agreement. The Reserve maintains the discretion to determine whether a deed restriction meets the terms to be considered a Qualified Deed Restriction.

Qualified Conservation Easements or Qualified Deed Restrictions may be voluntarily employed with any project type. Projects that choose to employ Qualified Conservation Easements or Qualified Deed Restrictions have reduced obligations to the Reserve's CRT Buffer Pool, as described in Section 7 and Appendix A.

Qualified Conservation Easements and Qualified Deed Restrictions must be recorded no earlier than one year before a project's start date. If a Qualified Conservation Easement or Qualified Deed Restriction was recorded more than one year prior to the start date, the limits imposed by the easement or deed restriction on forest management activities must be considered as a legal mandate for the purpose of satisfying the legal requirement test for additionality (Section 3.3.1) and in determining the project's baseline (Section 6).

3.8 Regulatory Compliance

Each time the Forest Project is verified, the Project Operator must attest that the project is in material compliance with all applicable laws relevant to the project activity. For this protocol, instances of non-compliance are likely to be considered "material" if they directly pertain to the management of project carbon stocks. Project Operators are required to disclose in writing to the verifier all instances of violations of laws that directly protect forests (trees), wildlife, water quality, or other environmental benefits, and which result in criminal or civil penalties. If a verifier finds that a project is in a state of material non-compliance, then CRTs will not be issued for GHG reductions that occurred during the period of non-compliance. Non-compliance solely due to administrative or reporting issues, or due to "acts of nature," will not affect CRT crediting.

3.9 Sustainable Harvesting and Natural Forest Management Practices

Forest Projects can create long-term climate benefits as well as provide other environmental benefits, including the sustaining of natural ecosystem processes. To be in conformance with this protocol, Forest Projects must:

1. Employ sustainable long-term harvesting practices, both within their Project Area and on other forest landholdings controlled by the Project Operator and its Affiliate(s) within the project's Assessment Area(s), as described in Section 3.9.1. Forest landholdings are considered "controlled" by the Project Operator if the Project Operator owns the land in fee or has been deeded timber rights on it.
2. Employ Natural Forest Management practices within the Project Area, including meeting species composition, forest structure, and age and habitat distribution requirements, as described in Section 3.9.2.
3. Maintain or increase standing live carbon stocks over the project life, as described in Section 3.9.3.

3.9.1 Sustainable Harvesting Practices

At the time Commercial Rotational Harvesting is initiated on any of the forest landholdings controlled by the Project Operator and its Affiliate(s) within the project's Assessment Area(s), the Project Operator and its Affiliate(s) must employ and demonstrate sustainable long-term harvesting practices on all of its forest landholdings within the project's Supersection(s), including the Project Area, using one of the following options:

1. Certification under the Forest Stewardship Council, Sustainable Forestry Initiative, or Tree Farm System certification programs. Regardless of the program, the terms of certification must require adherence to and verification of harvest levels which can be permanently sustained over time.

2. Adherence to a renewable long-term (50 years minimum) management plan that demonstrates harvest levels which can be permanently sustained over time and that is sanctioned and monitored by a state or federal agency (for federal lands only).
3. The use of silvicultural practices (if harvesting occurs) that maintain canopy cover averaging at least 40 percent, as measured on any 20 acres of the Project Operator's and its Affiliate(s') landholdings within the project's Supersections(s), including the Project Area.[14] Exceptions may be granted by the Reserve where it can be demonstrated that the harvest openings are intended to restore plantations to forest conditions with greater species diversity. The Project Operator is not responsible for harvest openings that preceded their ownership if the previous ownership had no direct business affiliation with the current ownership.
4. Adherence to a deeded conservation easement(s) with terms that ensure growth equals or exceeds harvest over time.

This requirement shall be met always during the project life and is assessed at each site visit verification. Failure to meet this requirement will result in all Reserve account activity being suspended until it is met.

Project Operators and their Affiliate(s) who acquire new forest landholdings within the project's Assessment Area(s) have up to five years to incorporate such acquisitions under their certification or management plan, or otherwise must abide immediately by the terms of the Sustainable Harvesting Practices, whether or not such land is contiguous with the Project Area.

3.9.2 Natural Forest Management

All Forest Projects must promote and maintain a diversity of native species and utilize management practices that promote and maintain native forests comprised of multiple ages and mixed native species within the Project Area and at multiple landscape scales ("Natural Forest Management").

The following key requirements shall apply to all Forest Projects regardless of the silvicultural or regeneration methods that are used to manage or maintain the forest:

1. Forest Projects must show verified progress (verified at scheduled site visit verifications) towards native tree species composition and distribution requirements described below, consistent with the forest type and forest soils native to the Assessment Area.
2. Forest Projects must manage the distribution of habitat/age classes and structural elements, as described below, to support functional habitat for locally native plant and wildlife species naturally occurring in the Project Area.

Forest Projects must incorporate the criteria for Natural Forest Management throughout the project life. The information provided in Table 3.3 shall be used to determine if the Forest Project meets the criteria for engaging in Natural Forest Management. This evaluation must be completed and verified at a Forest Project's initial verification and at all subsequent verifications. Forest Project carbon stock inventories (requirements for which are found in Appendix B) should be used as the basis of these assessments where applicable. Forest Projects that do not initially meet Natural Forest Management criteria but can demonstrate progress towards meeting these criteria at the times identified in Table 3.3 are compliant with the protocol.

[14] Areas impacted by Significant Disturbance may be excluded from this test.

1. Species Composition

All Forest Projects are required to establish and/or maintain forest types that are native to the Project Area. For the purposes of this protocol, native forests are defined as those forests occurring naturally in an area, as neither a direct nor indirect consequence of human activity post-dating European settlement, and are based on reference metrics for each Assessment Area provided in an Assessment Area Data File, a companion document to the FPP available on the Reserve's website. The planting of native species outside of their current distribution is allowed up to 5% of the overall native species requirement as an adaptation strategy due to climate change. Plantings that will result in more than 5% of native species from beyond their current distribution must be done in accordance with a state or federally approved adaptation plan, or a local plan that has gone through a transparent public review process. In all cases, the Project Operator must obtain a written statement from the government agency in charge of forestry regulation in the state where the project is located stipulating that the planting of native trees outside their current range is appropriate as an adaptation to climate change. The specifications for meeting the requirements for species composition are included in Table 3.3.

2. Forest Structure

A variety of silvicultural practices may be employed in the Project Area during the course of a Forest Project, though the protocol does not endorse any particular practice. Any practices employed, however, must meet a minimum set of standards to ensure environmental integrity associated with a balanced distribution of age and habitat classes across the landscape, as well as certain structural elements within the forest.

Harvesting may be conducted within forest projects using a variety of silviculture methods. However, to ensure harvest practices maintain habitat refugia, even-aged rotations are limited to the following guidelines in Table 3.2.

Table 3.2. Even-Aged Management Retention Guidelines

Harvest Retention (Square Feet Basal Area/Acre of All Species)	**Maximum Size of Harvest Block** (Acres)
0	40
>= 15 < 20	60
>=20 < 25	80
>=25 < 30	120
>= 30 < 40	400
>= 40 < 50	600
>=50	Unlimited

Harvest retention is evaluated based on conditions immediately following harvest. Up to 10% of the harvest retention standard may be met with standing dead trees. Where any harvest occurs in harvest blocks where the harvest retention is less than 50 square feet of basal area per acre, additional harvesting may only occur within 300 feet of the harvest area (with less than 50 square feet basal area per acre) if the harvest retention of the additional harvest exceeds 50 square feet of basal area per acre. This requirement shall remain in place until the regeneration within the original harvested area (i.e., with retention less than 50 square feet basal area per acre) achieves a height of five feet or is five years old.

On a watershed scale up to 10,000 acres, all projects must maintain, or make progress toward maintaining, no more than 40 percent of their forested acres in ages less than 20 years. Areas impacted by a Significant Disturbance are exempt from this test until 20 years after reforestation of such areas.

The protocol does not override a landowner's obligation to abide by applicable laws and regulations, including any governing forest practice rules that may be more stringent. Regardless of the silvicultural practice employed, landowners must fulfill their commitment under the protocol to permanently maintain or increase onsite standing live carbon stocks (i.e., the carbon in live trees within the Project Area) as specified in Section 3.9.3.

Structural elements such as standing dead trees and lying dead wood are features typically found in natural forests. They provide a variety of benefits, including wildlife habitat. Management of Forest Projects must ensure that standing dead trees and lying dead wood are present on the Project Area at certain minimum levels in accordance with the requirements outlined in Table 3.3.

Table 3.3. Evaluation Criteria to Test if a Forest Project Meets the Requirement for the Establishment and Maintenance of Native Species and Natural Forest Management

Criteria	Assessment	Application Rules
Native Species		
Project consists of at least 95% native species, or demonstrates continuous progress over 50 years toward 95% native species. The assessment shall be conducted using basal area per acre from the inventory of standing live trees.	Assessed at initial verification from inventory data. Assessment during site visit verifications must demonstrate continuous compliance with goal (if already met) or continuous progress toward the goal (if not yet met).	Applies to all project types throughout the project life. If criterion is not met within 50 years, all the Forest Project's Reserve account activity will be suspended[15] until the criterion is met.
Composition of Native Species		
No single species' prevalence in a given Assessment Area, measured as the percent of the basal area of all live trees in that Assessment Area, exceeds the percentage value shown under the heading 'Composition of Native Species' in the Assessment Area Data File maintained on the Reserve's website. Where portions of the Project Area falling within a given Assessment Area naturally consists of a single species' dominance, and is inconsistent with the percentage value in the Assessment Area Data File, the Project Operator may obtain a letter from the State Forester or their representative stating that the Project Area's species diversity is reflective of background natural species diversity (despite any inconsistencies with the Assessment Area Data File). Projects must show continuous progress toward criteria. These criteria must be met within 50 years, except in cases where a variance has been granted at the initial verification, a Significant Disturbance has impacted species diversity, or natural mortality takes a project out of compliance	Species composition is assessed at initial verification from inventory data. Species composition is also assessed during the project at each site visit verification.	Applies to all project types throughout the project life. If criterion is not met within 50 years, all the project's Reserve account activity will be suspended until the criterion is met (excluding the aforementioned exceptions).
Distribution of Age Classes		
On a watershed scale up to 10,000 acres (or the Project Area, whichever is smaller), all projects must maintain, or make progress toward maintaining, no more than 40 percent of their forested acres in ages less than 20 years. (Areas impacted by Significant Disturbance may be excluded from this test.) Applies to all project types at first Commercial Rotational Harvest. Project must show continuous progress toward criterion. This criterion must be met within 25 years	Age classes are assessed during project life at each site visit verification.	If criterion is not met within 25 years, all Reserve account activity will be suspended until the criterion is met.

[15] For the purpose of Table 3.3, suspension of Reserve account activity refers to issuance of CRTs and transaction of CRTs. Projects can continue to provide documentation to the Reserve for purposes of completing verification and demonstrating compliance with the Natural Forest Management criteria.

Structural Elements (Standing and Lying Dead Wood)		
Project Operators must ensure that dead wood is recruited and maintained in sufficient quantities, as described below. **Option I**. Monitoring dead wood throughout Project Area. Project Operators may maintain inventories of lying dead wood as part of their normal inventory processes. Where inventory measurements are used to demonstrate compliance with this requirement, monumented plots or line transects must be used so the plot data can be verified. Dead wood measurements must achieve a minimum statistical confidence of +/- 30% at 1 Standard Error. The combination of standing dead and lying dead wood shall be retained at average per acre values at quantity levels identified in the Assessment Area data file. If dead material does not exist at the quantities identified in the Assessment Area data file, dead trees shall be recruited as described below for Option II. **Option II**: Monitoring dead wood on harvested areas. The assessment of sufficient lying and standing dead material shall be made in areas harvested since the last site verification. **For portions of the Project Area that have been harvested under normal circumstances (not salvage harvested):** The combination of standing dead and lying dead wood shall be retained at average per acre values at quantity levels identified in the Assessment Area data file within each harvested unit. If dead material does not exist at the required levels within the harvest units, live trees shall be retained and tagged with aluminum tags at three times the amount identified in the Assessment Area data file minus whatever quantity does exist within each harvest unit. **For portions of the Project Area that have been salvage harvested:** The combination of standing dead and lying dead wood shall be retained at a combined four tonnes per acre on average within each harvest unit. Verification that the requirement has been met shall be conducted using the methodology for verification of dead material transects found in Appendix B **Option III:** No harvesting Projects without any harvesting activities within the project area do not need to monitor specifically for structural elements.	Assessed during project at each site visit verification.	Applies to all project types throughout the project life. If not met within 25 years, all Reserve account activity will be suspended until the areas verified since the previous site-verification meet the requirement.

3.9.3 Promotion of the Onsite Standing Live Carbon Stocks

To promote and maintain the environmental benefits of Forest Projects, the Reserve requires that the standing live carbon stocks within the Project Area be maintained and/or increased during the project life. Therefore, except as specified below, the Reserve will not issue CRTs for quantified GHG reductions and removals achieved by a Forest Project if the Forest Project's monitoring reports – over any ten-year consecutive period – indicate a decrease in the standing live carbon stocks.

Exceptions to this policy are allowed where reductions in standing live carbon stocks are important for maintaining and enhancing forest health, environmental co-benefits, or the long-term security of all carbon stocks; where reductions are due to non-harvest disturbances; or where reductions are required by law. Note that these exceptions in no way change or affect the Reserve's policies and requirements related to compensating for reversals, as detailed in Section 7.3.

Forest Project standing live carbon stocks that have decreased over a ten-year period may continue to receive CRTs issued by the Reserve for verified GHG reductions and removals if, and only if, the decrease in standing live carbon stocks is due to one of the following causes:

1. The decrease is demonstrably necessary to substantially improve the Project Area's resistance to wildfire, insect, or disease risks. The Project Operator must document the risks and the actions that will be taken to reduce the risks. The techniques used to improve resistance must be supported by relevant published peer reviewed research or professionally-accepted standards.
2. The decrease is associated with a planned balancing of age classes (regeneration, sub-merchantable, and merchantable) and is detailed in a long term environmentally responsible management plan. The Project Operator must demonstrate, using documentation submitted to the Reserve at the time of the Forest Project's registration, that the balancing of age classes, resulting in a decrease in the standing live carbon stocks, was planned at the initiation of the Forest Project.
3. The decrease is part of normal silviculture cycles for forest ownerships less than 1,000 acres. Inventory fluctuations are a normal part of silvicultural activities. Periodic harvest may remove more biomass than the biomass growth over the past several years. At no time shall the Forest Project's inventory of carbon in the standing live carbon stocks fall below the Forest Project's baseline carbon stock estimates for the standing live carbon stocks, or 20 percent less than the Forest Project's standing live carbon stocks at the project's initiation, whichever is higher. Documentation submitted to the Reserve at the time the Forest Project is registered must indicate that fluctuations in the Forest Project's standing live carbon stocks are an anticipated silvicultural activity and that the overall trend will be for standing live carbon stocks to increase or stay the same over the life of the project (Figure 3.1).

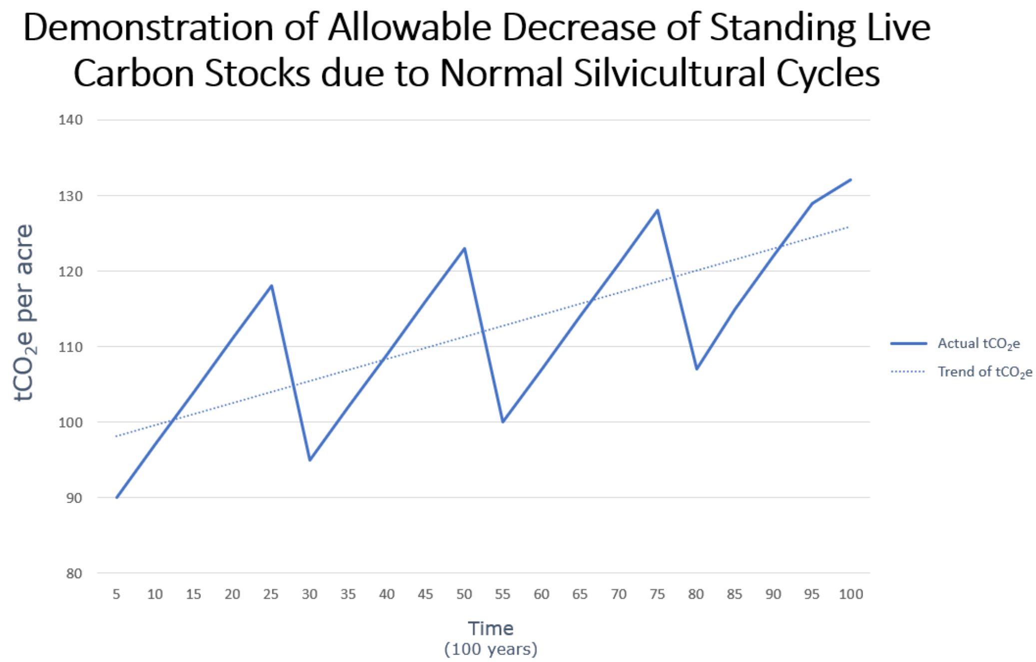


Figure 3.1. Example of Allowable Decrease of Standing Live Carbon Stocks due to Normal Silviculture Cycles

4. The decrease is part of a non-harvest disturbance, including wildfire, disease, flooding, wind-throw, insect infestation, landslides, or as otherwise approved by the Reserve.

4 Identifying the Project Area

The geographic boundaries defining the project area must be described in detail at the time a Forest Project is listed on the Reserve. The boundaries must be defined using a map, or maps that displays public and major private roads, major watercourses (fourth order or greater), topography, towns, and Public Land Survey Townships, Ranges, and Sections or latitude and longitude. The maps must be of adequate resolution to clearly identify the required features.

Once a project's Supersection(s) has been identified, Assessment Area(s) must be determined. A project may do this by comparing dominant species present in the project inventory to the list of native species provided in the Assessment Area Data File. Projects may also utilize Landfire Existing Vegetation Types (EVT) to determine the most appropriate Assessment Areas for the project. EVT descriptions must be used to identify the species descriptions that most closely match the native species provided in the Assessment Area Data File. The Reserve also reserves the right to provide a spatially explicit map of Assessment Areas to be used for identification purposes. The Project Area may also extend across multiple Assessment Areas within a Supersection), and across no more than two adjacent Supersections.

A Geographical Information System (GIS) file depicting the Project Area must be submitted to the Reserve with the project. The file must be submitted in the KML file format. Additionally, the current assessor's parcel identification numbers associated with the project area must be submitted to the Reserve.

For Avoided Conversion Projects, the Project Area is defined through the required appraisal process. The Project Area must be determined following the guidance in Table 4.1 based on the type of anticipated conversion.

Table 4.1. Project Area Definition for Avoided Conversion Projects

Conversion Type	Project Area Definition
Residential	The boundary of the parcel or parcels that have been appraised as having a 'higher and better use' in residential development.
Agricultural Conversion	The boundary of the parcel or parcels that have been appraised as having a 'higher and better use' in agricultural production.
Golf Course	The boundary of the parcel or parcels that have been appraised as having a 'higher and better use' as a golf course. This is to include forested areas within 200 feet of fairways, greens, and buildings.
Commercial Buildings	The boundary of the parcel or parcels that have been appraised as having a 'higher and better use' in commercial buildings. This is to include forested areas with 200 feet of suitable building sites.

4.1 Project Configuration and Limitations

To ensure Project Areas are representative of the Forest Owners' general forest management, Improved Forest Management projects must include all forested areas owned by the Forest Owner(s) within an area no smaller than an area defined by HUC 14-digit hydrological units (HUC 14) where available (or HUC 12-digit hydrological units if HUC 14 is unavailable), or the entire area owned by the Forest Owner, whichever is smaller. HUC 14 or HUC 12 hydrological units must be identified using the USGS National Hydrography Dataset.[16] Exceptions may be

[16] The National Hydrography Dataset can be accessed via the USGS website: http://nhd.usgs.gov/.

provided if approved by the Reserve. Non-forested areas (brush, rocks, range, etc.) may be excluded from all project types. For Improved Forest Management Projects, areas not under forest management may also be excluded from the Project Area. For all project types, the Project Area can be contiguous or separated into tracts or distinct polygons (areas).

4.2 Project Area Acreage

Project acreage shall be based on area calculations derived from GIS analysis, such as ArcGIS or Google Earth. GIS data are generally considered to be improvements over strict adherence to county parcel acreages as they are based on correcting property boundaries to geographic characteristics and/or property corners as described in property deeds or official survey notes. A KML (Google Earth) file depicting the Project Area shall be included with the PDD.

The project must list the county assessor's parcels (APs), the portion of each AP included in the project as a percentage (if GIS parcel data is available from the relevant state, county, or municipality), the sum of acres derived from the county tax records for all included APs, and the sum of acres derived from the GIS analysis. The sum of acres should be compared between the AP and GIS sources, with the lesser of the two used for the project area.

If there is a discrepancy between AP and GIS acres, the Project Operator has the following options:

- Resolve the acres on a per AP basis by using the lesser of the two area references
- Work with the county assessor to resolve acreage disputes on AP acres
- Demonstrate to verifier that GIS acres are based on recorded surveyed corners and correctly referenced with GPS

4.3 Modifying the Project Area

It is possible for project activities to be terminated on a portion of the Project Area. These adjustments must be treated as Avoidable Reversals, as described in Section 3.5. If a project proceeds with terminating the project on a portion of the Project Area, a new KML file must be provided to reflect the new Project Area. An addendum to the Project Design Document (PDD) must also be submitted to reflect this change, and the new legal description of the project will be recorded with the next PIA or PIA Amendment after the change has been verified. The inventory for the modified Project Area will be assessed during the next regularly scheduled site visit verification, unless it is determined that an Avoidable Reversal has taken place, in which case, the guidance in Section 7.3.2 must be followed.

5 GHG Assessment Boundary

The GHG Assessment Boundary defines all the GHG sources, sinks, and reservoirs that must be accounted for in quantifying a Forest Project's GHG reductions and removals (Section 6). The GHG Assessment Boundary encompasses all the GHG sources, sinks, and reservoirs that may be significantly affected by Forest Project activities, including forest carbon stocks, sources of biological CO_2 emissions, and mobile combustion GHG emissions. For accounting purposes, the sources, sinks, and reservoirs included in the GHG Assessment Boundary are organized according to whether they are predominantly associated with a Forest Project's "Primary Effect" (i.e., the Forest Project's intended changes in carbon stocks, GHG emissions, or GHG removals) or its "Secondary Effects" (i.e., unintended changes in carbon stocks, GHG emissions, or GHG removals caused by the Forest Project).[17] Secondary Effects may include increases in mobile combustion CO_2 emissions associated with site preparation, as well as increased CO_2 emissions caused by the shifting of harvesting activities from the Project Area to other forestlands (often referred to as "leakage"). Projects are required to account for Secondary Effects following the methods described in Section 6.

The following tables provide a comprehensive list of the GHG sources, sinks, and reservoirs (SSRs) that may be affected by a Forest Project and indicate which SSRs must be included in the GHG Assessment Boundary for each type of Forest Project. If an SSR is designated as a "reservoir/pool," this means that GHG reductions and removals are accounted for by quantifying changes in carbon stock levels. For SSRs designated as sources or sinks, GHG reductions and removals are accounted for by quantifying changes in GHG emission or removal rates, as described in the tables.

5.1 Improved Forest Management Projects

Table 5.1. GHG Assessment Boundary – Improved Forest Management Projects

SSR	Description	Type	Gas	Included or Excluded	Relevant to Baseline or Project	Justification/Explanation
Primary Effect Sources, Sinks, and Reservoirs						
IFM-1	Standing live carbon (carbon in all portions of living trees)	Reservoir / Pool	CO_2	*Included*	**Baseline:** Modeled based on initial field inventory measurements, regulatory environment, and financial feasibility **Project:** Measured by field measurements and updating forest carbon inventory	Increases in standing live carbon stocks are likely to be the largest Primary Effect of Improved Forest Management Projects.
IFM-2	Shrubs and herbaceous understory carbon	Reservoir / Pool	CO_2	*Excluded*	**Baseline:** N/A **Project:** N/A	Shrubs and herbaceous understory constitute a relatively small proportion of carbon stocks in an Improved Forest Management project.

[17] The terms "Primary Effect" and "Secondary Effect" come from WRI/WBCSD, 2005. *The Greenhouse Gas Protocol for Project Accounting*, World Resources Institute, Washington, DC. Available at http://www.ghgprotocol.org.

SSR	Description	Type	Gas	Included or Excluded	Relevant to Baseline or Project	Justification/Explanation
IFM-3	Standing dead carbon (carbon in all portions of dead, standing trees)	Reservoir / Pool	CO_2	*Included*	**Baseline:** Assumed to be static based on initial field inventory measurements **Project:** Measured by updating forest carbon inventory	Improved Forest Management Projects may significantly increase standing dead carbon stocks over time. The protocol requires recruitment and retention of dead material, including standing dead wood as a structural element. Minimum volume thresholds are stated to meet Natural Forest Management criteria. (See Section 3.9.2).
IFM-4	Lying dead wood carbon	Reservoir / Pool	CO_2	*Excluded*	**Baseline:** N/A **Project:** N/A	Lying dead wood is highly variable and it is therefore difficult to achieve accurate estimates. It also constitutes a minor portion of forest carbon. With required retention for Natural Forest Management (see below), it is a conservative programmatic measure not to include it. For Natural Forest Management criteria, the protocol requires recruitment and retention of dead material, including lying dead wood as a structural element. Minimum volume thresholds are stated to meet Natural Forest Management criteria. (See Section 3.9.2).
IFM-5	Litter and duff carbon (carbon in dead plant material)	Reservoir / Pool	CO_2	*Excluded*	**Baseline:** N/A **Project:** N/A	Changes in this reservoir are unlikely to have a significant effect on total quantified GHG reductions/removals. It is a conservative programmatic measure not to include it.
IFM-6	Soil carbon	Reservoir / Pool	CO_2	*Included for emissions estimates*	**Baseline:** Assumed to be static with start date inventory estimates **Project:** Emissions from project activities estimated with standardized guidelines in found in Appendix B	Soil carbon is not anticipated to change significantly as a result of most Improved Forest Management activities. However, all projects must use standardized guidance to account for potential soil carbon emissions associated with management activities.
IFM-7	Carbon in in-use forest products	Reservoir / Pool	CO_2	*Included*	**Baseline:** Estimated from modeled harvesting volumes **Project:** Estimated from measured harvesting volumes	Included because many Improved Forest Management Projects may significantly change carbon storage in in-use forest products relative to baseline levels. Treated as a "source/sink" because forest product carbon is quantified according to the change in harvesting volumes, relative to baseline levels, in each year. Of this change (increase or decrease), only the average amount of carbon expected to remain stored for 100 years is included in the final

SSR	Description	Type	Gas	Included or Excluded	Relevant to Baseline or Project	Justification/Explanation
						quantification of annual net GHG removals/emissions. This approach accounts for CO_2 emissions from decomposition or disposal of wood products (see SSR IFM-17).
IFM-8	Forest product carbon in landfills	Reservoir / Pool	CO_2	*Excluded when project harvesting exceeds baseline* *Included when project harvesting is below baseline*	**Baseline:** Estimated from modeled harvesting volumes **Project:** Estimated from measured harvesting volumes	Because of significant uncertainties associated with forecasting the quantity of forest product carbon that will remain stored in landfills, landfill carbon is excluded from quantification in years when project harvesting volumes exceed baseline volumes. Landfill carbon is included, however, in years when project harvesting volumes are below baseline levels. This case-dependent exclusion or inclusion is necessary to ensure that total GHG reductions and removals caused by the Forest Project are not overestimated.
Secondary Effect Sources, Sinks, and Reservoirs						
IFM-9	Biological emissions from site preparation activities	Source	CO_2	*Included*	**Baseline:** N/A **Project:** Quantified based on measured carbon stock changes in included reservoirs (SSR IFM-6, where applicable)	Biological emissions from site preparation are not quantified separately, but rather are captured by measuring changes in included carbon reservoirs (soil carbon, where applicable). For other carbon reservoirs, changes are unlikely to have a significant effect on total quantified GHG reductions/removals.
IFM-10	Mobile combustion emissions from site preparation activities	Source	CO_2	*Excluded*	**Baseline:** N/A **Project:** N/A	Mobile combustion CO_2 emissions from site preparation are not expected to be significantly different from baseline levels for Improved Forest Management Projects. In addition, this protocol assumes that combustion emissions in the U.S. will be controlled under a regulatory cap-and-trade program in the near future, meaning that changes in activity due to the Forest Project will have no effect on total net emissions.
			CH_4	*Excluded*	**Baseline:** N/A **Project:** N/A	Changes in CH_4 emissions from mobile combustion associated with site preparation activities are not considered significant.
			N_2O	*Excluded*	**Baseline:** N/A **Project:** N/A	Changes in N_2O emissions from mobile combustion associated with site preparation activities are not considered significant.

SSR	Description	Type	Gas	Included or Excluded	Relevant to Baseline or Project	Justification/Explanation
IFM-11	Mobile combustion emissions from ongoing project operation and maintenance	Source	CO_2	*Excluded*	**Baseline:** N/A **Project:** N/A	Mobile combustion CO_2 emissions from ongoing project operation and maintenance are unlikely to be significantly different from baseline levels, and are therefore not included in the GHG Assessment Boundary. In addition, this protocol assumes that such emissions will be controlled under a regulatory cap-and-trade program in the near future, meaning that changes in activity due to the Forest Project will have no effect on total net emissions.
			CH_4	*Excluded*	**Baseline:** N/A **Project:** N/A	Changes in CH_4 emissions from mobile combustion associated with ongoing project operation and maintenance activities are not considered significant.
			N_2O	*Excluded*	**Baseline:** N/A **Project:** N/A	Changes in N_2O emissions from mobile combustion associated with ongoing project operation and maintenance activities are not considered significant.
IFM-12	Stationary combustion emissions from ongoing project operation and maintenance	Source	CO_2	*Excluded*	**Baseline:** N/A **Project:** N/A	Stationary combustion CO_2 emissions from ongoing project operation and maintenance could include GHG emissions associated with electricity consumption or heating/cooling at Project Operator facilities, or at facilities owned or controlled by contractors. These emissions are unlikely to be significantly different from baseline levels, and are therefore not included in the GHG Assessment Boundary. In addition, this protocol assumes that such emissions will be controlled under a regulatory cap-and-trade program in the near future, meaning that changes in activity due to the Forest Project will have no effect on total net emissions.
			CH_4	*Excluded*	**Baseline:** N/A **Project:** N/A	Changes in CH_4 emissions from stationary combustion associated with ongoing project operation and maintenance activities are not considered significant.
			N_2O	*Excluded*	**Baseline:** N/A **Project:** N/A	Changes in N_2O emissions from stationary combustion associated with ongoing project operation and maintenance activities are not considered significant.

SSR	Description	Type	Gas	Included or Excluded	Relevant to Baseline or Project	Justification/Explanation
IFM-13	Biological emissions from clearing of forestland outside the Project Area	Source	CO_2	*Excluded*	**Baseline:** N/A **Project:** N/A	Improved Forest Management Projects are not expected to cause significant shifts in alternative land uses that might lead to clearing of forestland.
IFM-14	Biological emissions/ removals from changes in harvesting on forestland outside the Project Area	Source / Sink	CO_2	*Included / Excluded*	**Baseline:** N/A **Project:** Estimated "leakage" factor applied to the difference in harvested carbon relative to baseline based on the magnitude of that difference relative to baseline harvest amounts	Improved Forest Management Projects may either increase or decrease harvesting relative to baseline levels. If harvesting is reduced in the Project Area, harvesting on other lands may increase to compensate for the lost production. This "leakage" effect is included in the GHG Assessment Boundary. If harvesting is increased in the Project Area, harvesting on other lands may decrease in response to the increased production. The reduction in harvesting may lead to increased carbon stocks on other lands. Carbon stock increases on other lands are excluded from the GHG Assessment Boundary, however, because it is not possible to ensure their permanence.
IFM-15	Combustion emissions from production, transportation, and disposal of forest products	Source	CO_2	*Excluded*	**Baseline:** N/A **Project:** N/A	This protocol assumes that combustion emissions will be controlled under a regulatory cap-and-trade program in the near future. Thus, for most of a Forest Project's duration, changes in activity due to the project will have no effect on total net emissions due to production, transportation, and disposal of forest products. These emissions are therefore excluded from the GHG Assessment Boundary.
			CH_4	*Excluded*	**Baseline:** N/A **Project:** N/A	Combustion-related CH_4 emissions related to changes in the production, transportation, and disposal of forest products are not considered significant.
			N_2O	*Excluded*	**Baseline:** N/A **Project:** N/A	Combustion-related N_2O emissions related to changes in the production, transportation, and disposal of forest products are not considered significant.
IFM-16	Combustion emissions from production, transportation, and disposal of alternative materials to forest products	Source	CO_2	*Excluded*	**Baseline:** N/A **Project:** N/A	Changes in forest-product production may cause consumers of these products to increase or decrease their consumption of substitute materials (such as alternative building materials, including cement or steel). In many cases, alternative materials will have

SSR	Description	Type	Gas	Included or Excluded	Relevant to Baseline or Project	Justification/Explanation
						higher combustion GHG emissions associated with their production, transportation, and/or disposal than wood products. This protocol assumes, however, that combustion emissions will be controlled under a regulatory cap-and-trade program in the near future. Thus, for most of a Forest Project's duration, changes in activity due to the project will have no effect on total net emissions due to production, transportation, and disposal of alternative materials. These emissions are therefore excluded from the GHG Assessment Boundary.
			CH_4	*Excluded*	**Baseline:** N/A **Project:** N/A	Combustion-related CH_4 emissions related to changes in the production, transportation, and disposal of alternative materials are not considered significant.
			N_2O	*Excluded*	**Baseline:** N/A **Project:** N/A	Combustion-related N_2O emissions related to changes in the production, transportation, and disposal of alternative materials are not considered significant.
IFM-17	Biological emissions from decomposition of forest products	Source	CO_2	*Included*	**Baseline:** Quantified as a component of calculating carbon stored for 100 years in wood products (SSR IFM-7) and landfills (SSR IFM-8) **Project:** Quantified as a component of calculating carbon stored for 100 years in wood products (SSR IFM-7) and landfills (SSR IFM-8)	CO_2 emissions from the decomposition of forest products are built into calculations of how much forest product carbon will remain in in-use wood products and in landfills, averaged over 100 years (see SSR IFM-7 and Appendix B).
			CH_4	*Excluded*	**Baseline:** N/A **Project:** N/A	In-use wood products will produce little to no CH_4 emissions. CH_4 emissions can result from anaerobic decomposition of forest products in landfills. This protocol assumes that landfill CH_4 emissions will be largely controlled in the near future due to federal and/or state regulations. Thus, changes in forest-product production are assumed to have no significant effect on future CH_4 emissions from anaerobic decomposition of forest products in landfills. These emissions are therefore excluded from the GHG Assessment Boundary.

SSR	Description	Type	Gas	Included or Excluded	Relevant to Baseline or Project	Justification/Explanation
			N_2O	*Excluded*	**Baseline:** N/A **Project:** N/A	Decomposition of forest is not expected to be a significant source of N_2O emissions.

5.2 Avoided Conversion Projects

Table 5.2. GHG Assessment Boundary – Avoided Conversion Projects

SSR	Description	Type	Gas	Included or Excluded	Relevant to Baseline or Project	Justification/Explanation
Primary Effect Sources, Sinks, and Reservoirs						
AC-1	Standing live carbon (carbon in all portions of living trees)	Reservoir / Pool	CO_2	*Included*	**Baseline:** Modeled based on initial field inventory measurements and expected land-use conversion rates **Project:** Measured by field measurements and updating forest carbon inventory	Preservation and/or increases of standing live carbon stocks and/or soil carbon stocks relative to baseline levels are likely to be a large Primary Effect of Avoided Conversion Projects.
AC-2	Shrubs and herbaceous understory carbon	Reservoir / Pool	CO_2	*Excluded*	**Baseline:** N/A **Project:** N/A	Changes in this reservoir/reservoir are unlikely to have a significant effect on total quantified GHG reductions/removals. Additionally, it is a conservative programmatic measure to exclude shrubs and herbaceous understory carbon.
AC-3	Standing dead carbon (carbon in all portions of dead, standing trees)	Reservoir / Pool	CO_2	*Included*	**Baseline:** Assumed to be static based on initial field inventory measurements **Project:** Measured by updating forest carbon inventory	Avoided Conversion Projects may significantly increase standing dead carbon stocks over time. The protocol requires recruitment and retention of dead material, including standing dead wood as a structural element. Minimum volume thresholds are stated to meet Natural Forest Management criteria. (See Section 3.9.2).
AC-4	Lying dead wood carbon	Reservoir / Pool	CO_2	*Excluded*	**Baseline:** N/A **Project:** N/A	Exclusion of lying dead wood is programmatically conservative for accounting of total quantified GHG reductions/removals, since project activities most likely will lead to increases in lying dead wood carbon. Lying dead wood is highly variable and is difficult to measure accurately, and therefore challenging to achieve confidence with estimates For Natural Forest Management criteria, the protocol requires recruitment and retention of dead material, including lying dead wood as a structural element. Minimum volume thresholds are stated

SSR	Description	Type	Gas	Included or Excluded	Relevant to Baseline or Project	Justification/Explanation
						to meet Natural Forest Management criteria. (See Section 3.9.2).
AC-5	Litter and duff carbon (carbon in dead plant material)	Reservoir / Pool	CO_2	*Excluded*	**Baseline:** N/A **Project:** N/A	Exclusion of litter and duff carbon is programmatically conservative for accounting of total quantified GHG reductions/removals, since project activities most likely will lead to increases in litter and duff carbon. Litter and duff is highly variable, difficult to measure accurately, and therefore challenging to achieve confidence with estimates.
AC-6	Soil carbon	Reservoir / Pool	CO_2	*Optional for reporting project benefits* *Included for reporting project emissions*	**Baseline:** When included, assumed to have emissions and emission rates according to soil order and baseline conversion activity **Project:** Emissions calculated using standardized guidance in Appendix B. Project Operators may opt to quantify net removals or avoided emissions by updating forest soil carbon inventory	Soil carbon is likely a large primary effect of an Avoided Conversion Project. It is conservative to exclude the conversion effect on soil from the project accounting, which is why it is optional. All projects must use standardized guidance to account for potential soil carbon emissions associated with project management activities. If Project Operators choose to quantify net removals or avoided emissions from soil carbon, they may do so by undertaking and updating a soil carbon inventory.
AC-7	Carbon in in-use forest products	Reservoir / Pool	CO_2	*Included*	**Baseline:** Estimated from modeled harvesting volumes **Project:** Estimated from measured harvesting volumes	Included because many Avoided Conversion Projects may significantly change carbon storage in in-use forest products relative to baseline levels. Treated as a “source/sink” because forest product carbon is quantified according to the change in harvesting volumes, relative to baseline levels, in each year. Of this change (increase or decrease), only the average amount of carbon expected to remain stored for 100 years is included in the final quantification of annual net GHG removals/emissions. This approach accounts for CO_2 emissions from decomposition or disposal of wood products (see SSR AC-17).
AC-8	Forest product carbon in landfills	Reservoir / Pool	CO_2	*Excluded when project harvesting exceeds baseline* *Included when project harvesting is below baseline*	**Baseline:** Estimated from modeled harvesting volumes **Project:** Estimated from measured harvesting volumes	Because of significant uncertainties associated with forecasting the quantity of forest product carbon that will remain stored in landfills, landfill carbon is excluded from quantification in years when project harvesting volumes exceed baseline volumes. Landfill carbon is included, however, in years when project harvesting volumes are below baseline levels. This case-dependent exclusion or inclusion is necessary to ensure that total GHG

SSR	Description	Type	Gas	Included or Excluded	Relevant to Baseline or Project	Justification/Explanation
						reductions and removals caused by the Forest Project are not overestimated.
Secondary Effect Sources, Sinks, and Reservoirs						
AC-9	Biological emissions from site preparation activities	Source	CO_2	*Included*	**Baseline:** N/A **Project:** Quantified based on measured carbon stock changes in included reservoirs (SSR AC-6, where applicable)	Biological emissions from site preparation are not quantified separately, but rather are captured by measuring changes in included carbon reservoirs (soil carbon, where applicable). For other carbon reservoirs, changes are unlikely to have a significant effect on total quantified GHG reductions/removals.
AC-10	Mobile combustion emissions from site preparation activities	Source	CO_2	*Excluded*	**Baseline:** N/A **Project:** N/A	Mobile combustion CO_2 emissions from site preparation (including land-use conversion activities) are likely to be higher in the baseline than under project. These emissions are therefore excluded from the GHG Assessment Boundary in order to be conservative. In addition, this protocol assumes that combustion emissions in the United States will be controlled under a regulatory cap-and-trade program in the near future, meaning that changes in activity due to the Forest Project will have no effect on total net emissions.
			CH_4	*Excluded*	**Baseline:** N/A **Project:** N/A	Differences in CH_4 emissions from mobile combustion associated with site preparation activities are not considered significant.
			N_2O	*Excluded*	**Baseline:** N/A **Project:** N/A	Differences in N_2O emissions from mobile combustion associated with site preparation activities are not considered significant.
AC-11	Mobile combustion emissions from ongoing project operation and maintenance	Source	CO_2	*Excluded*	**Baseline:** N/A **Project:** N/A	Mobile combustion CO_2 emissions from ongoing project operation and maintenance are unlikely to be significantly different from baseline levels and are therefore not included in the GHG Assessment Boundary. In addition, this protocol assumes that such emissions will be controlled under a regulatory cap-and-trade program in the near future, meaning that changes in activity due to the Forest Project will have no effect on total net emissions.
			CH_4	*Excluded*	**Baseline:** N/A **Project:** N/A	Changes in CH_4 emissions from mobile combustion associated with ongoing project operation and maintenance activities are not considered significant.
			N_2O	*Excluded*	**Baseline:** N/A **Project:** N/A	Changes in N_2O emissions from mobile combustion associated with ongoing project operation and maintenance activities are not considered significant.
AC-12	Stationary combustion emissions from	Source	CO_2	*Excluded*	**Baseline:** N/A **Project:** N/A	Stationary combustion CO_2 emissions from ongoing project operation and maintenance could include GHG

SSR	Description	Type	Gas	Included or Excluded	Relevant to Baseline or Project	Justification/Explanation
	ongoing project operation and maintenance					emissions associated with electricity consumption or heating/cooling at Project Operator facilities, or at facilities owned or controlled by contractors. These emissions are unlikely to be significantly different from (or will be lower than) baseline levels and are therefore not included in the GHG Assessment Boundary. In addition, this protocol assumes that such emissions will be controlled under a regulatory cap-and-trade program in the near future, meaning that changes in activity due to the Forest Project will have no effect on total net emissions.
			CH_4	*Excluded*	**Baseline:** N/A **Project:** N/A	Changes in CH_4 emissions from stationary combustion associated with ongoing project operation and maintenance activities are not considered significant.
			N_2O	*Excluded*	**Baseline:** N/A **Project:** N/A	Changes in N_2O emissions from stationary combustion associated with ongoing project operation and maintenance activities are not considered significant.
AC-13	Biological emissions from clearing of forestland outside the Project Area	Source	CO_2	*Included*	**Baseline:** N/A **Project:** Estimated using default forestland conversion factors	Avoided Conversion Projects may cause land-use pressures to shift to other forestlands, causing biological emissions that partially negate the benefits of the project.
AC-14	Biological emissions/ removals from changes in harvesting on forestland outside the Project Area	Source / Sink	CO_2	*Excluded*	**Baseline:** N/A **Project:** N/A	Over time, Avoided Conversion Projects will tend to increase harvesting levels relative to the baseline, potentially causing other landowners to reduce harvesting in response to increased wood product supply. The reduction in harvesting may lead to increased carbon stocks on other lands. Carbon stock increases on other lands are excluded from the GHG Assessment Boundary, however, because it is not possible to ensure their permanence. Avoided Conversion Projects are not expected to cause an increase in harvesting on other lands over the long run (except where clearing is involved for other land uses, per SSR AC-13), so this potential effect is also excluded from the GHG Assessment Boundary.
AC-15	Combustion emissions from production, transportation, and disposal of forest products	Source	CO_2	*Excluded*	**Baseline:** N/A **Project:** N/A	This protocol assumes that combustion emissions will be controlled under a regulatory cap-and-trade program in the near future. Thus, for most of a Forest Project's duration, changes in activity due to the project will have no effect on total net emissions due to production, transportation, and disposal of forest products. These emissions are therefore

SSR	Description	Type	Gas	Included or Excluded	Relevant to Baseline or Project	Justification/Explanation
						excluded from the GHG Assessment Boundary.
			CH_4	*Excluded*	**Baseline:** N/A **Project:** N/A	Combustion-related CH_4 emissions related to changes in the production, transportation, and disposal of forest products are not considered significant.
			N_2O	*Excluded*	**Baseline:** N/A **Project:** N/A	Combustion-related N_2O emissions related to changes in the production, transportation, and disposal of forest products are not considered significant.
AC-16	Combustion emissions from production, transportation, and disposal of alternative materials to forest products	Source	CO_2	*Excluded*	**Baseline:** N/A **Project:** N/A	Changes in forest-product production may cause consumers of these products to increase or decrease their consumption of substitute materials (such as alternative building materials, including cement or steel). In many cases, alternative materials will have higher combustion GHG emissions associated with their production, transportation, and/or disposal than wood products. This protocol assumes, however, that combustion emissions will be controlled under a regulatory cap-and-trade program in the near future. Thus, for most of a Forest Project's duration, changes in activity due to the project will have no effect on total net emissions due to production, transportation, and disposal of alternative materials. These emissions are therefore excluded from the GHG Assessment Boundary.
			CH_4	*Excluded*	**Baseline:** N/A **Project:** N/A	Combustion-related CH_4 emissions related to changes in the production, transportation, and disposal of alternative materials are not considered significant.
			N_2O	*Excluded*	**Baseline:** N/A **Project:** N/A	Combustion-related N_2O emissions related to changes in the production, transportation, and disposal of alternative materials are not considered significant.
AC-17	Biological emissions from decomposition of forest products	Source	CO_2	*Included*	**Baseline:** Quantified as a component of calculating carbon stored for 100 years in wood products (SSR AC-7) and landfills (SSR AC-8) **Project:** Quantified as a component of calculating carbon stored for 100 years in wood products (SSR AC-7) and landfills (SSR AC-8)	CO_2 emissions from the decomposition of forest products are built into calculations of how much forest product carbon will remain in in-use wood products and in landfills, averaged over 100 years (see SSR AC-7 and Appendix B).

SSR	Description	Type	Gas	Included or Excluded	Relevant to Baseline or Project	Justification/Explanation
			CH_4	*Excluded*	**Baseline:** N/A **Project:** N/A	In-use wood products will produce little to no CH_4 emissions. CH_4 emissions can result from anaerobic decomposition of forest products in landfills. This protocol assumes that landfill CH_4 emissions will be largely controlled in the near future due to federal and/or state regulations. Thus, changes in forest-product production are assumed to have no significant effect on future CH_4 emissions from anaerobic decomposition of forest products in landfills. These emissions are therefore excluded from the GHG Assessment Boundary.
			N_2O	*Excluded*	**Baseline:** N/A **Project:** N/A	Decomposition of forest is not expected to be a significant source of N_2O emissions.

6 Quantifying Net GHG Reductions and Removals

This section provides requirements and guidance for quantifying a Forest Project's net GHG reductions and removals. The Reserve will issue Climate Reserve Tonnes (CRTs) to a Forest Project upon confirmation by an ISO-accredited and Reserve-approved verification body that the Forest Project's GHG reductions and removals have been quantified following the applicable requirements of this section (see Section 9 for verification requirements).

For each type of Forest Project, quantification proceeds in seven steps:

1. **Estimating baseline onsite carbon stocks.** The baseline is an estimate of what would have occurred in the absence of a Forest Project. To establish baseline onsite carbon stocks, the Project Operator must estimate 100 years of carbon stock changes in each of the Forest Project's required and selected optional onsite carbon pools (identified in Section 5). The baseline must be based on inventoried carbon stocks at the time of the Forest Project's initiation, following the applicable requirements in this section for modeling or implementing a conservative default baseline. Onsite carbon stocks are inventoried following the requirements described in Appendix B. Modeling of onsite carbon stocks over time must be conducted following the requirements in this section and the guidance in Appendix B. Baseline onsite carbon stocks are estimated over a Forest Project's entire crediting period (100 years) at the time of the project's initiation and are not modified thereafter, except for reconciliation of project baselines to changes in inventory estimates associated with inventory methodology updates.
2. **Estimating baseline carbon in harvested wood products.** In conjunction with estimating baseline onsite carbon stocks, the Project Operator must forecast any harvesting that would have occurred in the baseline and convert this to an average annual harvesting volume. From this, the Project Operator must determine the amount of carbon that would have been transferred each year (on average) to long-term storage in wood products. Baseline harvesting is forecasted following the guidance in this section, depending on the project type - either through a default or modeling approach, and carbon stored in wood products must be calculated following the requirements in Appendix B.
3. **Determining actual onsite carbon stocks.** Each year, the Project Operator must determine the Forest Projects' actual onsite carbon stocks. This must be done by updating the Forest Project's forest carbon inventory for the current year, following the guidance in this section and in Appendix B. The estimate of actual onsite carbon stocks must be adjusted by an appropriate confidence deduction, as described in Appendix B.
4. **Determining actual carbon in harvested wood products.** Each year, the Project Operator must report any harvesting in the Project Area and from this determine the amount of carbon transferred to long-term storage in wood products. Carbon stored in wood products must be calculated following the requirements available in Appendix B
5. **Calculating the project's Primary Effect.** Each year, the Project Operator must quantify the actual change in GHG emissions or removals associated with the Forest Project's intended ("Primary") effect, as defined in Section 5. For any given year, the Primary Effect is calculated by:

   a. Taking the difference between actual onsite carbon stocks for the current year and actual onsite carbon stocks for the prior year[18]
   b. Subtracting from (a) the difference between baseline onsite carbon stocks for the current year and baseline onsite carbon stocks for the prior year[19]
   c. Adding to (b) the calculated difference between actual and baseline carbon in harvested wood products for the current year (see Equation 6.1)

6. **Quantifying the project's Secondary Effects.** Each year, the Project Operator must quantify the actual change in GHG emissions or removals associated with the Forest Project's unintended ("Secondary") effects, as defined in Section 5. Requirements and guidance for quantifying Secondary Effects are provided below for each type of Forest Project.

7. **Calculating total net GHG reductions and removals.** For each year, total net GHG reductions and removals are calculated by summing a Forest Project's Primary and Secondary Effects. If the result is positive, then the Forest Project has generated GHG reductions and/or removals in the current year. If the result is negative, this may indicate a reversal has occurred (see Section 7).[20]

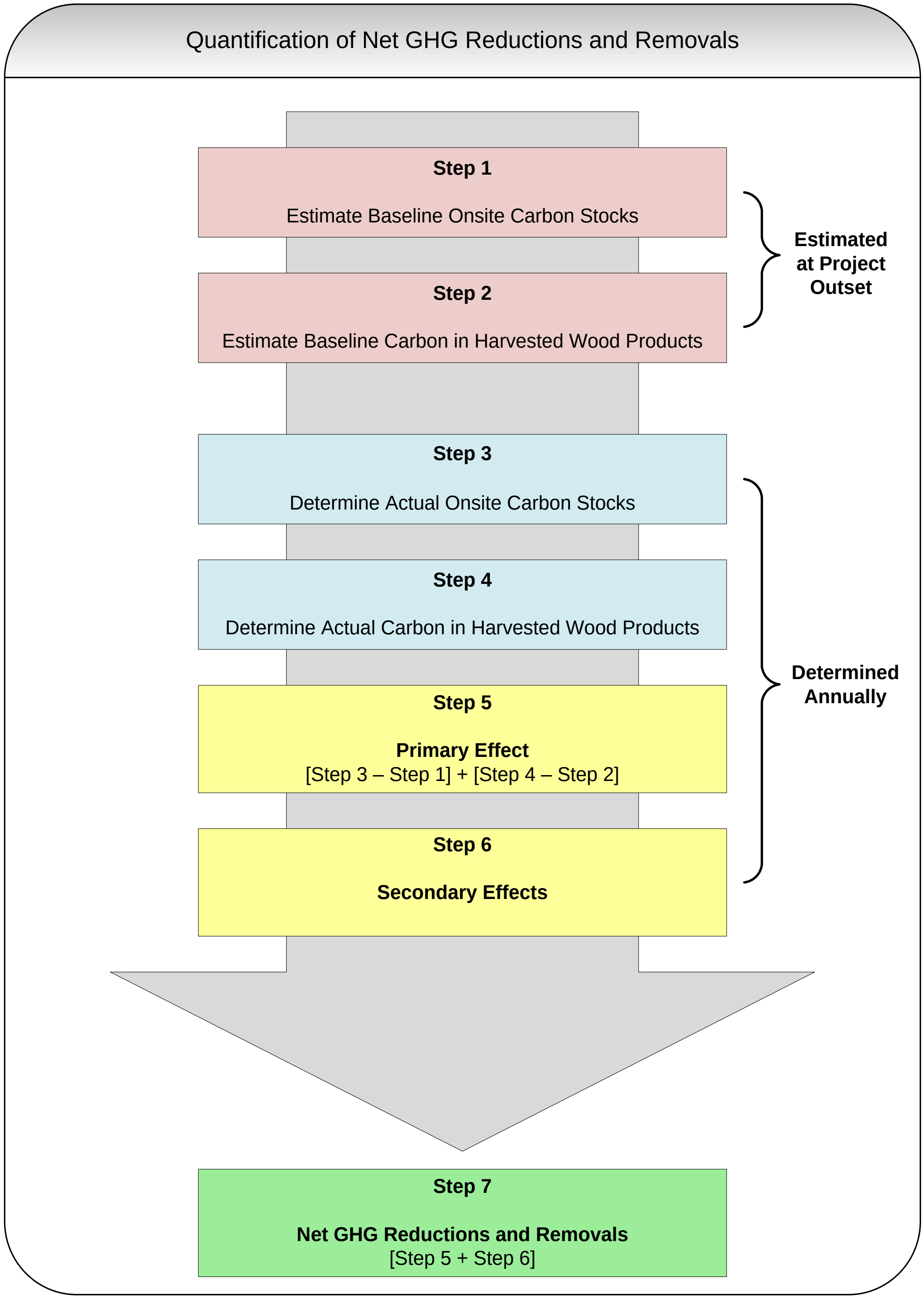
Requirements and guidance for how to perform quantification steps 1 to 4 for each Forest Project type are presented in the remainder of this section.

The required formula for quantifying annual net GHG reductions and removals is presented in Equation 6.1. Net GHG reductions and removals must be quantified and reported in units of carbon dioxide-equivalent (CO_2e) metric tons.

[18]For the purposes of calculating the project's Primary Effect, actual and baseline carbon stocks prior to the start date of the project are assumed to be zero.

[19] See footnote 18.

[20] A reversal occurs only if: (1) total net GHG reductions and removals for the year are negative; and (2) CRTs have previously been issued to the Forest Project. If calculated GHG reductions and removals are negative and no CRTs have been issued to the project since its start date, then the result should be treated as a "negative carryover" to GHG reduction calculations in subsequent years (variable N_{y-1} in Equation 6.1). This may happen, for example, because the confidence deduction applied to actual onsite carbon stocks can result in actual values being less than baseline values in a Forest Project's initial years.



Quantification of Net GHG Reductions and Removals
Step 1
Estimate Baseline Onsite Carbon Stocks
Step 2
Estimate Baseline Carbon in Harvested Wood Products
Estimated at Project Outset
Step 3
Determine Actual Onsite Carbon Stocks
Step 4
Determine Actual Carbon in Harvested Wood Products
Determined Annually
Step 5
Primary Effect
[Step 3 – Step 1] + [Step 4 – Step 2]
Step 6
Secondary Effects
Step 7
Net GHG Reductions and Removals
[Step 5 + Step 6]

Equation 6.1. Annual Net GHG Reductions and Removals

$$QR_y = \left[(\Delta AC_{onsite} - \Delta BC_{onsite}) + SC_y + \left(AC_{wp,y} - BC_{wp,y}\right) \times 0.80 + SE_{as,y}\right] + N_{y-1}$$

Where,

			Units
QR_y	=	Quantified GHG reductions and removals for year *y*	CO_2e
SC_y	=	Soil carbon project emissions (if included, and if using the standardized guidance in Appendix B). If an avoided conversion project is reporting avoided emissions from sampled soil carbon, it will be included in AC_{onsite}, in order to apply the confidence deduction as required by Appendix B.	CO_2e
$AC_{wp,y}$	=	Actual carbon in wood products produced in year *y* that is projected to remain stored for at least 100 years (i.e., derived for actual harvest volumes following the guidance in Appendix B)	CO_2e
$BC_{wp,y}$	=	Annual baseline carbon in wood products that would have remained stored for at least 100 years (i.e., derived for baseline harvest volumes following the guidance in Appendix B)	CO_2e
0.80	=	The net change in carbon in harvested wood products, ($AC_{wp,y}$ – $BC_{wp,y}$), is multiplied by 80 percent in Equation 6.1 to reflect market responses to changes in wood-product production. The general assumption in this protocol is that for every tonne of reduced harvesting caused by a Forest Project, the market will compensate with an increase in harvesting of 0.2 tonnes on other lands (see Section 6.1.6). Since wood product production is directly related to harvesting levels, the net change in wood products caused by a project is subject to this same market dynamic. Thus, any one-tonne increase in wood product production by a project will result in only a 0.8 tonne increase overall, because it has been assumed other landowners will decrease production by 0.2 tonnes in response. Similarly, any one-tonne decrease in wood product production by a project will result in only a 0.8 tonne decrease overall, because it has been assumed other landowners will increase production by 0.2 tonnes in response	
$SE_{as,y}$	=	Secondary Effect GHG emissions that may result from activity shifting outside the project area, as a result of the project activity in year *y*	CO_2e
N_{y-1}	=	Any negative carryover from the prior year (occurs when total quantified GHG reductions are negative prior to the issuance of any CRTs for the project– see footnote 20, p. 38)	CO_2e

And,

$$\Delta AC_{onsite} = \left(AC_{onsite,y}\right)\left(1 - CD_y\right) - \left(AC_{onsite,y-1}\right)\left(1 - CD_{y-1}\right)$$

Where,

$AC_{onsite,\,y}$	=	Actual onsite carbon as inventoried for year *y* (*y* may be less than a year for the first reporting period following the start date). Includes soil carbon for avoided conversion projects reporting avoided emissions from sampled soil carbon	CO_2e
$AC_{onsite,\,y-1}$	=	Actual onsite carbon as inventoried for year *y-1*. Includes soil carbon for avoided conversion projects reporting avoided emissions from sampled soil carbon	CO_2e
CD_y	=	Appropriate confidence deduction for year *y*, as determined following the Appendix B	%
CD_{y-1}	=	Appropriate confidence deduction for year *y-1*, as determined following the Appendix B	%

And,

$$\Delta BC_{onsite} = \left(BC_{onsite,y}\right) - \left(BC_{onsite,y-1}\right)$$

Where,

$BC_{onsite,\ y}$	=	Baseline onsite carbon as estimated for year *y* (*y* may be less than a year for the first reporting period following the start date)	CO_2e
$BC_{onsite,\ y-1}$	=	Baseline onsite carbon as estimated for year *y-1*	CO_2e

6.1 Improved Forest Management Projects

Improved Forest Management Projects that take place on private land – or on land that is transferred to public ownership at the time the project is initiated – must estimate baseline onsite carbon stocks following the requirements and procedures in Section 6.1.1 (default approach) or Section 6.1.2 (modeling approach). Improved Forest Management Projects that take place on land that was publicly owned prior to the project start date must estimate baseline onsite carbon stocks following the requirements and procedures in Section 6.1.3. Requirements for determining actual onsite carbon stocks, determining actual carbon in harvested wood products, and quantifying Secondary Effects are the same for all Improved Forest Management Projects.

The approach to additionality for all Improved Forest Management Projects relies on an averaged baseline value. The time commitment for a project under this protocol is 100 years, and the baseline is a counterfactual representation of one of a multitude of potential legally compliant and financially feasible management scenarios that could play out in reality in the absence of the project.

6.1.1 Estimating Baseline Onsite Carbon Stocks – Private Lands – Default Approach

The baseline approach for Improved Forest Management Projects on private lands applies a standardized set of assumptions to project-specific conditions. A project must determine a start date inventory and consider how legal and financial constraints affect the baseline carbon stocks. Furthermore, performance standard criteria are applied to Improved Forest Management Projects based on Common Practice statistics, described below in this section.

The first baseline approach option for an Improved Forest Management Project on private lands is to use a conservative default approach, which eliminates the modeling effort required for baseline estimation. The steps are:

1. Determine the start date inventories of aboveground standing live carbon stocks, belowground standing live carbon stocks, aboveground standing dead carbon stocks, and belowground standing dead carbon stocks for the Project Area.
2. Determine Common Practice for the Project Area. Determine the project's initial baseline, based on whether initial carbon stocks are above or below the Common Practice value.
3. Determine the applicable level of legal and financial constraints applicable to the Project Area based on the guidance below and adjust the initial baseline accordingly.
4. Determine the baseline harvest volume based on the guidance below.
5. Combine the results to produce the final baseline for all required carbon stocks.

6.1.1.1 Inventory Carbon Stocks within the Project Area

The start date inventory of standing live carbon stocks, separated into aboveground and belowground portions, and the start date inventory of standing dead carbon stocks, also with aboveground and belowground portions separated, must be determined following the guidance in Appendix B. Projects may choose to use the Standardized Inventory Methodology and/or the Climate Action Reserve Inventory Tool (CARIT),[21] both available on the Reserve's website, but use of the methodology and CARIT is optional.

In the formulas throughout this section, initial carbon stocks are denoted by the variable PUB_0 (i.e., the *preliminary unadjusted baseline* at time zero).

6.1.1.2 Determining Common Practice and the Initial Baseline

Common Practice refers to the average stocks of aboveground standing live and standing dead carbon associated with the Assessment Area(s) covered by the Project Area. This value represents the result of the suite of management activities taking place within the Assessment Area(s) and is used to approximate a Performance Standard for Improved Forest Management Projects. The overall intent of this protocol is for projects to contribute to long-term increases in average carbon stocking in the Assessment Area(s) where they are located. Projects with initial stocking below Common Practice will increase their stocking over time. Projects with initial stocking above Common Practice will also likely increase their stocking over time, but, as or more importantly, will prevent activities that otherwise would have decreased the stocking on the project site to or below Common Practice stocking. In the absence of a forest project, there is no guarantee that a site with stocking above Common Practice will maintain their stocking levels, especially over the 100-year period committed to by projects.

The Common Practice statistic applicable to a project can be found by consulting the Assessment Area Data File on the Reserve's FPP webpage. If the Project Area covers multiple Assessment Areas, Common Practice must be calculated as the average of the values for each Assessment Area, weighted by the percentage of the Project Area that falls within each Assessment Area.

Common Practice statistics are calculated from United States Forest Service Forest Inventory and Analysis (USFS FIA) program. The Reserve will update the Common Practice statistics in the Assessment Area Data File periodically. The frequency of updating Common Practice statistics will be subject to the availability of new USFS FIA data but will be no more frequent than once every five years. The Reserve will announce any forthcoming updates to the Common Practice statistics before they are released, and any updates will not be retroactive.

The performance standard criteria establish minimum aboveground standing live and standing dead carbon stock values for the baseline, regardless of what is legally and financially viable. For projects whose initial aboveground standing live and standing dead carbon stocks are above Common Practice, the *initial baseline* for the project is equal to Common Practice. For projects whose initial aboveground standing live and standing dead carbon stocks are below Common Practice, the *initial baseline* for aboveground standing live and standing dead carbon stocks is either (1) the initial aboveground standing live and standing dead carbon stocks (PUB_0) or (2) the High Stocking Reference, whichever is greater. The High Stocking Reference is a measure of carbon stocks in aboveground standing live and standing dead biomass over

[21] The Standardized Inventory Methodology and Climate Action Reserve Inventory Tool (CARIT) were developed based upon work supported by the Natural Resources Conservation Service, U.S. Department of Agriculture, under number 69-3A75-16-024.

the 10 years preceding the project start date. It governs baseline carbon stocks in certain instances where aboveground standing live and standing dead carbon stocks have declined prior to the start date. Refer to Section 6.1.2.4.1 for guidance around determining High Stocking Reference.

6.1.1.3 Adjust the Initial Baseline for Legal and Financial Constraints

To ensure that projects receive credits for only those GHG removals that are undertaken in addition to existing legal requirements, such legal and financial constraints must be factored into the project's baseline. For the conservative default approach, the Reserve has calculated a multiplier to be applied to the *initial baseline*, which is designed to be a conservative representation of project constraints. Equation 6.2 describes how the *initial baseline* is adjusted. However, if:

1. deeded encumbrances exist that limit forest management beyond existing federal, state, and local laws and regulations that govern forest management, or
2. the project does not pass the Reserve's conservative default baseline screening tool[22], which considers the extent of legal and financial constraints on the Project Area,

then the project may not proceed with the default approach and must instead use the baseline modeling approach described in Section 6.1.2.

Equation 6.2. Determining the *Adjusted Initial Baseline*

$$\boldsymbol{AB = IB \times 1.06}$$

Where,

			Units
AB	=	*Adjusted initial baseline* for aboveground standing live and aboveground standing dead carbon stocks value	tCO_2e/acre
IB	=	*Initial baseline* for aboveground standing live and aboveground standing dead carbon stocks (determined according to the guidance in Section 6.1.1.2)	tCO_2e/acre
1.06	=	A conservative multiplier to raise the *initial baseline* by 6%, to account for legal and financial constraints that may prevent harvesting to minimum baseline levels	

6.1.1.4 Estimate the Project's Baseline Harvest Volume

The estimate of baseline harvest volume shall be based on the equation below. The resulting volume shall be used in conjunction with the guidance in Appendix B to determine harvested wood products. The harvest volume shall remain constant for the project life.

[22] The Reserve's default baseline screening tool is available on the FPP website.

Equation 6.3. Calculate the Baseline Harvest Volume

$$HV_{BL} = \left(\left(\frac{PUB_0 - IB}{IB}\right) \times 0.0272\right) + 0.02$$

Where,

			Units
HV_{BL}	=	Baseline harvest volume	tCO_2e/acre
PUB_0	=	Initial aboveground standing live and standing dead carbon stocks	tCO_2e/acre
IB	=	*Initial baseline* for aboveground standing live and aboveground standing dead carbon stocks (determined according to the guidance in Section 6.1.1.2)	tCO_2e/acre
0.0272	=	Regression coefficient derived from analysis to predict baseline harvest volumes based on data reported by existing Improved Forest Management offset projects[23]	
0.02	=	Y-intercept derived from analysis to predict baseline harvest volumes based on data reported by existing Improved Forest Management offset projects[24]	

6.1.1.5 Calculate the Final Baseline for Onsite Carbon Stocks

The final baseline is determined by accounting for belowground biomass and adding the estimated harvested wood products to the *adjusted initial baseline*.

Equation 6.4. Calculate the *Final Baseline*

$$FBL = AB + \left(\frac{AB \times IBG}{PUB_0}\right) + HWP_{BL}$$

Where,

			Units
FBL	=	*Final baseline* for all required onsite carbon stocks	tCO_2e/acre
AB	=	*Adjusted initial baseline* for aboveground standing live and aboveground standing dead carbon stocks value, from Equation 6.2	tCO_2e/acre
IBG	=	Belowground standing live and standing dead carbon stocks measured in the project's initial inventory	tCO_2e/acre
PUB_0	=	Initial aboveground standing live and dead carbon stocks per acre within the Project Area	tCO_2e/acre
HWP_{BL}	=	Baseline harvested wood products calculated following Appendix B, using HV_{BL}	tCO_2e/acre

6.1.2 Estimating Baseline Onsite Carbon Stocks – Private Lands – Modeling Approach

The following steps must be followed to estimate baseline carbon stocks:

1. Determine the start date inventories of aboveground standing live carbon stocks, belowground standing live carbon stocks, aboveground standing dead carbon stocks, and belowground standing dead carbon stocks for the Project Area.

[23] Includes only those Improved Forest Management offset projects that are participating in the California Air Resources Board's Compliance Offset Program and have completed their initial verification as of 10/02/2018.
[24] See footnote 23.

2. Model a 100-year growth and harvest regime reflecting legal and financial constraints. The result is a *preliminary unadjusted baseline* for aboveground standing live carbon stocks that reasonably reflects the harvesting opportunities present within the Project Area.
3. Standardize the *preliminary unadjusted baseline* for aboveground standing live carbon stocks by averaging the annual values or, if legal constraints require stocks to increase over time, constructing an upward sloping straight line to the apex of the legal constraints and averaging annual values thereafter. Baseline carbon stocks for other carbon pools must be similarly averaged. This results in the *unadjusted averaged baseline* for reported carbon stocks.
4. Apply performance standard criteria to adjust the aboveground standing live and standing dead portions of the *unadjusted averaged baseline*. The result is an *adjusted averaged baseline* for aboveground standing live and standing dead carbon stocks.
5. Proportionally adjust other reported carbon stocks to match the *adjusted averaged baseline*.
6. Combine the results to produce the *final baseline* for all onsite carbon stocks.

For all calculations in this section, all values for “carbon stocks” should be expressed in metric tons of CO_2-equivalent.

6.1.2.1 Inventory Carbon Stocks within the Project Area

The start date inventory of standing live carbon stocks, separated into aboveground and belowground portions, and the start date inventory of standing dead carbon stocks, also with aboveground and belowground portions separated, must be determined following Appendix B. Projects may choose to use the Standardized Inventory Methodology and/or the Climate Action Reserve Inventory Tool (CARIT), both available on the Reserve’s website, but use of the methodology and CARIT is optional.

In the formulas throughout this section, initial carbon stocks are denoted by the variable PUB_0 (i.e., the *preliminary unadjusted baseline* at time zero).

6.1.2.2 Model Growth and Harvesting Over 100 Years

The *preliminary unadjusted baseline* for onsite carbon stocks must be estimated through a modeling exercise. The modeling exercise must use the inventories of the carbon from Section 6.1.2 as a starting point for modeling. The *preliminary unadjusted baseline* will consist of each of the following carbon pools that are maintained separately during this stage of baseline development:

- Aboveground standing live
- Belowground standing live
- Aboveground standing dead
- Belowground standing dead
- Harvested aboveground and belowground standing live
- Bole portion of harvested standing live

To determine the *preliminary unadjusted baseline,* model the initial inventory of aboveground standing live carbon stocks through a series of growth and harvesting scenarios over a 100-year timeframe. Modeling must be conducted using an approved growth model, as identified in the

Modeling Carbon Stocks section of Appendix B. Modeling of the growth and harvesting scenarios must reflect all legal requirements that constrain the ability to harvest carbon stocks. In addition, harvesting assumptions must reflect realistic financial constraints, as described in Section 6.1.2.2.2.

Standing dead carbon stocks shall be assumed to remain static throughout the modeling process. Exceptions may be provided, at the Reserve's discretion, if compelling justification can be provided that standing dead carbon stocks are likely to fluctuate substantially as part of the project's baseline.

6.1.2.2.1 Modeling Legal Constraints

All legal constraints that affect the ability to manage carbon stocks must be included in the model design. The *preliminary unadjusted baseline* must represent a growth and harvesting regime that fulfills all legal requirements. Voluntary agreements that can be rescinded, such as rental contracts and forest certifications, are not legal constraints. Habitat Conservation Plans (HCPs) and Safe Harbor Agreements (SHAs) that are in place more than one year prior to the project's start date shall be modeled as legal constraints. HCPs and SHAs that are approved after the date one year prior to the project's start date are not considered legal constraints for baseline modeling and may be disregarded.

Legal constraints include all laws, regulations, and legally-binding commitments applicable to the Project Area at the time of the project's initiation that could affect carbon stocks. Legal constraints include:

1. Federal, state/provincial, or local government regulations that are required and might reasonably be anticipated to influence carbon stocking over time including, but not limited to:
    a. Zones with harvest restrictions (e.g., buffers, streamside protection zones, wildlife protection zones)
    b. Harvest adjacency restrictions
    c. Minimum stocking standards
2. Forest practice rules, or applicable Best Management Practices established by federal, state, provincial or local government that relate to forest management.
3. Other legally binding requirements affecting carbon stocks including, but not limited to, covenants, conditions and restrictions, and other title restrictions in place prior to or at the time of project initiation, including pre-existing conservation easements, HCPs, SHAs, and deed restrictions, excepting an encumbrance that was put in place and/or recorded less than one year prior to the project start date, as defined in Section 3.7.

For Forest Projects located in California, the *preliminary unadjusted baseline* must be modeled to reflect all silvicultural treatments associated with timber harvest plans (THPs) active within the Project Area at the time of the project's initiation. All legally enforceable silvicultural and operational provisions of a THP – including those operational provisions designed to meet California Forest Practice Rules requirements for achieving Maximum Sustained Production of High Quality Wood Products [14 CCR 913.11 (933.11, 953.11)] – are considered legal constraints and must be reflected in baseline modeling for if the THP will remain active. For portions of the Project Area not subject to THPs (or over time periods for which THPs will not be active), baseline carbon stocks must be modeled by considering any applicable requirements of the California Forest Practice Rules and all other applicable laws, regulations, and legally binding commitments that could affect onsite carbon stocks. On a case-by-case basis, the California Department of Forestry and Fire Protection (CAL FIRE) may assist Project Operators in identifying minimum carbon stocking levels that would be effectively required under California Forest Practice Rules.

6.1.2.2.2 Modeling Financial Constraints

Harvest assumptions included in the model must be financially viable. The Project Operator must demonstrate that the growth and harvesting regime assumed for the *preliminary unadjusted baseline* is financially feasible through a financial analysis of the anticipated growth and harvesting regime that captures all relevant costs and returns, taking into consideration all legal, physical, and biological constraints. Cost and revenue variables in the financial analysis may be based on regional norms or on documented costs and returns for the Project Area or other properties in the project's Assessment Area.

A financially viable project is defined in this protocol as a project that has a positive net present value using a discount rate of 4%. This would indicate a management regime that does not lose money in the practice of performing long-term forest management activities, including road management, watercourse restoration, fuels management, etc. Inputs to the analysis include the volume of species harvested, logging and hauling costs, delivered log prices, and forest management costs.

6.1.2.3 Generate an Unadjusted Averaged Baseline

The periodic modeled outputs from the *preliminary unadjusted baseline* must be standardized according to the following guidance for each carbon pool. The result will be an *unadjusted averaged baseline* for each carbon pool.

Aboveground standing live carbon stocks: The periodic modeled outputs for aboveground standing live carbon stocks must be either averaged or converted to a straight-line approximation reflective of legal constraints.

If legal constraints do *not* result in an upward trend in aboveground standing live carbon stocks, then the periodic model outputs must be averaged using Equation 6.5. See Figure 6.1 for a simplified example of the resulting *unadjusted averaged baseline*.

If legal constraints do result in an increasing trend of aboveground standing live carbon stocks, beginning at the project start date, then the periodic model outputs may be standardized using a straight-line approximation, as defined in Equation 6.6. The approximation must consist of two line segments. The first of the line segments must initiate at the initial inventory at the project start date and terminate at the point where carbon stocks reach their highest legally required level. The second segment is a straight line with a constant value, defined by the terminus of the first line segment, for the balance of the 100-year modeling timeframe. See Figure 6.2 for a simplified example of the resulting *unadjusted averaged baseline* with an upward slope.

Equation 6.5. Formula for Averaging *Preliminary Unadjusted Baseline* Carbon Stocks

For all years *y*, $UAB_y = \frac{\sum_{y=0}^{100} PUB_y}{100}$

Where,			Units
UAB_y	=	*Unadjusted averaged baseline* value for year *y* (including the start date at *y*=0)	tCO_2e/acre
PUB_y	=	*Preliminary unadjusted baseline* value for year *y.*	tCO_2e/acre

Equation 6.6. Formula for Approximating *Preliminary Unadjusted Baseline* Carbon Stocks as a Straight-Line Trend

For years *y* < Y, $UAB_y = PUB_0 + y \times \frac{ES - PUB_0}{Y}$

For years *y* ≥ Y, $UAB_y = ES$

Where,			Units
UAB_y	=	*Unadjusted averaged baseline* value for year *y*	tCO_2e/acre
Y	=	Time in years between the project start date and the year at which the highest legally required stocking level is reached. This is determined by modeling a forest growth and yield simulation that includes legal and financial constraints (in Section 6.1.2.2, above)	years
PUB_0	=	Initial aboveground standing live and dead carbon stocks per acre within the Project Area (as determined in Section 6.1.2)	tCO_2e/acre
ES	=	Ending stocks = The highest legally required stocking level, as determined in Step 2	tCO_2e/acre

Belowground standing live carbon stocks: The belowground portion of the standing live carbon stocks must be standardized in the same way as the aboveground standing live carbon stocks, i.e., either averaged (Equation 6.5), or calculated with an upward-sloping line to a potential terminus (Equation 6.6).

The aboveground and belowground portions of standing dead carbon stocks: Standing dead carbon stocks shall be set at the quantity of carbon stocks present in the standing dead carbon stock pool at the project start date. Exceptions may be provided, at the Reserve's discretion, if compelling justification can be provided that standing dead carbon stocks are likely to fluctuate substantially as part of the project's baseline. Standing dead stocks are not adjusted based on adjustments to the standing live carbon stocks. However, aboveground and belowground portions of standing dead carbon stocks should be maintained as separate values since aboveground standing dead stocks should be combined with the *unadjusted averaged baseline* for aboveground standing live carbon for the purpose of applying the performance standard criteria as described in Section 6.1.2.4 below.

Carbon stocks in the aboveground and belowground portions of standing live trees harvested for wood products: The carbon stocks shall be calculated as the average of the periodic outputs for the entire 100-year modeling if the aboveground live tree carbon stocks do not result in an upward trend.

If the carbon stocks in aboveground standing live carbon stocks results in an upward trend, the carbon stocks shall be calculated as an average from the start date to the highest point of the aboveground standing live carbon stocks. A separate average of carbon stocks in both the aboveground and belowground portions of standing live trees harvested for wood products between the highest point of the aboveground standing live carbon stocks and the end point of the 100-year modeling shall be calculated, as applicable.

Carbon stocks in the bole portion of trees harvested for wood products: The carbon stocks shall be calculated as the average of periodic outputs for the entire 100-year modeling if the aboveground live tree carbon stocks do not result in an upward trend.

For upward-sloping lines, the values shall be based on the carbon stocks harvested to the legal constraint terminus and be based on the average carbon stocks from the terminus to the balance of the 100-year modeling (if applicable).

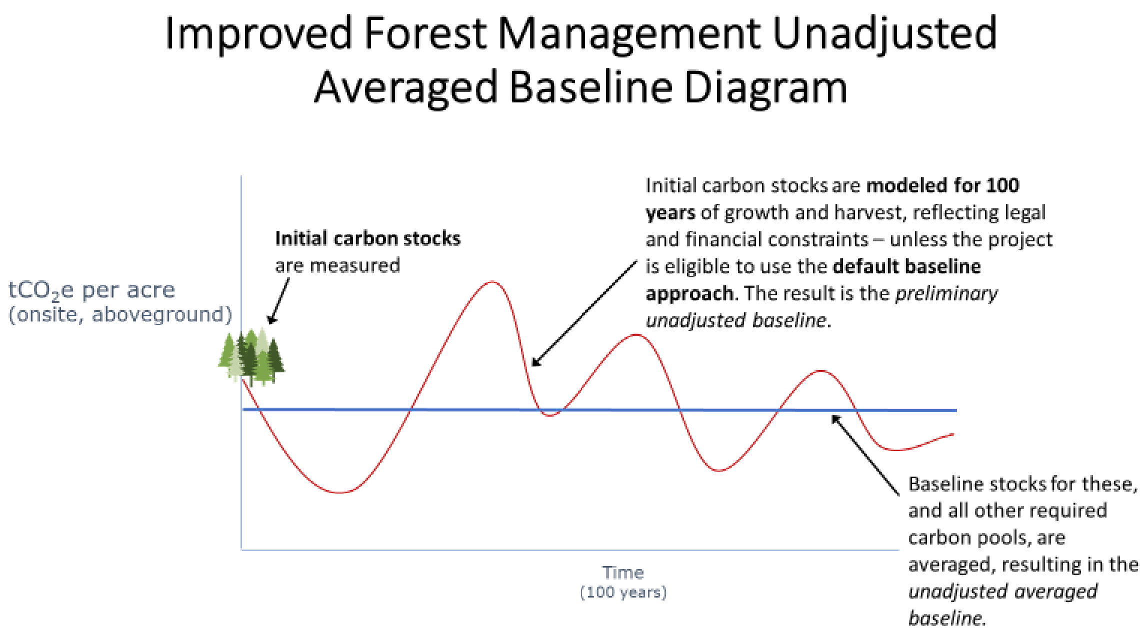


Figure 6.1. Example of an *unadjusted averaged baseline*
(Resulting from Equation 6.5.)

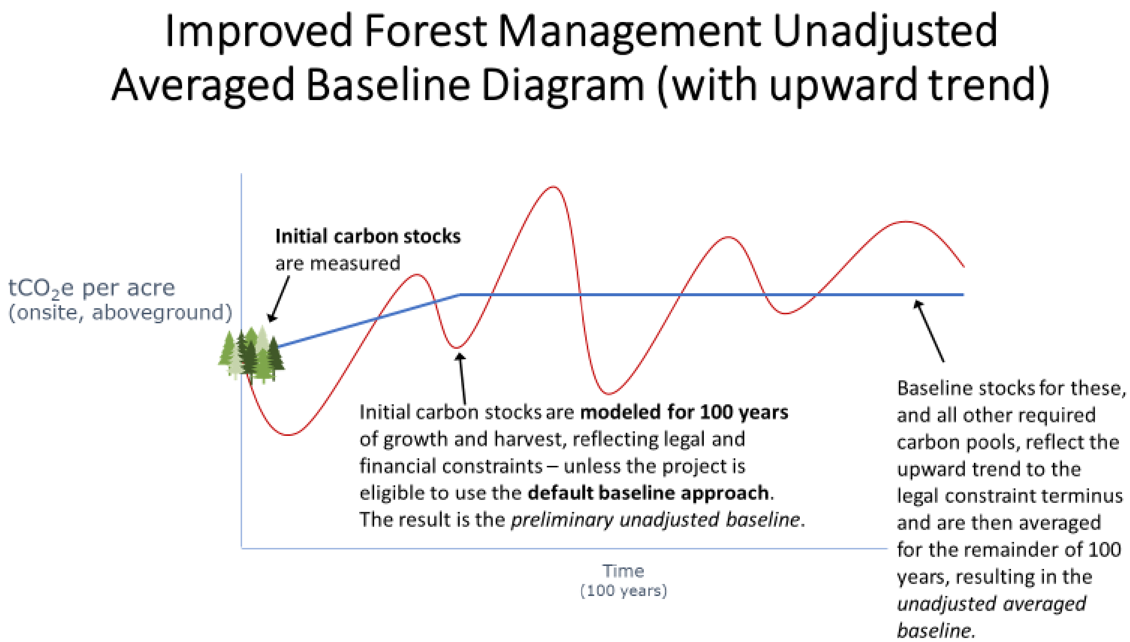


Figure 6.2. Example of an *unadjusted averaged baseline* with an upward trend (Resulting from Equation 6.6.)

6.1.2.4 Apply Performance-Standard Criteria

Once the components of the *unadjusted averaged baseline* are determined in Section 6.1.2.3, the aboveground standing live and standing dead components must be adjusted to conform to a set of performance standard criteria, as described below. The result is an *adjusted averaged baseline* for aboveground standing live and standing dead carbon stocks. Other reported carbon pools are adjusted in Section 6.1.2.5.

The performance standard criteria establish minimum aboveground standing live and standing dead carbon stock values for the baseline, regardless of what is legally and financially viable. The elements of the performance standard are:

- *The High Stocking Reference:* The High Stocking Reference is a measure of carbon stocks in aboveground standing live and standing dead biomass over the 10 years preceding the project start date. It governs baseline carbon stocks in certain instances where aboveground standing live and standing dead carbon stocks have declined prior to the start date. See further guidance below on how to determine the High Stocking Reference.
- *Comparison of initial carbon stocks to Common Practice*: If the *unadjusted averaged baseline* for aboveground standing live carbon stocks was determined according to Equation 6.5, then the *adjusted averaged baseline* may depend on how the initial carbon stocks compare to Common Practice levels (see guidance in Section 6.1.1 for how to determine Common Practice). For projects whose initial aboveground standing live and standing dead carbon stocks are above Common Practice, the *adjusted averaged baseline* for aboveground standing live and standing dead carbon stocks may not be below Common Practice. For projects whose initial aboveground standing live and standing dead carbon stocks are below Common Practice, the *adjusted averaged*

baseline for aboveground standing live and standing dead carbon stocks may not be below either (1) the initial inventory level or (2) the High Stocking Reference, whichever is greater. See Equation 6.7 and Equation 6.8 below.

The procedure for determining the *adjusted averaged baseline* depends on whether the *unadjusted averaged baseline* for aboveground standing live carbon stocks was determined according to Equation 6.5, or as an upward sloping straight-line trend (according to Equation 6.6.

Where the *unadjusted averaged baseline* for aboveground standing live carbon stocks was determined using Equation 6.5:

- If the project's initial aboveground standing live and standing dead carbon stocks (PUB_0) are above Common Practice, use Equation 6.7 to determine the *adjusted averaged baseline*
- If the project's initial aboveground standing live and standing dead carbon stocks (PUB_0) are below Common Practice, use Equation 6.8 to determine the *adjusted averaged baseline*

In both cases, values must be determined for all years, *y*, starting with zero (the start date of the project) and ending with 100.

Equation 6.7. Determining the *Adjusted Averaged Baseline* for Aboveground Live and Aboveground Standing Dead Carbon Stocks Where Initial Stocks Are at or Above Common Practice

$$\boldsymbol{AAB_y = MAX\left(CP, MIN(PUB_0, UAB_y)\right)}$$

Where,			Units
AAB_y	=	*Adjusted averaged baseline* for aboveground standing live and aboveground standing dead carbon stocks value in year *y*	tCO_2e/acre
CP	=	Common Practice (determined according to the guidance in Section 6.1.1)	tCO_2e/acre
PUB_0	=	Initial aboveground standing live and dead carbon stocks per acre within the Project Area (as determined in Section 6.1.2)	tCO_2e /acre
UAB_y	=	Value of the aboveground standing live and aboveground standing dead portion of the *unadjusted averaged baseline* for year *y,* as determined in Section 6.1.2.3	tCO_2e/acre

Equation 6.8. Determining the *Adjusted Averaged Baseline* for Aboveground Live and Aboveground Standing Dead Carbon Stocks Where Initial Stocks Are Below Common Practice

$$AAB_y = MAX\left(MAX(HSR, PUB_0), MIN(CP, UAB_y)\right)$$

Where,

			Units
AAB_y	=	*Adjusted averaged baseline* for aboveground standing live and aboveground standing dead carbon stocks value in year *y*	tCO_2e/acre
HSR	=	"High Stocking Reference" for the Project Area. See guidance below for how the *HSR* is determined	tCO_2e/acre
CP	=	Common Practice (determined according to the guidance in Section 6.1.1)	tCO_2e/acre
PUB_0	=	Initial aboveground standing live and standing dead carbon stocks per acre within the Project Area (as determined in Section 6.1.2)	tCO_2e /acre
UAB_y	=	Value of the *unadjusted averaged baseline* for year *y,* as determined in Section 6.1.3.3, plus the aboveground standing dead carbon stocks for year *y*	tCO_2e/acre

Where the *unadjusted averaged baseline* for aboveground standing live and standing dead carbon stocks was determined using Equation 6.6, the *adjusted averaged baseline* (*AABy*) may be determined according to Equation 6.9.

Equation 6.9. Formula for Determining the *Adjusted Averaged Baseline* Where the *Unadjusted Averaged Baseline* was Approximated using Equation 6.6

For years *y* < Y, $AAB_y = MAX(PUB_0, HSR) + y \times \frac{ES - PUB_0}{Y}$

For years *y* ≥ Y, $AAB_y = ES$

Where,

			Units
AAB_y	=	*Adjusted averaged baseline* value for year *y*	tCO_2e/acre
Y	=	Time in years between the project start date and the year at which the highest legally required stocking level is reached. This is determined by modeling a forest growth and yield simulation that includes legal and financial constraints (in Section 6.1.2.2, above)	years
PUB_0	=	Initial aboveground standing live and dead carbon stocks per acre within the Project Area (as determined in Section 6.1.2)	tCO_2e/acre
HSR	=	"High Stocking Reference" for the Project Area. See guidance below for how the *HSR* is determined.	tCO_2e/acre
ES	=	Ending stocks = The highest legally required stocking level, as determined in Section 6.1.2.2	tCO_2e/acre

6.1.2.4.1 Determining the High Stocking Reference

The High Stocking Reference is defined as 80 percent of the highest value for aboveground standing live and standing dead carbon stocks per acre within the Project Area during the 10-year period preceding the project start date. To determine the High Stocking Reference, the Project Operator must document changes in the Project Area's aboveground standing live and standing dead carbon stocks over the 10 years prior to the initiation of the project, or for as long as the Project Operator has had control of the stocks, whichever is shorter. Figure 6.3. presents a graphical portrayal of a High Stocking Reference determination.

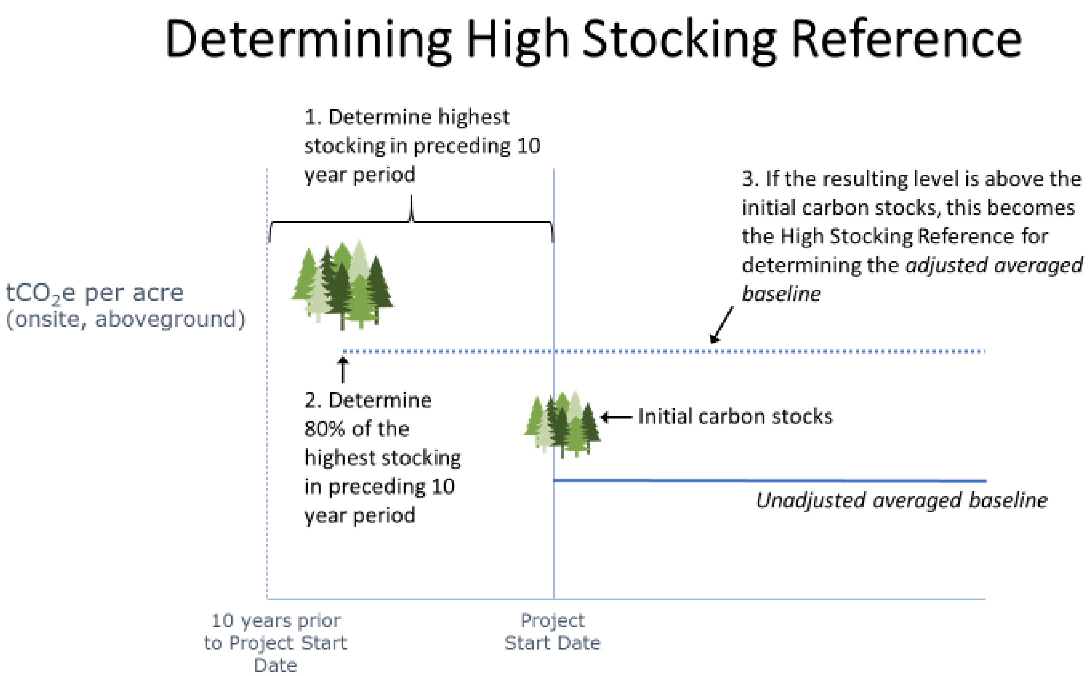


Figure 6.3. Determining a Project Area's High Stocking Reference

Note that it is possible for the High Stocking Reference to be higher than Common Practice, even where initial live and standing dead tree carbon stocks for the project are below Common Practice.

6.1.2.5 Proportionally Adjust Other Reported Carbon Stocks

The *adjusted averaged baseline* for other reported carbon stocks must be determined by adjusting carbon stock values to reflect the *adjusted averaged baseline* for aboveground standing live and standing dead carbon stocks. The guidance for adjusting the other reported carbon stocks is shown in Table 6.1.

Table 6.1. Guidance for Adjusting Other Carbon Pools

Carbon Pool	Relationship to Adjustments of Aboveground Live Carbon Stocks	Adjustment
Belowground Standing Live Carbon Stocks	Directly Proportional	$\boldsymbol{AAB_{bg,y} = (AAB_{ag,y}/UAB_{ag,y}) \times UAB_{bg,y}}$ *Where,* *$AAB_{bg,y}$ = Adjusted averaged baseline* for belowground standing live carbon stocks in year *y* *$AAB_{ag,y}$ = Adjusted averaged baseline* for aboveground standing live and standing dead carbon stocks in year *y* *$UAB_{ag,y}$ = Unadjusted averaged baseline* for aboveground standing live carbon stocks in year *y*,

Carbon Pool	Relationship to Adjustments of Aboveground Live Carbon Stocks	Adjustment
		plus the aboveground standing dead carbon stocks for year *y* $UAB_{bg,y}$ = *Unadjusted averaged baseline* for belowground standing live carbon stocks in year *y*
Aboveground and Belowground Standing Dead Carbon Stocks	N/A	No adjustment is conducted. Aboveground and belowground standing dead carbon stocks remain constant with inventories of aboveground and belowground standing dead carbon stocks at the project start date. Exceptions may be allowed as described previously. Standing dead carbon stocks are not adjusted based on changes to standing live carbon stocks, but must be used in the comparison to Common Practice.
Harvested Aboveground and Belowground Standing Live Carbon Stocks	Inversely Proportional	$\boldsymbol{AAB_{ht,y}} = \frac{\boldsymbol{UAB_{ht,y}}}{(\boldsymbol{AAB_{ag,y}}/\boldsymbol{UAB_{ag,y}})}$ *Where,* $AAB_{ht,y}$ = *Adjusted averaged baseline* for harvested aboveground and belowground standing live carbon stocks in year *y* $UAB_{ht,y}$ = *Unadjusted averaged baseline* for harvested aboveground and belowground standing live carbon stocks in year *y* $UAB_{ag,y}$ = *Unadjusted averaged baseline* for aboveground standing live carbon stocks in year *y*, plus the aboveground standing dead carbon stocks for year *y* $AAB_{ag,y}$ = *Adjusted averaged baseline* for aboveground standing live and standing dead carbon stocks in year *y*
Harvested Bole Portion of Aboveground and Belowground Standing Live Carbon Stocks	Inversely Proportional	$\boldsymbol{AAB_{htb,y}} = \frac{\boldsymbol{UAB_{htb,y}}}{(\boldsymbol{AAB_{ag,y}}/\boldsymbol{UAB_{ag,y}})}$ *Where,* $AAB_{htb,y}$ = *Adjusted average baseline* for the bole portion of harvested aboveground and belowground standing live carbon stocks in year *y* $UAB_{htb,y}$ = *Unadjusted averaged baseline* for the bole portion of harvested aboveground and belowground standing live carbon stocks in year *y* $UAB_{ag,y}$ = *Unadjusted averaged baseline* for aboveground standing live carbon stocks in year *y*, plus the aboveground standing dead carbon stocks for year *y* $AAB_{ag,y}$ = *Adjusted averaged baseline* for aboveground standing live and standing dead carbon stocks in year *y*

6.1.2.6 Combine All Adjusted Averaged Baseline Components

The *final baseline* is the sum of *adjusted averaged baselines* for all reported *onsite* carbon stocks and must include:

- Aboveground and belowground standing live carbon stocks
- Aboveground and belowground standing dead carbon stocks
- Harvested wood products

The *adjusted averaged baselines* for harvested standing live carbon stocks (aboveground and belowground) and the bole portion of harvested standing live carbon stocks must also be maintained separately from the carbon stocks listed above. The reporting of harvested carbon stocks is conducted separately from other reported carbon stocks.

6.1.3 Estimating Baseline Onsite Carbon Stocks – Public Lands

The baseline is developed for a public forest by determining carbon levels in the Project Area with the assumed condition that the entire forest is at a rotation age common for the forest community (by Assessment Area). The rotation ages are provided as default values and are found with the Assessment Area data. Where forest practice laws, or any other legal encumbrances, require specific management of forest stands at levels that exceed the age criteria mentioned above, the stands must be managed at sufficient stocking levels to ensure compliance with the legal constraints. Project credits are determined by calculating the project's carbon stocks and subtracting the baseline stocks from them.

6.1.3.1 Generate COLE Report

Using the Carbon Online Estimator (COLE),[25] select Forest Inventory and Analysis (FIA) plots using the "plots within this radius" tool. The circle developed must be centered within the Project Area. The radius of the sample area must be at least 100 kilometers. Following the guidance on the website, fetch the data within the circle. Next, filter the data using the 'Filter' tab on the website by selecting species in the 'Forest Type' menu bar that are found in the species list in the Assessment Area Data File for Assessment Area(s) the project is in. Click on the 'Reports' tab and submit the request to produce the 1605(b) report, which will be provided through a web interface. The report must be included as an appendix in the PDD.

Using Table 1 of the COLE 1605(b) report, the baseline for the project, barring any adjustments as part of the legal analysis (below), shall be determined by summing the live tree and dead tree values from the COLE 1605(b) report that correspond with the rotation length value found in Table 6.2. The 1605(b) values are given as metric tons of carbon per hectare and shall be converted into metric tons CO_2e per acre. The determination of rotation length is made using the Assessment Area Data File and identified for rotation length.

Table 6.2. Table Rotation Lengths

Rotation Length	Years
Short	30
Medium	40
Long	60
Extremely Long	70

[25] http://www.ncasi2.org/COLE/. After opening, zoom into project area on map and follow instructions to "get plots within this radius…". Once the data has been retrieved, the report can be obtained following the instructions on the site.

6.1.3.2 Adjust for Legal Constraints

The baseline must exceed all legal constraints. A determination must be made whether the legal constraints that affect forest management within the Project Area require further adjustments to the initial baseline developed above, using the following steps:

1. Identify legal constraints affecting the Project Area.
    a. Identify and describe the legal requirements affecting the Project Area.
    b. Spatially identify (map) the areas to which the legal requirements apply within the Project Area to determine the affected acres.
2. Determine forest structure needed to comply with the legal requirements.
    a. Describe the forest structure needed to ensure compliance with the legal requirements affecting each area.
    b. Explain and justify the forest conditions and associated age class that meets the forest conditions identified for meeting the minimum criteria of the legal requirement. In no case shall the age class be less than the age class associated with the rotation length from Table 6.2.
3. Adjust baseline values
    a. Use the live and dead tree values associated with the age class from the COLE 1605(b) report that is associated with the previous step. The 100-year values for live and dead trees in the COLE 1605(b) report shall be used in cases where determinations of forest structure are not easily justified.
    b. Develop a weighted average by multiplying the acres for each constraint class by the COLE 1605(b) values and dividing by the total acres to determine the adjusted baseline.

6.1.3.3 Estimate the Project's Baseline Harvest Volume

The estimate of baseline harvest volume shall be determined by multiplying the adjusted baseline (above) by 3%. The resulting volume shall be used in conjunction with the guidance in Appendix B to determine harvested wood products. The harvest volume shall remain constant for the project life.

6.1.3.4 Determining the Final Project Baseline

The final baseline is determined by adding the estimated harvested wood products to the adjusted baseline.

6.1.4 Determining Actual Onsite Carbon Stocks

Actual carbon stocks for Improved Forest Management Projects must be determined by updating the Project Area's forest carbon inventory. This is done by:

1. Incorporating any new forest inventory data obtained during the previous year into the inventory estimate. Any plots sampled during the previous year must be incorporated into the inventory estimate.
2. Using an approved model or a stand table projection to "grow" (project forward) prior-year data from existing forest inventory plots to the current reporting year. Guidance for projecting forest inventory data is identified in Appendix B.

3. Updating the forest inventory estimate for harvests and/or disturbances that have occurred during the previous year. To allow some flexibility in updating the forest inventory during onsite verification years, a project may defer updating a small percentage of plots until the following reporting period, as detailed in Appendix B. This will help streamline the sequential sampling process when recent disturbances have taken place.
4. Applying an appropriate confidence deduction for the inventory based on its statistical uncertainty, following the guidance in Appendix B.

6.1.5 Determining Actual Carbon in Harvested Wood Products

Perform the following steps to determine actual carbon in harvested wood products:

1. Determine the actual amount of carbon in standing live carbon stocks (prior to delivery to a mill) harvested in the current year (based on harvest volumes determined in Section 6.1.4).
2. Determine the amount of actual harvested carbon that will remain stored in wood products, averaged over 100 years, following the requirements in Appendix B.

6.1.6 Quantifying Secondary Effects

For Improved Forest Management Projects, significant Secondary Effects can occur if a project reduces harvesting in the Project Area, resulting in an increase in harvesting on other properties. Emission reductions due to substituting wood for materials with higher GHG footprints, such as concrete or steel, are not accounted for as an emission reduction in this protocol because the emission reductions are accounted for by the energy sector.

The risk that Secondary Effects may be occurring is calculated in this protocol. However, the magnitude of risk of Secondary Effects is dependent on how much harvesting occurs on the Project Area relative to the baseline scenario. This protocol considers the impacts of shifting harvest activities over the project life. As discussed above, since the baseline is a representative scenario of legally permissible and financially feasible growth and harvesting regimes in the absence of a project, baseline pools, including those used to quantify the risk of Secondary Effects, are averaged across the baseline period (i.e., 100 years). The risk of Secondary Effects for the project are thus considered in relation to such averaged baseline harvesting. Improved Forest Management Projects, where harvesting is anticipated to be an ongoing activity over the project life, are expected to increase harvest levels over time compared to baseline management due to improved stocking and growth levels and harvesting closer to an optimal age for forest productivity. However, this SSR must be reported annually due to the risk that Secondary Effects may be occurring in any given year.

Equation 6.10 must be used to estimate the Secondary Effects risk for Improved Forest Management Projects. Recognizing that Secondary Effects from projects may be influenced by long term harvesting trends, the evaluation in Equation 6.10 considers how actual cumulative harvest amounts vary from baseline cumulative harvest amounts since project inception.

When baseline cumulative harvested carbon exceeds actual cumulative harvested carbon - *but actual onsite harvested carbon exceeds the baseline amount in a given reporting period* - net GHG reductions are increased (Equation 6.10.B). This allows for prior deductions for Secondary Effects to be recouped, because the risk has been lowered. However, once actual cumulative harvest amounts exceed baseline cumulative harvest amounts, Secondary Effects risk is zero, and will remain zero for as long as actual cumulative harvest amounts exceed baseline cumulative harvest amounts (Equation 6.10.A). Under no circumstances shall the net balance of Secondary Effects CRTs over the course of a project be positive. However, maintaining actual cumulative harvest above baseline cumulative harvest will allow a project to accrue any uncredited positive carryover that can counteract the amount of future Secondary Effects deductions that would be applied if baseline cumulative harvested carbon were to exceed actual harvested carbon again (Equation 6.10.C). Refer to Appendix B for an example of how Secondary Effects are evaluated over time, and how prior Secondary Effects may be recouped. The Reserve also provides a calculation workbook for quantifying Secondary Effects risk (in addition to the other calculations required by the protocol).

Values used for onsite carbon harvested in the project and baseline scenarios ($AC_{hv,n}$ and $BC_{hv,n}$) shall represent all harvested trees, not just merchantable species.

Equation 6.10. Secondary Effects Emissions

Equation 6.10.A:

$$\boldsymbol{If} \sum_{\boldsymbol{n=1}}^{\boldsymbol{y}} (\boldsymbol{AC_{hv,n}} - \boldsymbol{BC_{hv,n}}) \geq 0, and \sum_{\boldsymbol{n=1}}^{\boldsymbol{y-1}} \boldsymbol{SE_{as,n}} \geq 0,$$

$$then\ \boldsymbol{SE_{as,y}} = \boldsymbol{0}^{\dagger}$$

Equation 6.10.B:

$$\boldsymbol{If} \left(\sum_{\boldsymbol{n=1}}^{\boldsymbol{y}} (\boldsymbol{AC_{hv,n}} - \boldsymbol{BC_{hv,n}}) < 0\ and \sum_{\boldsymbol{n=1}}^{\boldsymbol{y-1}} \boldsymbol{SE_{as,n}} < 0 \right)\ or\ \left(\sum_{\boldsymbol{n=1}}^{\boldsymbol{y}} (\boldsymbol{AC_{hv,n}} - \boldsymbol{BC_{hv,n}}) \geq 0\ and \sum_{\boldsymbol{n=1}}^{\boldsymbol{y-1}} \boldsymbol{SE_{as,n}} < 0 \right),$$

$$then\ \boldsymbol{SE_{as,y}} = \boldsymbol{MIN}\left((\boldsymbol{AC_{hv,y}} - \boldsymbol{BC_{hv,y}}) \times \boldsymbol{20}\%, \left| \sum_{\boldsymbol{n=1}}^{\boldsymbol{y-1}} \boldsymbol{SE_{as,n}} \right| \right)$$

Equation 6.10.C:

$$\boldsymbol{If} \sum_{\boldsymbol{n=1}}^{\boldsymbol{y}} (\boldsymbol{AC_{hv,n}} - \boldsymbol{BC_{hv,n}}) < 0, and \sum_{\boldsymbol{n=1}}^{\boldsymbol{y-1}} \boldsymbol{SE_{as,n}} \geq 0,$$

$$then\ \boldsymbol{SE_{as,y}} = \boldsymbol{MIN}\left(\textstyle\sum_{\boldsymbol{n=1}}^{\boldsymbol{y-1}} \boldsymbol{SE_{as,n}} + \left((\boldsymbol{AC_{hv,y}} - \boldsymbol{BC_{hv,y}}) \times \boldsymbol{20}\% \right), \boldsymbol{0} \right)^{\dagger}$$

Where,

			Units
$SE_{as,y}$	=	Estimated annual Secondary Effects in current reporting period *y* (used in Equation 6.1)	tCO_2e
$SE_{as,n}$	=	Estimated annual Secondary Effects in reporting period *n*	tCO_2e
$AC_{hv,n}$	=	Actual amount of onsite carbon harvested in reporting period *n* (prior to delivery to a mill)	tCO_2e
$BC_{hv,n}$	=	Estimated average baseline amount of onsite carbon harvested in reporting period *n* (prior to delivery to a mill), as determined above	tCO_2e
$AC_{hv,y}$	=	Actual amount of onsite carbon harvested in current reporting period *y* (prior to delivery to a mill)	tCO_2e

$BC_{hv,y}$	=	Estimated average baseline amount of onsite carbon harvested in current reporting period *y* (prior to delivery to a mill), as determined in Section 6.1.1.4, 6.1.2.5, or 6.1.3.3 as applicable	tCO_2e

† Secondary Effects are not awarded CRTs but may accrue as positive carryover. Annual accruals are calculated in the same way that Secondary Effects are calculated when baseline cumulative harvested carbon exceeds actual harvested carbon. Cumulative Secondary Effects as of the current reporting period are calculated by the following: $\sum_{n=1}^{y} \boldsymbol{SE_{as,n}} = \sum_{n=1}^{y-1} \boldsymbol{SE_{as,n}} + ((\boldsymbol{AC_{hv,y}} - \boldsymbol{BC_{hv,y}}) \times \mathbf{20}\%)$. Positive carryover reduces or negates future Secondary Effects deductions.

6.2 Avoided Conversion Projects

6.2.1 Estimating Baseline Onsite Carbon Stocks

The baseline for Avoided Conversion Projects is a projection of onsite forest carbon stock losses that would have occurred over time due to the conversion of the Project Area to a non-forest land use. Estimating the baseline for Avoided Conversion Projects involves two steps:

1. Characterizing and projecting a baseline
2. Adjusting the baseline based on conversion risk

Step 1 – Characterizing and Projecting the Baseline

Project Operators must characterize and project the baseline by:

1. Clearly specifying an alternative highest-value land use for the Project Area, as identified by an appraisal(s) (required by this protocol). The appraisal(s) must include accompanying documentation that demonstrates the type of anticipated land use conversion is legally permissible. Such documentation must fall into at least one of the following categories:
    a. Documentation indicating that the current land use policies, including zoning and general plan ordinances, and other local and state statutes and regulations, permit the anticipated type of conversion.
    b. Documentation indicating that the Project Operator has obtained all necessary approvals from the governing county to convert the Project Area to the proposed type of non-forest land use (including, for instance, certificates of compliance, subdivision approvals, timber conversion permits, other rezoning, major or minor use permits, etc.).
    c. Documentation indicating that similarly situated forestlands within the project's Assessment Area were recently able to obtain all necessary approvals from the governing county, state, or other governing agency to convert to a non-forest land use (including, for instance, certificates of compliance, subdivision approvals, timber conversion permits, other rezoning, major or minor use permits, etc.).
2. Estimating the rate of conversion and removal of onsite standing live and dead carbon stocks. The rate of conversion and removal of onsite standing live and dead carbon stocks must be estimated by either:
    a. Referencing planning documentation that has been approved and permitted by the appropriate planning department for the Project Area (e.g., construction

documents or plans) that specifies the timeframe of the conversion and intended removal of forest cover on the Project Area; or

b. In the absence of specific documentation, identifying a default annual conversion rate for carbon in standing live and dead carbon stocks from Table 6.3. The default value is subject to any legal constraints, which must be incorporated in modeling the project's baseline.

Table 6.3. Default Avoided Conversion Rates for Standing Live and Dead Carbon Stocks

Type of Conversion Identified in Appraisal	Total Conversion Impact	Annual Rate of Conversion
	This is the assumed total effect over time of the conversion activity on standing live and dead carbon stocks. (The total conversion impact is amortized over a 10-year period to determine the annual rate of conversion in the next column.)	This is the assumed annual rate of the conversion activity on standing live and dead carbon stocks. The percentages below are multiplied by the initial standing and dead carbon stocks for the project on an annual basis for the first 10 years of the project.
Residential	Estimate using the following formula: *TC*% = (min(1,(*P**3) / *PA*)) *Where,* *TC* = % total conversion (*TC* cannot exceed 100%) *PA* = the Project Area (acres) identified in the appraisal *P* = the number of unique parcels that would be formed on the Project Area as identified in the appraisal * Each parcel is assumed to deforest 3 acres of forest vegetation	Estimate using the following formula: *ARC* = *TC* / 10 *Where,* *ARC* = % annual rate of conversion *TC* = % total conversion
Mining and Agricultural Conversion, including Pasture or Crops	90%	9.0%
Golf Course	80%	8.0%
Commercial Buildings	95%	9.5%

A computer simulation, based on 2a or 2b above, must be conducted to project changes in onsite standing live and dead carbon stocks over 100 years. The computer simulation of the onsite standing live and dead carbon stocks must approximate the identified rate of conversion over time to estimate changes in standing live and dead carbon stocks, beginning with the Project Area's initial onsite standing live and dead carbon stocks. If the projected conversion rate does not result in a complete removal of onsite standing live and dead carbon stocks, the baseline projection must account for any residual forest carbon value as a steady condition for the balance of a 100-year projection.

3. Estimating the rate of soil carbon emissions (optional):
   Soil carbon emissions associated with conversion to agriculture (for all soil types) or residential and commercial (for histosols only) may be reported for the baseline. The amount of soil carbon and the rate of soil carbon emissions are dependent upon the soil type ("soil order") and the conversion activity. Emissions from soil carbon are estimated by applying the default emissions estimators from Table B.19 of Appendix B to the estimates of soil carbon in the Project Area. Appendix B provides an estimated

percentage emitted as the result of conversion and presents the rate of emissions associated with each soil order. A weighted estimate of emissions must be conducted where more than one soil order is found in the Project Area.

4. As with standing live and dead carbon, the baseline trend of soil carbon stocks must be graphed to display the soil carbon stocks on an annual basis.

The carbon stock trends for standing live carbon, standing dead carbon, and soil carbon are added together to determine a project baseline for the onsite carbon stocks. Figure 6.4. displays a simplified view of the the baseline trend of onsite carbon stocks, as well as the basis for project crediting over time.

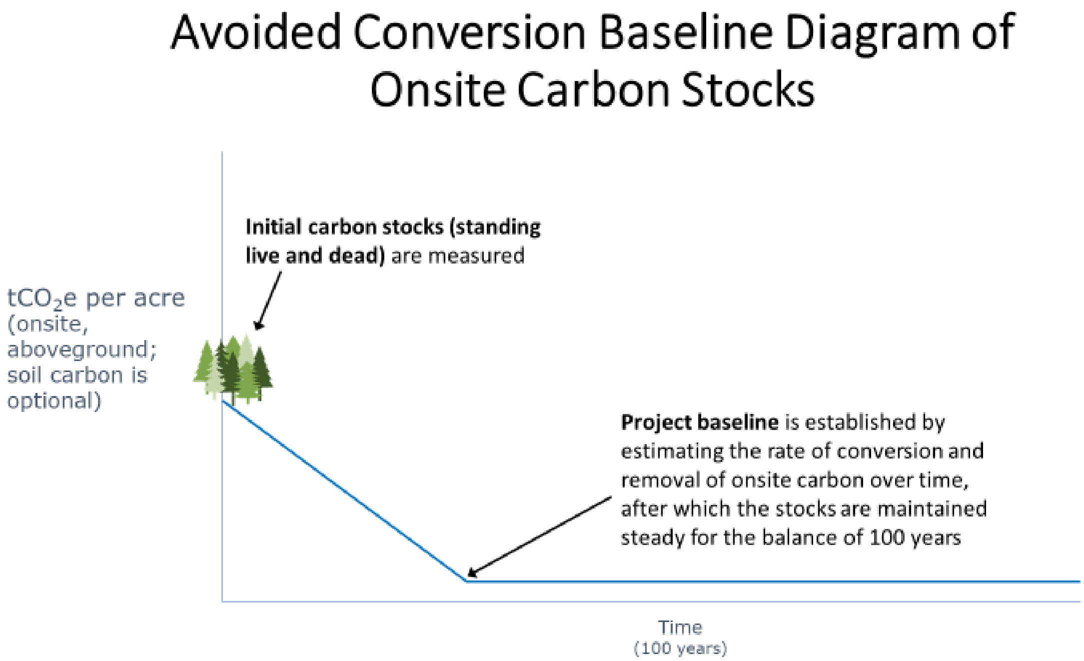


Figure 6.4. Example of an Avoided Conversion Project Baseline

Step 2 – Adjusting the Baseline Based on Conversion Risk

If the fair market value of the anticipated alternative land use for the Project Area (as determined by the required appraisal) is *not more than 80 percent greater* than the value of the current forested land use, then the baseline must be adjusted to reflect uncertainty about the risk of conversion. If the project utilizes multiple appraisals to cover the entire Project Area, the appraisals must all result in the same Conversion Risk Adjustment Factor to be considered for use in the same project.

Equation 6.11. Conversion Risk Adjustment Factor

If 0.4 < ((*VA* / *VP*) – 1) < 0.8, **then** *CRA* = [80% – ((*VA* / *VP*) – 1)] x 2.5
If ((*VA* / *VP*) – 1) ≥ 0.8, **then** *CRA* = 0%
If ((*VA* / *VP*) – 1) ≤ 0.4, **then** *CRA* = 100%

Where,

CRA	=	Conversion Risk Adjustment factor
VA	=	Appraised fair market value of the anticipated alternative land use for the Project Area
VP	=	Appraised fair market value of the current forested land use for the Project Area

The baseline is adjusted by applying the Conversion Risk Adjustment factor to the unadjusted baseline determined in Step 1, using Equation 6.12 below.

Equation 6.12. Adjusted Baseline Onsite Carbon Stocks

$$\boldsymbol{BC_{onsite,y} = BLU_y + (IS - BLU_y) \times CRA}$$

Where,

			Units
$BC_{onsite,\,y}$	=	Adjusted baseline onsite carbon stocks in year *y*, for each of the 100 years calculated in the project's baseline	tCO_2e
BLU_y	=	Unadjusted baseline onsite carbon stocks in year *y*, for each of the 100 years calculated in the project's baseline (determine in Step 1, above)	tCO_2e
IS	=	Initial onsite carbon stocks at the project start date	tCO_2e
CRA	=	Conversion Risk Adjustment factor, as described above	%

6.2.2 Estimating Baseline Carbon in Harvested Wood Products

Harvesting is assumed to occur in the baseline over time as the Project Area is converted to another land use. To estimate the baseline carbon transferred to long-term storage in harvested wood products each year:

1. Determine the amount of carbon in standing live carbon stocks (prior to delivery to a mill) that would have been harvested in each year, consistent with the rate of reduction in baseline standing live carbon stocks determined in Section 6.2.1. This projection is determined at the project outset, using the same biomass equations used to calculate biomass in live trees, and will not change over the course of the project.
2. On an annual basis, determine the amount of harvested carbon that would have remained stored in wood products, averaged over 100 years, following the requirements in Appendix B.

6.2.3 Determining Actual Onsite Carbon Stocks

Actual carbon stocks for Avoided Conversion Projects must be determined by updating the Project Area's forest carbon inventory. This is done by:

1. Incorporating any new forest inventory data obtained during the previous year into the inventory estimate. Any plots sampled during the previous year must be incorporated into the inventory estimate.
2. Using an approved model to "grow" (project forward) prior-year data from existing forest inventory plots to the current reporting year. Approved growth models are identified in

Appendix B. Guidance for projecting forest inventory plot data using models is also provided in Appendix B.

3. Updating the forest inventory estimate for harvests and/or disturbances that have occurred during the previous year. To allow some flexibility in updating the forest inventory, a project may defer updating a small percentage of plots until the following reporting period, as detailed in Appendix B.
4. Applying an appropriate confidence deduction for the inventory based on its statistical uncertainty, following the guidance in Appendix B.

6.2.4 Determining Actual Carbon in Harvested Wood Products

Perform the following steps to determine actual carbon in harvested wood products:

1. Determine the actual amount of carbon in standing live carbon stocks (prior to delivery to a mill) harvested in the current year (based on harvest volumes determined in Section 6.2.2).
2. Determine the amount of actual harvested carbon that will remain stored in wood products, averaged over 100 years, following the requirements in Appendix B.

6.2.5 Quantifying Secondary Effects

Significant Secondary Effects for Avoided Conversion Projects can arise if the type of land use conversion that would have happened on the Project Area is shifted to other forest land.

To quantify Secondary Effects risk for Avoided Conversion Projects, Project Operators must quantify Secondary Effect emissions risk using Equation 6.13. The value for Secondary Effect emissions will always be negative or zero.

Equation 6.13. Secondary Effects Emissions Risk

$$\boldsymbol{SE_{as,y}} = (-\mathbf{1}) \times \mathbf{3.6}\% \times (\boldsymbol{\Delta AC_{onsite}} - \boldsymbol{\Delta BC_{onsite}})$$ **or 0, whichever is lower**

Where,

			Units
$SE_{as,y}$	=	Secondary Effect GHG emissions that may result from activity shifting outside the project area, as a result of the project activity in year *y* (Equation 6.1)	tCO_2e
ΔAC_{onsite}	=	Annual difference in actual onsite carbon as defined in Equation 6.1	tCO_2e
ΔBC_{onsite}	=	Annual difference in baseline onsite carbon as defined in Equation 6.1	tCO_2e

7 Ensuring the Permanence of Credited GHG Reductions and Removals

The Reserve requires that credited GHG reductions and removals be effectively "permanent." For Forest Projects, this requirement is met by ensuring that the carbon associated with credited GHG reductions and removals remains stored for at least 100 years.

The Reserve ensures the permanence of GHG reductions and removals through three mechanisms:

1. The requirement for all Project Operators to monitor onsite carbon stocks, submit regular monitoring reports, and submit to regular third-party verification of those reports along with periodic verification site visits (as detailed in Sections 7 through 9 of this protocol) for the duration of the Project Life.
2. The requirement for all Project Operators to sign a Project Implementation Agreement with the Reserve, as described in Section 3.6, which obligates Project Operators to retire CRTs to compensate for reversals of GHG reductions and removals.
3. The maintenance of a Buffer Pool to provide insurance against reversals of GHG reductions and removals due to unavoidable causes (including natural disturbances such as fires, pest infestations, or disease outbreaks).

GHG reductions and removals can be "reversed" if the stored carbon associated with them is released (back) to the atmosphere. Many biological and non-biological agents, both natural and human-induced, can cause reversals. Some of these agents cannot completely be controlled (and are therefore "unavoidable"), such as natural agents like fire, insects, and wind. Other agents can be controlled, such as the human activities like land conversion and over-harvesting. Under this protocol, reversals due to controllable agents are considered "avoidable". As described in this section, Project Operators are required to identify and quantify the risk of reversals from different agents based on project-specific circumstances. The resulting risk rating determines the quantity of Climate Reserve Tonnes (CRTs) that the project must contribute to the Reserve Buffer Pool to insure against reversals.

7.1 Definition of a Reversal

Project owners must demonstrate, through annual reporting and periodic site visit verification, that stocks associated with credited GHG reductions and removals are maintained for a period of time considered to be permanent (i.e., 100 years). If the quantified GHG reductions and removals (i.e., QR_y in Equation 6.1) in a given year are negative, and CRTs were issued to the Forest Project in any previous year, the Reserve will consider this to be a reversal regardless of the cause of the decrease. Planned thinning or harvesting activities, for example, may cause a reversal if they result in a negative value for QR_y.

7.2 Insuring Against Reversals

The Reserve requires Project Operators to insure against reversals, based on a project-specific risk evaluation. Currently, insurance must take the form of contributing CRTs to the Buffer Pool administered by the Reserve. In the future, the Reserve anticipates that other insurance instruments may be available to insure against reversals.

7.2.1 About the Buffer Pool

The Buffer Pool is a holding account for Forest Project CRTs, which is administered by the Reserve. All Forest Projects must contribute a percentage of CRTs to the Buffer Pool any time they are issued CRTs for verified GHG reductions and removals. Each Forest Project's contribution is determined by a project-specific risk rating, as described in Section 7.2.2. If a Forest Project experiences an unavoidable reversal of GHG reductions and removals (as defined in Section 7.3), the Reserve will retire a number of CRTs from the Buffer Pool equal to the total amount of carbon that was reversed (measured in metric tons of CO_2-equivalent). The Buffer Pool therefore acts as a general insurance mechanism against unavoidable reversals for all Forest Projects registered with the Reserve.

7.2.2 Contributions to the Buffer Pool

Each time the Reserve issues CRTs for verified GHG reductions and removals achieved by a Forest Project, a certain percentage of those CRTs must be contributed to the Buffer Pool. The size of the contribution to the Buffer Pool will depend on the Forest Project's risk rating for reversals. For example, if a Forest Project is issued ten CRTs after annual verification, and the project's reversal risk rating is ten percent, then nine CRTs will be issued to the Project Operator's Reserve account and 1 CRT must be deposited in the Buffer Pool.

Project Operators must determine the reversal risk rating for a project by following the requirements and guidance in Appendix A. The risk rating must be determined prior to registration and recalculated in every year the project undergoes a verification site visit (see Section 9.3.2).

Project Operators who record a Qualified Conservation Easement or Qualified Deed Restriction in conjunction with implementing a Forest Project will receive a lower risk rating (see Appendix A).

Project Operators may be able to reduce the risk rating through actions that lower the risk profile of their project. If a Forest Project's risk rating declines, the Reserve may distribute previously withheld Buffer Pool CRTs to the Project Operator in proportion to the reduced risk. Similarly, however, the Reserve may require additional contributions to the Buffer Pool if the risk rating increases, to ensure that all CRTs (including those issued in prior years) are properly insured.

7.2.3 Other Insurance Options for Reversals

It is the Reserve's expectation that other options to insure against reversals will develop for projects in the future. These options may include direct insurance. Alternative insurance mechanisms could be used to directly reduce the required Buffer Pool contributions for a project. The Reserve must review and approve alternative insurance mechanisms before they may be used.

7.3 Compensating for Reversals

The Reserve requires that all reversals be compensated through the retirement of CRTs. If a reversal associated with a Forest Project was unavoidable (as defined below), then the Reserve will compensate for the reversal on the Project Operator's behalf by retiring CRTs from the Buffer Pool. If a reversal was avoidable (as defined below) then the Project Operator must compensate for the reversal by surrendering CRTs from its Reserve account.

7.3.1 Unavoidable Reversals

An Unavoidable Reversal is any reversal not due to the Project Operator's negligence, gross negligence or willful intent, including wildfires or disease that are not the result of the Project Operator's negligence, gross negligence or willful intent. Requirements for Unavoidable Reversals are as follows:

1. If the Project Operator determines there has been an Unavoidable Reversal, it must notify the Reserve in writing of the Unavoidable Reversal within six months of its occurrence.
2. The Project Operator must explain the nature of the Unavoidable Reversal and provide a verified estimate of onsite carbon stocks so that the reversal can be quantified (in units of CO_2-equivalent metric tons).
   a. Annual monitoring reports submitted for the project must provide observations of ongoing mortality. Based on such observations, an estimate of mortality related to the natural disturbance must be provided. Once mortality has stabilized to background levels, a full verified estimate of the onsite carbon stocks must be submitted to the Reserve, no later than 2 years following the occurrence. Exceptions to this timing may be made if the Reserve agrees that an extension is warranted, for example, if mortality has not stabilized. Observations submitted by the Project Operator are subject to oversight by the Reserve.

If the Reserve determines that there has been an Unavoidable Reversal, it will retire a quantity of CRTs from the Buffer Pool equal to the size of the reversal in CO_2-equivalent metric tons (i.e., QR_y, as specified in Equation 6.1).

7.3.2 Avoidable Reversals

An Avoidable Reversal is any reversal that is due to the Project Operator's negligence, gross negligence, or willful intent, including harvesting, development, and harm to the Project Area due to the Project Operator's negligence, gross-negligence, or willful intent. Avoidable Reversals may also be caused by planned harvest activities or overestimation of the project's growth and yield model.

Requirements for Avoidable Reversals are as follows:

1. If an Avoidable Reversal has been identified during annual monitoring, the Project Operator must give written notice to the Reserve within thirty days of identifying the reversal.
2. Alternatively, if the Reserve determines that an Avoidable Reversal has occurred, it shall deliver written notice to the Project Operator. Within thirty days of receiving the avoidable reversal notice from the Reserve, the Project Operator must provide a written description and explanation of the reversal to the Reserve.
3. Within a year of notifying the Reserve of an Avoidable Reversal or receiving the Avoidable Reversal notice, the Project Operator must provide the Reserve with a verified estimate of current onsite carbon stocks. The verified estimate may be a desk review verification, unless:
   a. a regularly scheduled site visit verification coincides with the year of the reversal, or

b. the loss represents 35% or more of the previous year's onsite carbon stocks or peak carbon stocks in all previous years of the carbon project.

4. Within four months of the Reserve's approval of the verified estimate of onsite carbon stocks, the Project Operator must surrender a quantity of CRTs from its Reserve account equal to the size of the reversal in CO_2-equivalent metric tons (i.e., QR_y, as specified in Equation 6.1). In addition:
   a. The surrendered CRTs must be those that were issued to the Forest Project, unless those CRTs were previously retired for other purposes. Otherwise, the surrendered CRTs must be from other Forest Projects (US or Mexico) registered with the Reserve.
   b. The surrendered CRTs will be cancelled by the Reserve and designated in the Reserve's software system as compensating for the Avoidable Reversal.

7.3.3 Computational Reversals

Computational Reversals include reversals that occur as a result of required protocol calculations. Confidence deductions and accounting for Secondary Effects may cause a computational reversal under certain circumstances. These types of reversals – which are not directly related to on-the-ground activities, but which nonetheless result in a situation in which the project has been overcredited – must be compensated for as described below.

Requirements for Computational Reversals are as follows:

1. If a Computational Reversal has been identified during annual monitoring, the Project Operator must give written notice to the Reserve within thirty days of identifying the reversal.
2. Alternatively, if the Reserve determines that a Computational Reversal has occurred, it shall deliver written notice to the Project Operator.
3. No additional verification requirements will be imposed for a Computational Reversal – the Project Operator may conduct verification at the next regularly scheduled verification period.
4. The Project Operator may true up the Computational Reversal during the next regularly scheduled verification period by deducting the reversed quantity from the to-be-issued CRTs. If growth has not compensated for the amount of the Computational Reversal, then existing CRTs will be cancelled as follows:
   a. The Reserve will cancel CRTs that were issued to the Forest Project, preferably from the relevant vintage, unless those CRTs were previously retired for other purposes or are no longer held by the Project Operator. Otherwise, CRTs must be purchased from other Forest Projects registered with the Reserve and provided for cancellation.
   b. The cancelled CRTs must be designated in the Reserve's software system as compensating for the Computational Reversal.

7.4 Disposition of Forest Projects after a Reversal

If a reversal lowers the Forest Project's actual standing live carbon stocks below its approved baseline standing live carbon stocks, the Forest Project will automatically be terminated, as the original approved baseline for the project would no longer be valid. If the Forest Project is automatically terminated due to an Unavoidable Reversal, another project may be initiated and submitted to the Reserve for registration on the same Project Area. New projects may not be initiated on the same Project Area if the Forest Project is terminated due to an Avoidable Reversal.

If the Forest Project has experienced a reversal and its actual standing live carbon stocks are still above the approved baseline levels, it may continue without termination as long as the reversal has been compensated. The project must continue contributing to the Buffer Pool in future years based on its verified risk rating.

8 Project Monitoring

This section provides requirements and guidance on project monitoring, reporting rules and procedures.

8.1 Project Documentation

Project Operators must provide the following documentation to the Reserve in order to register a forest project.

- Project Submittal form
- KML file
- Project Design Document
- Signed Attestation of Title form
- Signed Attestation of Regulatory Compliance form
- Signed Attestation of Voluntary Implementation form
- Verification Report
- Verification Statement
- Project Implementation Agreement
- Project Operator agreement (if Project Operator is not a Forest Owner)

Project Operators must provide the following documentation each time a Forest Project is verified in order for the Reserve to issue CRTs for quantified GHG reductions.

- Monitoring report
- Calculation worksheet
- Verification Report
- Verification Statement
- Signed Attestation of Title form
- Signed Attestation of Regulatory Compliance form
- Signed Attestation of Voluntary Implementation form (Improved Forest Management projects only)
- Project Implementation Agreement Amendment
- Conservation Easement (if one is employed)

Project submittal forms can be found at http://www.climateactionreserve.org/how/program/documents/.

All reports that reference carbon stocks must be submitted with the oversight of a Professional Forester, for jurisdictions with a Professional Forester law or regulation, or a Certified Forester, managed by the Society of American Foresters (see www.certifiedforester.org) so that professional standards and project quality are maintained. Any Professional Forester or Certified Forester preparing a project in an unfamiliar jurisdiction must consult with a Professional Forester or Certified Forester practicing forestry in that jurisdiction to understand all laws and regulations that govern forest practice within the jurisdiction. The Reserve may evaluate and approve alternative certification credentials if requested, but only for jurisdictions where professional forester laws or regulations do not exist. This requirement does not preclude the project's use of technicians or other unlicensed/uncertified persons working under the supervision of the Professional Forester.

All projects shall submit a KML file depicting the Project Area that matches the maps submitted to depict the Project Area. The project's reported acres shall be calculated in accordance with the requirements in Section 4.1. The Reserve will create a file of all verified forest carbon projects on Google Maps for public dissemination.

8.1.1 Forest Project Design Document

The forest Project Design Document (PDD) is a required document for reporting information about a project. The document is submitted at the initial verification. A PDD template has been prepared by the Reserve and is available on the Reserve's website. The template is arranged to assist in ensuring that all requirements of the FPP are addressed. The template is required to be used by all projects. The template is designed to manage the varying requirements based on project type.

Each project must submit a PDD at the project's first verification. The Project Operator must include a general description of the methodology that will be incorporated by the Project Operator to update their inventory estimates on an annual basis per guidance in Appendix B for the reported carbon pools.

PDDs are intended to serve as the main project document that thoroughly describes how the project meets eligibility requirements, discusses the quantification methodologies utilized to generate project estimates, outlines how the project complies with terms for additionality and describes methods for updating inventory estimates and how permanence will be addressed, including how project reversal risks are calculated. All methodologies used by Project Operators and descriptions in the PDD must be clear in a way that facilitates review by verifiers, Reserve staff, and the public. PDDs must be of professional quality and free of incorrect citations, missing pages, incorrect project references, etc.

8.2 Monitoring Report

Monitoring is the process of regularly collecting and reporting data related to a project's performance. Annual monitoring of Forest Projects is required to ensure up-to-date estimates of project carbon stocks and provide assurance that GHG reductions or removals achieved by a project have not been reversed. Project Operators must conduct monitoring activities and submit monitoring reports according to the schedule and requirements presented in Section 8.3. Monitoring is required for a period of 100 years following the final issuance of CRTs to a project for quantified GHG reductions or removals.

For Forest Projects, monitoring activities consist primarily of updating a project's forest carbon inventory, entering the updated inventory into the Forest Project's Calculation Worksheet, and submitting it to the Reserve at frequencies defined in Section 8.3. CRTs are only issued in years that the project data are verified, as described in Section 9.

A monitoring report must be prepared for each Reporting Period. Monitoring reports must be provided to verification bodies whenever a Forest Project undergoes verification. In addition, monitoring reports must be provided to the Reserve upon the completion of any Reporting Period for which verification will be deferred (e.g., if the Project Operator foregoes a desk-review verification). All monitoring reports are due within 12 months of the end of the Reporting Period. Monitoring reports must include an update of the project's calculation worksheet. The project's calculation worksheet includes:

1. An updated estimate of the current year's carbon stocks in the reported carbon pools. Specific methods used to update the forest inventory must follow the inventory methodology approved at the time the project is registered. Modifications to inventory methodologies must be approved in advance by the Reserve. Any changes in inventory estimates associated with the use of the modified inventory methodology will need to be reconciled with previously verified project inventory estimates and baseline projections. The updated estimate of carbon stocks is determined by:
    a. Including any new forest inventory data obtained during the Reporting Period.
    b. *Applying growth estimates to existing inventory.
    c. Updating inventory estimates for harvest and/or disturbances that have occurred during the Reporting Period.
2. The appropriate confidence deduction for the forest carbon inventory, as determined at the last full site visit verification for the project (following Appendix B). The same confidence deduction must be used in interim years between verification site visits.
3. An estimate of current-year harvest volumes and associated carbon in harvested wood products.
4. Estimated mill efficiency, as determined following the guidance in Appendix B.
5. The baseline carbon stock estimates for all required and optional carbon pools for the current year, as determined following the requirements in Section 6 and approved at the time of the project's registration.
6. An estimate of Secondary Effects, following calculation steps and/or factors provided in Section 6 and approved at the time of the project's registration.
7. The uncertainty discount for Avoided Conversion Projects, as determined following the requirements of Section 6.2 and approved at project registration. (Once a project is registered with the Reserve, the uncertainty discount does not change.)
8. A calculation of total net GHG reductions and removals (or reversals) for the year, following the requirements in Section 6.
9. The project's reversal risk rating, as determined following the requirements in Section 7 and Appendix A. The risk rating is updated during each full site visit verification. Between verification site visits, the project's reversal risk rating does not change.
10. A calculation of the project's Buffer Pool contribution.

In addition to data reported using the project calculation worksheet, the following must be submitted to the Reserve as part of a monitoring report.

For each Reporting Period:

1. A description of how the project meets (or will meet) the definition of Natural Forest Management (refer to Section 3.9.2), including progress on criteria that have not been fully met in previous years.
2. An updated estimate of canopy cover across the Project Area. Estimates may be conducted using recent satellite images from within the last year.

Conditional reporting, as pertinent:

1. An explanation for any decrease over any ten-year consecutive period in the standing live carbon pool.
2. Any changes in the status of the Project Operator including, if applicable per Section 3.9.1, the acquisition of new forest landholdings.
3. If a reversal has occurred during the previous year, the report must provide a written description and explanation of the reversal, whether the Reserve classified the reversal as Avoidable or Unavoidable, and the status of compensation for the reversal.

8.3 Reporting and Verification Cycle

A Forest Project is considered automatically terminated (see Section 3.5) if the Project Operator chooses not to report data and undergo verification at required intervals.

8.3.1 Reporting Period Duration and Cycle

A Reporting Period is a discrete period of time for which a Project Operator quantifies and reports GHG reductions and removals, as well as required project data to the Reserve. The initial Reporting Period may cover any length of time, up to one year. Reporting Periods subsequent to the initial Reporting Period must cover 12 months of project activity.

Reporting Periods must be contiguous, i.e., there must be no gaps in reporting during the crediting period of a Forest Project once the project has begun receiving CRTs.

8.3.2 Verification Cycle

All Forest Projects must be initially verified within 30 months of being submitted to the Reserve. The initial verification of all project types must include the initial Reporting Period, confirm the project's eligibility, and confirm that the project's initial inventory and the baseline have been established in conformance with the FPP. Subsequent verification may include multiple Reporting Periods and is referred to as the "Verification Period." The end date of any Verification Period must correspond to the end date of a Reporting Period.

Verification is required at specific intervals to ensure that ongoing monitoring of forest carbon stocks, inventory confidence, and risk ratings are accurate and up to date. Optional verification is at the Project Operator's discretion and may be conducted between required verifications for crediting (non-aggregated projects), to adjust the project's confidence estimate and/or risk ratings, among other rationale, based on changed management circumstances. Submission of annual monitoring reports to the Reserve is required even if the Project Operator chooses to forego an optional verification. The schedule of required verification is dependent upon the project type and whether the project is aggregated or non-aggregated. Details of verification scheduling requirements are provided in Table 8.1.

Verification must be completed within 12 months of the end of the Reporting Period(s) being verified. For required verifications, failure to complete verification within the 12 month time period will result in account activities being suspended until the verification is complete. The project will terminate if the required verification is not completed within 36 months of the end of the Reporting Period(s) being verified. There is no consequence for failure to complete verification activities within 12 months for optional verifications.

8.3.2.1 Site Visit and Desk Review Verification Schedule

Refer to the table below for minimum required site visit schedules, optional desk reviews, and any exceptions to the minimum requirements by project type.

Table 8.1. Forest Project Verification Schedule

Aggregation	Project Type	Verification Type	Required Timing
All	All Forest Projects	Initial verification of the first Reporting Period (with or without site visit, as detailed below)	Must be completed within 30 months of being submitted to the Reserve
All	All Forest Projects	All verifications (full site visit verifications, and desk reviews)	Must be completed within 12 months of the end of the Reporting Period(s) being verified
All	All Forest Projects	Site Visit	Required any time the Project Operator would like to establish new confidence deductions and/or reversal risk ratings, except when confidence deduction changes as a result of a project joining an aggregate
			Required to be completed within one year of notifying the Reserve of an avoidable reversal, when the threshold in section 7.3.2 is met
			Required to be completed within 2 years of notifying the Reserve of an unavoidable reversal
		Desk Review	Required to be completed within one year of notifying the Reserve of an avoidable reversal, unless the threshold in section 7.3.2 is met
Non-aggregated	All Forest Projects	Site Visit	Required for initial verification
			Required for the verification following the end of every 6th Reporting Period thereafter, unless one of the exceptions below are applicable (for under 4,000 CRTs/year, or no CRTs in a given year)
		Desk Review	Optional, between required site visit years
	Any Forest Project receiving under 4,000 CRTs/year[26]	Site Visit	Required for the verification following the end of every 12th Reporting Period after a site visit verification has taken place, or once 48,000 CRTs have been accumulated across the unverified Reporting Periods.[27] If the Reserve has reason to believe that a project proponent has been reporting artificially low numbers to take advantage of this option, the Reserve will require the project to revert to the 6 year site visit cycle.[28]

[26] The 4,000 CRT/year threshold will be assessed as an average of the reported annual gross CRTs (including buffer pool credits) since the last site visit.

[27] When the 48,000 CRT threshold is met, a site visit will be required after the following reporting period. For example, if the threshold is met during reporting period 7, a site visit will be required following reporting period 8.

[28] "Artificially low numbers" will be assessed based on the verifier's review of quantitative materiality. If the project experiences an avoidable reversal, then it will not be eligible for the 12-year verification cycle and will revert to following the 6-year verification cycle until the completion of the next site visit.

Aggregation	Project Type	Verification Type	Required Timing
		Desk Review	Optional, between required site visit years
	Any Forest Project not seeking CRTs by the time a site visit is required	Desk Review	If a forest project opts not to receive additional CRTs during a normal site visit year and has not experienced a reversal, they must undergo a desk review of the monitoring reports submitted since the last verification. If canopy cover has declined on the project area by more than 5%, then the project must be evaluated for a potential reversal and a site visit may be required as described in Section 7.3.. Reporting periods evaluated as part of this type of desk review are considered to be part of the project crediting period, even though credits are not sought. This type of verification cannot be used in the last year of a project's crediting period.[29]
Aggregated	All Forest Projects	Site Visit	Refer to the Reserve's *Guidelines for Aggregating Forest Projects*
		Desk Review	Refer to the Reserve's *Guidelines for Aggregating Forest Projects*

8.3.3 Issuance and Vintage of CRTs

The Reserve will issue Climate Reserve Tonnes (CRTs) for quantified GHG reductions and removals that have been verified through either site visits, desk reviews, or in an aggregate through the aggregated method of site visits and desk reviews described above. A site visit verification may determine that earlier desk reviews overestimated onsite carbon stocks. A net downward adjustment to carbon stock estimates will be treated as a reversal (see Section 7.1). In this case, the Project Operator must retire CRTs in accordance with the requirements for compensating for a reversal (Section 7.3).

Vintages are assigned to CRTs based on the proportion of days in each calendar year within a reporting period.

8.4 Record Keeping

For purposes of independent verification and historical documentation, Project Operators are required to keep all documents and forms related to the project for a minimum of 100 years after the final issuance of CRTs from the Reserve. This information may be requested by the verification body or the Reserve at any time.

8.5 Transparency

The Reserve requires data transparency for all Forest Projects, including data that displays current carbon stocks, reversals, and verified GHG reductions and removals. For this reason, all non-confidential project data reported to the Reserve will be publicly available on the Reserve's website.

[29] This option is not possible in the project's final year because certain aspects of project quantification (like leakage) are assessed over the 100-year time frame of the project. A verification is required in the final year in order to true-up this quantification and ensure the project has not been over-credited.

9 Verification Guidance

This section provides guidance to Reserve-approved verification bodies for verifying GHG emission reductions associated with a planned set of activities to remove, reduce or prevent CO_2 emissions in the atmosphere by conserving and/or increasing forest carbon stocks.

This section supplements the Reserve's Verification Program Manual,[30] which provides verification bodies with the general requirements for a standardized approach for independent and rigorous verification of GHG emission reductions and removals. The Verification Program Manual outlines the verification process, requirements for conducting verification, conflict of interest and confidentiality provisions, core verification activities, content of the verification report, and dispute resolution processes. In addition, the Verification Program Manual explains the basic verification principles of ISO 14064-3:2006 which must be adhered to by the verification body.

Forest Project verification bodies must read and be familiar with the following International Organization for Standardization (ISO) and Reserve documents and reporting tools:

1. Forest Project Protocol (this document)
2. Reserve Program Manual
3. Reserve Verification Program Manual
4. Reserve software
5. ISO 14064-3:2006 Principles and Requirements for Verifying GHG Inventories and Projects

Only Reserve-approved Forest Project verification bodies are eligible to verify Forest Project reports. To become a recognized Forest Project verifier, verification bodies must become accredited under ISO 14065. Information on the accreditation process can be found on the Reserve website at http://www.climateactionreserve.org/how/verification/how-to-become-a-verifier/.

The verification of reports that reference carbon stocks must be conducted with the oversight of a Professional Forester, for jurisdictions with a Professional Forester law or regulation, or a Certified Forester,[31] managed by the Society of American Foresters, so that professional standards and project quality are maintained. Any Professional Forester or Certified Forester verifying a project in an unfamiliar jurisdiction must consult with a Professional Forester or Certified Forester practicing forestry in that jurisdiction to understand all laws and regulations that govern forest practice within the jurisdiction. The Reserve may evaluate and approve alternative certification credentials if requested, but only for jurisdictions where professional forester laws or regulations do not exist.

9.1 Standard of Verification

The Reserve's standard of verification for Forest Projects is the Forest Project Protocol (FPP), the Reserve Program Manual, and the Reserve Verification Program Manual. To verify a land owner's initial Forest Project Design Document and annual monitoring reports, verification

[30] Found on the Reserve website at http://www.climateactionreserve.org/how/program/program-manual/.
[31] See www.certifiedforester.org.

bodies apply the verification guidance in the Reserve's Verification Program Manual and this section of the FPP to the requirements and guidance described in Sections 2 through 8 of the FPP.

This section of the protocol provides requirements and guidance for the verification of projects associated with the two Forest Project types defined in Section 2. Both project types involve planned activities that result in conserving and/or increasing forest carbon stocks. This section describes the core verification activities and criteria for both Forest Project types that are necessary for a verification body to provide a reasonable level of assurance that the GHG removals or reductions quantified and reported by Project Operators are materially correct.

Verification bodies will use the criteria in this section to determine if there exists reasonable assurance that the data submitted on behalf of the Project Operator to the Reserve addresses each requirement in the FPP, Sections 2 through 8. Project reporting is deemed accurate and correct if the Project Operator is in compliance with the Section 2 through 8.

Further information about the Reserve's principles of verification, levels of assurance, and materiality thresholds can be found in the Reserve's Verification Program Manual at http://www.climateactionreserve.org/how/program/program-manual/.

9.2 Emission Sources, Sinks, and Reservoirs

For all verification activities, verification bodies review a project's reported sources, sinks, and reservoirs to ensure that all are identified properly and to confirm their completeness. Table 5.1 and Table 5.2 in Section 5 provide comprehensive lists of all GHG sources, sinks, and reservoirs that must be included in the quantification and reporting of GHG reductions and removals for the two Forest Project types.

It is the Project Operator's responsibility to ensure that verifications are conducted according to the minimum required schedule specified in Section 8.3.2. A Verification Report, List of Findings, and Verification Statement must be submitted within twelve months of the end of any verification period. Site visit verification requirements are described in Section 9.3.2. Desk review verification requirements are described in Section 9.3.3.

9.3 Project Verification Activities

Required verification activities for Forest Projects will depend on whether the verification body is conducting an initial verification for registration on the Reserve, a minimum required verification involving a site visit, or an optional annual verification involving a desk review. Both the initial verification and ongoing verifications must include review of the criteria for Natural Forest Management, inventory of onsite carbon stocks, assessment of carbon in harvested wood products, and review of reversal risk ratings. The following sections contain guidance for all of these verification activities.

9.3.1 Initial Verification

Initial verification includes verification that the Forest Project has met the FPP criteria and requirements for eligibility, Project Area definition, modeling baseline onsite carbon stocks, and calculating baseline carbon in harvested wood products. The initial verification must include a site visit. The verification body must assess and ensure the completeness and accuracy of all required reporting elements for the Forest Project Design Document (Section 8.1.1). Initial verification items are presented in Table 9.1A through 9.1H.

At a Forest Project's initial verification, these items must be verified in addition to all the items required for a standard site visit verification, as detailed in Section 9.3.2.

9.3.1.1 Initial Eligibility

Verification bodies are required to affirm the project's eligibility according to the rules in this protocol. Tables 9.1A and 9.1B provide the initial verification items concerning eligibility for the different Forest Project types and include references to sections of this protocol where requirements are further specified.

Table 9.1A. Initial Eligibility Verification Items – Improved Forest Management Projects

Verification Items		Section of FPP	Apply Professional Judgment?
1. Project Definition	a. Evidence is provided indicating the canopy cover exceeds 10%. b. No evidence exists for use of broadcast fertilization.	2.1.1	Yes (for 1.b)
2. Legal Requirement Test	Proof that a signed Attestation of Voluntary Implementation form is on file with the Reserve.	3.3.1.1	No
3. Start Date	Identification of a discrete, verifiable action that delineates a change in practice relative to the project's baseline.	3.2	No
4. Project Implementation Agreement	Proof that a Project Implementation Agreement (PIA) between the Project Operator and the Reserve has been signed and recorded in the county of interest.	3.6	No
5. Project Location	a. Project is located in the United States of America. b. Project is on private land, or c. If non-federal public lands, provide documentation showing approval by the government agency or agencies responsible, or d. If tribal land, provide documentation that demonstrates that the land within the Project Area is owned by a tribe or private entities.	3.1	No

Table 9.1B. Initial Eligibility Verification Items – Avoided Conversion Projects

Verification Items		Section of FPP	Apply Professional Judgment?
1. Project Definition	a. Proof that the project is/was on private land prior to project initiation. b. Proof that a conservation easement was recorded, or the land was transferred to public ownership. c. Demonstration that conversion out of forest is a significant risk (following the requirements of Section 6.2.1 – see also Table 9.1H). d. No evidence exists for use of broadcast fertilization.	2.1.2, 6.2.1	Yes (for 1.c and 1.d)
2. Legal Requirement Test	a. Proof that a signed Attestation of Voluntary Implementation form is on file with the Reserve. b. Documentation has been provided that demonstrates that the type of land use conversion anticipated by the project is legally permissible; documentation must fall into at least one of the three categories specified in Section 3.3.1.2.	3.3.1.2	No
3. Performance Test	Copy of real estate appraisal(s) for the Project Area indicating conformance to criteria in Section 3.3.2.2.	3.3.2.2	No
4. Start Date	Identification of date on which a conservation easement that dedicates the Project Area to continuous forest cover was recorded or the Project Area was transferred to public ownership.	3.2, 3.7	No
5. Project Implementation Agreement	Proof that a Project Implementation Agreement (PIA) between the Project Operator and the Reserve has been signed and recorded in the county of interest.	3.6	No
6. Project Location	a. Project is located in the United States of America. b. Project is on private land, or c. If non-federal public lands, provide documentation showing approval by the government agency or agencies responsible, or d. If tribal land, provide documentation that demonstrates that the land within the Project Area is owned by a tribe or private entities.	3.1	No

9.3.1.2 Project Area Definition

Verification bodies are required to review the geographic boundaries defining the Project Area and their compliance with the requirements outlined in Section 4 of this protocol. These items are verified only at the project's initiation.

Table 9.1C. Project Area Definition Verification Items

Project Type	Verification Items	Section of FPP	Apply Professional Judgment?
1. All	Proof that a description, shapefile, and maps of the geographic boundaries defining the Project Area are on file at the Reserve.	4, 8.1	No
2. Avoided Conversion	Project Area has been defined following the guidance in Section 4, Table 4.1 for the appropriate conversion type.	4	No

9.3.1.3 Baseline Onsite Carbon Stocks

Verification bodies are required to confirm that the Project Operator has developed a baseline characterization for onsite carbon stocks according to the requirements in this protocol. These items are verified only at the project's initiation.

Table 9.1D. Baseline Estimation Verification Items – Improved Forest Management Projects – Private Lands

Verification Items		Section of FPP	Apply Professional Judgment?
1. Inventory of Onsite Carbon Stocks	An inventory of the Project Area's carbon stocks in required and optional pools has been conducted in accordance with the requirements of the FPP (see Section 9.3.5 for further verification guidance).	6.1.2, Appendix B	Yes
2. Compare Initial Aboveground Standing Live Carbon Stocks with Common Practice	a. Initial aboveground standing live and standing dead carbon stocks have been estimated correctly following the requirements of the FPP. b. The baseline analysis utilizes the correct value for Common Practice c. The project has undertaken the correct baseline analysis, according to whether initial carbon stocks are above or below Common Practice.	6.1.1, 6.1.2, Appendix B	No
3. Estimating Baseline Carbon Stocks	a. The project is qualified to use the conservative default approach, and has correctly implemented the baseline in accordance with the guidance in Section 6.1.1. b. Where using the modeled approach, a 100-year forest management simulation of standing live and dead carbon stocks has been conducted in accordance with the requirements and guidance in Section 6.1.2 and Appendix B (see Section 9.3.6 for further verification guidance).	6.1.1, 6.1.2, Appendix B	Yes
4. Description of Forest Project Activities	A description has been provided of the management activities that will lead to increased carbon stocks in the Project Area compared to the baseline.	2	No

Table 9.1E. Baseline Estimation Verification Items – Improved Forest Management Projects – Public Lands

Verification Items		Section of FPP	Apply Professional Judgment?
1. Initial Forest Carbon Stock Inventory	An inventory of the Project Area's carbon stocks in required and optional pools has been conducted in accordance with the requirements of the FPP (see Section 9.3.5 for further verification guidance).	6.1.3, Appendix B	Yes
2. Estimating Baseline Carbon Stocks	A COLE report and analysis has been conducted per the requirements in Section 6.1.3 and the Appendix B.	6.1.3, Appendix B	Yes
3. Description of Forest Project Activities	A description has been provided of the management activities that will lead to increased carbon stocks in the Project Area compared to the baseline.	2	No

Table 9.1F. Baseline Modeling Verification Items – Avoided Conversion Projects

Verification Items		Section of FPP	Apply Professional Judgment?
1. Initial Forest Carbon Stock Inventory	An inventory of the Project Area's carbon stocks in required and optional pools has been conducted in accordance with the requirements of the FPP (see Section 9.3.5 for further verification guidance).	6.2.1, Appendix B	Yes
2. Baseline Carbon Stock Modeling	a. An alternative highest-value land use for the Project Area has been clearly identified by the required appraisal(s). b. The rate of conversion and removal of onsite forest carbon stocks has been appropriately estimated in accordance with the requirements of Section 6.2.1. c. A 100-year forest management simulation of standing live carbon stocks has been conducted per the requirements in Section 6.2.1, and Appendix B (see Section 9.3.6 for further verification guidance).	3.3.2.2, 6.2.1	Yes
3. Discount for the Uncertainty of Conversion Probability	The Avoided Conversion Discount factor has been correctly calculated per Equation 6.6 in Section 6.2.1.	3.3.2.2, 6.2.1	No
4. Description of Forest Project Activities	A description has been provided of the management activities that will lead to increased carbon stocks in the Project Area compared to the baseline.	2	No

9.3.1.4 Calculating Baseline Carbon in Harvested Wood Products

Verification bodies are required to confirm that the Project Operator has developed a baseline characterization for carbon in harvested wood products according to the requirements of this protocol and requirements and guidance in Section 6.1.1, Section 6.1.2, Section 6.1.3, or Section 6.2.2, and Appendix B.

Table 9.1G. Baseline Carbon in Wood Products Verification Items – Improved Forest Management Projects

Verification Items		Section of FPP	Apply Professional Judgment?
1. Baseline Harvest Volume	The average volume of harvesting in the baseline has been derived from the growth and harvesting regime used to develop the baseline for onsite carbon stocks, following the requirements and guidance in Section 6.1.2, or through the appropriate default approach in Section 6.1.1 or Section 6.1.3, and Appendix B (see Section 9.3.7 for further verification guidance).	6.1.1, 6.1.2, 6.1.3, Appendix B	No
2. Long-Term Storage in Wood Products	The average amount of carbon expected to be transferred to wood products each year and stored over the long-term (100 years) has been calculated following the requirements and guidance in Appendix B (see Section 9.3.7 for further verification guidance).	Appendix B	No

Table 9.1H. Baseline Carbon in Wood Products Verification Items – Avoided Conversion Projects

Verification Items		Section of FPP	Apply Professional Judgment?
1. Baseline Harvest Volume	The volume of harvesting in each year of the baseline over 100 years has been derived from the harvesting regime assumed for the baseline for onsite carbon stocks, following the requirements and guidance in Section 6.2.2, and Appendix B (see Section 9.3.7 for further verification guidance).	6.2.2, Appendix B	No
2. Long-Term Storage in Wood Products	The amount of harvested wood that would be delivered to mills in each year has been determined, and the amount of carbon expected to be transferred to wood products each year and stored over the long-term (100 years) has been calculated following the requirements and guidance of Section 6.2.2 and Appendix B (see Section 9.3.7 for further verification guidance).	6.2.2, Appendix B	No

9.3.2 Site Visit Verification

Site visit verification involves review of the Forest Project's carbon stock inventory estimates, relevant attestations, soil carbon emissions associated with management activities, risk of reversal ratings, and compliance with Natural Forest Management criteria. After a Forest Project's initial verification, subsequent site visits must assess and ensure accuracy in measurement and monitoring techniques and onsite record keeping practices.

Table 9.2. Site Visit Verification Items

Verification Items		Section of FPP	Apply Professional Judgment?
1. Attestation of Title	Proof that a signed Attestation of Title is on file at the Reserve for the dates of the verification period. In addition to reviewing this form, the verification body must conduct a review to confirm ownership and claims to GHG reductions/removals that have occurred over the verification period.	3.7	Yes
2. Attestation of Regulatory Compliance	Proof that a signed Attestation of Regulatory Compliance form is on file with the Reserve for the reporting period. In addition to reviewing this form, the verification body must perform a risk-based assessment to confirm the statements made by the Project Operator in the Attestation of Regulatory Compliance form.	3.8	Yes
3. Attestation of Voluntary Implementation	Proof that a signed Attestation of Voluntary Implementation form is on file with the Reserve for the reporting period. Required for every reporting period for Improved Forest Management projects, and for initial reporting periods only for Avoided Conversion projects.	3.3	No
4. Sustainable Harvesting Practices	a. Commercial Rotational Harvesting has not commenced within the Project Area, or b. At the time Commercial Rotational Harvesting is initiated within the Project Area, the Project Operator meets sustainable harvest practices on all of its landholdings, as described in Section 3.9.1.	3.9.1	No
5. Change in Project Operator Landholdings	If the Project Operator has acquired additional forestlands outside of the Project Area, the Project Operator must incorporate the newly acquired land in their demonstration of sustainable long-term harvesting practices within 5 years of the acquisition.	3.9.1	No
6. Maintenance of Standing Live Carbon Pool	No decrease has occurred in the Project Area's standing live carbon stocks over any ten-year consecutive period not accounted for by allowable exceptions.	3.9.3	No
7. Natural Forest Management	Natural Forest Management eligibility criteria in Section 3.9.2 have been and continue to be met (see Section 9.3.4 for further verification guidance).	3.9.2	Yes
8. Estimates of Actual Onsite Carbon Stocks	An inventory of the Project Area's carbon stocks in required and optional pools has been conducted in accordance with the requirements in Section 6 and the requirements and guidance in Appendix B (see Section 9.3.5 for further verification guidance)	6, Appendix B	Yes
9. Estimates of Actual Carbon	The amount of harvested wood that has been delivered to mills over the reporting period has been determined correctly, and the amount of	6, Appendix B	No

Verification Items		Section of FPP	Apply Professional Judgment?
in Harvested Wood Products	carbon expected to be transferred to wood products and stored over the long-term (100 years) has been calculated correctly, per the requirements in Section 6 and Appendix B (see Section 9.3.7 for further verification guidance).		
10. Quantification of Primary Effect	Calculations for the Primary Effect are complete and accurate for both onsite carbon stocks and harvested wood products.	6	No
11. Quantification of Secondary Effects	Calculations for quantifying Secondary Effects are complete and accurate.	6.1.6, 6.2.5	No
12. Reversal Determination	If a reversal has occurred, the type of reversal (avoidable or unavoidable) has been properly identified.	7.3	Yes
13. Reversal Risk Rating	Project's risk rating has been calculated following the requirements of Appendix A	Appendix A	No

9.3.3 Desk Review Verification

For reporting periods in between required site visits, project verification activities may consist of a desk review. During a desk review, the verification body will review the data in annual monitoring reports to check calculations and information for reasonability, accuracy, and completeness.

Table 9.3. Desk Review Verification Items

Verification Items		Section of FPP	Apply Professional Judgment?
1. Attestation of Title	Proof that a signed Attestation of Title is on file at the Reserve for the dates of the verification period. In addition to reviewing this form, the verification body must conduct a review to confirm ownership and claims to GHG reductions/removals that have occurred over the verification period.	3.7	Yes
2. Attestation of Regulatory Compliance	Proof that a signed Attestation of Regulatory Compliance form is on file with the Reserve for the reporting period. In addition to reviewing this form, the verification body must perform a risk-based assessment to confirm the statements made by the Project Operator in the Attestation of Regulatory Compliance form.	3.8	Yes

Verification Items		Section of FPP	Apply Professional Judgment?
3. Attestation of Voluntary Implementation	Proof that a signed Attestation of Voluntary Implementation form is on file with the Reserve for the reporting period. Required for every reporting period for Improved Forest Management projects, and for initial reporting periods only for Avoided Conversion projects.	3.3	No
4. Maintenance of Standing Live Carbon Pool	No decrease has occurred in the Project Area's standing live carbon stocks over any ten-year consecutive period not accounted for by allowable exceptions.	3.9.3	No
5. Estimates of Actual Onsite Carbon Stocks	Reported onsite carbon stocks are within expected bounds given reported harvest, growth, and disturbance effects since the prior reporting period.	6, Appendix B	Yes
6. Estimates of Actual Carbon in Harvested Wood Products	The reported amount of wood that has been delivered to mills over the reporting period is consistent with reported harvest levels, and the amount of carbon expected to be transferred to wood products and stored over the long-term (100 years) has been calculated correctly, per the requirements in Section 6 and Appendix B (see Section 9.3.7 for further verification guidance).	6, Appendix B	Yes
7. Quantification of Primary Effect	Calculations for the Primary Effect are complete and accurate for both onsite carbon stocks and harvested wood products.	6	No
8. Quantification of Secondary Effects	Calculations for quantifying Secondary Effects are complete and accurate.	6.1.6, 6.2.5	No
9. Reversal Determination	If a reversal has occurred, the type of reversal (avoidable or unavoidable) has been properly identified.	7.3	Yes
10. Reversal Risk Rating	Reversal risk rating is the same used since the previous site visit verification.	Appendix A	No

9.3.4 Natural Forest Management

All Forest Projects must promote and maintain a diversity of native species and utilize management practices that promote and maintain native forests comprised of multiple ages and mixed native species at multiple landscape scales (Natural Forest Management). At a Forest Project's first site visit verification and at all subsequent site visit verifications, the verification body must evaluate the project against the Natural Forest Management criteria described in Section 3.9.2, referencing the most current Assessment Area Data File available on the Forest Project Protocol webpage. Forest project carbon stock inventories (requirements for which are contained in Appendix B) should be used as the basis of these assessments where applicable. Forest projects that do not initially meet Natural Forest Management criteria but can demonstrate progress towards meeting these criteria within the required timelines are eligible to register and maintain that registration with the Reserve.

Table 9.4. Natural Forest Management Verification Items

Verification Items		Apply Professional Judgment?
1. Native Species	Completed inventory demonstrates that project consists of at least 95% native species. Must demonstrate continuous progress toward goal and criterion must be met within 50 years.	No
2. Composition of Native Species	Completed inventory demonstrates distribution of average basal area of standing live tree species meets composition of native species goal. Project is not eligible unless it is demonstrated that management activities will enable this goal to be achieved over the project life or an exception has been made through a letter from the State Forester as described in Section 3.9.	No
3. Sustainable Harvesting Practices	a. Documentation showing that the forest, including entity lands outside Project Area, is currently under one of the following: i. Third party certification under the Forest Stewardship Council or Sustainable Forestry Initiative/ Tree Farm System, or ii. A renewable long-term management plan sanctioned and monitored by a state or federal agency within a Reserve-approved Assessment Areas, or iii. Silvicultural practices that maintain canopy retention averaging at least 40% across the entire forestland owned by the Project Operator in the same Assessment Areas covered by the Project Area, as measured on any 20 acres within the Project Operator's landholdings found in any of these Assessment Areas, including land within and outside of the Project Area (areas impacted by Significant Disturbance may be excluded from this test), or iv. Possessing a deeded conservation easement(s) that contain terms that ensure growth equals or exceeds harvest over time. Verifiers should make a reasonable attempt to contact the steward of the conservation easement to confirm compliance.	No
4. Forest Structure	a. If the project employs even-aged management, ensure the retention guidelines have been followed. b. Completed inventory demonstrates the project maintains, or makes progress toward maintaining, no more than 40% of forested acres in ages less than 20 years (on a watershed scale up to 10,000 acres, or the Project Area, whichever is smaller). Project must show continuous progress and this criterion must be met within 25 years.	No
5. Structural Elements (Lying and Standing Dead Wood)	Completed inventory work demonstrates that lying and standing dead wood is retained in sufficient quantities and for sufficient duration depending on whether portions of the Project Area have undergone salvage harvesting.	Yes

9.3.5 Verifying Carbon Inventories

Verification bodies are required to verify carbon stock inventory estimates of all sampled carbon pools within the Project Area. Inventories of carbon stocks are used to determine the project baseline and to quantify GHG reductions and removals against the project baseline over time.

Verification of carbon inventories consists of ensuring the Project Operator's sampling methodology conforms to requirements listed in the protocol and that the project's inventory sample plots are within specified tolerances when compared to the verifier's sample plots. Verification is effectively an audit to infer that the inventory estimate is sound. Verification of the project's onsite stocks must occur at each site verification and focus on ensuring that the project's inventory methodology is technically sound and that the methodology has been correctly implemented.

The project must meet the inventory standards in Table 9.5 prior to the verification body initiating field sampling activities. The verifier will re-measure existing monumented sample plots or install sample plots, consistent with the objectives of a random, risk-based, and efficient approach. In doing so, the verifier may weigh the probability of selecting strata and plots based on various criteria – including carbon stocking, access difficulty, and vegetation heterogeneity. Verifiers may choose to sample project plots within a given stratum with a cluster design. The selection of a stratum may use probability proportional to carbon stocks or probability proportional to the risk of errors (as hypothesized by the verifier).

9.3.5.1 Sequential Sampling for Verification

As a policy to ensure a trend of agreement with sampled data is sustained between the verifier and Project Operator, this protocol requires a sequential sampling method for verification of project estimates. Sequential sampling is intended to provide an efficient sampling method for verifiers to determine if randomly selected project measurements are within specified tolerance bounds established by the protocol.

Verification using the sequential sampling methodology requires the verification body to sequentially sample successive plots. Sequential approaches have stopping rules rather than fixed sample sizes. Verification is successful after a minimum number of successive plots in a sequence indicate agreement. Where the stopping rules indicate the potential presence of a bias, additional verification plots may be collected after that time if it is felt that random chance may have caused the test to fail and a convergence towards agreement is expected with additional verification samples. The results of any additional verification plot may also be inconclusive and require additional verification plots for a determination to be made. For effective application of the sequential statistics in the field, the determination of when the stopping rule is met is made as soon as is convenient for the verification team and will include the full set of plots measured in that timeframe.

Worksheets are available on the Reserve's website for use by verifiers to assist in verifying sampled data. The verifier will review the descriptive statistics of the carbon stocks independently for each pool or combination of pools that is being reported for crediting (applicable pool) as shown below:

- Standing live and dead trees
- Soil

To increase efficiency in the verification process, three nested levels of sequential sampling are processed in the sequential sampling worksheets, based on a single sampling exercise performed by the verifier. All tests are performed with the same randomly selected plots and can only be completed by analysis of the plots in the sequential order they were randomly selected. However, inventory data is only considered successfully verified when the stopping rules for the CO_2e/acre test have been met. Passing the diameter and height tests only improves the overall efficiency of the verification effort. The data identified below used for each test are input into the appropriate sequential sampling tool.

- CO_2e/acre: The testing of inventory data can only be satisfied when the CO_2e/acre comparison between the verifier and Forest Owner is completed. This test is conducted on a plot by plot basis using estimates of CO_2e/acre. The verifier's estimates of CO_2e/acre are derived by measurements of diameter and height (measured by verifier or using Forest Owner's data, as described below), species determinations, defect and decay determinations, and a determination of the appropriate trees to be included in the sample ("in" or "out" trees).
- Diameter Test (paired sequential sampling only): A comparison of diameter data between the verifier and the Forest Owner is conducted on a tree by tree basis until sequential sampling stopping rules have been achieved, indicating that the verifier and Forest Owner measurements of diameter are aligned within acceptable tolerance levels. If the stopping rule for diameter is met before the sequential sampling exercise has ended for CO_2e/acre, verifiers may stop taking their own diameter measurements and may instead use the diameter data provided for each tree from the Forest Owner's database for any additional data inputs needed for the CO_2e/acre comparison. If this happens, the focus of the sampling exercise from that point on will be measuring height (if applicable, see below), making species determinations, defect and decay determinations, and "in" or "out" tree assessments.
- Height Test (paired sequential sampling only): Like the diameter test, a comparison of height data is performed between the verifier and the Forest Owner until sequential sampling stopping rules have been achieved, indicating that the verifier and Forest Owner measurements of height are aligned within acceptable tolerance levels. If the stopping rule for height is met before the sequential sampling exercise has ended for CO_2e/acre, verifiers may stop taking their own height measurements and may instead use the height data provided for each tree from the Forest Owner's database for any additional data inputs needed for the CO_2e/acre comparison. If this happens, the focus of the sampling exercise from that point on will be measuring diameter (if applicable, see above), making species determinations, defect and decay determinations, and "in" or "out" tree assessments.

Separate worksheets have been developed to assess both monumented (paired) and non-monumented (unpaired) plots as well as for DBH, height, and CO_2e/acre. Worksheets are found on the Forest Project Protocol webpage.

The Reserve has established a ten percent allowance as an acceptable level of agreement between the verifier and the Project Operator, without adjusting the project estimates for uncertainty.

9.3.5.2 Inventory Estimates

The items in Table 9.5 are evaluations that should be made before the verifier goes to the field and analyzes the plots. If a project opts to utilize the Reserve's Standardized Inventory Methodology, the methodology need not be assessed beyond correct implementation.

Table 9.5. Inventory Methodology Verification Items

Verification/Evaluation Standards	
1.a	Inventory methodology describes the methodology for plot location in the field. The plot locations are either random or systematic with a random initial point.
1.b	If inventory methodology describes a stratification design: The stratification methodology, including rules for stratification, is clearly defined. The stratification design is relevant for the sampling of biomass. In particular, the stratification design applies to all tree species without a bias for commercial tree species. Verifier shall randomly select 10% of the vegetation units, or strata polygons, by area, or 500 acres (whichever is least) to evaluate that the vegetation (or stratum) label assigned to the polygon is consistent with the stratification rules documented in the inventory methodology. The selection shall be made from a database or spreadsheet list of all vegetation (stratum) polygons within the project that have not experienced a harvest or disturbance that affects carbon stocks by more than 10%, using verifier judgment, within the past 10 years. Evaluation of post-harvest polygons and plots is described in 1.c. Evaluation for consistency shall be conducted through comparison with aerial photos or other remotely sensed data, and/or field observation. During evaluation, a verifier must use professional judgment to determine if a polygon is consistent or inconsistent with the stratification rules. Inconsistent means the existing vegetation (stratum) label is grossly incorrect to an extent that would substantially alter the associated carbon stocks. If more than 10% of the polygons evaluated are determined to be inconsistent with the stratification rules documented in the inventory methodology, the verification shall expand the assessment to an additional 10% of the vegetation units (stratum polygons), or an additional 500 acres (whichever is least) and expand the analysis, or determine that the project has failed to meet the standard.
1.c	Inventory methodology states how the inventory is updated on an annual basis to reflect growth, harvest, and other disturbances. An event is deemed to be a disturbance, whether natural or the result of human activities, if the event results in an estimated loss of more than 10% of the pre-disturbance carbon stocks in the applicable carbon pools. The methodology includes a process to: ▪ Update the inventory for harvest and other disturbances. The immediate updating of an inventory for disturbances will require that a tree list is assigned to the area disturbed, rather than developing a tree list from field measurements, to represent the area disturbed. This may occur by assigning a vegetation label (stratifying) and compiling the inventory so that the area disturbed obtains a tree list representative of the disturbed condition. For stratified inventories, this may be a solution that lasts many years until the forest vegetation is re-stratified due to changes from forest growth. Immediately updating an inventory may also occur by assigning a 'best-fit' tree list that represents the stand conditions to the plots that were affected by disturbance. This solution is a shorter term solution since the plots used to estimate the inventory have been affected. During all site visit verifications (following the initial site visit verification in cases where the project start date is the same year as the initial site visit verification), the Project Operator must provide a map(s) that displays areas where disturbance has occurred. For stratified inventories, a pre-disturbance map must display the vegetation stratum prior to the disturbance and a post-disturbance map must display the vegetation stratum following the disturbance. For non-stratified inventories, the disturbance map must display the underlying plots, if any, affected by the disturbance. For stratified inventories, a summary tree list associated with the updated vegetation strata shall be provided. For non-stratified inventories, tree lists shall be provided for each plot affected by disturbance. During site verification, verifiers shall randomly select a minimum of 10% of the vegetation polygons (strata polygons) or plots updated for disturbance and determine if the assigned tree lists do not obviously overestimate the carbon associated with the forest structure remaining after the disturbance. Where plots are updated through assignment of a tree list (instead of assigning a vegetation stratum) following the disturbance, the verifier shall ensure all plots have been updated and the updated tree list is consistent with

	the forest structure remaining after disturbance. For non-stratified inventories, it is not acceptable for a Project Operator to simply remove disturbed plots from the inventory. The plots must be assigned a tree list to estimate the post-disturbance condition. It is acceptable to remove plots from an inventory that is strata-based upon disturbance that affects the plots. Tree lists resulting from stratification or assignment are determined to be inconsistent if the tree list would result in carbon stocks substantially above what in the verifier's professional judgment would associate with the post-disturbance condition. The determination for consistency can be made through an office review by comparing the assigned tree lists with the disturbance events. A verifier can choose to enhance their review for consistency by visiting disturbed sites in the field. To minimize the risk of inaccuracies to the inventory, no more than 10% of the plots used to characterize the project's inventory can be developed from estimated tree lists without increased scrutiny from verification. The plots assigned an estimated tree list must be appropriately coded in the inventory database so that they can be queried and isolated. Plots assigned with an estimated tree list are not to be used in sequential sampling efforts unless the number of plots with estimated tree lists exceeds 10%, in which case all plots, measured or estimated, must be available for random selection for sequential sampling during verification. ▪ Update the inventory for growth using and approved growth model or a stand table projection, as described in Appendix B. The inventory being verified is determined to be current using the update methodology.
1.d	The inventory methodology has been implemented in a consistent manner since the project's inception. If changes have been made to the inventory methodology, such changes have been discussed and approved in writing by the Reserve.
1.e	The inventory methodology describes the volume and biomass equations used to compute the project's carbon stocks and these equations are consistent with those required by the protocol. Appropriate use of biomass equations is demonstrated.

Each applicable pool/combination of pools must meet the minimum precision threshold of +/- 20 percent at the 90 percent confidence interval. Project Operators can improve the precision of their estimates through additional inventory effort but can only include it in their reporting after the confidence estimate has been verified. Projects must include the uncertainty adjustment associated with their most recent verification effort.

Use of the Standardized Inventory Methodology (available on the Reserve's Forest Project Protocol webpage) will be considered to automatically meet the evaluation standards in Table 9.5 and does not need to be verified beyond ensuring proper implementation. The Reserve has also developed the Climate Action Reserve Inventory Tool (CARIT), an inventory management computer application that Project Operators may also optionally use to manage and update their forest inventories. The use of the Standardized Inventory Methodology does not obligate a Project Operator to use CARIT, nor does the use of CARIT obligate a Project Operator to use the Standardized Inventory Methodology. However, CARIT will only function properly if certain inventory standards are followed. Refer to Appendix B for more information.

9.3.5.3 Measurement Specifics for Verifiers

Verifiers must use the highest standard to conduct measurements during field measurements. Measurements utilized by verifiers during field inspections shall be consistent with the tolerance standards for measurements identified in Appendix B, with the following exceptions:

1. Verifiers shall measure the heights of all trees according to the height measurement used for the species-specific biomass equation on the Reserve's Forest Project Protocol webpage.

2. The use of regressions to estimate heights is allowable for Forest Operators; verifiers should measure each height for comparisons with Forest Operator's estimates.
3. Tools and methods used for distance measurements for plot boundaries should be accurate within 1"/30'.
4. Tools and methods used for distance measurements for height measurements must be able to obtain an accuracy of 6"/100'.
5. Rules for determining 'in'/'out' trees:
   a. All borderline trees should be measured to determine status as an 'in' or 'out' tree.
   b. Verifiers may encounter trees that are 'in' that were not measured by the Project Operator. The cause of the omission(s) may be that the trees were determined to be too small to be included, per sampling methodology criteria, at the time of the Project Operator measurement. Per Appendix B, inventory estimates developed by the Project Operator must include all trees 5 inches DBH and larger.
   c. Additionally, Appendix B permits Project Operators to develop an inventory methodology with varying plot areas that are expanded on a per acre basis depending on the size of the plots and with varying DBH requirements for which trees are included in each plot. In such cases, trees that were determined to be too small to be included in a larger plot by the Project Owner, may have grown and now exceed the minimum threshold for inclusion in the larger plot.
   d. To account for this limited growth, the verifier shall not include trees in the verifier measurements (for sequential sampling purposes) if the tree was omitted by the Forest Owner and the tree diameters, at time of verification audit, are less than 7 inches DBH. Similarly, trees that were included by the Forest Owner in a plot with a certain expansion factor and, at the time of verifier audit, have not exceeded the threshold for being switched to a plot with a different expansion factor by more than 10%, shall continue to be entered in the plot determined by the Project Operator, such that the expansion values are consistent for the Project Operator and the verifier.
      i. This applies a reasonable cushion to Project Operators who apply the sampling methodology correctly, but through no fault of their own would otherwise be penalized due to forest growth changing measurement parameters. It should be noted that the cushion is minimal and will not relieve Project Operators from growth over long periods of time that would exceed these allowances. Hence, Project Operators need to base the re-measurement of the plots on an adequate timeframe to avoid verification problems with their inventory data.
      ii. Any trees that do not meet the criteria of the standards listed above shall be included as part of the verifier's plot estimate for purposes of sequential sampling.
6. Verifiers shall insert their own determination of species for each tree included in the verifier's inventory.
7. For defect and decay, verifiers may first consider the inputs of the Forest Owner and determine whether or not they were reasonable. If considered reasonable, the verifier may insert the same classification as the Forest Owner for each tree included in the verifier's inventory. If, however, not considered reasonable, or not recorded by the Forest Owner, the verifier shall insert their own determination.

9.3.5.4 Verifying a Stratified Inventory

If the Project Operator's inventory is based on a stratified design, verification shall be based on the measurement error that can be assessed at the stratum level, using the sequential sampling tools developed by the Reserve. Individual plots within the strata selected for assessment shall be selected randomly. The verifier shall perform independent assessments on a minimum of three strata, unless the stratification design has less than three strata, in which case the assessment is conducted on two strata. Verifiers shall select the strata used to perform the assessment based on their own professional judgement of where the risks of measurement error are likely to have the biggest effect on the overall inventory estimate. This may be based on criteria related to:

- Carbon stocking levels
- Area of a particular stratum relative to other strata
- Strata that may be found in difficult to access areas due to remoteness or terrain which could lead to a reduced effort by forest inventory personnel

9.3.5.5 Verifying a Non-Stratified Inventory

If the project is not stratified for each applicable pool, the verifier shall select the plots randomly (if plot center can be located) or allocate the plots systematically or in clusters for efficiency. Plots may be measured and assessed one at a time or in reasonable batches that correspond to logistical realities of fieldwork.

9.3.5.6 Verification Within a Strata

Plots must be independently selected using a random or systematic design.

Table 9.6. Number of Passing Plots in Sequence, as a Function of Project Size

Test	Number of Strata Verified	Project Acres				
			<100 – 500	501 - 5,000	5,001 – 10,000	>10,000
Paired/Unpaired	3		3	4	5	6
	2		4	6	8	10
	1		8	10	12	12

The project passes sequential sampling when the minimum number of passing plots in sequence is achieved (as identified in Table 9.6), or the first passing plot after a minimum of 12 plots (paired) or 30 plots (unpaired) have been measured – whichever is achieved first. There are two possible statistical procedures that can be applied to the stratum-level verifications. A paired test can be applied when plot locations can be found and it is statistically appropriate to use a paired test (i.e., plot measurements can be replicated). An unpaired test can be applied when plots cannot be relocated. The range of acceptable error (***δ*, delta**) is fixed at ten percent for both tests.

Paired Plots

The statistical test is based on a comparison of the verifier's measurements of plots within a selected stratum, calculated as CO_2e compared to the Project Operator's measurements of plots, which may include any adjustments for growth.

Use α**=0.05** and β**=0.20** to control for error.

The null hypothesis (H_0) is that the verification and project plots are equal.

1) Perform verification sampling on at least the minimum number of passing plots required in a sequence from Section 9.3.5.4.

2) If $\boldsymbol{n \geq ((Z_\alpha + Z_\beta)^2 \times S_n^2) / D^2}$ then stop and evaluate. Otherwise take another sample.

   Where,
   n = Number of verification plots measured
   $Z_\alpha = \alpha\%\ N(0,1) = 1.645$
   $Z_\beta = \beta\%\ N(0,1) = 0.8416$
   S_n^2 = sample variance of the differences
   $D = \delta \times$ project average estimate

3) If stopped, then evaluate.

   If $\bar{X}_N \leq K$ then accept H_0,
   If $\bar{X}_N > K$ then reject H_0.

   Where,
   $\bar{X}_N$ = sample mean of the differences
   N = total number of plots measured
   $K = (Z_\alpha \times D) / (Z_\alpha + Z_\beta)$.

4) If H_0 was rejected, then additional samples may be taken as long as the verifier is of the opinion that there is a chance that H_0 may be accepted based on the variability and trend observed.

Unpaired Plots

The statistical test is based on comparing the average CO_2e estimates for each stratum from the verifier plots to the Project Operator plots.

Use $\boldsymbol{\alpha}$**=0.05** to control for error; the β is not specified because we are constructing a confidence interval not a test. The null hypothesis (H_0) is that the verification and stratum averages are equal. The following procedure is appropriate for the unpaired test.

1) Perform verification sampling on at least the minimum number of plots required in a sequence from Section 9.3.5.5. Calculate n as the sum of the number of plots from both the stratum (n_p) and the verification (n_v).

2) Calculate the following:

   $T_n = \bar{X}_P - \bar{X}_n$

   Where,
   T_n = the difference between the means
   $\bar{X}_P$ = stratum mean
   $\bar{X}_n$ = verification mean after sample n

3) If $\boldsymbol{n \geq (a^2/D^2) \times (S_n^2 + S_P^2)}$ then stop and evaluate. Otherwise take another sample.

   Where,
   a = the percentile from a standard normal distribution for one half of alpha; 1.96 for α=0.05
   $n = n_p + n_v$
   S_n^2 = sample variance of the verification plots
   S_P^2 = sample variance of the stratum plots
   $D = \delta \times$ stratum average estimate

4) If stopped, then evaluate. Construct a confidence interval $T_n \pm D$.
   If the confidence interval includes zero then accept H_0,
   Otherwise reject H_0.

5) If H_0 was rejected, then additional samples may be taken until as long as the verifier is of the opinion that there is a chance that H_0 may be accepted based on the variability and trend observed.

If the stopping rule in step (3) above cannot be attained within 100 plots, then apply a standard unpaired t-test comparison using $\boldsymbol{\alpha}$**=0.05** and $\boldsymbol{\beta}$**=0.80**.

9.3.5.7 Determining if the Stopping Rules Have Been Met

The verifier must determine if the stopping rules have been met for each stratum as soon as is convenient. The Reserve provides tools to assist verifiers with determining if the stopping rules have been met or not. The tools are Microsoft Excel based and are distinct for paired designs and for unpaired designs.

The verifier must enter their data into the appropriate spreadsheet based upon use of a paired or unpaired test. It is required that the verifier apply the random order selection in the sampling process. The verifier is free to measure the set of plots that were randomly selected in any order that provides the greatest efficiency while sampling in the field, but when the verifier inputs data into the spreadsheet, the verifier must follow the random selection order in order to properly conduct the analysis and maintain the integrity of sequential analysis. This may provide significant efficiencies when selected stands and/or plots are in close geographic proximity and it is hypothesized that the stopping rules will require the full number of plots.

The statistical test is based on a comparison of the verifier's measurements of plots, calculated as CO_2e per acre compared to the Forest Owner's measurements of plots, which may include any adjustments for growth. The inventory verification is complete based on the stopping rules detailed in Section 9.3.5.1. Passing of the plot height and/or diameter stopping rules is not required to pass the inventory verification; however, as discussed above, verifiers may separately compare their measurements for height and diameter with the Forest Owner's measurements in the sequential sampling tool. When those inputs have met the sequential sampling stopping requirements, verifiers may use the height and diameter data provided for each tree from the Forest Owner's database for any additional data inputs needed for the CO_2e/acre comparison.

Finally, in addition to evaluating and verifying adherence to the Project Operator's inventory methodology, the verification body must verify the items in Table 9.7. If the project is using the

Standardized Inventory Methodology and/or CARIT, the verification team need not verify these tools beyond proper implementation.

Table 9.7. Additional Verification Items for Inventory Methodology and Implementation

Verification Items		Apply Professional Judgment?
1. Inventory Update Processes	a. Project Operator's inventory document describes methodology for updating inventory data resulting from growth, harvest, and disturbances. Methodology adheres to acceptable forestry practices* b. Harvest/Disturbance updates in inventory management system are implemented per the specified methodology and are representative of the harvest or disturbance. c. Growth is accounted for using an approved growth model or using a stand table projection, as described in Appendix B.	Yes
2. Biomass Equations and Calculations	a. The carbon tonnes per acre for a representative sample plot, computed using the Project Operator's calculation tools, replicate output computed by the verification body.** b. All conversions and expansions are accurate.	Yes

*A forest biometrician employed by the state in which the project is located, or a consulting forest biometrician may be consulted in the event of a dispute between the verification body and Project Operator. The written opinion of the forest biometrician, submitted to the Reserve as part of the verification report, shall be considered the authoritative word.
**The verification body must provide an (idealized) 'verification plot' consisting of all tree species in Project Area with varying heights and diameters existing within the Project Area. The plot need not correspond to an actual plot within the Project Area.

9.3.6 Baseline Estimation

Forest Project baselines include assumptions about forest growth and harvest, as influenced by legal and financial constraints, and assumptions regarding the extent of harvest operations under Business As Usual conditions. These are based on either modeled assumption, or default assumptions, as described in Section 6.

Verification bodies are required to verify the baseline estimate for the project at the initial site visit verification for Improved Forest Management Projects and Avoided Conversion Projects.

All reports that reference carbon stocks must be submitted by the Project Operator with the oversight of a Professional Forester. If the project is located in a jurisdiction without a Professional Forester law or regulation, then Certified Forester credentials managed by the Society of American Foresters (see http://www.certifiedforester.org) are required so that professional standards and project quality are maintained.

Table 9.8. Modeled Baseline Verification Items
(Improved Forest Management projects using the modeling approach, and Avoided Conversion Projects)

Verification Items		Section of FPP	Apply Professional Judgment?
1. Document	A modeling document exists that contains all the verification items in this table.	9	No

Verification Items		Section of FPP	Apply Professional Judgment?
2. Qualitative Characterization (Avoided Conversion Projects Only)	A sufficiently detailed qualitative characterization has been included in the modeling document that documents the general assumptions of the project's baseline. The qualitative assessment addresses the vegetative conditions and activities that would have occurred.	6.2	Yes
3. Model Choice and Calibration	a. The model used is an approved model. b. The Project Operator has provided a rationale for any model calibrations or a sufficient explanation of why calibrations were not incorporated. c. The Project Operator has provided a description of the site indexes used for each species and a sufficient explanation of the source of the site index values used.	Appendix B	Yes
4. Legal Constraints	A list of legal constraints is provided that includes an accurate description of the type and effect of each constraint on the ability to harvest trees and the area constrained.	3.3.1, 6.1.2, 6.2.1	Yes
5. Financial Constraints	a. A sufficient qualitative description is provided indicating that the harvesting activity modeled in the baseline is a financially viable activity. b. For Improved Forest Management projects, Project Operator has provided either a financial analysis of the anticipated growth and harvesting regime that captures all relevant costs and returns, taking into consideration all legal, physical, and biological constraints.	3.3.2, 6.1.3, 6.2.1	Yes
6. Silviculture Guidelines	The silviculture guidelines incorporated in the model demonstrate all legal constraints are applied in the model. The silviculture guidelines must include: i. A description of the trees retained by species group ii. The level of retention iii. Harvest frequency iv. Regeneration assumptions	Appendix B	No
7. Modeling Guidelines	a. Improved Forest Management: Modeling is conducted per Section 6.1. b. Avoided Conversion: Modeling is conducted per Section 6.2.	6.1, 6.2	No
8. Modeling Outputs	a. The Project Operator has provided reports that display periodic harvest, inventory, and growth estimates for the entire Project Area presented as total carbon tonnes and carbon tonnes per acre. b. Estimates are within the range of expected growth patterns for the Project Area.	9, Appendix B	Yes

Table 9.9. Default Baseline Verification Items
(Improved Forest Management projects using the conservative default approach, and Improved Forest Management projects on public lands)

Verification Items		Section of FPP	Apply Professional Judgment?
1. Document	The PDD explains the baseline quantification steps undertaken.	9	No
2. Default Approach	a. The project is eligible to use the conservative default approach and has followed the steps to establish a default baseline in Section 6.1.1 b. The project has correctly run the COLE report as described in Section 6.1.3	6.1.1, 6.1.3, Appendix B	No
4. Legal Constraints	The project has correctly accounted for baseline legal constraints	6.1.1, 6.1.3	Yes
5. Incorporating Other Carbon Stocks	The final baseline has been adjusted to account for all required SSRs	6.1.1, 6.1.3, Appendix B	No

9.3.7 Verifying Estimates of Carbon in Harvested Wood Products

Verification bodies are required to verify the estimates of carbon that are likely to remain stored in wood products over a 100-year period, as submitted in the Forest Project Design Document (for baseline estimates) and annual monitoring reports (for actual wood product production). Accounting for wood product carbon must be applied only to actual or baseline volumes of wood harvested from within the Project Area. Trees harvested outside of the Project Area are not part of the Forest Project and must be excluded from any calculations.

Table 9.10. Carbon in Harvested Wood Products Verification Items

Verification Items		Section of FPP	Apply Professional Judgment?
1. Carbon in Harvested Wood Delivered to Mills	a. Amount of wood harvested that will be delivered to mills has been estimated and reported. b. The appropriate wood density factor has been applied and/or water weight subtracted to result in pounds of biomass with zero moisture content. c. Total dry weights for all harvested wood have been calculated. d. Total carbon weight has been computed. e. The total has been converted to metric tons of carbon.	Appendix B	No
2. Account for Mill Efficiencies	The correct mill efficiency factors have been used to calculate total carbon transferred into wood products.	Appendix B	No

3. Wood Product Classification	The percentages of harvest by wood product class has been determined correctly with verified reports from the mill(s) where the Project Area's logs are sold; or by looking up default wood product classes for the project's Assessment Area(s); or if not available from either of these sources, by classifying all wood products as "miscellaneous."	Appendix B	No
4. Calculation of In-Use and Landfill Carbon Storage	a. The average amount of carbon stored in in-use wood products over 100 years has been calculated correctly using the worksheets referenced in Appendix B. b. The average amount of carbon stored in landfilled wood products over 100 years has been calculated correctly using the worksheets referenced in Appendix B.	Appendix B	No
5. Total Average Carbon Storage in Wood Products Over 100 Years	Total average carbon storage in wood products over 100 years for a given harvest volume has been calculated and reported.	Appendix B	No

9.3.8 Verifying Calculations of Reversal Risk Ratings and Contributions to the Buffer Pool

At each site visit verification, Project Operators must derive a reversal risk rating for their Forest Project using the worksheets in Appendix A. The worksheets are designed to identify and quantify the specific types of risks that may lead to a reversal, based on project-specific factors.

Table 9.11. Reversal Risk Rating Verification Items

Verification Items		Section of FPP	Apply Professional Judgment?
1. Financial Risk	Use of a Qualified Conservation Easement or Qualified Deed Restriction, occurrence on public lands, or use of a PIA alone.	Appendix A.1	No
2. Management Risk	a. Management Risk I – Illegal removals of forest biomass. b. Management Risk II – Conversion of Project Area to alternative land uses. c. Management Risk III – Over-harvesting.	Appendix A.2	No
3. Social Risk	Social Risk.	Appendix A.3	No
4. Natural Disturbance Risk	a. Natural Disturbance Risk I – Wildfire, Disease or insect outbreak. c. Natural Disturbance Risk II – Other episodic catastrophic events.	Appendix A.4	Yes

Verification Items		Section of FPP	Apply Professional Judgment?
5. Completing the Risk Rating Analysis	Reversal risk rating calculated correctly using the formula in Appendix A.5.	Appendix A.5	No

9.4 Completing the Verification Process

After completing the core project verification activities for a Forest Project, the verification body must do the following to complete the verification process:

1. Complete a detailed List of Findings containing both immaterial and material findings (if any) and deliver it to the Project Operator (private document).
2. Exchange correspondence as necessary to resolve issues detailed in the List of Findings, until all material misstatements and nonconformances have been addressed.
3. If a reasonable level of assurance opinion is successfully obtained, complete a Verification Report to be delivered to the Project Operator (public document).
4. Complete the Verification Statement form, detailing the vintage and the number of GHG reductions and removals verified and deliver it to the Project Operator (public document).
5. Verify that the number of GHG reductions and removals, as well as the reversal risk rating, specified in the Verification Report and Statement match the number entered into the Reserve software.
6. Conduct an exit meeting with the Project Operator to discuss the Verification Report, List of Findings, and Verification Statement.
7. Upload electronic copies of the Verification Report, List of Findings, Verification Statement, and Verification Activity Log into the Reserve.

The recommended content for the Verification Report, List of Findings, and Verification Statement can be found in the Reserve's Verification Program Manual.[32] The Verification Program Manual also provides further guidance on quality assurance, negative verification statements, use of an optional Project Verification Activity Log, goals for exit meetings, dispute resolution, and record keeping.

[32] Available at http://www.climateactionreserve.org/how/program/program-manual/.

10 Glossary of Terms

Aboveground Live Biomass	Live trees including the stem, branches, and leaves or needles, brush, and other woody live plants aboveground.
Activity-Based Funding	The budget line items that are dedicated to agency accomplishments in vegetation management, including pre-commercial thinning, commercial thinning, harvest, hazard tree removal, hazardous fuel reductions, and other management activities designed to achieve forest sustainability health objectives.
Additionality	A criterion for Forest Project eligibility. A Forest Project is “additional” if it would not have been implemented without incentives provided by the carbon offset market, including the incentives created through the Climate Action Reserve program. Under this protocol, Forest Projects meet the additionality criterion by demonstrating that they pass a legal requirement test and a performance test, as described in Section 3.1, and by achieving GHG reductions and removals quantified against an approved baseline, determined according to the requirements in Section 6.
Affiliate	An “affiliate” is defined as any person or entity that, directly or indirectly, through one or more intermediaries, controls or is controlled by or is under common control with the Forest Owner(s) participating in a project, including any general or limited partnership in which the Forest Owner is a partner and any limited liability company in which the Forest Owner is a member. For the purposes of this definition, "control" means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of a person, whether through the ownership of voting securities, by contract or otherwise, and “person” means an individual or a general partnership, limited partnership, corporation, professional corporation, limited liability company, limited liability partnership, joint venture, trust, business trust, cooperative or association or any other legally-recognized entity.
Allometric Equation	An equation that utilizes the genotypical relationship among tree components to estimate characteristics of one tree component from another. Allometric equations allow the belowground root volume to be estimated using the aboveground bole volume.
Assessment Area	A distinct forest community within geographically identified ecoregions defined by the Reserve that consists of common regulatory and political boundaries that affect forest management. The size of the Assessment Areas is determined by efforts to achieve optimal statistical confidence across multiple scales using U.S. Forest Service Forest Inventory and Analysis Program (FIA) plots

	for biomass. Maps of the Assessment Areas and the associated data may be found on the Reserve's website.
Avoidable Reversal	An avoidable reversal is any reversal that is due to the Project Operator's negligence, gross negligence, or willful intent, including harvesting, development, and harm to the Project Area
Avoided Conversion Project	A type of Forest Project consisting of specific actions that prevent the conversion of forestland to a non-forestland use by dedicating the land to continuous forest cover through conservation easement recordation or transfer to public ownership.
Baseline	The level of GHG emissions, removals, and/or carbon stocks at sources, sinks or reservoirs affected by a Forest Project that would have occurred under a Business As Usual scenario. For the purposes of this protocol, a project's baseline must be estimated following standard procedures in Section 6.
Best Management Practices	Management practices determined by a state or designated planning agency to be the most effective and practicable means (including technological, economic, and institutional considerations) of controlling point and nonpoint source pollutants at levels compatible with environmental quality goals.[33]
Biological Emissions	For the purposes of the Forest Project Protocol, biological emissions are GHG emissions that are released directly from forest biomass, both live and dead, including forest soils. For Forest Projects, biological emissions are deemed to occur when the reported tonnage of onsite carbon stocks, relative to baseline levels, declines from one year to the next.
Biomass	The total mass of living organisms in a given area or volume; recently dead plant material is often included as dead biomass.[34]
Bole	A trunk or main stem of a tree.
Broadcast Fertilization	A fertilizer application technique where fertilizer is spread across the soil surface by tractor or aerial application.
Buffer Pool	The buffer pool is a holding account for Forest Project CRTs administered by the Reserve. It is used as a general insurance mechanism against unavoidable reversals for all Forest Projects registered with the Reserve. If a Forest Project experiences an unavoidable reversal of GHG reductions and removals (as defined in Section 7.3), the Reserve will retire a number of CRTs from the buffer pool

[33] Helms. (1998).
[34] Metz, Davidson, Swart, & Pan. (2001).

	equal to the total amount of carbon that was reversed (measured in metric tons of CO_2-equivalent).
Business As Usual	The activities, and associated GHG reductions and removals that would have occurred in the Project Area in the absence of incentives provided by a carbon offset market. Methodologies for determining these activities – and/or for approximating carbon stock levels that would have resulted from these activities – are provided in Section 6 of this protocol for each type of Forest Project.
Carbon Pool	A reservoir that has the ability to accumulate and store carbon or release carbon. In the case of forests, a carbon pool is the forest biomass, which can be subdivided into smaller pools. These pools may include aboveground or belowground biomass or harvested wood products, among others.
Climate Reserve Tonne (CRT)	The unit of offset credits used by the Climate Action Reserve. Each Climate Reserve Tonne represents one metric ton (2204.6 lbs) of CO_2 reduced or removed from the atmosphere.
Commercial Rotational Harvesting	For the purpose of this protocol, commercial rotational harvesting refers to harvesting activities undertaken by a Forest Owner with the intent to create a new cohort of regenerated trees, where the harvested trees are delivered to a mill.
Common Practice	The average stocks of the aboveground standing live and dead carbon pools from within the Forest Project's Assessment Area, derived from FIA plots on all private lands within the defined Assessment Area.
Computational Reversal	A computational reversal is any reversal that is due to required protocol calculations (including the confidence deduction and secondary effects).
Even-Aged Management	Management where the trees in individual forest stands have only small differences in their ages (a single age class). By convention, the spread of ages does not differ by more than 20 percent of the intended rotation.
FIA	USDA Forest Service Forest Inventory and Analysis program. FIA is managed by the Research and Development organization within the USDA Forest Service in cooperation with State and Private Forestry and National Forest Systems. FIA has been in operation under various names (Forest Survey, Forest Inventory and Analysis) for 70 years.
Forest Carbon	The carbon found in forestland resulting from photosynthesis in trees and associated vegetation, historically and in the present. Forest Carbon is found in soils, litter and duff, plants and trees, both dead and alive.

Forest Management	The commercial or noncommercial growing and harvesting of forests.
Forest Owner	A corporation or other legally constituted entity, city, county, state agency, individual(s), or a combination thereof that has legal control (described in Section 2.2) of any amount of forest carbon within the Project Area
Forest Project	A planned set of activities designed to increase removals of CO_2 from the atmosphere, or reduce or prevent emissions of CO_2 to the atmosphere, through increasing and/or conserving forest carbon stocks.
Forest Project Design Document	A standard document for reporting required information about a Forest Project. The Forest Project Design Document must be submitted for review by a verification body and approved by the Reserve before the Forest Project can be registered with the Reserve.
Forestland	Land that supports, or can support, at least ten percent tree canopy cover and that allows for management of one or more forest resources, including timber, fish and wildlife, biodiversity, water quality, recreation, aesthetics, and other public benefits.
GHG Assessment Boundary	The GHG Assessment Boundary defines all the GHG sources, sinks, and reservoirs that must be accounted for in quantifying a Forest Project's GHG reductions and removals (Section 6). The GHG Assessment Boundary encompasses all the GHG sources, sinks, and reservoirs that may be significantly affected by Forest Project activities, including forest carbon stocks, sources of biological CO_2 emissions, and mobile combustion GHG emissions.
GHG Reductions and Removals	See definitions for Reduction and Removal.
Greenhouse Gas (GHG)	Gas that contributes to global warming and climate change. For the purposes of this Forest Project Protocol, GHGs are the six gases identified in the Kyoto Protocol: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).
Improved Forest Management Project	A type of Forest Project involving management activities that increase carbon stocks on forested land relative to baseline levels of carbon stocks.
Listed	A Forest Project is considered "listed" when the Project Operator has created an account with the Reserve, submitted the required Project Submittal form and other required documents, paid the project submission fee, and the Reserve has approved and accepted the project for listing.

Litter	Any piece(s) of dead woody material from a tree, e.g., dead boles, limbs, and large root masses, on the ground in forest stands that is smaller than material identified as lying dead wood.
Lying Dead Wood	Any piece(s) of dead woody material from a tree, e.g., dead boles, limbs, and large root masses, on the ground in forest stands. Lying dead wood is all dead tree material with a minimum average diameter of five inches and a minimum length of eight feet. Anything not meeting the measurement criteria for lying dead wood will be considered litter. Stumps are not considered lying dead wood.
Metric Ton or "tonne" (t)	A common international measurement for the quantity of GHG emissions, equivalent to about 2204.6 pounds or 1.1 short tons.
Native Forest	For the purposes of this protocol native forests shall be defined as those occurring naturally in an area, as neither a direct nor indirect consequence of human activity post-dating European settlement.
Natural Forest Management	Forest management practices that promote and maintain native forests comprised of multiple ages and mixed native species at multiple landscape scales. The application of this definition, its principles, detailed definition, and implementation are discussed further in Section 3.9.2.
Non-Forest Cover	Land with a tree canopy cover of less than ten percent.
Non-Forest Land Use	An area managed for residential, commercial, or agricultural uses other than for the production of timber and other forest products, or for the maintenance of woody vegetation for such indirect benefits as protection of catchment areas, wildlife habitat, or recreation.
Non-Harvest Disturbance	Reduction in forest cover that is not a direct result of harvest, such as wildfire and insect disturbances.
Onsite Carbon Stocks	Carbon stocks in living biomass, dead biomass, and soils within the Project Area.
Permanence	The requirement that GHGs must be permanently reduced or removed from the atmosphere to be credited as carbon offsets. For Forest Projects, this requirement is met by ensuring that the carbon associated with credited GHG reductions and removals remains stored for at least 100 years.
Primary Effects	The Forest Project's intended changes in carbon stocks, GHG emissions or removals.
Professional Forester	A professional engaged in the science and profession of forestry. A professional forester is credentialed in jurisdictions that have professional forester licensing laws and regulations. Where a jurisdiction does not have a

	professional forester law or regulation then a professional forester is defined as having the Certified Forester credentials managed by the Society of American Foresters (see www.certifiedforester.org).
Project Area	The area inscribed by the geographic boundaries of a Forest Project, as defined following the requirements in Section 4 of this protocol. Also, the property associated with this area.
Project Life	Refers to the duration of a Forest Project and its associated monitoring and verification activities, as defined in Section 3.5.
Public Lands	Lands that are owned by a public governmental body such as a municipality, county, state or country.
Project Operator	A Forest Owner responsible for undertaking a Forest Project and registering it with the Reserve. The Forest Owner who executes the Project Implementation Agreement, as described in Section 2.2.
Qualified Conservation Easement	A qualified conservation easement must explicitly refer to the terms and conditions of the Project Implementation Agreement, apply to current and all subsequent Project Operators for the full duration of the Forest Project's minimum time commitment, as defined in Section 3.5 of this protocol.
Qualified Deed Restriction	A qualified deed restriction shall ensure that the Project Implementation Agreement runs with the land and applies to all current and subsequent Project Operators for the full duration of the Forest Project's minimum time commitment, as defined in Section 3.4 of this protocol, to be determined in the Reserve's reasonable discretion. A deed restriction is not "qualified" if it merely consists of a recording of the Project Implementation Agreement or a notice of the Project Implementation Agreement, as such a recording is already required by the Project Implementation Agreement.
Reduction	The avoidance or prevention of an emission of CO_2 (or other GHG). Reductions are calculated as gains in carbon stocks over time relative to a Forest Project's baseline (also see Removal).
Registered	A Forest Project becomes registered with the Reserve when it has been verified by a Reserve-approved and ISO-accredited verification body, all required documentation (see Section 8) has been submitted by the Project Operator to the Reserve for final approval, and the Reserve approves the project.
Removal	Sequestration ("removal") of CO_2 from the atmosphere caused by a Forest Project. Removals are calculated as gains in carbon stocks over time relative to a Forest Project's baseline (also see Reduction).

Reporting Period	The period of time over which a Project Operator quantifies and reports GHG reductions and removals.
Reservoir	Physical unit or component of the biosphere, geosphere or hydrosphere with the capacity to store or accumulate carbon removed from the atmosphere by a sink, or captured from a source.
Retire	To retire a CRT means to transfer it to a retirement account in the Climate Action Reserve's software system. Retirement accounts are permanent and locked, so that a retired CRT cannot be transferred or retired again.
Reversal	A reversal is a decrease in the stored carbon stocks associated with quantified GHG reductions and removals that occurs before the end of the Project Life. Under this protocol, a reversal is deemed to have occurred if there is a decrease in the difference between project and baseline onsite carbon stocks from one year to the next, regardless of the cause of this decrease (i.e., if the result of (Δ AC_{onsite} - Δ BC_{onsite}) in Equation 6.1 is negative).
Secondary Effects	Unintended changes in carbon stocks, GHG emissions, or GHG removals caused by the Forest Project.
Sequestration	The process of increasing the carbon (or other GHGs) stored in a reservoir. Biological approaches to sequestration include direct removal of CO_2 from the atmosphere through land-use changes[35] and changes in forest management.
Significant Disturbance	Any natural impact that results in a loss of least 20 percent of the aboveground live biomass that is not the result of intentional or grossly negligent acts of the Project Operator.
Sink	Physical unit or process that removes a GHG from the atmosphere.
Source	Physical unit or process that releases a GHG into the atmosphere.
Stand	An individual unit or polygon that is relatively homogeneous in terms of the carbon stocking within its borders. For live and dead trees, the determination of stand boundaries is usually based on forest vegetation attributes, such as species, size (age), and density characteristics. For soils, the determination of soil stand boundaries is made on similar soil orders.
Standing Dead Carbon Stocks	The carbon in standing dead trees. Standing dead trees include the stem, branches, roots, or section thereof, regardless of species, with minimum diameter (breast

[35] Metz, Davidson, Swart, & Pan. (2001).

	height) of five inches and a minimum height of 15 feet. Stumps are not considered standing dead stocks.
Standing Live Carbon Stocks	The carbon in the live tree pool. Live trees include the stem, branches, roots, and leaves or needles of all aboveground live biomass, regardless of species, with a minimum diameter (breast height) of five inches and a minimum height of 15 feet (inventory methodology must include all trees five inches and greater)
Stocks (or Carbon Stocks)	The quantity of carbon contained in identified carbon pools.
Strata	Plural of stratum. The set of different groupings for a specific attribute, such as vegetation or soil.
Stratum	A group of stands that contain a similar attribute, such as vegetation or soils attributes.
Submitted	The Reserve considers a Forest Project to be “submitted” when all of the appropriate forms have been uploaded and submitted to the Reserve’s software system, and the Project Operator has paid a project submission fee.
Tree	A woody perennial plant, typically large and with a well-defined stem or stems carrying a more or less definite crown with the capacity to attain a minimum diameter at breast height of five inches and a minimum height of 15 feet with no branches within three feet from the ground at maturity.[36]
Unavoidable Reversal	An unavoidable reversal is any reversal not due to the Project Operator’s negligence, gross negligence or willful intent, including wildfires or disease that are not the result of the Project Operator's negligence, gross negligence or willful intent.
Uneven-Aged Management	Management that leads to forest stand conditions where the trees differ markedly in their ages, with trees of three or more distinct age classes either mixed or in small groups.
Verification	The process of reviewing and assessing all of a Forest Project’s reported data and information by an ISO-accredited and Reserve-approved verification body, to confirm that the Project Operator has adhered to the requirements of this protocol.
Verification Period	The period of time over which GHG reductions/removals are verified. A verification period may cover multiple reporting periods. The end date of any verification period must correspond to the end date of a reporting period.

[36] Helms. (1998).

Appendix A Determination of a Forest Project's Reversal Risk Rating

Project Operators must derive a reversal risk rating for their Forest Project using the worksheets in this section. The worksheets are designed to identify and quantify the specific types of risks that may lead to a reversal, based on project-specific factors.

This risk assessment must be updated every time the project undergoes a verification site visit. Therefore, a project's risk profile and its assessment are dynamic. Furthermore, estimated risk values and associated mitigation measures will be updated periodically by the Reserve as improvements in quantifying risks or changes in risks are determined. Any adjustments to the risk ratings will affect only current and future year contributions to the Buffer Pool. The Reserve may, from time to time, transfer Climate Reserve Tonnes (CRTs) from the Buffer Pool to the Project Operator's account if the Reserve determines that previously assessed risk ratings were unnecessarily high. Alternatively, the Reserve may waive a Project Operator's future contributions to the Buffer Pool until excess contributions from previous years are recouped. If a Forest Project's risk rating increases, the Project Operator must contribute additional CRTs to the Buffer Pool to ensure that all CRTs (including those issued in prior years) are properly insured.

Risks that may lead to reversals are classified into the categories identified in Table A.1.

Table A.1. Forest Project Risk Types

Risk Category	Risk Type	Description	How Risk is Managed in this Protocol
Financial	Financial Failure Leading to Bankruptcy	Financial failure can lead to bankruptcy and/or alternative management decisions to generate income that result in reversals through over-harvesting or conversion	Default Risk
	Project Implementation Agreement (PIA) Subordination	Subordinating the PIA to mortgages or deeds on or affecting the Project	Default Risk
Management	Illegal Harvesting	Loss of project stocks due to timber theft	Default by Area
	Conversion to Non-Forest Uses	Alternative land uses are exercised at project carbon expense	Default Risk
	Over-Harvesting	Exercising timber value at expense of project carbon	Default Risk
Social	Social Risks	Changing government policies, regulations, and general economic conditions	Default Risk

Risk Category	Risk Type	Description	How Risk is Managed in this Protocol
Natural Disturbance	Wildfire	Loss of project carbon through wildfire	Project-specific Risk
	Disease/Insects	Loss of project carbon through disease and/or insects	
	Other Episodic Catastrophic Events	Loss of project carbon from wind, snow and ice, or flooding events	

A.1 Financial Risk

Financial failure of an organization resulting in bankruptcy can lead to dissolution of agreements and forest management activities to recover losses that result in reversals. Projects that employ a Qualified Conservation Easement or Qualified Deed Restriction, or that occur on public lands, are at a lower risk than projects with a PIA alone.

Table A.2. Financial Failure Leading to Bankruptcy

Applies to all projects		
Identification of Risk	**Contribution to Reversal Risk Rating**	
	PIA only	PIA combined with Qualified Conservation Easement or Qualified Deed Restriction or on public or tribal[37] lands
Default Financial Risk	5%	1%

Table A.3. PIA Subordination

Applies to all projects		
Identification of Risk	**Contribution to Reversal Risk Rating**	
	PIA with "Subordination Clause Type II"	PIA with "Subordination Clause Type I"
Default Financial Risk	10%	2%

A.2 Management Risk

Management failure is the risk of management activities that directly or indirectly could lead to a reversal. Projects that employ a conservation easement or deed restriction, or that occur on public lands, are exempt from this risk category.

Management Risk I – Illegal Removals of Forest Biomass

Illegal logging occurs when biomass is removed either by trespass or outside of a planned set of management activities that are controlled by regulation. Illegal logging is exacerbated by lack of controls and enforcement activities.

[37] For the purposes of this protocol, "tribal lands" includes tribal land, land owned by Alaska Native Corporations, and Hawaiian home land.

Table A.4. Risk of Illegal Removals of Forest Biomass

Applies to all projects	
Identification of Risk	**Contribution to Reversal Risk Rating**
United States Default Harvesting Risk	0%

Management Risk II – Conversion of Project Area to Alternative Land Uses

High values for development of housing and/or agriculture may compete with timber and carbon values and lead to a change in land use that affects carbon stocks. The risk of conversion of any Project Area to other non-forest uses is related to the probability of alternative uses, which are affected by many variables, including population growth, topography, proximity to provisions and metropolitan areas, availability of water and power, and quality of access to the Project Area.

Table A.5. Risk of Conversion to Alternative Land Use

Applies to all projects	
Identification of Risk	**Contribution to Reversal Risk Rating**
With Qualified Conservation Easement or Qualified Deed Restriction that explicitly encumbers all development rights or on public or tribal lands	0%
Without Qualified Conservation Easement or Qualified Deed Restriction	2%

Management Risk III – Over-Harvesting

Favorable timber values, among other reasons, may motivate some project managers to realize timber values at the expense of managing carbon stocks for which CRTs have been credited. Additionally, reversals can occur as the result of harvest associated with fuels treatments.

Table A.6. Risk of Over-Harvesting

Applies to all projects	
Identification of Risk	**Contribution to Reversal Risk Rating**
With Qualified Conservation Easement or Qualified Deed Restriction that explicitly encumbers timber harvesting associated with project stocks or on public or tribal lands	0%
Without Qualified Conservation Easement or Qualified Deed Restriction	2%

A.3 Social Risk

Social risks exist due to changing government policies, regulations, and general economic conditions. The risks of social or political actions leading to reversals are low but could be significant.

Table A.7. Social Risk Identification

Applies to all projects	
Identification of Risk	**Contribution to Reversal Risk Rating**
United States Default Social Risk	2%

A.4 Natural Disturbance Risk

Natural disturbances can pose a significant risk to the permanency GHG reductions and removals. Natural disturbance risks are only partially controllable by management activities. Management activities that improve resiliency to wildfire, insects, and disease can reduce these risks. Management activities that shift harvesting practices from live sequestering trees to trees that have succumbed to natural disturbances reduce or negate the reversal depending on the size and location of the disturbance.

Natural Disturbance Risk I – Wildfire, Disease, or Insect Outbreak

Wildfire, disease, or insect outbreak have the potential to cause significant reversals, especially in certain carbon pools. These risks can be reduced by certain techniques including reducing surface fuel loads, removing ladder fuels, adding fuel breaks, and reducing stand density. However, these techniques cannot reduce emission risk to zero because all landowners will not undertake fuel treatments, nor can they prevent wildfire from occurring. Strategies implemented to reduce fuel loads can also improve resiliency to disease or insect outbreak.

Table A.8. Natural Disturbance Risk I – Wildfire, Disease, or Insect Outbreak

Applies to all projects	
Identification of Risk	**Contribution to Reversal Risk Rating**
Refer to the Assessment Area Data File for the project's Natural Disturbance risk rating	*X*%
If vegetation management treatments have been implemented for the Project Area, reduce the value above by the appropriate percent as indicated below.	*X*% **x** *Y*%

Vegetation treatments must be available in a report and aligned with aa comprehensive vegetation management plan that identifies specific temporal and spatial actions to enhance forest resilience across the Project Area. The vegetation management plan must be approved by a state agency or, if approval by a state agency is not possible, developed under the oversight of a Professional Forester and reviewed by the Reserve. Verifiers must confirm the status of implementation of the management plan.

Table A.9. Vegetation Management Treatments (Y)

Description of Status of Vegetation Management	Y
Approved vegetation management plan exists, and the plan is being implemented across at least 80% of the intended implementation area detailed in the plan	20%
Approved vegetation management plan exists, and the plan is being implemented across at least 50% of the intended implementation area detailed in the plan	70%
Approved vegetation management plan does not exist, or the plan has not yet been implemented across at least 50% of the intended implementation area detailed in the plan	100%

Natural Disturbance Risk II – Other Episodic Catastrophic Events

A major wind-throw event (hurricane, tornado, high wind event) has the potential to cause a reversal, especially in certain carbon pools.

Table A.10. Natural Disturbance Risk III – Other Episodic Catastrophic Events

Applies to all projects	
Identification of Risk	**Contribution to Reversal Risk Rating**
Default Risk Contribution from Other Catastrophic Events	3%

A.5 Summarizing the Risk Analysis and Contribution to Buffer Pool

Use the table below to summarize the Forest Project's reversal risk rating. As indicated above, projects that employ a conservation easement or deed restriction, or that occur on public or tribal lands, are exempt from certain risk categories. Such Qualified Conservation Easements and Qualified Deed Restrictions must clearly identify the goals and objectives of the Forest Project according to the terms of this protocol.

Table A.11. Project Contribution to the Buffer Pool Based on Risk

Risk Category	Contribution from Risk Descriptions Above		
	Source	**PIA Only**	**PIA and Qualified Conservation Easement and/or a Qualified Deed Restriction and/or Public or Tribal Ownership**
Financial Failure[38]	Default Risk -Remedies for reversals addressed in PIA	15% or 7%	11% or 3%
Illegal Forest Biomass Removal	Default Risk	0%	0%
Conversion	Default Risk - Remedies for reversals addressed in PIA	2%	0%
Over-Harvesting	Default Risk - Remedies for reversals addressed in PIA	2%	0%
Social	Default Risk	2%	2%
Wildfire, Disease, or Insect Outbreak	Calculated Risk from Table A.8	*X*% or (*X*% x *Y*%)	*X*% or (*X*% x *Y*%)
Other Catastrophic Events	Default Risk	3%	3%

[38] When determining the appropriate risk rating for the Financial Failure Risk Category, use the higher value if intending to use PIA Subordination Clause Type I and the lower value if intending to use PIA Subordination Clause Type II. Please refer to the Project Implementation Agreement on the Reserve website for further information.

Completing the Risk Rating Analysis

The project's reversal risk rating is calculated as follows:

$$
\begin{aligned}
100\% - \big[&(1 - FinancialFailure\%) \times (1 - IllegalForestBiomassRemoval\%) \\
&\times (1 - Conversion\%) \times (1 - OverHarvesting\%) \times (1 - SocialRisk\%) \\
&\times (1 - Wildfire\ /\ Disease/\ InsectOutbreak\%) \\
&\times (1 - OtherCatastrophicEvents\%)\big]
\end{aligned}
$$

Appendix B Quantification Guidance for Use with Forest Carbon Projects

This appendix provides guidance for quantifying a forest project's onsite carbon stocks and carbon in harvested wood products, both for purposes of estimating a project's baseline as well as providing ongoing estimates of onsite project carbon stocks throughout the project life.

B.1 Reporting Requirements for Forest Carbon Pools

Onsite forest carbon pools are broadly grouped into living biomass, dead biomass, and soils. Living biomass includes biomass in live trees and shrubs and herbaceous understory (live non-tree biomass). Onsite dead biomass includes biomass in dead trees, lying dead wood, and litter. Offsite dead biomass includes harvested wood products.

For standardized reporting, all estimates of forest carbon stocks must be provided in terms of metric tons (tonnes) of CO_2-equivalent (CO_2e) on a project and a per acre basis. Unless otherwise required in the referenced biomass equations, the following conversion formulae shall be used:

<table>
<tr><th>Base Unit</th><th>Conversion</th><th></th><th>Final Unit</th></tr>
<tr><td>Biomass</td><td>0.5 x biomass</td><td rowspan="4">=</td><td>Carbon</td></tr>
<tr><td>Carbon</td><td>3.667 x carbon</td><td>CO_2e</td></tr>
<tr><td>Pounds</td><td>lbs / 2204.6</td><td>Metric tons or tonnes (t)</td></tr>
<tr><td>Acres</td><td>0.404686 x acres</td><td>Hectares</td></tr>
</table>

Reporting requirements vary for each of the carbon pools. The estimates for the pools that are derived from sampling must meet the quality standards described later in this document. Table B.1 displays the reporting requirements for each of the carbon pools.

Table B.1. Reserve Requirements for Carbon Pool Categories and Determination of Value for Pool

<table>
<tr><th>Category</th><th>Carbon Pool</th><th>Improved Forest Management</th><th>Avoided Conversion</th></tr>
<tr><td rowspan="2">Living Biomass</td><td>Live Trees</td><td colspan="2">Required for project reporting</td></tr>
<tr><td>Shrubs and Herbaceous Understory</td><td colspan="2">Not allowed for project reporting</td></tr>
<tr><td rowspan="5">Onsite Dead Biomass</td><td rowspan="2">Standing Dead Trees</td><td colspan="2">Required for adherence to Natural Forest Management criteria</td></tr>
<tr><td colspan="2">Required for project reporting</td></tr>
<tr><td rowspan="2">Lying Dead Wood</td><td colspan="2">Required for adherence to Natural Forest Management criteria</td></tr>
<tr><td colspan="2">Not allowed for project reporting</td></tr>
<tr><td>Litter</td><td colspan="2">Not allowed for project reporting</td></tr>
<tr><td>Soil</td><td>Soil</td><td colspan="2">Required for emissions reporting associated with management activities, if applicable</td></tr>
</table>

		Not allowed for reporting of project benefits	Optional for reporting of project benefits in Avoided Conversion projects only
Offsite Dead Biomass	Harvested Wood Products	Required for project reporting	

B.2 Guidance for Estimating Carbon in Forest Carbon Pools

This section describes requirements for the development of values for the forest carbon pools described in Table B.1. Project Operators must include an inventory methodology in the Project Design Document. The inventory methodology must include the required provisions identified in this section.

B.2.1 Inventory Methodologies

All inventory methodologies must be based on randomized or systematic sampling and include the minimum quality parameters described in this section for each carbon pool. Inventory methodologies must describe the process for locating sample plots. Sample plot locations may be monumented in such a way to assist in relocating them for quantification and verification purposes. Plot monument strategies that incorporate Global Positioning Systems (GPS) along with additional navigational strategies at close range to plot centers (that direct verifiers to the precise plot location) that are resistant to weather, wildlife, and other environmental factors, can substantially reduce verification costs. Project Operators are advised to consider the verification guidance (Section 9) associated with verification of sampled carbon pools (in particular, the sequential sampling guidance) prior to settling on a strategy to monument plot locations.

To increase the efficiency of both project development by Project Operators and verification by verifiers, the Reserve has developed a Standardized Inventory Methodology that Project Operators may optionally use to determine how to collect sample data. The Standardized Inventory Methodology is available on the Forest Project Protocol webpage and draws on observations about the standards and methodologies that have performed well for registered forest carbon projects. Designed in consultation with experienced project developers, verifiers and forest mensuration experts, it was created in consideration of a variety of factors, such as being suitable for use in a variety of forest conditions, achieving consistent results in consecutive plot measurements, and minimizing ambiguity in interpretation of conditions in the field.

Additionally, the Standardized Inventory Methodology was developed to be consistent with the Climate Action Reserve Inventory Tool (CARIT), an inventory management computer application that Project Operators may also optionally use to manage and update their forest inventories. CARIT is available on the Forest Project Protocol webpage at no cost. With CARIT, Project Operators will be able to manage forest inventories, calculate timber and carbon stocking, and update inventories for growth, disturbances (including harvests), and updated sampling data. The volume and biomass equations required by the Forest Project Protocol are already programmed into CARIT, eliminating the need for Project Operators to apply such equations on their own and ensure they are correctly applied. Additionally, CARIT generates reports that are tailored specifically to the reporting requirements of the Forest Project Protocol.

The use of the Standardized Inventory Methodology does not obligate a Project Operator to use CARIT, nor does the use of CARIT obligate a Project Operator to use the Standardized

Inventory Methodology. However, CARIT will only function properly if certain inventory standards are followed. For example, only fixed area plots may be used—variable radius plots are not allowed.

B.2.2 Updating Forest Inventories

Forest inventories are always in flux due to forest growth, harvest, and natural disturbances. Therefore, inventories of carbon pools must either be updated or re-measured at a frequency commensurate with the anticipated or actual changes in the specific carbon pools so that sample plots and forest stratification reflect current conditions. Project Operators must report their estimated carbon stocks on an annual basis. Since it is infeasible to immediately re-measure all plots following forest growth and disturbances that affect plot measurements, acceptable strategies for updating project inventory estimates are described in this section.

B.2.2.1 Updating for Forest Growth

Updating plot data for forest growth can be accomplished through the use of growth models or stand table projections that mimic the diameter and height increment of trees in the inventory database. Any plot data that are updated to reflect current conditions with the use of predicted increments of height and diameter data will be used during site visit verifications to compare against verifier's field measurements using the sequential sampling techniques described in Section 9 of the protocol. This provision ensures that plot measurements and update processes are within accuracy thresholds.

Plot data reported should always coincide with the end of the reporting period. If plot data was taken before the end of the reporting period, it should be grown forward to coincide with the end date. Similarly, if plot data was taken after the end of the reporting period, it should be degrown to the end date. The Project Operator may determine a reasonable method for apportioning growth to the reporting period end date, and should employ the same method whenever new inventory measurements are taken. Projects utilizing CARIT should report plot data for the relevant reporting period year as output by CARIT.

B.2.2.2 Updating for Disturbances (Including Harvest)

Inventory estimates must be updated annually for any disturbance (including harvest disturbance) that results in an estimated reduction to the reported carbon pools of 0.5 percent or more. However, given that it may be infeasible to re-measure all plots following a disturbance, up to 5 percent of the total inventory plots used to derive the inventory estimate can be excluded at any one time. Only plots in disturbed areas may be excluded, and no plot can be excluded for a period of time greater than one reporting period. Plots that are geographically situated in areas that experienced forest cover class-changing harvests and/or natural disturbances in the previous year must be excluded from the inventory analysis until the plots are updated with re-measured data from field visits, subject to the 5 percent limit on excluded plots outlined above.

If the inventory is stratified, the area that has been disturbed can simply be re-stratified with a stratum that reflects the post-disturbance forest condition, following the stratification rules developed for the project. Any plots that existed in the disturbed area must be removed from the set of plots used to estimate the stratum average unless, and until, the affected plots are re-measured. Verification of stratified inventories must ensure that the area disturbed is accurately characterized in the inventory GIS system and that the assigned stratum reflects the forest condition.

For non-stratified inventories, an estimated tree list that represents the post-disturbance condition of the forest must be assigned to any plots affected by the disturbance. The tree list must be carefully selected to not overstate the carbon pools present. Site verification of post-disturbance plots will evaluate whether the tree list assigned is appropriate for the post-disturbance condition. No more than 10 percent of the project's area may be represented through estimated plots without increased verification scrutiny during a site visit. Specifically, where more than 10 percent of the project's area is based on estimated tree lists assigned to plots, verification using sequential sampling techniques shall include all plots (including estimated plots) in the sequential sampling comparison between Project Operator estimates and verifier estimates.

Plots that are estimated shall not be used in the calculations for sampling error. Estimates from sampled pools must meet a minimum confidence standard of +/- 20 percent at the 90 percent confidence interval. It is acceptable to calculate the descriptive statistics, including confidence intervals, using plot data that have been updated to a current date. Discounts for uncertainty are applied to project estimates when confidence standards are below +/- 5 percent at the 90 percent confidence interval. This is described in greater detail below.

B.2.3 Requirements for Estimating Carbon in Standing Live and Dead Trees

It is required that both standing live and standing dead trees be sampled. It is acceptable, but not required, to combine standing live and dead trees during sampling such that descriptive statistics, including confidence statistics, address the combined pools. Whether combined or not, tree data must be coded so that mean estimates can be interpreted independently for standing live and standing dead pools to allow monitoring of standing dead trees with respect to requirements in Section 3.9.2 (Natural Forest Management).

Inventory methodologies must include a description of how the sampled data will be archived and the analytical tools that will be included in the analysis of carbon stocks. The tree lists that are developed from inventory sampling and used to expand inventory estimates to the project level must be available for verification review. It is acceptable for the tree list to be presented and reviewed in an electronic format, such as in a database or spreadsheet application. Table B.2 displays the requirements that all project inventory methodologies must include for standing live and dead trees.

Table B.2. Requirements for Sampling Standing Live and Standing Dead Trees

Species	1. All trees sampled must include a species identifier. The inventory methodology must provide a crosswalk between any codes used to identify a species and the species name the codes represent. 2. Since all trees contain carbon, the inventory methodology must indicate that the sample methodology will include all species present within the project area.
Diameter at Breast Height (DBH) Measurements	1. Inventory estimates must include all trees 5 inches DBH and larger. It is acceptable that inventory methodologies include trees with DBH less than 5 inches. 2. The location of the measurement of DBH must follow U.S. FIA sampling guidelines (can be found on the Forest Project Protocol webpage). 3. Measurement precision must be no greater than the nearest inch.

Height	1. Inventory methodologies must describe whether all trees on sample plots are measured for height or whether a subset of the sample plot heights is measured and regression estimators are developed for unmeasured heights. 2. Inventory methodology must describe whether height measurements describe the tree's total height or some other top height measurement (regression estimators, or published form equations, may also be used to estimate top heights from a partial height or vice versa). Where regression estimators are used for tree heights, the inventory methodology must describe the populations from which the regression estimators were acquired. 3. The sampling precision for tree heights (when measured) must be stated in the inventory methodology. Stated acceptable precision for measured heights not to be greater than +/- 10 feet. 4. The inventory methodology must include a description of the maximum angle accepted for measuring tree heights. The stated maximum acceptable slope to the measured height shall not exceed 120 percent.
Weight (Plot Area and Forest Strata)	1. All methodologies must describe the sample plot areas used to determine which trees are included for measurement. 2. All tree lists must include a field(s) that displays the weighting of each sampled tree in order to expand the sampled tree to a per acre value. 3. Where inventories are stratified, the governing rules for stratification and stratification methodology must be described. The process for updating forest strata must be described. 4. Where inventories are stratified, stratum areas must be provided at verification with maps and tabular outputs.
Status	1. Each sampled tree must be identified as live or dead. 2. Dead trees must be coded with the decay status so density adjustments can be made. Decay class descriptions and density adjustments are provided below.
Biomass Equations	1. All projects must calculate the biomass in each tree using the biomass equations provided by the Reserve (can be found on the Forest Project Protocol webpage). 2. The project's inventory methodology must include a list of the equations and cite the version of the Reserve's equation file from which they were copied. a. The CARIT tool (optional) includes approved biomass equations to reduce the burden of verification.
Deductions for Missing Biomass	1. Both live and dead trees may have cavities, broken tops or other deformities that reduce the biomass in the trees. Therefore, the inventory methodology must include a description of how deductions are estimated to account for missing biomass. The Reserve has provided guidance below that is acceptable. Alternative methods that address deductions for missing biomass are subject to approval by the Reserve.

Sampling methodologies and measurement standards should be consistent throughout the duration of the forest project. If new sampling methodologies are incorporated during the project life, they must be approved by the Reserve. Sampling methodologies and measurement standards will be evaluated for their statistical validity. Additionally, uncertainties in estimates associated with modifications to sampling methodologies may require reconciliation to project data and/or baseline estimates and shall be conducted at the Reserve's sole discretion. The application of a revised sampling methodology can only occur as part of a site visit verification.

B.2.4 Use of Regression Equations

It is acceptable to develop carbon inventories using regression estimators to estimate tree heights. Project Operators must keep in mind that plots or (sub) populations will be randomly selected for verification and that regression estimators should be used where a high level of certainty can be developed from the estimators. Failure to do so will result in increased effort and cost to meet the standards of verification.

B.2.5 Forest Vegetation Stratification

Stratification is not required, but it may simplify verification and possibly lower the costs of verification. Where forest vegetation is stratified, inventory methodologies must describe the guidelines used for stratification. Traditional stratification decisions are usually based on species composition, forest stem size (DBH or height), and density. It is important that the stratification be relevant to sampling forest carbon. The minimum polygon size to which the stratification guidelines apply must be included in the methodology. A map of current forest strata must be included in the Project Design Document. The methodology must also include the process guidelines for updating forest strata for disturbance and growth events.

B.2.6 Quantification of Carbon in Live Trees from Project Data

All projects must use the appropriate biomass equations for the assessment areas the project is located in. The required biomass equations are found on the Reserve's Forest Project Protocol webpage. The calculation of CO_2e for each tree must be conducted in a manner that provides project estimates for:

- Whole tree biomass (roots, stump, bark, bole, top, and branches). Whole tree estimates are used to provide project totals and estimates of emissions associated with harvest activities.
- Bole biomass. The bole must be calculated when the bole portion of harvested trees are delivered to manufacturing facilities for processing. It is used as the basis for determining carbon persisting in long-term wood products.
- Aboveground portion (stump, bark, bole, top, and branches) used to compare project data to Common Practice statistics for Improved Forest Management projects.

Projects outside of California, Oregon, Washington, Alaska, and Hawaii use estimators for non-bole portions of the tree referred to as the Component Ratio Method (CRM). The CRM must be used to compute the various portions of the tree mentioned above. Guidance for the use of the CRM is provided in the biomass equations section of the Reserve's Forest Project Protocol webpage.

Projects in California, Oregon, Washington, Alaska, and Hawaii must use the biomass equations provided on the Reserve's Forest Project Protocol webpage to calculate the aboveground portion of the trees. The Cairn's equations (Cairns, Brown, Helmer, & Baumgardner, 1997) must be used to calculate CO_2e in the below-ground portion of the trees. The Cairn's equations must be used for the appropriate latitude for the project. The Cairn's equations are as follows:

Equation B.1. California, Oregon, Washington (Temperate Equation)

BBD = exp[-0.7747 + 0.8836 x ln(ABD)]			
Where,			Units
BBD	=	Belowground biomass density of standing live trees	tonnes/hectare
ABD	=	Aboveground biomass density of standing live trees	tonnes/hectare

Equation B.2. Alaska (Boreal Equation)

BBD = exp[-0.8713 + 0.8836 x ln(ABD)]			
Where,			Units
BBD	=	Belowground biomass density of standing live trees	tonnes/hectare
ABD	=	Aboveground biomass density of standing live trees	tonnes/hectare

Equation B.3. Hawaii (Tropical Equation)

BBD = exp[-1.0587 + 0.8836 x ln(ABD)]			
Where,			Units
BBD	=	Belowground biomass density of standing live trees	tonnes/hectare
ABD	=	Aboveground biomass density of standing live trees	tonnes/hectare

This estimate must be converted from biomass in tonnes per hectare to CO_2e in tonnes per acre using the conversions identified earlier in this guidance.

B.2.7 Adjustments to Standing Live and Standing Dead Trees for Missing Volume and Decay

Both standing dead trees and standing live trees may be missing portions of the tree as the result of physical and biological disturbances. Tree biomass needs to be adjusted for missing parts to produce an improved estimate of the tree's biomass. Calculating CO_2e in standing dead trees raises additional challenges since they may be in stages of decay such that density equations in standard biomass equations for live trees do not provide an accurate estimate. The guidance in this section provides a standardized method to account for biomass adjustments.

The first step is to estimate the gross biomass in the tree as if it were whole, using the biomass equations (the first step in the biomass and carbon calculations) provided on the Reserve's Forest Project Protocol webpage. The tree's biomass is then adjusted based on the tree's 'net' biomass and adjusted density estimates for standing dead trees. To standardize, the tree is divided into four parts: top, middle, bottom (visually estimating the original disposition of the aboveground portion of the tree when it was alive and vigorous), and the below-ground portion. The below-ground portion must be calculated as it would for a normal, healthy tree, using the Cairn's equation where the regional biomass equations are used instead of the CRM. It is assumed that the below-ground portion is intact and complete. The standardized percentages assumed to be in each portion of the tree are shown in Table B.3.

Table B.3. Assumed Percentages of Biomass in Each Portion of the Tree

Tree Portion	Percent of Tree Biomass
Top 1/3	10%
Middle 1/3	30%
Bottom 1/3	60%

An ocular estimate is made of the portion remaining in each section of the tree during field sampling. Deductions from gross volume are made for anything that reduces the tree's gross biomass, including breakage and cavities. The percentage remaining in each third is then summed to calculate the net biomass remaining in the tree.

The tree's density must be adjusted to account for the varying states of decay in the remaining portion of the tree. Because standing dead wood does not have the same density as a live tree, a density reduction must be applied. Standing dead wood may fall into five decay classes, which must be recorded during the field sampling. The five decay classes, described in Table B.4, are qualitative, based on the physical characteristics of the dead tree (USDA 2007, Woundenberg et al., 2010).

Table B.4. Decay Classes

Decay Class	Description of Condition of Standing Dead Wood
1	All limbs and branches are present; the top of the crown is still present; all bark remains; sapwood is intact with minimal decay; heartwood is sound and hard.
2	There are few limbs and no fine branches; the top may be broken; a variable amount of bark remains; sapwood is sloughing with advanced decay; heartwood is sound at base but beginning to decay in the outer part of the upper bole.
3	Only limb stubs exist; the top is broken; a variable amount of bark remains; sapwood is sloughing; heartwood has advanced decay in upper bole and is beginning at the base.
4	Few or no limb stubs remain; the top is broken; a variable amount of bark remains; sapwood is sloughing; heartwood has advanced decay at the base and is sloughing in the upper bole.
5	No evidence of branches remains; the top is broken; less than 20 percent of the bark remains; sapwood is gone; heartwood is sloughing throughout.

The density identified for each species in the biomass equations posted on the Reserve's Forest Project Protocol webpage must be modified for decay classes 2 to 5 using the reduction factors displayed in Table B.5,[39] which are multiplied by the densities provided in the biomass equations.

Table B.5. Average Density Reduction Factors for Standing Dead Wood for Hardwoods and Softwoods by Decay Class

Softwoods		Hardwoods	
Decay Class	Reduction Factor	Decay Class	Reduction Factor
2	1.0	2	0.8
3	0.92	3	0.54
4	0.55	4	0.43
5	0.29	5	0.22

[39] Harmon et al. (2011). Differences between standing and downed dead tree wood density reduction factors: A comparison across decay classes and tree species. Res. Pap. NRS-15. Newtown Square, PA: U.S. Department of Agriculture, Forest Service, Northern Research Station. 40 p.

An example of field data that has all of the required elements for calculating the standing dead tree's CO_2e is shown in Table B.6.

Table B.6. Example: Data Attributes Needed to Calculate CO_2e in Standing Dead Trees

Tree Number	Species (type)	Status	DBH (inches)	Height* (feet)	Percent Remaining			Decay Class
					Top 1/3 of Tree	Middle 1/3 of Tree	Bottom 1/3 of Tree	
1	Hardwood	Dead	16	95	0%	50%	100%	3

*Estimated height prior to death

The density of the tree must be adjusted based on its decay class. The first step is to calculate the tree's biomass as if the tree were a normal tree to determine the tree's gross biomass. Net biomass is determined by multiplying the gross biomass of the tree by the reduction factor displayed in Table B.5. An example is provided in Table B.7.

Table B.7. Example: Adjusting Biomass Calculation for Decay Using Density Adjustment Factors

Tree Gross Biomass	Density Reduction Based on Decay	Net Biomass
(tonnes CO_2e) (Assumed)	(from Table B.5 for a hardwood with a decay class '3')	(tonnes CO_2e) (Assuming tree is whole)
0.100	0.54	0.054

As an example of the application of the biomass deductions for missing sections of the tree, using the data from Table B.6 above, a tree (assuming normal form) with a net biomass of 0.054 CO_2e tonnes would be further adjusted to a net biomass for the missing portions of the tree as shown in Table B.8.

Table B.8. Example: Calculating Net Biomass in a Tree

Tree Portion	Percent of Tree Biomass	Gross Biomass	Percent Remaining in Tree	Net Biomass
	(from Table B.3)	(tonnes CO_2e) Percent of tree biomass **x** tree biomass adjusted for density (Table B.7)	(from example in Table B.6)	(tonnes CO_2e) Percent remaining in tree **x** gross biomass
Top 1/3	10%	10% **x** 0.054 **=** 0.0054	0%	0.00000
Middle 1/3	30%	30% **x** 0.054 **=** 0.0162	50%	0.0081
Bottom 1/3	60%	60% **x** 0.054 **=** 0.0324	100%	0.0324
Total Biomass			200	0.0405

B.2.8 Requirements for Estimating Lying Dead Wood Carbon

All projects must either maintain an inventory of lying dead wood for the project area or monitor harvested areas according to the guidance in this section to ensure the project meets the conditions identified in Section 3.9.2 (Natural Forest Management). Lying dead wood is not eligible for crediting due to the high variability associated with estimating lying dead wood, resulting in estimates with unacceptable levels of uncertainty for crediting. Project Operators are required to include the status of lying dead wood with each monitoring report.

Project Operators that choose to meet the monitoring requirement by maintaining an inventory of lying dead wood must meet the following requirements:

1. Inventory plots or transects used to provide the lying dead wood estimate must be no older than 12 years.
2. Data collected for lying dead wood must include the estimated species, adequate data to estimate volume, and decay class, as defined by Table B.9 below, to estimate the density of the piece of lying dead wood to determine biomass.
3. The sampling methodology must be included in the Project Design Document. The Reserve is not prescriptive with regards to the sampling design, other than adhering to general statistical principles of randomness. Fixed area plots and line transects, among other sampling methodologies, are acceptable.
4. The inventory sampling confidence in the estimate of lying dead wood must be at +/- 30 percent at 1 standard error.

Project Operators that choose to meet the monitoring requirement through monitoring of harvested areas must meet the following requirements:

1. A harvested area is any area where commercial removal of forest vegetation has occurred.
2. A map of all areas harvested during the last reporting period must be submitted with the annual monitoring report and must include the harvest date.
3. All harvested areas must be monitored within one year of the harvest date.
4. Fixed area strips shall be randomly located on compass bearings chosen by the Project Operator (but maintained consistent within each harvest area). A recommended width of the fixed area strip is 66 feet (1 chain), which will require monitoring in each of the 33 foot areas on either side of the center line. Ten square chains equals one acre. Project Operators can determine the width of the strip that best suits the vegetation conditions present in the harvested area.
5. A map shall be produced that displays the location of the fixed area strips on the harvested areas. The width of the strip shall be documented for each strip.
6. The minimum area monitored shall be 5 percent of each harvested area.
7. Data collected within the fixed area strip must include the estimated length of the piece of lying dead wood, the average diameter of the lying dead wood, the estimated species, and the decay class as defined by Table B.9 below.

Lying dead wood density must be adjusted to account for the state of decay. Because lying dead wood does not have the same density as a live tree, a density reduction must be applied. Lying dead wood may fall into five decay classes, which must be recorded during the field sampling. The five decay classes are qualitative based on the physical characteristics of the dead tree (USDA 2007, Woundenberg et al., 2010).

Table B.9. Decay Class Descriptions of Lying Dead Wood

Decay Class	Description of Condition of Lying Dead Wood
1	Sound, freshly fallen, intact logs with no rot; no conks present indicating a lack of decay; original color of wood; no invading roots; fine twigs attached with tight bark.
2	Sound log sapwood partly soft but cannot be pulled apart by hand; original color of wood; no invading roots; many fine twigs are gone and remaining fine twigs have peeling bark.
3	Heartwood is still sound with piece supporting its own weight; sapwood can be pulled apart by hand or is missing; wood color is reddish-brown or original color; roots may be invading sapwood; only branch stubs are remaining which cannot be pulled out of log.
4	Heartwood is rotten with piece unable to support own weight; rotten portions of piece are soft and/or blocky in appearance; a metal pin can be pushed into heartwood; wood color is reddish or light brown; invading roots may be found throughout the log; branch stubs can be pulled out.
5	There is no remaining structural integrity to the piece with a lack of circular shape as rot spreads out across ground; rotten texture is soft and can become powder when dry; wood color is red-brown to dark brown; invading roots are present throughout; branch stubs and pitch pockets have usually rotten down.

The density identified for each species in the biomass equations posted on the Reserve's website must be modified for decay classes 2 to 5 using the reduction factors displayed in Table B.10,[40] which are multiplied by the densities provided in the biomass equations.

Table B.10. Average Density Reduction Factors for Lying Dead Wood for Hardwoods and Softwoods by Decay Class

Softwoods		Hardwoods	
Decay Class	**Reduction Factor**	**Decay Class**	**Reduction Factor**
2	0.87	2	0.74
3	0.70	3	0.51
4	0.40	4	0.29
5	0.29	5	0.22

An adjusted density coefficient for the downed logs is calculated by multiplying the density coefficient provided with the biomass equations on the Reserve's Forest Project Protocol webpage by the reduction value in the table above. The adjusted density value is multiplied by the volume estimate in the lying dead wood to determine the biomass.

[40] Harmon et al. (2011). Differences between standing and downed dead tree wood density reduction factors: A comparison across decay classes and tree species. Res. Pap. NRS-15. Newtown Square, PA: U.S. Department of Agriculture, Forest Service, Northern Research Station. 40 p.

B.2.9 Requirements for Estimating Soil Carbon Emissions and Soil Carbon Quantification for Avoided Conversion Projects

All projects must estimate the soil carbon emissions associated with project management practices. Avoided Conversion projects are eligible (optional) to report the baseline soil carbon emissions the project activity is avoiding. This section provides guidance for estimating soil CO_2e within the project boundaries, and quantifying emissions associated with project activities.

No direct sampling of soil carbon is required for projects that are reporting soil carbon emissions only as part of project management practices. Rather, the estimate of emissions is based on soil carbon estimates from United States Geological Survey (USGS) data for project sites and comparing the data to standardized guidance to assess emissions based on management activities.

For Avoided Conversion projects, the project benefit is determined by comparing the project soil carbon estimate (from sampling) to the standardized estimate of emissions associated with the activity. Currently, only Avoided Conversion projects that demonstrate a risk of conversion to agriculture (all soil orders, grazing not included) and projects that demonstrate a risk of conversion to residential and commercial use (only histosols) are eligible to report soil carbon benefits associated with the avoided conversion activity. Other conversion risks are not currently eligible for this type of reporting.

To summarize, Table B.11 provides the two different approaches to quantifying soil carbon benefits and/or emissions.

Table B.11. Soil Carbon Quantification Methods by Project Type

<table>
<tr><th>Project Description</th><th>Project Type Identification</th><th>Method to Estimate Project Soil Carbon (CO_2e) Stocks</th><th>Method to Estimate Project Effects on Soil Carbon (CO_2e)</th></tr>
<tr><td rowspan="4">Project will provide benefits by avoiding soil carbon emissions associated with conversion to agriculture and, in certain cases, residential or commercial (Avoided Conversion)</td><td rowspan="4">1</td><td rowspan="2">Soil carbon sampling required at project initiation</td><td>Initial avoided conversion effects estimated through standardized guidance</td></tr>
<tr><td>Follow guidance in Step 7</td></tr>
<tr><td rowspan="2">Follow guidance in Steps 1, 4, 5, and 6</td><td>Ongoing project effects estimated through default estimates of soil carbon emissions</td></tr>
<tr><td>Follow guidance in Steps 1, 4, 5, and 6</td></tr>
<tr><td rowspan="2">Project is reporting management-related emissions</td><td rowspan="2">2</td><td>Use of USGS data</td><td>Project effects estimated through default estimates of soil carbon emissions</td></tr>
<tr><td>Follow guidance in Steps 1, 2, 3, and 6</td><td>Follow guidance in Step 7</td></tr>
</table>

B.2.9.1 Developing an Estimate of Soil CO_2e within the Project Boundaries

Step 1: Identify Soil Orders Present Within Project (**Project Types 1 and 2**)

Project Operators must determine the soil orders present in their project area and the area each soil order represents. Where Natural Resource Conservation Service (NRCS) soil data is available on the NRCS website (http://websoilsurvey.nrcs.usda.gov/app/WebSoilSurvey.aspx), projects must use this data. Where NRCS data is either unavailable or believed to be in error at the project site, Project Operators may present the soil orders and area represented by each order with an official letter from a local NRCS representative stating that the portrayal of the soil orders by the Project Operator is accurate. The letter must state why existing data is either absent on the NRCS website or why the data is not accurate.

On the NRCS website mentioned above, users must create an Area of Interest (AOI), using the website tools, that approximates the project boundaries. To determine the soil order, users select the soil reports tab, select land classifications, and select "Taxonomic Classification of Soils". This report provides a taxonomic classification of each of the soils in the AOI. The last four letters of the soil descriptions correspond to the soil order. For example, a soil classified as Xerochrepts is in the Inceptisol order. Table B.12 below displays the soil orders associated with the last four letters in the soil descriptions.

Table B.12. Soil Orders

Soil Order	Last Four Letters in Soil Description
Alfisol	-alfs
Andisol	-ands
Inceptisol	-epts
Mollisol	-olls
Spodosol	-ods
Ultisol	-ults
Histosol	-ists

Step 2: Obtain Soil Organic Matter Values (**Project Type 2**)

Select the tab entitled 'Soil Properties and Qualities', then select 'Soil Organic Matter' and within the advanced options, select 'Weighted Average'. For the aggregation method, select 'Higher' as the tie break rule, and designate '0-30 cm' for the soil depth. Next, click 'View Ratings' to review the organic matter percentage for each soil type in the AOI. Convert the number from the rating to decimal percent by dividing by 100.

Step 3: Obtain the Soil Bulk Density Values (**Project Type 2**)

Soil bulk density estimates are determined by first selecting the 'Soil Properties and Qualities' tab, the 'Bulk Density' tab next, followed by the 'On-third Bar'. Specify the 'Weighted Average' method and soil depth (0-30 cm, unless otherwise noted). Select 'View Ratings. The ratings will provide bulk density values for each soil type in the AOI. If the bulk density values are not available in the database, determine whether the soil orders are qualified as sandy, loamy, or clay using the 'Surface Texture' value in the Soil Properties and Qualities tab and then apply default values of 1.2 g/cm^3 for clay soils, 1.6 g/cm^3 for sand soils, and 1.4 g/cm^3 for loam soils.

Step 4: Sample for Soil Organic Matter (**Project Type 1**)

Soil carbon estimates are based on sampling soil organic matter for the project. Materials needed include:

- Rubber mallet
- Square spade (for removing organic material from core site)
- Soil probe

- Compass
- Trowel and/or sturdy knife (for cleaning soil off outside service of probe)
- Plastic bags (1 bag for each soil core)
- Marking pen
- Measuring tools (meters and centimeters)

Step 4a: Identifying the Plot Locations

Plots must be located randomly or systematically with a random start in each of the soil orders that occur on the project site. An adequate number of plots is needed to ensure the overall estimate of soil carbon meets or exceeds the minimum confidence levels stated in the protocol (+/- 20 percent at 90 percent confidence level). It is acceptable to use the same, or a subset of, plot locations as used for biomass sampling, so long as each soil order is sampled and the overall soil carbon estimate achieves the confidence standards stated above.

Step 4b: Identify Four Random Locations at Each Plot and Extract Soil Organic Matter Samples

4b-i: Select a random number by glancing at a watch's second hand (or digital version). Multiply this number by six to derive a compass bearing to use for the soil sample locations. Following the determined compass bearing, measure 10 meters from the plot center and establish each of the four soil sample locations. Minimal spatial adjustments (less than 2 meters) can be made to avoid rocks and roots from impacting the ability to sample. If obstacles cannot be avoided within 2 meters, an additional sample location must be selected using the method described above.

4b-ii: For each sample location, insert a soil core probe (minimum diameter, ½ inch) into the soil at the sample location to a depth of 30 cm. A rubber mallet may be used to facilitate penetration. If the probe will not penetrate to the required depth, the probe must be removed, wiped free of soil, and inserted in an alternate location with a 2 meter radius from the sample location. If repeated efforts result in difficulties achieving full penetration, an additional sample location must be chosen as described in Step 4b-i. If full penetration is not achieved within two efforts to locate a satisfactory sampling location, the sample must be taken from the initial sample location and the depth recorded.

4b-iii: Soil must be extracted carefully from the probe to avoid losing any of the soil collected. Should any soil be lost, the sample must be rejected and a new sample location selected as described above. The extracted soil is placed in a sealable plastic bag. Label the bag with the plot number followed by the letter "SOM", indicating the sample is a "soil organic matter" sample (not a bulk density sample).

4b-iv: The soil organic matter samples must be sent to a laboratory with expertise in analyzing soil carbon and physical properties within 106 hours of the acquisition of the samples from the plot sites. The laboratory must receive instructions that the samples are to be heated to over 1000 degrees Celsius. This heat will burn off the carbon and a detector is to be used to measure the amount of carbon dioxide produced and reported as a percent of the volume sampled.

Step 5: Sample for Bulk Density (**Project Type 1**)

Sampling for soil bulk density must be conducted on the project site. Materials needed include:

- Rubber mallet
- Piece of wooden 2x4 approximately 1 to 2 feet in length
- Square spade
- Soil core/ring with known volume
- Trowel and/or sturdy knife
- Plastic bags (1 bag for each soil pit)
- Marking pen
- Measuring tools (meters and centimeters)

Step 5a: One random location 4 meters from each plot center must be selected for soil data collection to dig a soil pit to a depth of at least 30 cm^3. The measure of depth must be below the organic layer (branches, leaves, moss, etc.). The sides of the pit can be made straight using the trowel or the study knife. Random selection is achieved through the use of the second-hand method described in Step 4b-i. Adjustments to the location of the pit can be made using the adjustments allowed for difficulties associated with inserting soil probes described in 4b-ii.

Step 5b: Two samples will be taken from the soil pit. The sample is taken by centering the soil ring at a depth of 7.5 cm and the second is taken by centering the ring at a depth of 22.5 cm. The ring is inserted perpendicular to the pit face. The location of each insertion must be into undisturbed soil, as occurs during the process of extracting the soil rings. The soil pit can be expanded to ensure that undisturbed soil is sampled.

5b-i: For each of the samples the sharp end of the ring is pushed in, without twisting, as far as possible with the hands.

5b-ii: The piece of wood is placed over the ring and gently hammered evenly into the soil. If strong resistance is encountered, an alternate location may be found within the pit, or a new pit located using the guidance described above.

5b-iii: Using the trowel or sturdy knife, soil is removed around the outside of the ring to allow for extraction of the ring without losing soil. The surfaces of the ring should be cleaned and cut flush to the surface of the ring. Small losses during extraction and cleaning (up to 2 cm^3) can be restored by filling the void with soil from the pit site and smoothing. Samples must be rejected if soil losses from the ring occurring during extraction and cleaning are greater than 2 cm^3.

5b-iv: The soil from both ring samples is placed in one sealable plastic bag and labeled with BD and the plot number.

5b-v: The bulk density samples must be sent to laboratory with expertise in analyzing soil carbon and physical properties within 106 hours of the acquisition of the samples from the plot sites. Bulk density instructions sent with the samples shall describe that the samples are to be dried at 105 degrees centigrade for at least 48 hours and that all portions of the sample are to be retained (including rocks). The laboratory shall present the results of the analysis of bulk density estimates as g/cm^3, displaying dry weight over total sample volume.

Step 6: Calculate the Total Soil CO_2 per Acre (**Project Types 1 and 2**)

Use Equation B.4 (below) to calculate the soil CO_2 per acre.

Equation B.4. Soil CO_2e per Acre

Soil CO_2e	=	Organic Matter Value (Steps 2 or 4) **x** 0.58 (Conversion of Organic Matter to Carbon) **x** Bulk Density Value (Steps 3 or 5) **x** Soil Depth Sampled (30 cm) **x** 40,468,600 (Conversion of 1 cm^2 to 1 acre) **x** 10^{-6} (Conversion of 1 gram to 1 metric ton) **x** 3.667 (Conversion of Carbon to CO_2)

An example is provided in Table B.13 below.

Table B.13. Example: Calculation for Total CO_2 per Acre

Organic Matter from Steps 2 or 4		0.05
Conversion of Organic Matter to Carbon	x	0.58
Bulk Density (g/cm^3) from Steps 3 or 5	x	1.2
Soil Depth Sampled (30 cm)	x	30
Conversion of 1 cm^2 to 1 acre (1 acre = 40,468,600 cm^2)	x	40,468,600
Conversion of 1 gram to 1 metric ton Carbon	x	0.000001
Conversion of 1 metric ton Carbon to 1 metric ton CO_2	x	3.667
Estimated Metric Tons CO_2 per Acre	=	155.05

Step 7: Quantify the Project Effects on Soil CO_2e (**Project Types 1 and 2**)

Project effects are calculated using the standardized guidance below. Avoided Conversion projects must use the standardized guidance for purposes of estimating project benefits. Soil carbon emissions resulting from management activities are determined where the activity, or set of activities, leads to a net loss of soil carbon across the entire project. Net emissions can occur across the project area in a sustainably managed forest where emissions from management activities are not restored during the rest, or growth, cycle of the stand. The default values provided are derived from scientific literature and address the high-end estimates of net emissions associated with management activities, except in the case of conversion where it is more conservative to underestimate the emissions associated with the avoided activity. The background documentation[41] for the default values is found on the Reserve's Forest Protocol Version 3.3 webpage under References.

Default emission values are provided as percentages for each soil order, based on harvesting intensity, site preparation intensity, and the frequency of disturbance. Project Operators must report their soil carbon emissions by grouping the total acres in each permutation, or class of soil order, harvesting intensity, site preparation intensity, and frequency of disturbance, rather than reporting on an individual stand basis. An example of reporting classes of management activities is provided below, following the descriptions of the management activities.

[41] Gershenson, Alex. Establishing a Standardized Method to Account for Soil Carbon Emissions Associated with Management Activities.

Net carbon emissions are estimated as the difference between carbon stocks (CO_2e) in the soil prior to the management activity and the carbon stocks (CO_2e) in the soil immediately prior to the subsequent harvest event for each harvested stand. Index values are provided for both harvesting intensity and site preparation intensity that, when combined, classify the harvesting intensity for the stand. The index value for harvesting intensity is derived from both the amount of biomass removed during harvest and the soil disturbance associated with the biomass removal. The index value for site preparation is based on the amount of soil disturbance associated with site preparation activities.

For each stand harvested in a given reporting year, Project Operators must determine the harvesting intensity using the guidance below. For Avoided Conversion projects, the guidance is used below to assist in determining baseline conditions and applied to the project rather than individual stands.

Step 7a: Harvesting Intensity

First, the biomass removal index value is determined for the stand based on the amount of biomass removed during harvest. The harvesting intensity value is calculated using a factor for the amount of biomass removed and the amount of soil disturbance that occurs removing the biomass. Both values are added together to calculate the harvesting intensity. The value for disturbance related to biomass removal is determined using Table B.14 below:

Table B.14. Determination of Biomass Removal Index

Biomass Affected by Harvest		
Percentage Pre-Harvest Aboveground Biomass Removed	**Silviculture Activities Generally Associated with Level of Biomass Removed**	**Biomass Removal Index**
< 10%	Sanitation Salvage	0
10 – 50%	Selection, Thinning	0
51 – 80%	Rotation harvest with biomass remaining in tree tops, seed/shelterwood and/or retained trees	1
> 80%	Rotation harvest with whole tree harvesting and little retention	2
Not a Silvicultural Activity – There is no intent to follow up with efforts to regenerate forested conditions		
Based on Table 6.3	Conversion – only relevant to assessment of Avoided Conversion baseline	10

Step 7b: Soil Disturbance from Harvesting Activities

The second value considered for determining the harvest intensity is based on the level of soil disturbance associated with biomass removal. Soil disturbance within the harvested stands boundary may be the result of skidding logs, tree falling, and harvesting equipment. The disturbance may be extensive or minimized, depending on site-specific conditions and care taken during harvesting operations. The soil disturbance index is based on the amount of mineral soil (below the organic layer, including litter and duff) exposed due to harvest activities. The determination of the amount of mineral soil disturbance is from ocular inspection of harvested stands. Table B.15 below is used to determine the soil disturbance index from harvesting.

Table B.15. Determination of Soil Disturbance Index

Percent of Mineral Soil Exposed during Harvest	Soil Disturbance Index
< 5%	0
5 - 20%	2
20 - 40%	3
40 - 60%	4
> 60%	5

Step 7c: Determining the Harvesting Intensity Class

The values for the biomass removal index and the soil disturbance index are summed together to determine the harvesting intensity class, displayed below in Table B.16.

Table B.16. Harvesting Intensity Classes based on Summing the Biomass Removal and Soil Disturbance Indexes

Harvesting Intensity Classes	
Harvesting Intensity Class	**Sum of Biomass Removal and Soil Disturbance Indexes**
Light to Medium	< 3
High	3 - 4
Very High	5 - 7
Conversion	> 7

Step 7d: Determining Site Preparation Classes

For each stand harvested, the Project Operator must determine the site preparation index using the guidance in Table B.17.

Table B.17. Site Preparation Classes and Descriptions of Management Activities

Site Preparation	
Site Preparation Class	**Description**
Very Light	Less than 5% surface area disturbance of soil below litter and duff due to ripping, grading, raking, etc.
Light	5% to 24% surface area disturbance below litter and duff due to ripping, grading, raking, etc.
Medium	25% to 59% surface area disturbance below litter and duff due to ripping, grading, raking, etc.
Heavy	60% to 100% surface area disturbance below litter and duff due to ripping, grading, raking, etc.
Conversion	Soils cleared of trees, stumps and other forest vegetation and prepared for agriculture, grazing, and/or development. No return to forest vegetation.

Step 7e: Determining the Frequency of Disturbance

The frequency of disturbance is determined as the time between harvest activities associated with the specific silviculture event that is being evaluated for soil carbon emissions. The value for frequency of disturbance is assigned to each harvested stand based on the amount of pre-harvest basal area remaining in the post-harvest stand. The standardization of these values is based on protocol requirements that onsite forest carbon stocks be maintained or increased and the minimum rotation age in even-aged management silviculture effectively set at 50 years.

Table B.18. Frequency of Disturbance Classification

Frequency of Disturbance	Harvest Retention	Assumed Years to Next Harvest
Short	> 75% of pre-harvest basal area	Up to 15 years
Medium	51 – 75% of pre-harvest basal area	16 to 35 years
Long	26 – 50% of pre-harvest basal area	36 to 50 years
Very Long	< 26% or pre-harvest basal area	> 51 years

Step 7f: Determining Emissions Associated with Management Activities

For each class of harvested stands, or stands that have received site treatment, a value is determined for each combination of harvest intensity, frequency of disturbance, site preparation, and soil order. A percent value is derived from Table B.19 below based on the combination of the various classes.

Table B.19. Estimated Net Carbon Loss

Harvesting Intensity	Frequency of Disturbance	Site Treatment	Estimated Net Carbon Loss by Soil Order						
			Alfisol	***Andisol***	***Inceptisol***	***Mollisol***	***Spodosol***	***Ultisol***	***Histosol***
Light to Medium	Short	Very Light	0%	0%	0%	0%	0%	0%	80%
	Medium		0%	0%	0%	0%	0%	0%	80%
	Long		0%	0%	0%	0%	0%	0%	80%
	Very Long		0%	0%	0%	0%	0%	0%	80%
High	Short	Very Light	Conifers 0% Hardwoods 20%	0%	8%	0%	10%	9%	80%
		Light	Conifers 5% Hardwoods 20%	5%	8%	5%	10%	9%	80%
		Medium	Conifers 10% Hardwoods 20%	10%	10%	10%	20%	11%	80%
		Heavy	Conifers and Hardwoods 20%	20%	20%	20%	41%	22%	80%
	Medium	Very Light	Conifers 6% Hardwoods 20%	0%	0%	0%	33%	24%	80%
		Light	Conifers 6% Hardwoods 20%	5%	5%	5%	33%	24%	80%
		Medium	Conifers 10% Hardwoods 20%	10%	10%	10%	33%	24%	80%
		Heavy	Conifers and Hardwoods 20%	20%	20%	20%	41%	24%	80%
	Long	Very Light	Conifers 0% Hardwoods 20%	0%	0%	0%	31%	0%	80%
		Light	Conifers 5% Hardwoods 20%	5%	5%	5%	31%	5%	80%
		Medium	Conifers 10% Hardwoods 20%	10%	10%	10%	31%	11%	80%
		Heavy	Conifers and Hardwoods 20%	20%	20%	20%	41%	22%	80%
	Very Long	Very Light	0%	0%	0%	0%	5%	0%	80%
		Light	0%	0%	0%	0%	10%	5%	80%
		Medium	0%	0%	0%	0%	20%	11%	80%
		Heavy	0%	0%	0%	0%	41%	22%	80%

Harvesting Intensity	Frequency of Disturbance	Site Treatment	Estimated Net Carbon Loss by Soil Order						
			Alfisol	***Andisol***	***Inceptisol***	***Mollisol***	***Spodosol***	***Ultisol***	***Histosol***
Very High	Short	Very Light	Conifers 6% Hardwoods 20%	6%	28%	6%	1%	6%	80%
		Light	Conifers 6% Hardwoods 20%	6%	28%	6%	10%	6%	80%
		Medium	Conifers 10% Hardwoods 20%	10%	28%	10%	20%	11%	80%
		Heavy	Conifers and Hardwoods 20%	20%	53%	20%	41%	22%	80%
	Medium	Very Light	Conifers 6% Hardwoods 20%	6%	6%	6%	0%	5%	80%
		Light	Conifers 6% Hardwoods 20%	6%	6%	6%	10%	6%	80%
		Medium	Conifers 6% Hardwoods 20%	10%	10%	10%	20%	11%	80%
		Heavy	Conifers and Hardwoods 20%	20%	20%	20%	41%	22%	80%
	Long	Very Light	Conifers 6% Hardwoods 20%	5%	6%	6%	0%	6%	80%
		Light	Conifers 6% Hardwoods 20%	6%	6%	6%	10%	6%	80%
		Medium	Conifers 6% Hardwoods 20%	10%	10%	10%	20%	11%	80%
		Heavy	Conifers and Hardwoods 20%	20%	20%	20%	41%	22%	80%
	Very Long	Very Light	Conifers 6% Hardwoods 6%	6%	6%	6%	0%	6%	80%
		Light	Conifers 6% Hardwoods 6%	6%	6%	6%	10%	6%	80%
		Medium	Conifers 6% Hardwoods 6%	6%	6%	6%	20%	6%	80%
		Heavy	Conifers 6% Hardwoods 6%	6%	6%	6%	41%	6%	80%

Harvesting Intensity	Frequency of Disturbance	Site Treatment	Estimated Net Carbon Loss by Soil Order						
			Alfisol	***Andisol***	***Inceptisol***	***Mollisol***	***Spodosol***	***Ultisol***	***Histosol***
Conversion	Conversion	Agriculture	30%	30%	30%	30%	30%	30%	80%
		Residential - Commercial	0%	0%	0%	0%	0%	0%	80%
		Timing of Estimated Emissions	30% in first 10 years	30% in first 10 years	30% in first 10 years	30% in first 10 years	30% in first 10 years	30% in first 10 years	8% every 10 years over 100 years

This percentage is multiplied by the soil carbon (CO_2e) estimate on a per acre basis and multiplied by the stand's acres to determine the emissions to report for each stand. The stand emissions are summed to determine the soil carbon emissions (CO_2e) reported annually. An example of the calculation is provided in Table B.20 below. For avoided conversion projects calculating baseline soil carbon, a weighted average must be used, taking into account the decadal soil carbon emissions, as shown in Table B.21.

Table B.20. Example: Calculations for Annual Soil Carbon Reporting

Reporting Year			**2012**						
A	B	C	D	E	F	G	H	I	J
Stand ID	Soil Order	Soil Carbon (tCO_2e) per Acre	Acres	Stand Soil Carbon (tCO_2e)	Harvesting Intensity	Disturbance Frequency	Site Preparation	Estimated Soil Carbon Loss %	Stand Soil Carbon Loss (tCO_2e)
	From Step 1	From Step 6		C **x** D	From Step 7a	From Step 7e	From Step 7d	Table B.19	I **x** E
1	Alfisol	85	595	50,575	Very High	Very Long	Heavy	6%	3,035
2	Alfisol	85	683	58,055	Light - Medium	Short	Very Light	0%	-
3	Alfisol	85	2,232	189,720	High	Long	Light	5%	9,486
Sum of Soil Carbon Emissions (tonnes CO_2e) for 2012									**12,521**

Table B.21. Example: Calculations for Avoided Conversion Baseline Soil Carbon Estimates

Conversion Type				**Agriculture**					
A	B	C	D	E	F	G	H	…	I
Stand ID	Soil Order	Soil Carbon (tCO_2e) per Acre	Acres	Timing of Estimated Emissions	Project Start Date Soil Carbon (tCO_2e)	Soil Carbon after 10 Years (tCO_2e)	Soil Carbon after 20 Years (tCO_2e)	…	Soil Carbon after 100 Years (tCO_2e)
	From Step 1	From Step 6			C **x** D	E **x** F		Table B.19	
1	Inceptisol	70	150	30% of stand soil carbon in first 10 years	10,500	7,350	7,350	…	7,350
2	Histosol	110	3500	8% of stand soil carbon every 10 years	385,000	354,200	323,400	…	77,000

B.2.10 Total Onsite Carbon Stocks and Calculating the Confidence Deduction

Annual reporting is conducted by summing the carbon stocks present at the end of the reporting period in all of the relevant carbon sources, sinks, and reservoirs for the project. The Reserve has developed a Monitoring Calculation Worksheet to assist in the reporting relevant pools and calculation of CRTs. The worksheet is available on the Reserve's Forest Project Protocol webpage in a bundle with the Harvested Wood Products Calculation Worksheet, and contains instructions for its use. Certain reported pools are sampled and the mean estimate is used for annual reporting. The number reported for the sampled pools is adjusted based on the confidence in the estimate of the carbon. The sampling error is calculated for each of the sampled pools at the 90 percent confidence level and subsequently calculated as a percentage of the mean, using the following steps:

Step 1: Calculate the mean and the standard error[42] of the inventory estimate (for each pool or combined pools where applicable, such as with standing live and dead wood).

Step 2: Multiply the standard error by 1.645.

Step 3: Divide the result in Step 2 by the total inventory estimate and multiply by 100. This establishes the sampling error (expressed as a percentage of the mean inventory estimate from field sampling) for a 90 percent confidence level.

[42] Under certain circumstances, the finite population correction factor is normally required for the calculation of the standard error. As a conservative measure, Project Operators may opt not to apply the finite population correction factor.

Table B.22. Example: Summing All Onsite Carbon Stocks and Calculating the Confidence Deduction

Carbon Pool	Source of Data	Project Type(s)	Required/ Optional	Mean CO_2e (Tonnes per Acre)	Sampling Error at 90% Confidence Level	Sampling Error as a Percentage of the Mean Carbon Pool Estimate
Data Derived from Sampling						
				Example Data		
Standing Live Trees	Sampled within project boundaries	All project types	Required	95	6	6.32%
Standing Dead Trees	Sampled within project boundaries	All project types	Required	6	2	33.33%
Soil Carbon	Sampled within project boundaries	Avoided Conversion	Optional	65	8	12.31%
				Sum of Reported Pools	Calculation of Combined Sampling Error	Calculation of Combined Sampling Error as a Percentage
Summarizing Sampled Data				All Reported Pools from Sampling	Combined Sampling Error as a Percentage*Sum of All Reported Pools from Sampling Used to Determine the Confidence Deduction	$U_S = \frac{((U_1 \mathbf{x} R_1)^2+(U_2 \mathbf{x} R_2)^2+ \ldots +(U_n \mathbf{x} R_n)^2)^{\wedge}0.5}{\lvert R_1 + R_2 + \ldots + R_n \rvert}$ *Where*, U_S = percentage uncertainty of the sum U_i = percentage uncertainty associated with pool *i* R_i = removal (emission) estimate for pool *i*
Summary of Example Data from Sampled Pools				**166**	**10.20**	**6.14%**
Data Not Derived from Sampling						
Soil Carbon Emissions	Standardized Guidance	All Projects	Required	-5 (Example)	NA Not Subject to Sampling Error	NA Not Subject to Sampling Error
Sum of Onsite CO_2e Tonnes				**156**	**NA**	**NA**

The per-acre unit must be expanded to the project area based on the number of acres in the project. The sum of onsite CO_2e tonnes for the project is input into the calculation worksheet for annual reporting.

B.2.10.1 Applying a Confidence Deduction to Sampled Estimates

Any forest carbon inventory derived from sampling will be subject to statistical uncertainty. Where statistical confidence is low, there is an increased risk of overestimating a project's actual carbon stocks and therefore a higher risk of over-quantifying GHG reductions and removals. To help ensure that estimates of GHG reductions and removals are conservative, Project Operators are required each year to apply a confidence deduction to the inventory of actual onsite carbon stocks. A confidence deduction is *not* applied to the forest carbon inventory when it is used to model baseline carbon stocks. Confidence deductions are applied, where appropriate, to estimated onsite forest carbon stocks each reporting period.

The confidence deduction must be updated each time the project is subject to a site visit verification but must remain unchanged between verification site visits. If increased sampling over time results in a lower confidence deduction at the time of a site visit verification, the lower deduction may be applied to inventory estimates in all previous years. The Reserve will issue CRTs in the current year for any increase in quantified GHG reductions and removals in prior years associated with the new (lower) confidence deduction. Conversely, if a loss of qualified sampling plots results in a higher confidence deduction, this higher deduction must also be applied to inventory estimates in all previous years. Any resulting decrease in creditable GHG reductions and removals for prior years will be treated as an avoidable reversal and must be compensated for by retiring CRTs in accordance with Section 7.3.2.

B.2.10.2 Applying a Confidence Deduction to Non-Aggregated Projects

The target sampling error for the combined inventory estimates for non-aggregated projects is +/- 5 percent of the mean at the 90 percent confidence level. Projects that cannot meet this target statistic are still eligible but may have to take a “confidence deduction” that reduces their net reported carbon stocks.

The process for calculating the combined sampling error at the 90 percent confidence level is shown above. The combined sampling error must be compared to the table below to determine the confidence deduction for the reporting period in which a site visit verification has occurred. The confidence deduction shall not be modified in the interim years between site visit verifications. The percent deduction from the table below is input into the calculation worksheet which calculates the net reported onsite stocks.

Table B.23. Forest Carbon Inventory Confidence Deductions Based on Level of Confidence in the Estimate Derived from Field Sampling

Sampling Error (Percent of Inventory Estimate)	Confidence Deduction
0 to 5%	0%
5.1 to 19.9%	(Sampling Error – 5%) to the nearest 1/10 percentage
20% or greater	100%

B.2.10.3 Applying a Confidence Deduction for Aggregated Projects

The target sampling error for the combined inventory estimates for aggregated projects is on a sliding scale based on the number of projects participating within the aggregate. Project Operators enrolled in an aggregate may submit project inventories with reduced sampling requirements based on the statistical principle that the targeted standard error (+/- 5 percent of the mean at the 90 percent confidence level) is achieved across the entire aggregate. Refer to the Reserve Guidelines for Aggregating Forest Projects for the targeted sampling error for individual aggregate participants.

B.2.11 Requirements for Calculating Carbon in Harvested Wood Products

A portion of the carbon in harvested trees continues to be sequestered for long periods of time as wood products. Standardized guidance is provided to account for forest carbon that remains sequestered in harvested wood products. The protocol bases the accounting of harvested wood products on the average amount of carbon sequestered over a 100-year period. The 100-year period is consistent with the Forest Project Protocol's definition of permanence. The average amount of carbon remaining sequestered over the 100-year period is determined by calculating the amount of carbon delivered to the mills, the portion of the carbon that is converted to wood products using a coefficient that estimates the mill's efficiency, and determining the wood product classes manufactured by the mill, as different wood products have different decay rates.

An estimate of the average carbon remaining in use over the 100-year term is provided for each wood product class, which is the basis of baseline and annual reporting of harvested wood products. Furthermore, some wood products eventually end up in landfills where anaerobic conditions serve to reduce the rate of further decomposition. Since the amount of harvested wood products that end up in landfills and the actual decay rate of the wood products in landfills are highly uncertain, the accounting of harvested wood products in landfills is included only when it is conservative to do so. Conservative in this case means that if, in a given reporting year, the amount of harvested wood products in the baseline exceeds the amount of harvested wood products in the project activity, the carbon in landfills is reported. If there is more harvesting of wood products in the project case than in the baseline case, harvested wood products are not considered in either the baseline or the project case.

The Reserve has developed a spreadsheet tool to assist in the calculation of harvested wood products, which is available on the Reserve's Forest Project Protocol webpage. The Harvested Wood Products Calculation Worksheet contains step by step instructions for its use. Project reporting of harvested wood products occurs on an annual basis. The volume of logs delivered to the mill in the baseline case remains static throughout the project life. However, the mill efficiencies and the wood product classes identified in a reporting period are applied to the baseline harvested wood products the same way they apply to the project harvested wood products. The intent of this policy is to provide the best comparison of project activity to baseline activity possible.

The spreadsheet is designed with default values for converting volumetric units from logs delivered to mills to cubic feet and the values of mill efficiencies to be used on a geographic basis. The annual reporting of carbon in trees harvested for wood products is based on the relative proportion of volume in trees harvested for wood products and volume delivered to the mill(s) in the baseline case. Therefore, the reporting of volume delivered to mills is essential to calculating the volume in trees harvested for wood products.

Mill efficiency estimates from the actual mills the project logs are delivered to can be used if data exists to support the claim in a form that can be verified. Users must identify the mill(s) the project logs are delivered to and input the volume that is manufactured into lumber, plywood, oriented strand board, non-structural panels, miscellaneous products, and paper/pulp. Where the wood product class is unknown, the Project Operator must classify the product as miscellaneous products. In order to quantify unknown products categorized as miscellaneous conservatively, miscellaneous products are assigned a default storage factor of zero.

Project Operators must provide an affidavit from the mill that the reported wood product classes are reasonable according to production records at the mill, unless they use the default product classes provided in the Assessment Area Data file. Again, the wood product classes reported for a given reporting year apply both to the project and the baseline case which eliminates the calculation of project benefits or detriments based on comparisons of the decay rates of wood products alone.

B.2.12 Improved Forest Management Leakage

Secondary Effects, or leakage, reflect market responses to changes in harvesting levels. The general assumption in this protocol is that modifying harvest in a Forest Project relative to baseline harvesting levels will lead the market to compensate via modifications to harvesting levels by other landowners. The greater the change in harvest by a Forest Project relative to baseline levels, the greater the response by the market to compensate.

Market leakage effects are accounted for under Improved Forest Management Projects by considering the impacts of shifting activities over the life of the project. Recognizing that risk of Secondary Effects from a project may be influenced by long term harvesting trends, the evaluation in Equation 6.10 considers cumulative harvest amounts since project inception. In some years, Secondary Effects may be negative, if project harvesting is below baseline harvesting (on both a cumulative and individual reporting period basis). If project harvesting later increases, deductions for prior negative Secondary Effects can be recouped. However, once all prior negative Secondary Effects are recouped, Secondary Effects when actual harvested carbon exceeds baseline harvested carbon are zero – under no circumstances shall the net balance of the Secondary Effects over the course of a project be positive. However, positive Secondary Effects may accrue as uncredited positive carryover that can counteract the amount of future negative Secondary Effects applied if baseline cumulative harvested carbon were to exceed actual harvested carbon again. Accruals of positive Secondary Effects carryover and their application against future negative Secondary Effects, if they occur, are calculated within the calculation worksheet.

Table B.24. Examples: How Secondary Effects Can Be Recouped and Positive Carryover Can Be Applied Over Time

a. Qualitative example

Reporting Period	Greater of Actual or Baseline		Protocol Equation Reference	Secondary Effect
	Annual	Cumulative		
1	Baseline	Baseline	Equation 6.10.B	Negative Secondary Effect resulting in deduction applied to GHG reductions
2	Actual	Baseline	Equation 6.10.B	Positive Secondary Effect resulting in recouping of previously deducted GHG reductions up until the cumulative Secondary Effect is zero
3	Actual	Actual	Equation 6.10.A	No Secondary Effect, excepting any previous negative Secondary Effect deductions that have not been recouped and including any positive Secondary Effects that are carried over to the following year
4	Baseline	Actual	Equation 6.10.C	No Secondary Effect, though adjusting any positive Secondary Effect carryover and carrying forward any remaining balance to the following year
5	Baseline	Baseline	Equation 6.10.B	Negative Secondary Effect resulting in deduction applied to GHG reductions, with deduction lowered by any positive secondary effects carryover from when actual cumulative harvest carbon exceeded baseline cumulative harvested carbon

b. Quantitative example

Reporting Period	1	2	3	4	5
Annual actual carbon in harvested trees	500	**1,400**	**1,400**	800	800
Annual baseline carbon in harvested trees	**1,000**	1,000	1,000	**1,000**	**1,000**
Cumulative actual carbon in harvested trees	500	1,900	**3,300**	**4,100**	4,900
Cumulative baseline carbon in harvested trees	**1,000**	**2,000**	3,000	4,000	**5,000**
Cumulative difference between actual and baseline C in harvested trees	(500)	(100)	300	100	(100)
Annual difference between actual and baseline C in harvested trees	(500)	400	400	(200)	(200)
Gross annual Secondary Effects	(100)	80	80	(40)	(40)
Adjusted gross annual Secondary Effects, not allowing positive cumulative Secondary Effects but not including positive Secondary Effects carryover	(100)	80	20	0	(40)
Carryover of positive Secondary Effects from prior year	NA	0	0	60	20
Net annual Secondary Effects	**(100)**	**80**	**20**	**-**	**(20)**

B.3 Modeling Carbon Stocks

This protocol requires the use of certain empirical models to estimate the baseline carbon stocks and project stocks of selected carbon pools within the project area for private land IFM projects (with the exception of the IFM default baseline approach). These models may also be used to supplement assessments of actual changes in carbon stocks resulting from the forest project.

B.3.1 Models and their Eligibility for Use with Forest Projects

Empirical models are used for estimating existing values where direct sampling is not possible or cost-effective. They are also used to forecast the estimations derived from direct sampling into the future. Field measurements (standing live and dead trees) provide the base input data for these models. Project Operators should be careful to ensure that all required data inputs for the models are included in the inventory methodology.

The models that simulate growth projections have two basic functions in the development and management of a forest project. Models project the results of direct sampling through simulated forest management activity. These models, often referred to as growth and yield simulation models, may project information regarding tree growth, harvesting, and mortality over time – values that must ultimately be converted into carbon in an additional step. Other models may combine steps and estimate tree growth and mortality, as well as changes in other carbon pools and conversions to carbon, to create estimated projections of carbon stocks over time.

Models are also used to assist in updating inventory plots so that the plots can represent a reporting year subsequent to their actual sample date. The model simulates the diameter and height increment of sampled trees for the length of time between their sampled date and the reporting year. Plot data can be projected for the length of time the projection method is expected to accurately reflect actual forest growth. Inaccurate updating of plot data can lead to the inability of a project to be verified. Verifiers are directed to randomly select plots or stands for verification. If the Project Operator's estimates deviate from the verifier's measurements, the verification will fail. Hence, it is required that plot data be no older than 12 years.

The following growth models have been approved:

- CACTOS: California Conifer Timber Output Simulator
- CRYPTOS: Cooperative Redwood Yield and Timber Output Simulator
- FVS: Forest Vegetation Simulator
- SPS: Stand Projection System
- FPS: Forest Projection System
- FREIGHTS: Forest Resource Inventory, Growth, and Harvest Tracking System
- CRYPTOS Emulator
- FORESEE

A Project Operator may update inventory plot data for estimating diameter and height growth by incorporating data obtained from sample plots, as in a stand table projection. An example of an appropriate method of applying a stand table projection is as follows:

1. The project area is stratified into even-age management and uneven-age management.

2. Diameter increment shall be based on the average annual increment of a minimum of 20 samples of radial growth for diameter increment for each 8 inch diameter-at-breast-height (DBH) class, beginning at 0 to 8 inch DBH for each management type (even-age or uneven-age). The average annual increment shall be added for each year according to the plot's sample date.
3. Height increment is based on regression curves for each management type (even-age or uneven-age) developed from height measurements from the same trees the diameter increment data was obtained. The estimated height shall be determined using the regression estimators for the 'grown' diameters as described above.

The Reserve may include additional models following approval of a state forestry authority (i.e., a state agency responsible for oversight of forests) who will acknowledge in writing that the model:

- Has been peer reviewed in a process that 1) primarily involved reviewers with necessary technical expertise (e.g., modeling specialists and relevant fields of biology, forestry, ecology, etc.), and 2) was open and rigorous
- Is parameterized for the specific conditions of the project area
- Limits use to the scope for which the model was developed and evaluated
- Is clearly documented with respect to the scope of the model, assumptions, known limitations, embedded hypotheses, assessment of uncertainties, and sources for equations, data sets, factors or parameters, etc.
- Underwent a sensitivity analysis to assess model behavior for the range of parameters for which the model is applied
- Is periodically reviewed

B.3.2 Using Models to Forecast Carbon Stocks

The use of simulation models is required for estimating a forest project's baseline carbon stocks (with the exception of projects using the Improved Forest Management default baseline approach). Models may also be required to forecast actual carbon stocks expected under the forest project (e.g., in conjunction with determining expected harvesting volumes or in updating forest carbon inventories).

Standing live tree information must be incorporated into the simulation models to project carbon stocks over time. If a model has the ability to convert biomass to carbon, it must include all the carbon pools required by this protocol. Standing dead trees must be assumed to be static over the baseline modeling. Exceptions to this rule are allowed if approved in writing by the Reserve prior to verification.

Projected baseline carbon stocks must be portrayed in a graph depicting time in the x-axis and carbon tonnes in the y-axis. Baseline carbon stocks must be projected forward from the forest project's start date. The graph should be supported with written characterizations that explain any annual changes in baseline carbon stocks over time. These characterizations must be consistent with the baseline analysis required in Section 6.

B.3.3 Modeling Requirements

A modeling plan must be prepared that addresses all required forecasting of baseline carbon stocks for the forest project (with the exception of projects using the Improved Forest

Management default baseline approach). The modeling plan shall contain the following elements:

1. A description of all silviculture methods modeled. The description of each silviculture method will include:
    a. A description of the trees retained (by species groups if appropriate) at harvest.
    b. The harvest frequency (years between harvests) for each silviculture method modeled.
    c. Regeneration assumptions.
2. A list of all legal constraints that affect management activities on the project area. This list must identify and describe the legal constraint, how the legal constraint affects the project area, and discusses the silviculture methods that will be modeled to ensure the constraint is respected.
3. A description of the site indexes used for each species and an explanation of the source of the site index values used.
4. A description of the model used and an explanation of how the model was calibrated for local use, if applicable.

Modeling outputs must include:

1. Periodic harvest, inventory, and growth estimates for the entire project area presented as total carbon tonnes and carbon tonnes per acre.
2. Harvest yield streams on modeled stands, averaged by silviculture method and constraints, which must include the period over which the harvest occurred and the estimated CO_2e of wood (CO_2e in logs delivered to mills) removed.

A.2.4 Grassland Project Protocol v2.1

CLIMATE ACTION RESERVE

Version 2.1 | February 13, 2020

Grassland

Project Protocol

Climate Action Reserve
www.climateactionreserve.org

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Abbreviations and Acronyms

AGC	Avoided grassland conversion
AGD	Animal grazing days
AOI	Area of Interest (within the NRCS Web Soil Survey application)
CARB	California Air Resources Board
CDL	Cropland Data Layer
CDM	Clean Development Mechanism
CFR	Code of Federal Regulations
CH_4	Methane
CO_2	Carbon dioxide
CRP	Conservation Reserve Program
CRT	Climate Reserve Tonne
CTIC	Conservation Tillage Information Center
DAYCENT	Daily CENTURY Model
EPA	U.S. Environmental Protection Agency
ERS	USDA Economic Research Service
ESA	Endangered Species Act
ESD	Ecological Site Description
FWS	U.S. Fish and Wildlife Service
GHG	Greenhouse gas
GRP	Grassland Reserve Program
GWP	Global warming potential
HCP	Habitat Conservation Plan
ICC	Irrigated Land Capability Classification
IDB	Inventory Database (from the NRI)
IPCC	United Nations Intergovernmental Panel on Climate Change
IRT	The Army Corps of Engineers-led Interagency Review Team
ISO	International Organization for Standardization
lb	Pound
LCC	Land Capability Classification
MODIS	Moderate Resolution Imaging Spectroradiometer
MLRA	Major Land Resource Area designations
NARR	North American Regional Reanalysis Product

NASA	National Aeronautics and Space Administration
NASS	USDA National Agricultural Statistics Service
NICC	Non-Irrigated Land Capability Classification
NLCD	National Land Cover Database
N_2O	Nitrous oxide
NRCS	USDA Natural Resources Conservation Service
NRI	Natural Resources Inventory
PIA	Project Implementation Agreement
QCE	Qualified Conservation Easement
Reserve	Climate Action Reserve
SHA	Safe Harbor Agreement
SOC	Soil organic carbon
SSR	Source, sink, and reservoir
SSURGO	Soil Survey Geographic database
t	Metric ton (or tonne)
tCO_2e	Metric ton of carbon dioxide equivalent
UNFCCC	United Nations Framework Convention on Climate Change
USDA	United States Department of Agriculture
USGS	United States Geological Survey
WSS	NRCS Web Soil Survey application

1 Introduction

The Climate Action Reserve (Reserve) Grassland Protocol provides guidance to account for, report, and verify greenhouse gas (GHG) emission reductions associated with projects that avoid the loss of soil carbon due to conversion of grasslands to cropland, as well as other associated GHG emissions. This protocol is designed to ensure the complete, consistent, transparent, accurate, and conservative quantification and verification of GHG emission reductions associated with an avoided grassland conversion project.[1]

The Reserve is an offset registry serving the California cap-and-trade program and the voluntary carbon market. The Reserve encourages actions to reduce GHG emissions and works to ensure environmental benefit, integrity, and transparency in market-based solutions to address global climate change. It operates the largest accredited registry for the California compliance market and has played an integral role in the development and administration of the state's cap-and-trade program. For the voluntary market, the Reserve establishes high quality standards for carbon offset projects, oversees independent third-party verification bodies, and issues and tracks the transaction of carbon credits (Climate Reserve Tonnes or CRTs) generated from such projects in a transparent, publicly-accessible system.[2] The Climate Action Reserve is a private 501(c)(3) non-profit organization based in Los Angeles, California.

Project Owners and Cooperative Developers that initiate avoided grassland conversion (AGC) projects use this document to quantify and register GHG reductions with the Reserve. The protocol provides eligibility rules, methods to calculate reductions, performance-monitoring instructions, and procedures for reporting project information to the Reserve. Additionally, all project reports receive independent verification by ISO-accredited and Reserve-approved verification bodies. Guidance for verification bodies to verify reductions is provided in the Reserve Verification Program Manual and Section 8 of this protocol. There are several additional resources which accompany this protocol document. Additional details for all of these resources can be found at the Grassland Protocol page on the Reserve's website: http://www.climateactionreserve.org/how/protocols/grassland/.

Resource	Required or Optional	Description
Grassland Project Parameters (MS Excel spreadsheet)	Required	This spreadsheet file contains parameters and emission factors which are required for the quantification of a grassland project. This includes stratum-level parameters, county-level parameters, and other necessary reference values. The parameters contained in this spreadsheet may be updated when new data becomes available. Stakeholders will be given advanced notice and guidance before updated parameters become effective for projects.
GrassTool v2.1 (MS Excel spreadsheet)	Optional	The GrassTool is built upon the quantification section of this protocol, allowing for Project Owners to conduct project quantification without first developing their own tool. It is updated periodically to enhance usability or correct errors.

[1] See the WRI/WBCSD GHG Protocol for Project Accounting (Part I, Chapter 4) for a description of GHG reduction project accounting principles.
[2] The online registry may be accessed from the Reserve homepage at: www.climateactionreserve.org.

Resource	Required or Optional	Description
Project Development Handbook (PDF)	Optional	This document provides additional context and description for the rules and requirements contained in the protocol. It is not considered to be official protocol language, and is not meant to be a standard of verification. It is informal guidance to help understand protocol requirements, and it is updated periodically.

2 The GHG Reduction Project

This section describes the GHG reduction project in terms of defining the project site, the related activities, the parties involved, and the possible project structures.

2.1 Background

Grasslands have the ability to both emit and sequester carbon dioxide (CO_2), the primary GHG responsible for human-caused climate change (1). Grasses and shrubs, through the process of photosynthesis, naturally absorb CO_2 from the atmosphere and store the gas as carbon in their biomass (i.e., plant tissues). As plants die and regrow, some of this carbon is also stored in the soils that support the grassland.

When grasslands are disturbed, such as when the land is tilled for crop cultivation, a portion of the stored carbon oxidizes and decays, releasing CO_2 into the atmosphere. The quantity and rate of CO_2 that is emitted may vary, depending on the particular circumstances of the land and the disturbance. Grasslands function as reservoirs in the global carbon cycle. Depending on how grasslands are managed or impacted by natural and human events, they can be a net source of emissions, resulting in a decrease to the reservoir, or a net sink, resulting in an increase of CO_2 to the reservoir. In other words, grasslands may have a net negative or net positive impact on the climate, depending on their characteristics and management.

Through sustainable management and protection, grasslands can play a positive and significant role to help address global climate change. This protocol is designed to take advantage of grasslands' unique capacity to sequester, store, and emit CO_2 and to facilitate the positive role that grasslands can play to address climate change. The protocol focuses on the avoided conversion of grasslands to cropland. Because conversion is avoided, we can never measure the exact GHG impacts of conversion activities on the project area, and thus cannot know exactly how much carbon would have been released if a particular area of land were converted. To avoid the cost and uncertainty related to site-specific soil sampling and ecosystem modeling, the Reserve has adopted a standardized, probabilistic approach to estimating baseline emissions for AGC projects. This approach is discussed in more detail in Section 5, as well as Appendix B.

2.2 Project Definition

For the purpose of this protocol, the GHG reduction project is defined as the prevention of emissions of GHGs to the atmosphere through conserving grassland belowground carbon stocks and avoiding crop cultivation activities on an eligible project area, as initiated by the recording of a perpetual conservation easement or an eligible transfer of ownership, as described in Section 3.2. The project area must be grassland, as defined below, and it must be suitable for conversion to crop cultivation, as defined in Section 3.3.1.2. The project area must have been in continuous grassland cover for at least 10 years prior to the project start date. The baseline scenario for all AGC projects is conversion to crop cultivation.

For the purposes of this protocol, grassland is defined as an area of land dominated by native or introduced grass species with little to no tree canopy. Other plant species may include woody shrubs, legumes, forbs, and other non-woody vegetation. Tree canopy may not exceed 10% of the land area on a per-acre basis. Areas that exceed this threshold may be eligible to use the

Forest Protocol.[3] For the purposes of this protocol, grassland may include managed rangeland and/or pastureland (as defined in Section 9).

The entire project area must be protected through a single conservation easement, except in cases where there are multiple easements with the same grantor (Grassland Owner) and grantee (Easement Holder). Multiple projects may be managed together as a project cooperative, as described in Section 2.2.2. In addition, the project area must have been privately-owned prior to the project start date, except in the case of non-federal public lands, where:

- The project area is legally able to be converted to cropland without requiring a rulemaking activity; and either
- The public agency in charge of management of the project area must have a legal directive to manage the lands that include the project area for profit; or
- A history of such management for profit,[4] including existing conversion, for similarly-situated lands can be documented during the 10 years prior to the start date.

An AGC project may involve moderate levels of seeding, organic fertilizer application (i.e., manure, compost, etc.), haying, forage harvesting, livestock grazing and/or irrigation as part of the project activity. Projects may not employ synthetic fertilizer additions; CRTs will not be issued for any calendar year during which this occurs. If grazing is employed in the project scenario, the livestock manure must not be managed in liquid form (i.e., containing less than 20% dry matter and subject to active management), and grazing activities must meet the criteria in Section 6.2.

Other recreational or economic activities incidental to the project activities may also occur on the project area (e.g., hunting, bird-watching, light haying), but only to the extent that the incidental activity does not threaten the integrity of the soil carbon stocks and is otherwise compatible with the maintenance of grassland under conservation. The Reserve maintains the right to determine whether an activity is "incidental" to the project or whether the presence of the activity would cause part or all of the project area to be considered an entirely different land use (i.e., not grassland). In those cases, the area used for such activities may not be considered to be part of the project area. For example, the extensive conversion of grasslands to forage crop production may result in that activity no longer being considered incidental to the project, and the subject land no longer eligible to be part of the project area.

The project lifetime for an AGC project is up to 150 years. This includes the crediting period, which may be up to 50 years (Section 3.4) and the permanence period, which is the 100 years following the crediting period (Section 3.5).

2.2.1 Defining the Project Area

An eligible project area consists of grassland that meets the criteria in Section 3 regarding the threat of conversion to cropland and the lack of legal barriers to such conversion. Only areas that are suitable for conversion to cropland, as defined in Section 3.3.1, are eligible to report under this protocol. The entire project area must be protected by the recording of one or more

[3] Information regarding the Reserve's voluntary forest carbon program can be accessed at: http://www.climateactionreserve.org/how/protocols/forest/. Information regarding the California Compliance Offset Protocol for forest projects can be accessed at: http://www.climateactionreserve.org/how/california-compliance-projects/compliance-offset-projects/.

[4] A practice of carrying out all leasing and sales based on fair market value may be considered "management for profit."

conservation easements (see Section 3.5.1). The area bound by the conservation easement(s) does not need to match the project area. However, the entire project area must be included within the area of a conservation easement. A single project may include multiple legal parcels if all of these conditions can be met. The project does not need to include every parcel listed on a deed, and project boundaries do not necessarily need to be coincident with parcel boundaries (i.e., the project area may contain a portion of a parcel without necessarily including the entire parcel).

The geographic boundaries defining the project area must be described in detail at the time a grassland project is listed on the Reserve (see Section 7.2 for details on project documentation). The boundaries must be defined using a georeferenced map, or maps, that displays legal property boundaries, public and private roads, major watercourses (fourth order or greater), topography, towns, and public land survey townships, ranges, and sections or latitude and longitude. The maps should be of adequate resolution to clearly identify the required features. The shapes delineating the project area must contain only areas that meet the eligibility requirements of this protocol. If the project area contains more than one legal parcel, these delineations must also be included. This map is not publicly accessible.

A Geographical Information System file (GIS shapefile) must be submitted with project documentation for the initial verification (see Section 7.2 for a full list of documentation required for each verification). If the project area is changed during a reporting period, the shapefile must be updated and resubmitted for the subsequent verification. The shapefile may be submitted as a KML file. The acres reported for the project must be based on the acres calculated from the shapefile. The project area can be contiguous or separated into tracts, but must share a common Grassland Owner, Project Owner, Easement Holder, and project start date. See Section 5.1 for guidance regarding the stratification of the project area.

After the project has been verified, sections of the project area may be removed (subject to the requirements of Section 5.4). The project area may also be expanded, so long as the new area(s) meets all requirements of this section. Any areas added to a project will share the same start date as the initial project area, but may not be eligible for crediting for the entire period (see Section 3.4). There are also timing requirements in relation to the date the new areas become bound by eligible easements, and the date the new areas are incorporated into the existing project area. The easements covering the new areas must have been put in place within 12 months of the start of the first reporting period for the new or expanded areas, in order to include the expanded project area. Project expansions may not be allowed in cases where a new area would change the eligibility determination of the original project. In such cases, the new area may need to be submitted as a new project. New projects may always be added to a project cooperative (see Section 2.3.4).

2.2.2 Project Cooperative

A “project cooperative” or “cooperative” is a collection of two or more individual grassland projects managed by a common entity (referred to as the “Cooperative Developer,” Section 2.3) that engage in joint monitoring, reporting, and verification (Sections 6.4, 7.6, and 8.1).

2.3 Project Ownership Structures and Terminology

A grassland project can be implemented using various ownership structures. Figure 2.1 displays possible ownership structures for grassland projects, indicating the flow of information and which entities are required to hold Reserve accounts. These are simplified representations;

actual project and cooperative structures may be more complex, but the relationships follow the same approach.

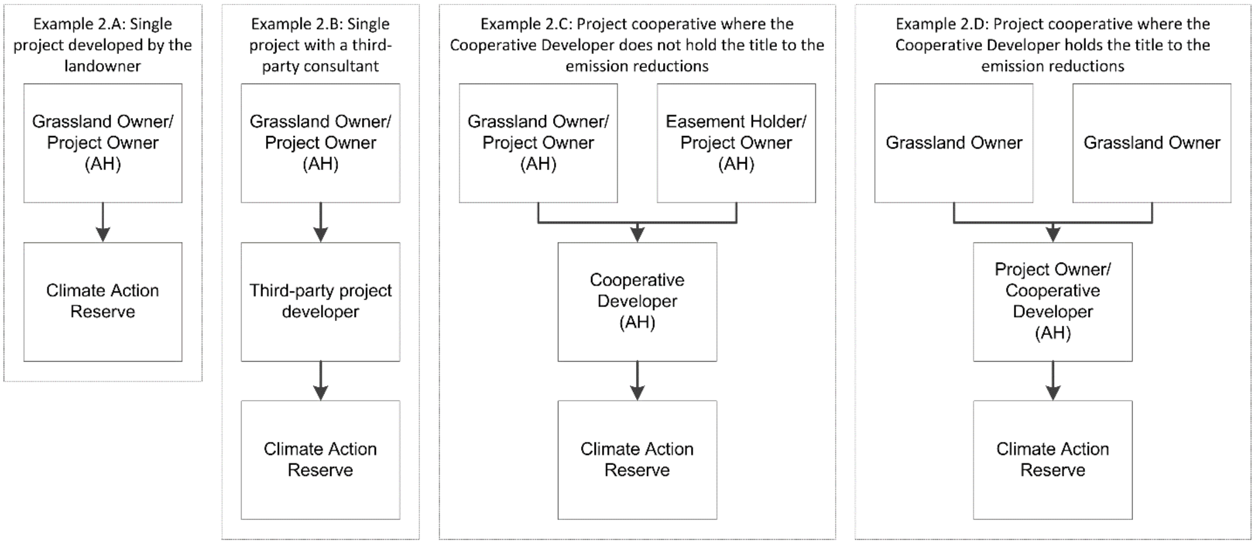

Figure 2.1. Grassland Project Ownership Structures and Terminology

Depending on the project structure, the existence and/or status of certain legal instruments must be verified in order to successfully register a project. The instruments required are described in general below. For every project, the fee owner of the land on which the project is implemented must demonstrate an understanding of the potential participation in a carbon offset program, either through implementing a project himself, or through clear conveyance of the GHG reduction rights associated with the land through a recorded legal instrument as described below. The sections outlined in Table 2.1 should be referred to for specific requirements for each respective legal instrument required. Additional discussion of these legal instruments can be found in Appendix D.

Table 2.1. Guide to Protocol Sections Related to Legal Instruments for Grassland Projects

Legal Instrument	Protocol Section(s)
GHG reduction rights contract	2.3.2
Indemnification agreement	2.3.2
Conservation easement	2.2, 3.2
Qualified Conservation Easement	3.5.1
Project Implementation Agreement	3.5.2
Reserve attestations (title, voluntary implementation, regulatory compliance)	2.3.2, 3.3.2, 3.6
Instruments associated with concurrently-joined conservation programs	3.3.2.1

2.3.1 Qualifications and Role of Grassland Owners

A Grassland Owner is an individual or a corporation or other legally constituted entity, city, county, state agency, or a combination thereof that has fee ownership and legal control of the land within the project area. A lessee is not a Grassland Owner. Deeded encumbrances that exist within the project area may prevent a fee owner from satisfying the definition of a Grassland Owner. The Grassland Owner is the entity that has the authority to execute and record a conservation easement on the project area. Any unencumbered soil carbon is presumed to be controlled by the Grassland Owner. Notwithstanding this presumption, the Reserve maintains the right to determine whether an individual or entity meets the definition of Grassland Owner.

2.3.2 Qualifications and Role of Project Owners

A Project Owner is the entity that holds legal title to the emission reductions related to the grassland project, and is responsible for undertaking the grassland project and registering it with the Reserve. The Project Owner may be a Grassland Owner, a holder of a conservation easement on the property, or they may be a third-party entity who has a signed contract with the Grassland Owner conveying title to the emission reductions. Title to the emission reductions may be conveyed through the conservation easement or in a separate contract, but in any case such rights must be legally established. If there are any Grassland Owners who are not party to the GHG reduction rights agreement, the Project Owner must also execute an indemnification stating that they will indemnify the Reserve in connection with any claims brought by other grassland owners or would-be grassland owners against the Reserve.[5] The Project Owner shall execute the Project Implementation Agreement (PIA) (see Section 3.5.2). The Project Owner is also responsible for the accuracy and completeness of all information submitted to the Reserve, and for ensuring compliance with this protocol, even if the Project Owner contracts with an outside entity to carry out these activities. The Project Owner must have a Reserve registry account[6] and must sign all required legal attestations (e.g., Attestation of Title, Attestation of Voluntary Implementation, and Attestation of Regulatory Compliance). Sample language related to ownership of emission reductions is included below, to be amended to fit each project's specific situation:

> *"TITLE TO CARBON OFFSET CREDITS. The [grantor/grantee- i.e., whichever party to the easement or agreement is the Project Owner] hereby retains, owns, and holds legal title to and all beneficial ownership rights to the following (the "Project Reductions"): (i) any removal, limitation, reduction, avoidance, sequestration or mitigation of any greenhouse gas associated with the Property including without limitation Climate Action Reserve Project No. [___] and (ii) any right, interest, credit, entitlement, benefit or allowance to emit (present or future) arising from or associated with any of the foregoing, including without limitation the exclusive right to be issued carbon offset credits or Climate Reserve Tonnes (CRTs) by a third party entity such as the Climate Action Reserve."*

In all cases, the Project Owner must attest to the Reserve that they have exclusive claim to the GHG reductions resulting from the project. Each time a project is verified, the Project Owner must attest that no other entities are reporting or claiming (e.g., for voluntary reporting or regulatory compliance purposes) the GHG reductions caused by the project.[7] The Reserve will not issue CRTs for GHG reductions that are reported or claimed by entities other than the Project Owner (e.g., grassland owners who are not the Project Owner). In the case of project

[5] A sample indemnification agreement is available at: http://www.climateactionreserve.org/how/protocols/grassland/.
[6] Information regarding Reserve accounts and the process for project submittal and registration is available here: http://www.climateactionreserve.org/how/projects/register/.
[7] This is done by signing the Reserve's Attestation of Title form, available at: http://www.climateactionreserve.org/how/program/documents/

cooperatives, each Project Owner must sign an attestation for each individual project. Attestations may be submitted by a third party, but must be signed by the Project Owner.

A Project Owner who will be managing the submittal, reporting, and verification of the grassland project through their own Reserve account will open a Project Developer account. A Project Owner whose project will be managed as part of a cooperative, and who will not be utilizing their Reserve account for any action beyond outgoing transfers of CRTs, will open a Project Owner account.

Project Owners are ultimately responsible for timely submittal of all required forms and complying with the terms of this protocol. Project Owners may designate a technical consultant or Cooperative Developer to manage the flow of documents and information to the Reserve. The scope of services provided by a technical consultant or Cooperative Developer should be determined by the Project Owner and the relevant management entity and reflected in the contracts between the Project Owner and the relevant management entity.

2.3.3 Qualifications and Role of Cooperative Developers

A "Cooperative Developer" is the entity that manages reporting and verification for a project cooperative, i.e., two or more individual grassland projects that report and verify jointly. A cooperative may consist of grassland projects involving multiple Project Owners. A Cooperative Developer must have an account on the Reserve.

A Cooperative Developer must open a Project Developer account on the Reserve and must remain in good standing throughout the duration of the cooperative(s) it manages. Failure to remain in good standing will result in all account activities of the participant projects in the cooperative(s) managed by that Cooperative Developer being suspended until issues are resolved to the satisfaction of the Reserve. In order for a Cooperative Developer to remain in good standing, Cooperative Developers must perform as follows:

- Complete cooperative contracts with Project Owners (see following section on Joining a Cooperative)
- Engage the services of a single verification body for all grassland projects enrolled in the cooperative in any given verification period
- Coordinate the submittal, monitoring, and reporting activities required by this protocol for all projects in the cooperative(s), observing all cooperative deadlines
- Coordinate a verification schedule that maintains appropriate verification status for the cooperative. Document the verification work and report to the Reserve on an annual basis how completed verifications demonstrate compliance (see Sections 6.4, 7.6, and 8.1)
- Maintain a Reserve account in good standing

As discussed in Section 2.3.2, Project Owners are ultimately responsible for timely submittal of all required forms and complying with the terms of this protocol.

2.3.4 Forming or Entering a Cooperative

Individual grassland projects may join a cooperative by being included in the cooperative's Cooperative Submittal Form[8] (if joining a cooperative at initiation) or by being added through the

[8] All forms referenced in this section are available at: http://www.climateactionreserve.org/how/program/documents/.

submission of a New Grassland Project Enrollment Form (if joining once the cooperative is underway).

The Cooperative Developer will initiate the creation of the cooperative by submitting a Cooperative Submittal Form. The Cooperative Submittal Form includes the submittal information for all of the individual projects to be initially included in the cooperative. If the Cooperative Developer is not the Project Owner for one or more projects within the cooperative, the appropriate Project Owner account will be confirmed at the time of project submittal. All documentation related to the cooperative and its participant projects is submitted by the Cooperative Developer. After successful verification, CRTs are issued to the accounts of the Project Owners for each project.

Individual grassland projects that have already been submitted to the Reserve may choose to join an existing cooperative by submitting a Cooperative Transfer Form to the Reserve. The Cooperative Developer must also submit a New Project Enrollment Form, listing that project area, if the cooperative is already underway. Emission reductions occurring on individual projects or new projects entering a cooperative are reported as part of the cooperative during the reporting period in which the transfer occurred.[9] The project will begin reporting with the cooperative no earlier than the beginning of the cooperative's current verification period. If the project has already been registered, either as an individual project or as part of another cooperative, reporting under the new cooperative may not include any period of time that has already been reported and verified.

The crediting periods of the individual projects within a cooperative are derived from their individual project start dates, and are not affected by the crediting periods of other projects within the cooperative. All projects within a cooperative must follow the same version of this protocol. If a project that is subject to a more recent version of the protocol wishes to enter an existing cooperative, the rest of the projects in that cooperative must elect to upgrade to the newer version of the protocol.

2.3.5 Leaving a Cooperative

Individual grassland projects must meet the requirements in this section in order to leave or change cooperatives and continue reporting emission reductions to the Reserve. Reporting must be continuous.

Individual Project Owners may elect to leave a cooperative and participate as an individual grassland project for the duration of their crediting period, effective as of the day after the end date of the project's most recently registered reporting period. To leave a cooperative and become an individual grassland project, the Project Owner must submit a Project Submittal Form to the Reserve, noting that it is a "transfer project" and identifying the cooperative from which it is transferring. For projects which leave a cooperative to become an individual project, the deadline for submittal of the subsequent monitoring or verification report (whichever is sooner) is extended by 12 months beyond the deadline specified in Section 7.4. The Project Owner must submit either a monitoring report or verification report (whichever is due) by this new deadline in order to keep the project active in the Reserve. If the Project Owner has a Project Owner account in the Reserve at the time they leave the cooperative, they must contact the Reserve Administrator to set up a Project Developer account.

[9] The transfer is considered to have occurred once the Reserve has approved the Cooperative Transfer Form and the New Project Enrollment Form.

To leave one cooperative and enter another cooperative, the Project Owner must submit a Cooperative Transfer Form to the Reserve prior to enrolling in the new cooperative. Reporting under the destination cooperative shall continue according to the guidance in Section 7.6.1.

2.4 Environmental Best Management Practices

The Grassland Protocol is intended to generate GHG reductions through the avoided conversion of grassland to cultivated cropland. The protocol also seeks to limit potential environmental harms caused by project activities through the requirements for regulatory compliance specified in Section 3.6. Environmental enhancements in addition to GHG reductions are beyond the scope of this document. However, the Reserve does strongly encourage Project Owners and Grassland Owners to adopt practices that provide additional benefits to the grassland ecosystem beyond the GHG reductions. Project Owners and Grassland Owners are encouraged to review and implement the appropriate recommendations for rangeland management developed by the United States Department of Agriculture (USDA) Natural Resources Conservation Service (NRCS) Conservation Effects Assessment Project (2). It is furthermore recommended that best management practices relevant to the project area be included as terms of the conservation easement(s) and/or the GHG reduction rights contract.

3 Eligibility Rules

Projects must fully satisfy the following eligibility rules in order to register with the Reserve. The criteria only apply to projects that meet the definition of a GHG reduction project (Section 2.2).

Eligibility Rule I:	Location	→	*Conterminous U.S. and tribal areas*
Eligibility Rule II:	Project Start Date	→	*No more than 12 months prior to project submission*
		→	*Record a conservation easement or eligible transfer of ownership*
Eligibility Rule III:	Additionality	→	*Meet performance standard*
		→	*Exceed legal requirements*
		→	*Satisfy credit and payment stacking requirements*
Eligibility Rule IV:	Project Crediting Period	→	*Emission reductions may only be reported during the crediting period, up to a maximum of 50 years*
Eligibility Rule V:	Permanence	→	*Maintain stored carbon for at least 100 years following issuance of CRTs*
		→	*Employ a Qualified Conservation Easement and Project Implementation Agreement*
Eligibility Rule VI:	Regulatory Compliance	→	*Compliance with all applicable laws*
Eligibility Rule VII:	Rangeland Health	→	*Periodic monitoring and adaptive management*

3.1 Location

Only projects located in the conterminous United States and on U.S. tribal lands are eligible to register reductions with the Reserve under this protocol. All sources within the project boundary (Figure 4.1) must be located within the conterminous United States. Under this protocol, reductions from international projects are not eligible to register with the Reserve. Grassland projects in tribal areas must demonstrate that the land within the project area is owned by a tribe or private entities. Projects are not eligible on organic soils (histosols),[10] including areas identified as wetlands or peatlands.

In addition, the project area must be located on land whose particular combination(s) of Major Land Resource Area (MLRA), soil texture, and prior land use history would result in emissions of soil carbon in the baseline scenario. To be eligible, the grassland project must be able to generate emission reductions through project activities. This is determined by identifying the project strata following the guidance in Section 5.1. The project location is ineligible if there are no baseline emission reductions from soil organic carbon in the first 10-year emission factor period.[11]

[10] Wherever soil types or characteristics are referenced in this protocol, they shall be assumed to describe the upper 20 cm soil layer, unless otherwise specified.
[11] Certain parameters required for project eligibility and quantification are contained in a separate document, *Grassland Project Parameters*, available at: http://www.climateactionreserve.org/how/protocols/grassland/.

3.2 Project Start Date

The project start date is defined as the date on which the project area is committed to the long-term management and protection of grassland and therefore avoids conversion to cropland.

Commitment to long-term management and protection of grassland must be demonstrated by one of the following:

1. Submitting the project to the Reserve.[12] Note that the project must meet the tests for additionality as of the project start date. Thus, this option is not applicable if the project is submitted after the recordation of a conservation easement covering the project area.
2. Recordation of a conservation easement on the project area, with a provision to maintain the project area as grassland for the protection of soil carbon. The project start date is the date the easement was recorded. If an easement is amended to meet the requirements of a Qualified Conservation Easement (Section 3.5.1), the recordation date of the unamended easement may be used for purposes of determining the project start date. If the Project Owner intends to use the date of recordation of the amended easement as the project start date, they must be able to show that, prior to amendment, the original conservation easement would not have violated any provisions of the legal requirement test (Section 3.3.2). If the project area is protected through multiple easements, the date of recordation of the earliest easement will establish the project start date under this option.
3. Transferring of property ownership to a public or private entity. The project start date is the date of property transfer. Projects are still required to record a conservation easement, as described above, prior to the initial registration.

To be eligible, the project must be submitted to the Reserve no more than 12 months after the project start date.[12]

Projects that have previously been submitted to and accepted by another offset project registry (transfer projects) may be eligible with a historical start date. Start date requirements for those projects are described in the Reserve Offset Program Manual.[13] Projects may always be submitted for listing by the Reserve prior to their start date.

3.3 Additionality

The Reserve strives to register only projects that yield surplus GHG reductions that are additional to what would have occurred in the absence of a carbon offset market.

Projects must satisfy the following criteria to be considered additional:

1. The performance standard test
2. The legal requirement test
3. Limits on payment and credit stacking

[12] Projects are considered submitted when the Project Developer has fully completed and filed the appropriate Project Submittal Form, available at: http://www.climateactionreserve.org/how/program/documents/.
[13] Please refer to the most current version of the Reserve Offset Program Manual, available at: http://www.climateactionreserve.org/how/program/program-manual/.

3.3.1 The Performance Standard Test

Projects pass the performance standard test by meeting a performance threshold, i.e,. a standard of performance applicable to all grassland projects, established by this protocol. The performance standard test is applied at the time a project applies for registration with the Reserve. The performance standard test for a grassland project has two parts:

1. Financial threshold
2. Suitability threshold

3.3.1.1 Financial Threshold

The Reserve has determined that there is a financial barrier to project activities due to the economic incentives to convert grassland to cropland. Rather than have each project demonstrate the existence of this barrier individually, the Reserve has developed a standardized threshold for financial additionality, referred to as the cropland premium. The cropland premium is determined as the percentage difference in the value (represented by land rental rates in $/acre) of cropland over pastureland in the county where the project is located. Project eligibility is based on the cropland premium for the county where the project is located, based on the conditions below:

1. Projects in counties with a cropland premium greater than 100% are eligible without any discount for uncertainty
2. Projects in counties with a cropland premium greater than 40% but less than 100% are eligible, but must apply a discount to their baseline emissions (see Section 5.2.4 for a description of DF_{conv}), unless the county can meet the requirements of step 4
3. Projects in counties with a cropland premium less than 40% are not eligible, unless the project meets the requirements of step 4
4. Projects in counties that meet the description of step 2 or step 3, or which are identified in the tables as having “No Data,” have the option to obtain a certified appraisal to determine a site-specific cropland premium, following the guidelines below for the appraisal process.

If more than 10% of the project area is located in a particular county, then eligibility must be assessed separately for that county.[14] If the county is not eligible, then that portion must be removed from the project area. If less than 10% of the project area is located in an ineligible county, that area may be included in the project area as long as it is physically contiguous with a portion of the project area which is located in an eligible county. A document and a spreadsheet with the eligibility status of each county are available from the Reserve website.[15] A paper copy of this list will be provided upon request. The standardized financial threshold will be updated whenever new rental rate data are published by the NASS. The new table of county-specific parameters will be published prior to the date on which the new values become effective.[16] When new tables are published, guidance will be given regarding the effective date. Figure 3.1 displays the county eligibility for projects submitted after December 31, 2019 (until such time as a new table and guidance are published by the Reserve). For counties that are identified as

[14] If this 10% threshold is exceeded only after an expansion of the project area per Section 2.2.1, the Project Owner must consult with the Reserve to determine whether the new project area is subject to an eligibility assessment separate from the existing project area.

[15] Certain parameters required for project eligibility and quantification are contained in a separate document, *Grassland Project Parameters*, available at: http://www.climateactionreserve.org/how/protocols/grassland/.

[16] Typically, rental rate data are released in September, in which case the Reserve will publish a new table in October with an effective date of January 1 of the following year. However, this could change if the NASS adopts a different schedule for data release.

having no data, a Project Owner may request that the Reserve examine the data for surrounding counties and determine whether the county may be considered eligible (and the appropriate value for DF_{conv}, if applicable). Additional information regarding the development of this threshold can be found in Appendix A.

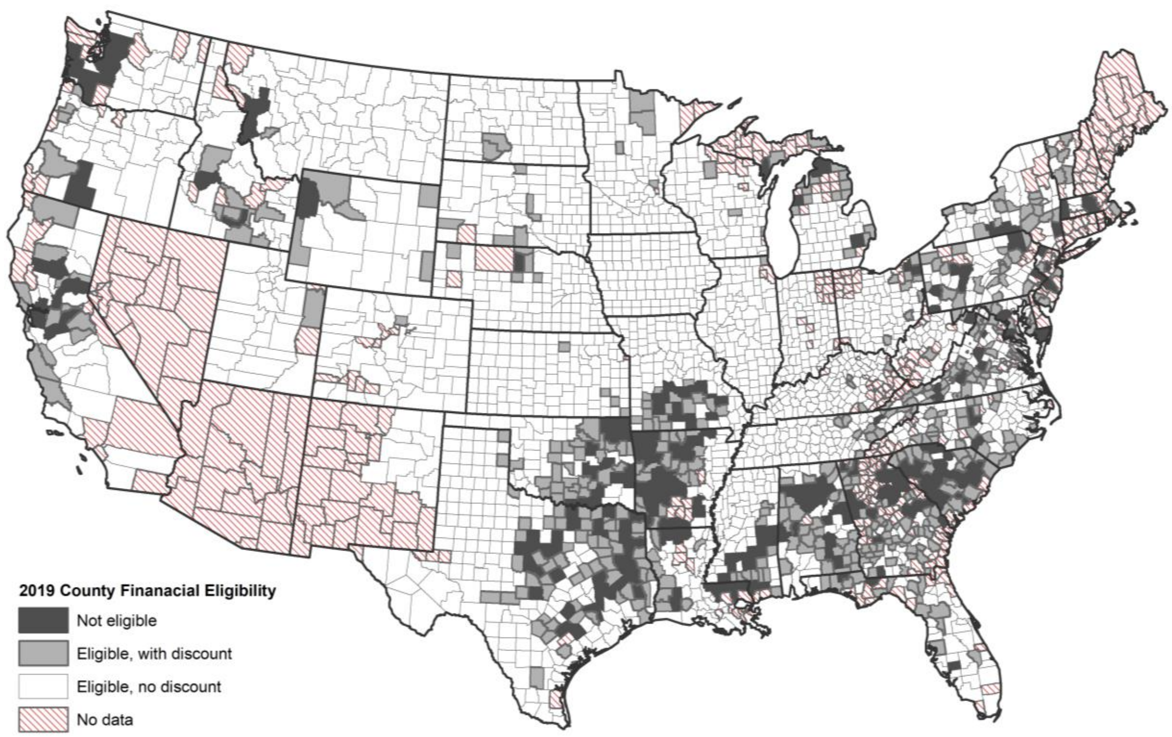

Figure 3.1. County Eligibility Map for Projects Submitted after December 31, 2019

Appraisal Option

If using step 4 above, a project may satisfy the financial threshold if the Project Owner provides an up-to-date[17] real estate appraisal for the project area (as defined in Section 2.2.1) indicating the following:

1. *The project area is suitable for conversion to cropland*. The appraisal must clearly indicate how the physical characteristics of the project area are suitable for crop cultivation, including the particular crops expected to be grown.
2. The appraisal must conform with the following minimum standards[18]:
    a. Appraisal reports shall be prepared and signed by a third-party, Licensed or Certified Real Estate Appraiser in good standing.
    b. Appraisal reports shall include descriptive photographs and maps of sufficient quality and detail to depict the subject property and any market data relied upon, including the relationship between the location of the subject property and the

[17] An appraisal will be considered "up-to-date" if it is finalized no more than12 months before or after the project start date.
[18] Adapted from Sections 5096.501 and 5096.517, Public Resources Code, State of California.

market data. The appraisal must provide a map that displays specific portions of the project area that are suitable for crop production. (For example, an appraisal that identified corn production as an alternative land use must specify the approximate acres suitable for both the crops and any related roads, buildings, or other infrastructure.)

c. Appraisal reports shall include a complete description of the subject property land, site characteristics and improvements. Valuations based on a property's development potential shall include:
    i. Verifiable data on the conversion potential of the land (e.g., Certificates of Compliance, Tentative Map, Final Map, approval for crop insurance, new breakings request form).
    ii. A description of what would be required for a conversion to cropland to proceed (e.g., legal entitlements, infrastructure).
    iii. Presentation of evidence that sufficient demand exists, or is likely to exist in the future, to provide market support for the conversion to cropland.
    iv. The appraisal must demonstrate that the slope of project area land is compatible with crop production by identifying two areas with similar average slope conditions to the project area within the project's MLRA that are currently in crop cultivation.
    v. The appraisal must also provide:
        1. Evidence of soil suitability for the type of expected agricultural land use.
        2. Evidence of water availability for the type of expected agricultural land use.

d. Appraisal reports shall include a statement by the appraiser indicating to what extent land title conditions were investigated and considered in the analysis and value conclusion.

e. Appraisal reports shall include a discussion of implied dedication, prescriptive rights or other unrecorded rights that may affect value, indicating the extent of investigation, knowledge, or observation of conditions that might indicate evidence of public use.

f. Appraisal reports shall include a separate valuation for ongoing grassland management prepared and signed by a certified or registered professional qualified in the field of specialty interest. This valuation shall be reviewed and approved by a second qualified, certified or registered professional, considered by the appraiser, and appended to the appraisal report. The valuation must identify and incorporate all legal constraints that could affect the valuation of the ongoing grassland management.

g. The appraisal must be conducted in accordance with the Uniform Standards of Professional Appraisal Practice[19] and the appraiser must meet the qualification standards outlined in the Internal Revenue Code, Section 170 (f)(11)(E)(ii).[20]

[19] The Uniform Standards of Professional Appraisal Practice may be accessed at: http://commerce.appraisalfoundation.org/html/2006%20USPAP/toc.htm

[20] Section 170 (f)(11)(E) of the Internal Revenue Code defines a qualified appraiser as "an individual who:
(I) has earned an appraisal designation from a recognized professional appraiser organization or has otherwise met minimum education and experience requirements set forth in regulations prescribed by the Secretary,
(II) regularly performs appraisals for which the individual receives compensation, and
(III) meets such other requirements as may be prescribed by the Secretary in regulations or other guidance."

3. *The alternative land use for the project area has a higher market value than maintaining the project area for sustainable grassland management, such that it meets the financial additionality threshold.* The appraisal for the property must provide an estimated fair market value for the rental rate (in US$ per acre per month) for the current grassland use condition of the project area (considering the land to be encumbered and thus unable to be converted to cropland) and an estimated fair market value of the rental rate for the anticipated use the project area as cropland. The appraisal must identify whether or not irrigation is considered in the valuation (or, alternatively, may provide estimations both with and without irrigation). The difference between the rental rate for cropland and the rental rate for grassland, divided by the rental rate for grassland, is the cropland premium for the project area. Eligibility is then determined according to the thresholds as outlined in the beginning of Section 3.3.1.1.

If a project that has been registered using the appraisal option later applies to expand the project area, they must first consult with Reserve staff to determine if a new appraisal is needed for the expanded project area.

3.3.1.2 Suitability Threshold

The project area must be suitable for conversion to cropland. Suitability is demonstrated by determining the Land Capability Classification (LCC) for the soil map units that are contained within or intersect the project area. Soil map units and their corresponding characteristics, such as LCC, are defined in the Soil Survey Geographic Database (SSURGO).[21] The LCC is divided into eight classes of decreasing value as cropland, with LCC I-IV being considered generally suitable for cultivation (3). SSURGO contains LCC for both irrigated and non-irrigated land uses. The Project Owner shall refer to the non-irrigated LCC (NICC) to determine eligibility for the project area. If a Project Owner would like to use the irrigated LCC (ICC) for a project, they must provide evidence that the project area would have access (both legal and physical) to irrigation in the baseline scenario. The entire project area must be assessed using a single version of the LCC and a single suitability threshold. This can be demonstrated by one or more of the following methods, subject to the verifier's professional judgment:

- Comprehensive assessment of the existence of available groundwater,[22] and the legal and economic feasibility of the Grassland Owner to access it from within the project area
- Documentation of the current availability of water rights and/or permits for the project area on or around the project start date
- Documentation of installation of new irrigation on lands within the project county within the 24 months prior to the project start date
- Evidence of ongoing irrigation practice on other parcels within the county

Grassland projects are generally only eligible on LCC I-IV soils, with allowances for a limited amount of LCC V-VI soils. LCC VII-VIII soils are not eligible for crediting. This protocol offers two options for determining the allowable amount of LCC V-VI soils in the project area: a default MLRA-specific threshold or an assessment of the LCC of local cropland. Project Owners may select either of the two options below.

[21] Additional background and details regarding SSURGO may be found at: http://www.nrcs.usda.gov/wps/portal/nrcs/detail/soils/survey/?cid=nrcs142p2_053627 (accessed 10/27/16).
[22] The groundwater assessment should be completed by an appropriately-trained professional, such as a Professional Geologist, Professional Engineer, or Certified Hydrogeologist.

If the project area is expanded at a later date, the suitability threshold is applied to the new, expanded project area as a whole. If the original suitability threshold was based on the ICC the project developer must demonstrate that the added land would have access to irrigation in the baseline scenario by either proving that the evidence for the initial project area applies to the expanded area or by providing additional evidence for the expanded area.

Option 1: Default Land Capability Classification Threshold Based on Major Land Resource Area

The Reserve has developed a table of default, MLRA-specific LCC thresholds. The specific default value for each MLRA is contained in the *Grassland Project Parameters* spreadsheet.[23] The percentage of cultivated land that is classified as NICC I-IV (rounded to the nearest whole number) represents the minimum allowable percentage of the project area for those land classes. For example, if the default value is 80%, the threshold for eligibility for that MLRA is 80% NICC I-IV, allowing for up to 20% NICC V-VI. Please see Appendix A for a description of how these thresholds were derived.

The default MLRA-specific thresholds are calculated using the NICC. Certain MLRAs with high levels of irrigation also have a default threshold provided based on the ICC. Project Owners have the option of applying the default NICC threshold, using the NICC values for their project area, or the default ICC threshold, using the ICC values for their project area. Use of the ICC values is subject to the requirements above to demonstrate access to irrigation in the baseline scenario.

If the project area includes more than one MLRA, the appropriate threshold for Class I-IV soils shall be an area-weighted average of the MLRA-specific thresholds (e.g., if half of the project area is in a MLRA with a threshold of 80%, and the other half is in a MLRA with a threshold of 70%, the overall threshold for the project area will be 75%).

Option 2: Local Cropland Assessment

In areas where the Project Owner believes that the option above does not accurately reflect the LCC of local cropland, a local assessment may be carried out. The assessment must include at least three actively-cultivated farms within 30 miles of the project area, with the total acreage of each farm being no less than the total acreage of the project area, and must include the entire area under cultivation for each property, excluding areas that are not used for crop cultivation. For each property the Project Owner shall identify the NICC of the soil map units, add up the acreage for each NICC across all properties in the assessment, and determine the percentage by area for NICC I-IV land. The fraction of cultivated land that is classified as NICC I-IV (rounded to the nearest whole number) represents the minimum allowable fraction of the project area for those land classes. This analysis may be conducted using the ICC values, in which case the Project Owner must follow the requirements above to demonstrate access to irrigation in the baseline scenario. Project Owners are strongly encouraged to consult with Reserve staff when conducting an assessment under this option.

3.3.2 The Legal Requirement Test

All projects are subject to a legal requirement test to ensure that the GHG reductions achieved by a project would not otherwise have occurred due to federal, state, or local regulations, or

[23] Certain parameters required for project eligibility and quantification are contained in a separate resource, *Grassland Project Parameters*, available at: http://www.climateactionreserve.org/how/protocols/grassland/.

other legally binding mandates. The legal requirement test for grassland projects involves three parts to ensure the project activity is allowed but not compelled:

1. There must be no federal, state, or local regulation for the project area to be maintained as grassland, either pre-existing or subsequent, or other pre-existing legally binding mandate, agreement, contract[24], deed restriction or deeded encumbrance[25] for the project area to be maintained as grassland (other than the easement that is enacted for the project); and,
2. There must be no zoning, permitting, ownership, or other legal obstacle to the conversion of the project area to cropland; and,
3. There must be no federal, state, or local regulation that would prohibit ongoing management of the project area as cropland.

Parts 1 and 2 are assessed as of the project start date. Part 3 is assessed on an ongoing basis following the project start date. Voluntary agreements that can be rescinded, such as rental contracts, are not considered legal requirements. Temporary or emergency restrictions or regulations shall be assessed with regard to the legal requirement test so long as they constitute a legally binding mandate, as described in this section. If a temporary legal restriction would violate parts 1 and/or 2 above, the project may delay implementation until such time that the project may pass the legal requirement test. If a temporary legal restriction violates part 3 above, the project is ineligible to receive CRTs for the period of time during which the regulation is effective.

Habitat Conservation Plans (HCPs) and Safe Harbor Agreements (SHAs) are voluntary agreements that shield landowners from certain liabilities under the Endangered Species Act. Agreements of this nature that were approved more than 6 months prior to the project's start date are considered to be pre-existing legally binding agreements.[26] Agreements of this nature that are approved no more than 6 months prior to the project's start date and that satisfy Section 3.3.2.1 are not considered pre-existing legally binding agreements for the purpose of the legal requirement test.[27]

Any agreement that serves to generate credits or payments for ecosystem services derived from the land is subject to the eligibility requirements in Section 3.3.3.

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[24] An agreement that can be enforced specifically, that is, where a party to the agreement (who is not participating as a "Grassland Owner") can prevent the physical breaking of the grassland, is considered a binding legal requirement.

[25] Unless all parties with a potential claim to soil carbon ownership participate in the project as Grassland Owners, per Section 3.2, any pre-existing encumbrance or restriction or any other recorded agreement, must expressly and unequivocally assign soil carbon ownership and control to the participating Grassland Owner(s) and/or expressly permit the participating Grassland Owner(s) and Project Developer(s) to undertake a soil carbon offset project on the project area. Any subsequent legally binding agreement must be made subordinate to the PIA (if applicable) and project-related conservation easement; the terms of a subsequent legally binding agreement must not be incompatible with an AGC project. See Sections 2.3.2 and 3.5.1 for more information on eligibility requirements regarding title recordings and encumbrances.

[26] While voluntary in nature, the penalties for terminating HCPs or SHAs are such that they are effectively legally-binding in the opinion of the Reserve. The allowance for agreements approved within 6 months of the project start date is based on the opinion that this represents a "concurrent" activity.

[27] While an agreement may not violate the legal requirement test, an easement or other deed restriction associated with the performance of that agreement may be a pre-existing legal requirement, and therefore disqualify certain portions, if not all, of the agreement area. See Section 3.3.2.1.

Deeded encumbrances, such as conservation easements, may effectively control soil carbon. Deeded encumbrances that are enacted prior to the project start date are considered legally binding mandates for the purposes of the legal requirement test.

To satisfy the legal requirement test, the Project Owner must submit a signed Attestation of Voluntary Implementation form[28] as part of the verification activities for the initial verification (see Section 8). In addition, the project's Monitoring Plan (Section 6) must include procedures that the Project Owner follows to ascertain and demonstrate that the project at all times passes the legal requirement test.

3.3.2.1 Requirements for Concurrent Legally Binding Agreements

A Grassland Owner may concurrently enter into a legally binding agreement related to ecosystem services or protection on the project area, subject to Sections 3.3.2 for liability shielding agreements and/or Section 3.3.3 for ecosystem services or protection credit and payment stacking, under the following conditions. For liability shielding programs, i.e., HCPs and SHAs, an agreement is considered concurrently entered into if the legal agreement is approved no more than 6 months prior to the project start date. For credit and payment stacking programs, the agreement is considered concurrently entered into if the easement required by the ecosystem program serves both the ecosystem services program and the start date requirement of the Grassland Protocol.

The Grassland Owner must ensure that the agreement, and/or the program under which the agreement is authorized, provides sufficiently clear language to demonstrate the legal additionality of the grassland project. Specifically, the agreement must make explicit that the Grassland Owner has the right to use the land covered by the agreement for the purposes of participating in a carbon offset market. The Reserve maintains the right to determine whether this issue is clear.

For agreements that require land to be put under perpetual conservation easement, the easement may also serve the requirements of a grassland project so long as the easement conforms to the requirements of Section 3.2. For agreements that require at least one perpetual conservation easement but allow for multiple subsequent easements, each easement should be evaluated individually. If any easement does not conform to Section 3.2, the portion of the land covered by that easement is ineligible as a project area.

3.3.3 Ecosystem Services Credit and Payment Stacking

When multiple ecosystem services credits or payments are sought for a single activity on a single piece of land, with some temporal overlap between the different credits or payments, it is referred to as "credit stacking" or "payment stacking," respectively (4). Under this protocol, credit stacking is defined as receiving both offset credits and other types of mitigation credits for the same activity on spatially overlapping areas (i.e., in the same acre). Mitigation credits are any instruments issued for the purpose of offsetting the environmental impacts of another entity, such as emissions of GHGs, removal of wetlands or discharge of pollutants into waterways, to name a few. Payment stacking is defined as issuing mitigation credits for a best management or conservation practice that is also funded by the government or other parties via grants, subsidies, payment, etc., on the same land.

[28] Attestation forms are available at http://www.climateactionreserve.org/how/program/documents/.

Any type of conservation or ecosystem service payment or credit received for activities on the project area must be disclosed by the Project Owner to the verification body and the Reserve on an ongoing basis.

3.3.3.1 Credit Stacking

The Reserve identified two mitigation credit market opportunities that need to be assessed as part of the eligibility of a grassland project. These markets credit the same activity on the same acreage as a grassland project: permanently conserving grassland.

Endangered Species Habitat Credits

Endangered species habitat credits can be generated through habitat conservation banks. These conservation banks are authorized under Section 10 of the Endangered Species Act (ESA) to restore, create or otherwise protect endangered species habitat (5). Section 10 allows landowner-developers to perform certain actions that would otherwise result in an illegal taking of an endangered species or its habitat under Section 9 of the ESA, provided that they receive and comply with an incidental take permit from the U.S. Fish and Wildlife Services (FWS)[29]. The permit requires the landowner-developer to mitigate the negative impacts of the activity on the habitat, and may allow the landowner-developer to achieve this mitigation by purchasing – or generating – endangered species habitat credits from habitat conservation banks.

In order to establish a conservation bank and generate endangered species credits, FWS requires landowner-bankers to enter into a conservation bank agreement with the FWS and other relevant government agencies, and to record a perpetual conservation easement on the land covered by the conservation bank. A Grassland Owner can concurrently seek the establishment of a conservation bank on the project area, but the Grassland Owner must ensure that both the conservation bank agreement and the perpetual easement provide sufficiently clear language to demonstrate the additionality of the grassland project, i.e., that potential revenues from the grassland project were considered at the time of the negotiation of both of these agreements.

The date of the easement recordation is subject to the start date requirements in Section 3.2 and the easement itself is subject to the easement requirements in Section 3.2. The conservation bank agreement is not considered to be a pre-existing legal requirement for the purposes of the legal requirement test so long as it satisfies Section 3.3.2.1.

Furthermore, FWS specifies that land used to establish conservation banks must not be previously designated for conservation purposes.[30] It is thus reasonable to assume that FWS would not approve a conservation bank and issue endangered species habitat credits to lands already engaged in a grassland project. However, it is ultimately the decision of FWS if such subsequent credit stacking is allowed.

Wetland Credits

Under the guidelines established for Section 404 of the Clean Water Act, developers may impact a wetland if those impacts are offset through the restoration, creation, enhancement or preservation of another wetland elsewhere. The Army Corps of Engineers-led Interagency

[29] U.S. Code Title 16, Chapter 35, §1539 - Exceptions (2009).
[30] *Ibid*.

Review Team (IRT)[31] may issue a Department of Army permit to authorize such actions subject to the creation of a wetland mitigation bank.[32] In some cases, wetland mitigation banks may include and credit the preservation of upland habitat that could be eligible under this protocol.

Similar to conservation banks, the acreage covered by mitigation banks is required to be protected in perpetuity.[33] A Grassland Owner can concurrently seek the establishment of a mitigation bank on the project area, but the Grassland Owner must ensure that both the mitigation bank agreement and the perpetual easement provide sufficiently clear language to demonstrate the additionality of the grassland project, i.e., that potential revenues from the grassland project were considered at the time of the negotiation of both of these agreements.

The date of the easement recordation is subject to the start date requirements in Section 3.2 and the easement itself is subject to the easement requirements in Section 3.2. The mitigation bank agreement is not considered to be a pre-existing legal requirement for the purposes of the legal requirement test so long as it satisfies Section 3.3.2.1.

Furthermore, federal law states that under no circumstances may the same credits be used to provide mitigation for more than one permitted activity but that, where appropriate, mitigation banks may be designed to holistically address requirements under multiple programs and authorities for the same activity.[34] It is then reasonable to assume that the IRT would not approve a mitigation bank and issue wetland credits to lands already engaged in a grassland project. However, it is ultimately the decision of the IRT if such subsequent credit stacking is allowed.

3.3.3.2 Payment Stacking

The Reserve has identified two general types of payments that support the grassland activities being credited under this protocol: “landscape-scale” payments and “enhancement” payments. The majority of these payments are available via programs implemented by the USDA NRCS. NRCS expressly allows the sale of environmental credits from enrolled lands,[35] but does not provide any further guidance on ensuring the additional environmental benefit of any payment for ecosystem service stacked with an NRCS payment.

Landscape-Scale Payments

Landscape-scale payments generally come from land conservation programs that prevent grazing and pasture land from being converted into cropland, used for urban development, or developed for other non-grazing uses. Participants in these programs voluntarily limit future development of their land through the use of long-term contracts or easements, and payments are generally made based on the value of the land being protected. Thus, these payments are incentivizing the same project activity as this protocol. Examples of landscape-scale payments include:

- NRCS Grasslands Reserve Program (2008 Farm Bill)
- NRCS Conservation Reserve Program (2008 Farm Bill)
- NRCS Farm and Ranch Lands Protection Program (2008 Farm Bill)

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[31] The Army Corps of Engineers is the chair; other members can be EPA, FWs, NRCS, NOAA and other federal, state, tribal, and local agency representatives.
[32] Code of Federal Regulations, Title 33, Part 332 (33 CFR 332).
[33] 33 CFR 332.3(h)(1)(v).
[34] 33 CFR 332.3 (j)(1)(ii).
[35] Environmental Quality Incentives Program: 7 CFR §1466.36; CSP, 7 CFR §1470.37.

- NRCS Agricultural Conservation Easement Program (2014 Farm Bill)
- Conservation easement support offered by non-governmental organizations such as Ducks Unlimited, The Nature Conservancy and the Trust for Public Land (which are often themselves funded by government programs)

If a Grassland Owner concurrently seeks a landscape-scale payment on the project area, any easement or agreement on the project area is subject to the start date requirements in Section 3.2 and the legal requirement test in Section 3.3.2.

Furthermore, under the current rules of government funded programs the recordation of a new permanent conservation easement in order to initiate a grassland project would disqualify the lands from continued participation in any NRCS payment program.[36] Therefore, the Reserve does not expect lands participating in such programs will have the opportunity to stack payments once the project easement has been recorded, or subsequently stack such payments.

Because every available landscape-scale payment is not comprehensively addressed by the protocol at this time, the Project Owner must disclose any such payments to the verifier and the Reserve on an ongoing basis. The Reserve maintains the right to determine if payment stacking has occurred and whether or not it would impact project eligibility.

Enhancement Payments

Enhancement payments provide financial assistance to landowners in order to implement discrete conservation practices that address natural resource concerns and deliver environmental benefits. For government-funded enhancement payments, participants sign short-term contracts and receive annual cost-share payments specific to the conservation practice they have implemented. Examples of relevant enhancement payments include:

- NRCS Environmental Quality Incentives Program (2014 Farm Bill)
- NRCS Conservation Stewardship Program (2014 Farm Bill)
- NRCS Continuous Conservation Reserve Program (2008 Farm Bill)
- NRCS Wildlife Habitat Incentive Program (2008 Farm Bill)

The practices that are compensated for by the programs above can only occur on land that is being maintained as grassland; however the payment contracts do not purport to pay for the preservation of the grassland, only its enhancement. Furthermore, the programs do not, in practice, sufficiently incentivize the preservation of grassland, much less compensate for the permanent conservation of grassland. Because of this, Grassland Owners may pursue enhancement payments without restriction.

Because every available enhancement payment is not comprehensively addressed by the protocol at this time, the Project Owner must still disclose any such payments to the verifier and the Reserve on an ongoing basis.

3.4 Project Crediting Period

The baseline for any grassland project registered under this protocol is valid for up to 50 years. This means that a registered grassland project is eligible to receive CRTs for GHG reductions

[36] Guidance on eligibility criteria for the CRP program, for both new enrollments and re-enrollments can be found here, respectively:
http://www.fsa.usda.gov/Internet/FSA_File/gs43factsheet.pdf
http://www.fsa.usda.gov/programs-and-services/conservation-programs/current-participants-general-public/index

quantified using this protocol, and verified by Reserve-approved verification bodies, for a period of up to 50 years following the project's start date. Certain strata may not generate baseline emissions for the full 50 years (as evidenced by a baseline emission factor for organic carbon loss equal to zero for a particular emission factor period), in which case the maximum crediting period is less than 50 years.

In the case of project cooperatives, project crediting periods are tied to each individual grassland project within the cooperative and their respective start dates. Thus, unless all of the projects in the cooperative share the same start date, there is not a single crediting period applicable to the entire cooperative.

In the case of project expansions, the entire project area will be bound to the existing project start date. However, the newly added project areas will only be eligible to receive credits beginning on the date the new portion of the project area became bound by the conservation easement or was transferred to the Grassland Owner, provided that this does not predate the reporting period during which the project area is expanded. In the latter case, the newly added project areas will be eligible to receive credits beginning with the reporting period start date during which the expansion took place.

Projects may elect to end their crediting period at any time. Any CRTs that have been issued are subject to the permanence requirements described in Section 3.5. Any project that wishes to end its crediting period must notify the Reserve prior to the next monitoring or reporting deadline, as determined in Section 7.4. If a project chooses to end its crediting period, no future emission reductions may be reported. If a project would like to forgo credits for a period of time in order to delay verification, this is considered a zero-credit reporting period.[37]

3.5 Requirements for Permanence

To validly offset GHG emissions, the reversible emission reductions credited under this protocol must be permanent. An emission reduction is considered reversible if it is related to carbon which remains stored in a carbon pool, such as soil organic carbon. An example of a non-reversible emission reduction on a grassland project would be the avoided N_2O emissions related to baseline fertilizer use. For the purposes of this protocol, an emission reduction is considered "permanent" if the quantity of carbon associated with that reduction is stored for at least 100 years following the issuance of a credit for that reduction. Once an emission reduction is considered permanent, it is no longer considered reversible. For example, if CRTs are issued to a grassland project in year 24 following its start date, soil carbon in the project area must be maintained through at least year 124. To meet this requirement, Project Owners must monitor and verify a grassland project for a minimum period of 100 years following the issuance of any CRT for GHG reductions achieved by the project, unless the project is terminated. Failure to maintain ongoing monitoring and verification may result in the automatic termination of the project. Note that this means that monitoring and verification for a project must continue even after the end of the project's crediting period. The period of time after the project crediting period has ended and before the minimum time commitment has been met is referred to as the "permanence period".

If carbon is released before the end of the 100-year period after a CRT is issued, the release is termed a "reversal". A reversal occurs if stored carbon is actually released through a disturbance of the project area, or is deemed to be released through termination of the project

[37] See the Reserve Offset Program Manual, available at: http://www.climateactionreserve.org/how/program/program-manual/.

or a portion of the project. Reversals may impact only a portion of the project area or the entire project area.

This protocol distinguishes between two categories of reversals, avoidable and unavoidable, and specifies separate remedies for each. Many biological and non-biological agents, both natural and human-induced, can cause reversals. Some of these agents cannot completely be controlled (and are therefore “unavoidable”), such as natural agents like fire, insects, and wind. This protocol also takes into consideration the extent to which a Project Owner has contributed towards the reversal through negligence, gross negligence or willful intent. Thus reversals caused by biological agents, where the Project Owner has not contributed to the reversal through negligence, gross negligence or willful intent, are considered unavoidable.

An avoidable reversal occurs if:

1. The Project Owner voluntarily terminates the project prior to the end of the 100-year time commitment. A Project Owner may voluntarily terminate the entire project, or a portion of the project area. If only a portion is terminated, then the reversal is considered to affect only the terminated area.
2. There is a breach of certain terms described within the Project Implementation Agreement (see Section 3.5.2, below). Such a breach results in the entire project being automatically terminated.
3. The Project Owner prematurely ceases ongoing monitoring and verification activities. Monitoring, reporting, and verification requirements are described in Sections 6, 7, and 8. Cessation of monitoring and verification results in the entire project being automatically terminated.
4. Any activity occurs on the project area that leads to a significant disruption of soil carbon. Examples include, but are not limited to, cropping activities (conversion to cropland), eminent domain, mining or drilling activities, or installation of wind turbines. In most cases, such disturbances would not constitute a reversal on the entire project area.
5. A natural disturbance occurs to the soil carbon in the project area, and the Reserve determines that the disturbance is attributable to the Grassland Owner’s or Project Owner’s negligence, gross negligence, or intentional mismanagement of the project area as grassland.

Avoidable reversals must be communicated to the Reserve and compensated for by the Project Owner, as prescribed in Section 5.4.

To ensure that the permanence obligations are guaranteed for the duration of the minimum time commitment, projects are required to employ a Qualified Conservation Easement (QCE) (Section 3.5.1) and a Project Implementation Agreement (Section 3.5.2).

For the purposes of this protocol, both QCEs and the PIA must be effective for 100 years following the issuance of CRTs. However, it may be the case that state law for the project area places limitations on the term length for contracts of this sort. For example, in North Dakota, property easements and restrictions are subject to a maximum limit of 99 years.[38] CRTs will only be issued for periods of time for which the required easement(s) are effective for at least 100 years following the year in which the emission reduction was generated. For projects where

[38] North Dakota Century Code §47-05-02.1, *Requirements of easements, servitudes, or nonappurtenant restrictions on the use of real property*. Accessible at: http://www.legis.nd.gov/cencode/t47.html.

length of property restrictions is limited by state law, CRTs issued for any given reporting period shall be held by the Reserve for a period of time based on the contract length. These CRTs shall be released following a subsequent renewal of the property restrictions such that the restrictions are effective through a date that is at least 100 years after the end of the relevant reporting period.

For example, if a verification period covers two 12-month reporting periods, and a 99-year easement is recorded at the end of the verification period, CRTs will only be issued for the first reporting period. CRTs for the second reporting period shall be withheld until such time as the easement is rerecorded, thus ensuring permanence for at least 100 years from the end of the second reporting period.

3.5.1 Qualified Conservation Easements

A conservation easement is required for all grassland projects. The area bound by the conservation easement does not need to match the project area. However, the entire project area must be included in the area of the conservation easement. A Qualified Conservation Easement (QCE) is one whose terms prevent the conversion of the project area from grassland to another land use, such that avoidable reversals are sufficiently precluded as long as the easement is enforced. For example, whereas a basic conservation easement may only restrict the subdivision and/or development of the project area, a QCE would also restrict activities such as plowing and farming, which could release carbon stored in the soil. The QCE may allow for other activities, such as road or building construction, on the land bound by the easement. However, insofar as these activities would result in a land use other than grassland, the areas where they are allowed should be specified in the QCE and subsequently excluded from the project area in order to avoid the occurrence of a reversal due to such activities. Additionally, the QCE may make reference to the carbon project and simply specify that any non-grassland land use must occur outside of the specified project area. The language of the QCE should be sufficiently clear to reasonably prevent cultivation on the entire project area.

All QCEs must include a statement indicating that the easement is granted pursuant to the state enabling statute for conservation easements for the state in which the project is located (e.g., California Civil Code Section 815). There are additional provisions for project conservation easements that the Reserve strongly encourages, but does not require. For enhanced transparency and legal clarity, the conservation easement should explicitly 1) refer to, and incorporate by reference, the terms and conditions of the PIA and the GHG reduction rights agreement, thereby binding both the grantor and grantee – as well as their subsequent assignees – to the terms of the agreements for the full duration of the grassland project's minimum time commitment, as defined in Section 3.5 of this protocol; and 2) make all future encumbrances and deeds subject to the PIA.[39] It is also recommended that the QCE incorporate and require environmental best management practices for rangeland management (Section 2.4).

3.5.2 Project Implementation Agreement

Permanence obligations must be guaranteed through a legal agreement that obligates the Project Owner to conduct monitoring activities on the project area for the required period of 100 years following CRT issuance, and to compensate for avoidable reversals that occur during that period. For grassland projects this agreement is known as the Project Implementation

[39] The approach to subordination of the PIA will impact the project's contribution to the risk buffer pool, as described in Section 5.4.3.

Agreement.[40] Requirements for monitoring and reporting activities during the permanence period are detailed in Section 7.5.

The PIA is an agreement between the Reserve and a Project Owner setting forth: (i) the Project Owner's obligation (and the obligation of its successors and assigns) to comply with the Grassland Protocol, and (ii) the rights and remedies of the Reserve in the event of any failure of the Project Owner to comply with its obligations. The PIA must be signed by the Project Owner before a project can be registered with the Reserve. The PIA is executed and submitted after the Reserve has reviewed the verification documents and is otherwise ready to register the project. It is not possible to terminate the PIA for only a portion of the project area; however an amended PIA may be executed that reflects a change to the project area as provided for by the exceptions to the minimum time commitment at the beginning of this section. The PIA is also amended at each subsequent verification in order to extend the term of applicability.

There are two types of PIAs available to a grassland Project Owner:

Contract PIA

A Contract PIA is a contract between the Project Owner and Reserve whereby the Project Owner agrees to the requirements of the protocol, including but not limited to monitoring, verification, and compensating for reversals. The PIA does not restrict the transferability of the specific CRTs issued, but does hold the Project Owner to the compensation requirements of Section 5.4. By the terms of the PIA, the contract is satisfied upon the Project Owner's full performance of the requirements of this protocol (i.e., monitoring and verifying permanence for 100 years following CRT issuance). The PIA is executed at the completion of the initial project verification, and then amended at the completion of each subsequent verification (prior to or at the time of CRT issuance). The Contract PIA is not a public document.

Recorded PIA

In the case where the Project Owner is the Grassland Owner, or where the Grassland Owner is willing to record the PIA on the deed to the property, the Project Owner may employ a Recorded PIA. This is a contract between the Project Owner and the Reserve that is recorded on the deed to the property and binds the Project Owner and Grassland Owner to the terms of the protocol. This version of the PIA does not grant the Reserve a security interest, but rather grants the Reserve the ability to enforce the protocol requirements on the project area. The Recorded PIA is publicly available from the records office of the county in which the project is located.

3.6 Regulatory Compliance

As a final eligibility requirement, Project Owners must attest that project activities do not cause material violations of applicable laws (e.g., air, water quality, safety, etc.). To satisfy this requirement, Project Owners must submit a signed Attestation of Regulatory Compliance form[41] prior to the commencement of verification activities each time the project is verified. Project Owners are also required to disclose in writing to the verifier any and all instances of legal violations – material or otherwise – caused by the project activities. Where a temporary or

[40] The template PIA is available on the Grassland Protocol webpage: http://www.climateactionreserve.org/how/protocols/grassland/.
[41] Attestation forms are available at http://www.climateactionreserve.org/how/program/documents/.

emergency restriction or regulation is in force during the reporting period, it shall be included in the assessment of the project's regulatory compliance.

A violation should be considered to be "caused" by project activities if it can be reasonably argued that the violation would not have occurred in the absence of the project activities. If there is any question of causality, the Project Owner shall disclose the violation to the verifier.

If a verifier finds that project activities have caused a material violation, then CRTs will not be issued for GHG reductions that occurred during the period(s) when the violation occurred. Individual violations due to administrative or reporting issues, or due to "acts of nature," are not considered material and do not affect CRT crediting. However, recurrent administrative or reporting violations directly related to project activities may affect crediting, especially if related to negligence or intent on the part of the Project Owner or Grassland Owner. Verifiers must determine if recurrent violations rise to the level of materiality. If the verifier is unable to assess the materiality of the violation, then the verifier shall consult with the Reserve.

3.7 Ecosystem Health

Grassland project areas, regardless of location or management, are subject to forces that could degrade the grassland ecosystem and potentially cause the land to transition to a different landscape type, even in the absence of a single disturbance event. Such degradation or landscape transition not only has the potential to negatively impact the belowground carbon stocks (thus jeopardizing the integrity of the project quantification), but may also lead to eventual conversion of the project area to a land use other than grassland (e.g., dense shrubland, forest, bare soil, etc.). Project activities such as livestock grazing or recreation could also lead to impaired rangeland health, if not properly managed. Projects that are located adjacent to land that has already been converted to cropland or development may also be subject to a higher risk of rangeland health impairment due to encroachment of invasive species or increased grazing/foraging by wild animals whose habitat has been constrained by land conversion. The Reserve does not seek to prescribe specific land management activities. Rather, the intent of this section is to encourage thoughtful and proactive land management to maintain and/or improve rangeland health.

In order to protect against long term degradation of the project area, periodic assessments of rangeland health[42] must be conducted according to the guidance contained in Section 6.4. If a project area is expanded to include land with an Ecological Site Description that differs from the original project area, the rangeland health assessment must be updated to incorporate the initial health condition metrics of the new project area. For any metrics that are determined to display "moderate" departure from the reference condition, the Project Owner must document how the land management will be adapted to address these deficiencies. If the assessment determines that the project area exhibits greater than "moderate" departure from the defined reference condition for any metric, the Project Owner must not only show a plan for management adaptation, but must also show improvement in that metric at the subsequent rangeland health assessment.

If projects that are required to improve rangeland health fail to do so at the subsequent assessment, the Reserve will determine whether the degradation was avoidable or unavoidable. Avoidable degradation could lead to ineligibility for the current reporting period, resulting in no CRTs being issued for that period. If the continued degradation is determined to be

[42] Additional details regarding the U.S. Federal Government's multi-agency program for assessing Rangeland Health can be found at: http://jornada.nmsu.edu/monit-assess/manuals/assessment (accessed 10/14/16).

unavoidable, the project may still receive CRTs for the reporting period, but must abide by the requirements of the previous paragraph to implement new management approaches to improve rangeland health.

In cases where there is a rangeland health assessment showing greater than moderate departure from the reference condition for one or more metrics, the Reserve will consult with rangeland health experts to determine whether the degradation is sufficiently significant to warrant the determination that a reversal has occurred. In cases where is the Reserve determines that a reversal has occurred, the requirements of Section 5.4 regarding avoidable and unavoidable reversals shall apply.

The requirements of this section may be satisfied through alternative assessment methods with written approval from the Reserve (See section 6.4 for alternatives).

4 The GHG Assessment Boundary

The GHG Assessment Boundary delineates the GHG sources, sinks, and reservoirs (SSRs) that must be assessed in order to determine the net change in emissions caused by an avoided conversion of grasslands project.[43] The GHG Assessment Boundary encompasses all of the GHG SSRs that may be significantly affected by project activities, including biological CO_2 emissions and soil carbon sinks and sources of N_2O.

Figure 4.1 illustrates all relevant GHG SSRs associated with grassland project activities and delineates the GHG Assessment Boundary.

Table 4.1 provides greater detail on each SSR and justification for the inclusion or exclusion of certain SSRs and gases from the GHG Assessment Boundary. The SSRs that are marked with "(R)" represent those for which baseline emissions are reversible, and thus subject to the requirements for permanence in Section 3.5.

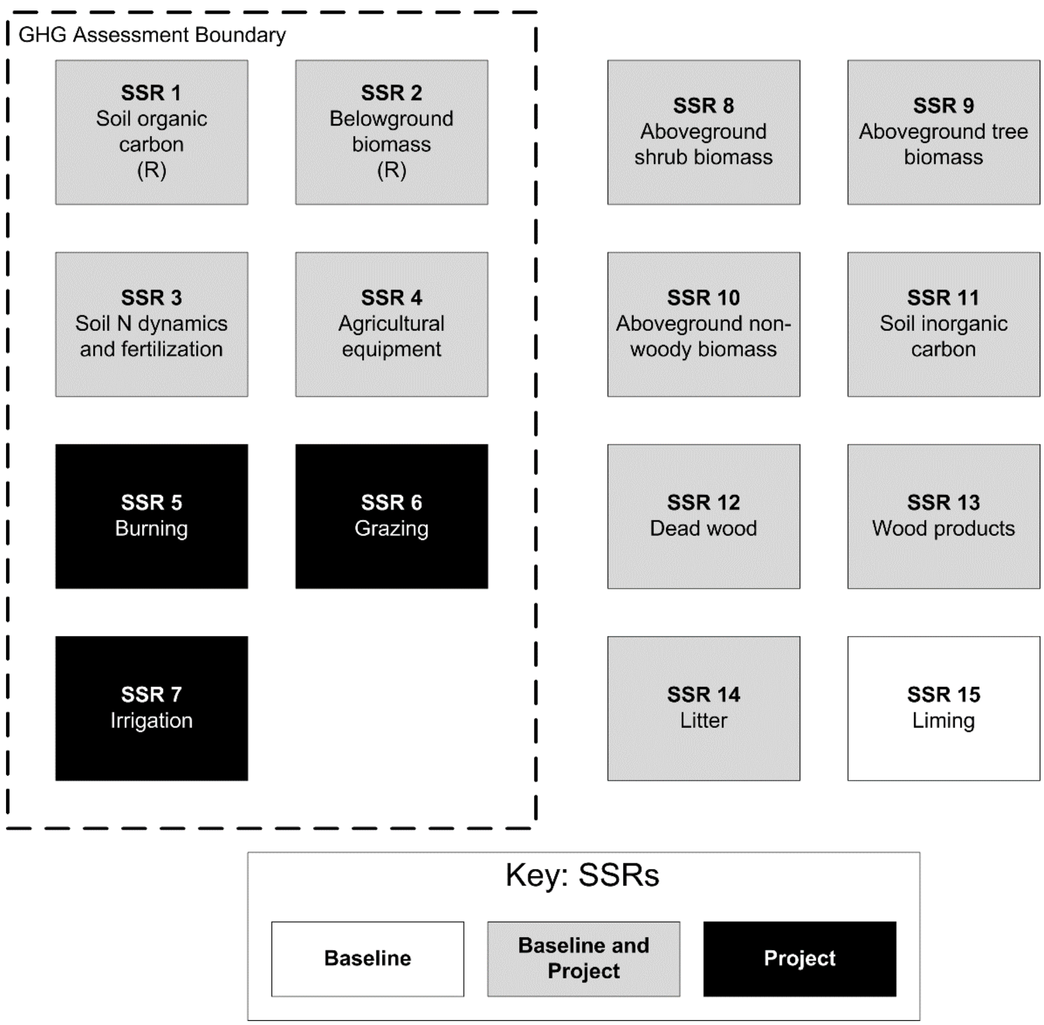

Figure 4.1. General Illustration of the GHG Assessment Boundary

[43] The definition and assessment of sources, sinks, and reservoirs is consistent with ISO 14064-2 guidance.

Table 4.1. Description of All Sources, Sinks, and Reservoirs

SSR	Source Description	Gas	Included (I), Optional (O), or Excluded (E)	Quantification Method	Justification/Explanation
1	Soil organic carbon	CO_2	I	Default emission factor modeled using DAYCENT	Emissions from the loss of soil organic carbon are a primary effect and major emission source in the baseline. Reversible.
2	Belowground biomass	CO_2	I	Default factor modeled using DAYCENT	Emissions from the loss of below-ground biomass are a primary effect and major emission source in the baseline. Reversible.
3	Soil nitrogen dynamics and fertilization	N_2O	I	**Baseline:** Default emission factors modeled using DAYCENT **Project:** Calculated based on monitored data	Direct and indirect N_2O emissions from conversion activities, soil processes and fertilization can be significant in the baseline. Direct and indirect N_2O emissions from fertilization can be significant in the project scenario, if applicable.
4	Agricultural equipment from site preparation and ongoing operations	CO_2	I*	**Baseline:** Default emission factor **Project:** Calculated based on monitored data	Fossil fuel emissions from equipment used for conversion site preparation and ongoing field operations (tillage, fertilization, etc.) may be significant in the baseline. * Associated emission reductions excluded in jurisdictions where these emissions are subject to a binding cap (e.g., California). Fossil fuel and electricity emissions from equipment used for grassland management may be significant in the project scenario.
		CH_4	E	N/A	Excluded, as this emission source is assumed to be very small.
		N_2O	E	N/A	Excluded, as this emission source is assumed to be very small.
5	Burning	CO_2	E	N/A	CO_2 emissions due to grass biomass burning are considered biogenic and thus are excluded from the project boundary.

SSR	Source Description	Gas	Included (I), Optional (O), or Excluded (E)	Quantification Method	Justification/Explanation
		CH_4	I	Calculated based on monitored data	When grass biomass is burned, a portion of the carbon is released as CH_4. Depending on the area burned, this could be a significant source of project emissions.
		N_2O	I	Calculated based on monitored data	When grass biomass is burned, a portion of the carbon is released as N_2O. Depending on the area burned, this could be a significant source of project emissions.
6	Grazing	CO_2	E	N/A	Excluded, as this is not a significant source of emissions. Additionally, any CO_2 emissions from grazing would be considered biogenic.
		CH_4	I	Calculated based on monitored data	Grazing livestock in the project scenario produces potentially significant quantities of CH_4 through the decomposition of manure, as well as enteric fermentation.
		N_2O	I	Calculated based on monitored data	Grazing livestock in the project scenario produces potentially significant quantities of N_2O through the decomposition of manure.
7	Irrigation	CO_2	I	Calculated based on monitored data	Emissions from equipment used for grassland management may be significant in the project scenario.
		CH_4	E	N/A	No significant CH_4 emissions related to irrigation of the project area are expected.
		N_2O	I	Calculated based on monitored data	Indirect N_2O emissions from irrigation can be significant in the project scenario, where livestock grazing and/or fertilizer application occurs.
8	Aboveground shrub biomass	CO_2	E	N/A	Emissions from the loss of above-ground shrub biomass can be a significant emission source in the baseline for certain projects. Exclusion is conservative.

SSR	Source Description	Gas	Included (I), Optional (O), or Excluded (E)	Quantification Method	Justification/Explanation
9	Aboveground tree biomass	CO_2	E	N/A	Trees may hold a significant amount of biomass, but the fate of that carbon after conversion is uncertain, depending upon the volume of wood, the species, and the accessibility of mills. This protocol conservatively excludes tree biomass from the baseline emissions calculations.
10	Aboveground non-woody biomass	CO_2	E	N/A	Excluded, as the permanent pool is assumed to be very small, despite seasonal fluxes. The exclusion is conservative.
11	Soil inorganic carbon	CO_2	E	N/A	Excluded, as this source is not included in the baseline modeling. The exclusion is conservative.
12	Dead wood	CO_2	E	N/A	Excluded, as this emission source is assumed to be very small. The exclusion is conservative.
13	Wood products	CO_2	E	N/A	Excluded, as this emission source is assumed to be very small. The exclusion is conservative.
14	Litter	CO_2	E	N/A	Excluded, as this emission source is assumed to be very small. The exclusion is conservative.
15	Liming	CO_2	E	N/A	Excluded, as the direction and magnitude of this emission source is uncertain. Current IPCC emission factors treat liming as an emission source, whereas current USDA quantification methodologies treat it as a net sink (6) (7).

5 Quantifying GHG Emission Reductions

GHG emission reductions from an avoided grassland conversion project are quantified by comparing actual project emissions to the calculated baseline emissions. Baseline emissions are an estimate of the GHG emissions from sources within the GHG Assessment Boundary (see Section 4) that would have occurred in the absence of the project. In the case of grassland projects, the baseline emissions include the loss of belowground organic carbon through conversion to cropland, as well as the GHG emissions from crop production. Project emissions are actual GHG emissions that occur at sources within the GHG Assessment Boundary. Project emissions include GHG emissions from grassland maintenance and grazing, as well as any leakage of baseline conversion activities. Project emissions must be subtracted from the baseline emissions to quantify the project's total net GHG emission reductions (Equation 5.1).

Quantification of baseline emissions is done through the use of default emission factors developed through a probabilistic composite modeling approach. This approach greatly simplifies the quantification and monitoring of grassland projects, as compared to an approach based on site-specific sampling and modeling. Additional discussion of this approach can be found in Appendix B.

Timelines for quantifying and reporting GHG emission reductions are detailed in Section 7.4. Project Owners may choose to quantify and verify GHG emission reductions on a more frequent basis if they desire. The length of time over which GHG emission reductions are periodically quantified is called the "reporting period." The length of time over which GHG emission reductions are verified is called the "verification period." Under this protocol, a verification period may cover multiple reporting periods (see Section 7.4).

As of this writing, the Reserve relies on values for global warming potential (GWP) of non-CO_2 GHGs published in the Fourth Assessment Report of the Intergovernmental Panel on Climate Change (2007).[44] The values relevant for this protocol are provided in Table 5.1, below. These values are to be used for all grassland projects unless and until the Reserve issues written guidance to the contrary.

Table 5.1. 100-year Global Warming Potential for Non-CO_2 GHGs

Non-CO_2 GHG	100-Year GWP (CO_2e)
Methane (CH_4)	25
Nitrous Oxide (N_2O)	298

For project cooperatives, the quantification of emission reductions is carried out separately for each individual project. The cooperative structure does not change the quantification methodology contained within this section. To report the total results for the cooperative, the Cooperative Developer shall sum the results of Equation 5.1 for each project in the cooperative. However, it should be noted that CRTs are serialized and issued to individual projects, rather than the cooperative.

[44] Available here: https://www.ipcc.ch/publications_and_data/publications_and_data_reports.shtml.

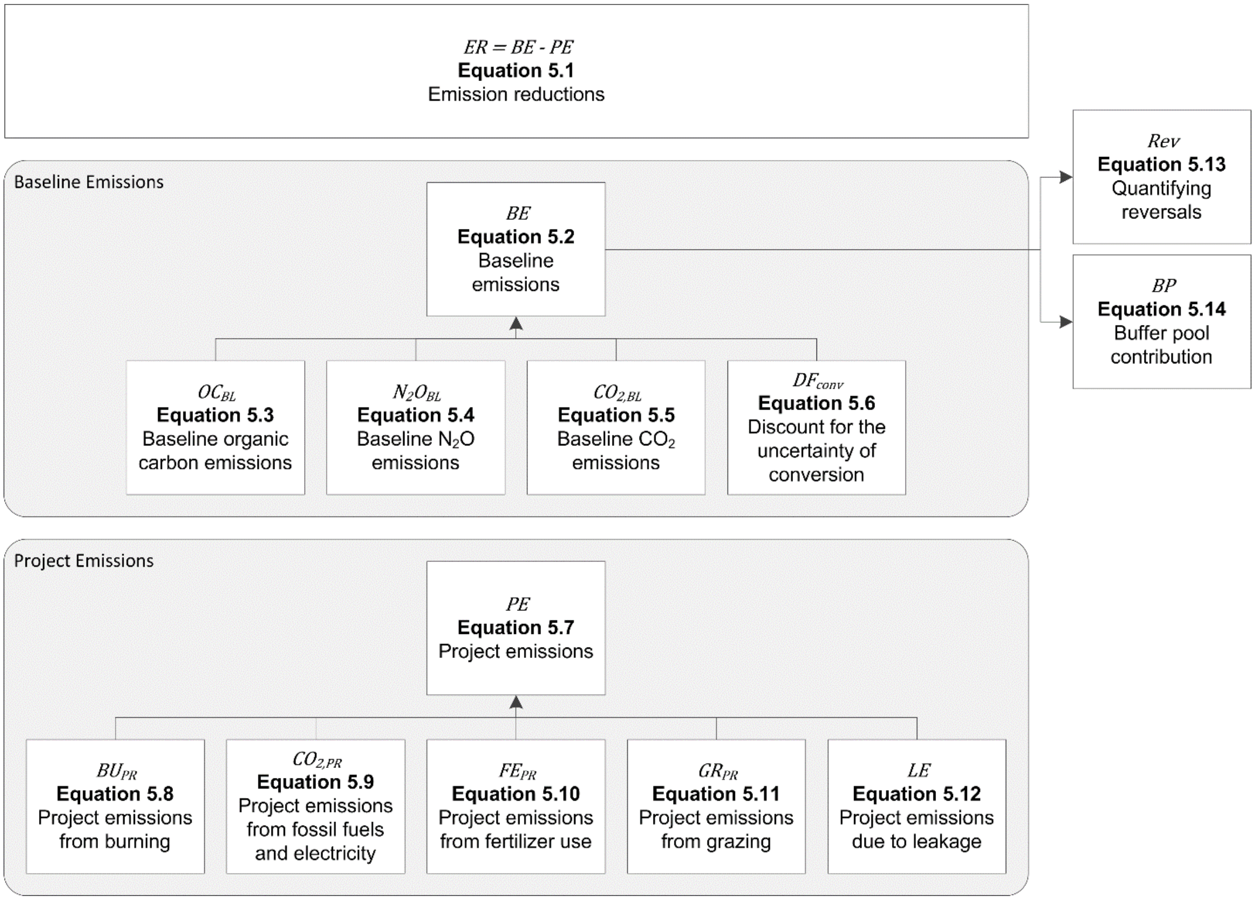

Figure 5.1. Organization of Quantification for Grassland Projects

Equation 5.1. GHG Emission Reductions

$$ER = BE - PE$$

Where, Units

ER	=	Total emission reductions for the reporting period	tCO_2e
BE	=	Total baseline emissions for the reporting period, from all SSRs in the GHG Assessment Boundary (as calculated in Section 5.1)	tCO_2e
PE	=	Total project emissions for the reporting period, from all SSRs in the GHG Assessment Boundary (as calculated in Section 5.3)	tCO_2e

5.1 Stratification

For the purposes of this protocol, the U.S. has been stratified in order to enable the development of baseline and project emissions estimates that correspond to local soil conditions, climatic conditions, starting condition, and agricultural practices. A stratum represents a unique combination of these variables. All baseline and project modeling has been performed at the stratum level, enabling the resulting emissions estimates to represent relatively fine distinctions in the primary drivers of variation in emissions. In total, this protocol establishes emissions estimates for 1,002 total strata within the U.S. By stratifying the country in this manner, the emissions estimates used in this protocol provide greater local accuracy and representation than would emission estimates generated at a national scale or with fewer variables. These variables act as filters that bring greater specificity to the emissions estimates by more precisely estimating the conditions of the project. Land is first broken down by climate and geography, then further delineated by the major soil type and texture, and finally evaluated based on the previous land use.

For large projects, the project area may cover more than one stratum. In these instances, the project itself shall be divided up on an acreage basis into all appropriate strata. Instructions for identifying and calculating acreage in each stratum are provided in Section 5.1.4. All calculations shall be performed at the stratum level and summed to the project level where indicated.

The following variables are used to stratify the U.S., and shall be used to determine the appropriate stratum for a project or project area:

- Geography and associated climate
- Soil texture
- Previous land use

Each project shall be evaluated on the basis of each of these variables to determine its appropriate stratum, or strata, should its area contain multiple strata. The following sections provide guidance on determining the appropriate stratum for any parcel or portion of the project area.

5.1.1 Geography and Associated Climate

The first level of stratification used in this protocol delineates land based on its geography and associated climate, due to these factors' important influence over carbon pools and sources in both natural and managed ecosystems (6). Regional climate and geographic conditions are determined through the use of Major Land Resource Area designations, as defined by the USDA NRCS (9). These designations are used for a variety of policy and planning decisions, as they represent information about land suitability for farming and other purposes. As such, they constitute a land area that has similar physical and climatic characteristics. In total, there are approximately 280 MLRAs in the U.S. However, some of these MLRAs contain very little cropland or grassland feasible for conversion. Appendix B provides an overview of the methodology used to screen out certain MLRAs based on the absence of significant areas of grassland or cropland, and constraints on data availability and modeling confidence.

The USDA NRCS makes available tools for the geographic identification of MLRAs.[45]

5.1.2 Soil Texture

Soil texture has a significant impact on land productivity and carbon dynamics through influences on soil fertility and water balance and on soil organic matter stabilization processes (8). Accordingly, the second level of stratification requires differentiating by soil texture. While successively finer delineations of soil type and texture would yield greater precision, this protocol limits the stratification of soils into three major classes of surface soil texture as defined by USDA. These are:

[45] MLRA geographic data are available at: http://www.nrcs.usda.gov/wps/portal/nrcs/detail/soils/survey/geo/?cid=nrcs142p2_053624.

- Coarse
- Medium
- Fine

Table 5.2 explains how these three categories can be mapped to the various soil surface textures as they are listed in the soil database.

5.1.3 Previous Land Use

Initial carbon pools at project commencement are significantly influenced by previous land uses. Additionally, soil quality at project initiation influences nutrient inputs and farming practices in the baseline scenario. Because this protocol allows for the avoided conversion of grasslands with somewhat varied histories, the third level of stratification requires grasslands to be delimited by the duration of time the project area has been in a grassland state. This protocol defines the following two categories for grasslands:

- Greater than 10, but less than 30 years continuous grassland
- Greater than 30 years continuous, long-term permanent grassland

Per Section 3.1, all lands enrolled under this protocol must have been in a documented grassland or pastureland state for at least 10 years prior to project commencement. This requirement is necessary to ensure the validity of the baseline soil carbon emission factors. Areas that have exceeded 30 years of pre-project grassland cover are classified in a different stratum.

The Project Owner must document that the project site meets the definition of grassland as of the project start date. This may be done through a site visit by the verifier, or through other sources of evidence. Project Owners can use a wide variety of types of evidence, subject to review by the verifier. Evidence must cover every year that the land is asserted to have been grassland. It is easier for a verifier to confirm that the project area was in grasslands when the Project Owner provides evidence that is as specific and objective as possible. The list below contains examples of evidence that may be employed to document land use of the project area for a given period of time.

Each piece of evidence must be corroborated by another piece of evidence of a different type. For example, if a Project Owner provides satellite data indicating grassland as the land cover on the project area for a given year, at least one additional form of documentation (such as a contract or an affidavit) is required for corroboration. Evidence cannot be corroborated by other evidence of the same type (e.g., satellite evidence cannot be corroborated by other satellite evidence). All land use evidence shall be subject to review and approval by the verifier.

<u>Examples of evidence demonstrating land use history:</u>

- Site visit by the verifier (applies only to the relevant reporting period)
- Time-referenced photos of the project area taken during the relevant year(s) (applies to the areas that can reasonably be assessed with these photos)
- Time-referenced aerial photos taken during the relevant year(s)

- Satellite data products, such as the Cropland Data Layer (CDL)[46], National Land Cover Database,[47] or MODIS Enhanced Vegetative Index[48]
- Continuous Vegetation Cover Report developed by the Rangeland Analysis Platform demonstrating the permanence of annual and perennial forb & grass cover[49]
- Contract(s) covering the relevant year(s) whose terms would require that the project area be grassland, but that would not cause the project to fail the legal requirement test (e.g., grazing leases or haying contracts)
- Tax records that indicate the land use during the relevant year(s)
- Notarized affidavit(s) from unrelated and unaffiliated parties attesting to the land use in the relevant year(s)
- Notarized affidavit from the Grassland Owner(s) attesting to the land use in the relevant year(s)
- Other official records submitted to or generated by a government agency that would indicate the land use or management during the relevant year(s)
- Easement monitoring reports applicable to the totality of the relevant reporting period(s)[50] and developed by the Grantee

This list is not meant to be comprehensive. The Project Owner may employ alternative approaches to monitoring land use on the project area, subject to review by the verifier. The evidence provided to satisfy this requirement must be sufficient to provide reasonable assurance as to the nature of the land use during the relevant time period. The Reserve has developed a companion document to this protocol, the Grassland Project Handbook, that provides further detail and discussion of the various options for satisfying the requirements of this section.[51]

5.1.4 Stratum Identification and Measurement

In total, this protocol stratifies the U.S. into 1,674 unique strata based on the three variables previously discussed (although emission factors were only able to be generated for 1,002 strata; see Appendix B for further details). Box 5.1 describes the method for naming each individual stratum. These names are then used in the companion tables for default parameters provided for each stratum.[52]

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[46] The Cropland Data Layer is a free remote sensing product developed and provided by the USDA National Agricultural Statistics Service. The data are available online at: http://nassgeodata.gmu.edu/CropScape/.

[47] The NLCD is a free remote sensing product provided by the Multi-Resolution Land Characteristics Consortium. The data are released every 5 years and is available online at: http://www.mrlc.gov/.

[48] MODIS data are provided by NASA and the USGS. Information regarding MOD13Q1 (the 16-day 250m global vegetation indices) is online at: https://lpdaac.usgs.gov/products/modis_products_table/mod13q1.

[49] The Continuous Vegetation Cover report can be generated by accessing https://rangelands.app and uploading a zip file of the project area to the service. These reports are only available for the Western United States.

[50] See this example for clarification: if a reporting period covers from January 1 to December 31 of one year and the easement monitoring report was issued on March of that year, the monitoring report cannot justify grassland permanence after March.

[51] The Grassland Project Handbook is available for download from the Reserve website at: http://www.climateactionreserve.org/how/protocols/grassland/. This handbook will be updated periodically.

[52] Certain parameters required for project eligibility and quantification are contained in a separate document, *Grassland Project Parameters*, available at: http://www.climateactionreserve.org/how/protocols/grassland/.

Box 5.1. Stratum Naming Convention

Name format: **X_Y_Z**

Where,		Range of Values
X =	Numbered designation of the MLRA in which the stratum is found	1 – 278
Y =	Soil texture classification	coarse, medium, or fine
Z =	Minimum year threshold for the previous land use	10 or 30

EXAMPLES:

Stratum	MLRA	Soil Texture	Previous Land Use
1_Medium_10	1 - Northern Pacific Coast Range, Foothills, and Valleys	Medium	Greater than 10, but less than 30 years continuous grassland or pastureland
150A_Fine_30	150A - Gulf Coast Prairies	Fine	Greater than 30 years continuous, long-term permanent grassland or pastureland

Most quantification in this protocol is conducted at the stratum level. Equations require inputs in the form of total acreage within each stratum, and use of stratum-specific emission factors for various carbon pools and emissions sources. Project Owners must prepare a georeferenced map file that contains the entire project area, excluding any portion of the project parcels not legally permitted to be converted due to buffer restrictions[53] or other requirements.

Data from the Soil Survey Geographic Database must be used to identify the acres of the stratum for each soil texture class. It is recommended that Project Owners utilize the NRCS Web Soil Survey application (WSS),[54] which is a user-friendly tool for accessing data from SSURGO. SSURGO data are also available for direct download from the USDA NRCS Geospatial Data Gateway.[55] If an alternate source of data from the SSURGO is available, use of the WSS as described here is not required. At a minimum, Project Owners must be able to identify the acreage of each soil texture group based on the dominant condition[56] of each SSURGO map unit within the project area.

Through the WSS application, the user may locate the general area of the project and then draw a detailed polygon around the project area. This identifies the Area of Interest (AOI) for which the data are generated (it is preferable to use a previously-created shapefile to define the AOI, which ensures that the project boundaries are consistently defined). After identifying the correct AOI, select the “Soil Data Explorer” tab, then the “Soil Properties” subtab below it. Using the

[53] For example, a landowner may be subject to regulations which limit how close crops may be grown to property boundaries or watercourses, or may require the maintenance of forested areas around watercourses or as windbreaks. In these cases, those restrictions would be represented by creating buffers around those features and excluding the buffered region from the project area.
[54] This web application is available at: http://websoilsurvey.sc.egov.usda.gov/App/WebSoilSurvey.aspx.
[55] The USDA NRCS Geospatial Data Gateway may be accessed at: https://gdg.sc.egov.usda.gov/GDGOrder.aspx (last accessed 12/14/16).
[56] Soil map units are comprised of multiple components, which are not represented on the map. In order to assign a single value to the map unit based on the values of the components, some aggregation method must be selected. This protocol applies the “dominant condition” method, whereby the value which applies to the greatest total area of the map unit is used to represent the value of the entire map unit.

menu to the left, select “Soil Physical Properties” and then “Surface Texture.” Within the options for Surface Texture, select the Aggregation Method as “Dominant Condition,” then click “View Rating.” This generates a table with the surface texture rating for each map unit within the AOI, identifying the acres for each. Then click “Printable Version” at the top right of the page to generate a PDF containing the AOI map and the table. This PDF aids with both stratification and verification. The texture ratings used in the soil data tables shall be aggregated into the three soil texture groups used in this protocol using the relationships described in Table 5.2.

Table 5.2. Soil Texture Categorization

SSURGO Texture Class	Grassland Protocol Texture Group
Sand	Coarse
Coarse sand	
Fine sand	
Very fine sand	
Loamy very fine sand	
Loamy fine sand	
Loamy sand	
Loamy coarse sand	
Coarse sandy loam	
Sandy loam	
Fine sandy loam	
Very fine sandy loam	
Loam	Medium
Silt loam	
Silt	
Sandy clay	Fine
Sandy clay loam	
Silty clay loam	
Clay loam	
Silty clay	
Clay	

5.2 Quantifying Baseline Emissions

Total baseline emissions for the reporting period are estimated by calculating and summing the emissions from all relevant baseline SSRs that are included in the GHG Assessment Boundary (as indicated in Table 4.1).

The baseline emission equations rely on emission factors that model the emissions of a full year. If this quantification methodology is being applied to a reporting period of less than one full year, Project Owners must refer to Box 5.2 in order to correctly pro-rate the annual baseline emission factors. Baseline emission factors for soil organic carbon, nitrous oxide, and fossil fuel emissions are organized in ten year groups. Those ten years are counted as calendar years from the year of the project start date, inclusive. The emission factor group to be used for a given reporting period is based on the beginning date of that reporting period, and applies throughout the reporting period. For example, if the project start date is May 9, 2015, the “Year

1-10" emission factor group shall be used for all reporting periods that begin during the years 2015-2024. For reporting periods beginning during 2025-2034, the "Year 11-20" emission factor group shall be applied.

Equation 5.2. Baseline Emissions

$$BE = \left[\left(OC_{BL} + N_2O_{BL} + CO_{2,BL}\right) \times (1 - DF_{\sigma})\right] \times (1 - DF_{conv}) \times Pro$$

Where,

			Units
BE	=	Total baseline emissions for the reporting period, rounded down to the nearest whole number	tCO_2e
OC_{BL}	=	Baseline emissions due to loss of organic carbon in soil and biomass (Equation 5.3)	tCO_2e
N_2O_{BL}	=	Baseline emissions of nitrous oxide (Equation 5.4)	tCO_2e
$CO_{2,BL}$	=	Baseline CO_2 emissions due to fossil fuel combustion (Equation 5.5)	tCO_2e
DF_{conv}	=	Discount factor for the uncertainty of baseline conversion (Equation 5.6)	%
DF_{σ}	=	Discount factor for the uncertainty of modeling future management practices and climatic conditions[57]	%
Pro	=	Pro-rating factor for reporting periods of less than one year (see Box 5.2)	%

Box 5.2. Pro-Rating for Reporting Periods of Less than One Year

Projects may report GHG reductions more frequently than on an annual basis. If a project reports on a sub-annual basis, then annual emission factors and quantities used in this section must be prorated. The following equation shall be used to determine the pro-rating factor for a sub-annual reporting period:

$$Pro = \frac{rd}{365.25}$$

Where,

			Units
Pro	=	Pro-rating factor	%
rd	=	Number of reporting days in the sub-annual reporting period (i.e., days for which the project is claiming credit for emission reductions)	Days
365.25	=	Average number of days in a calendar year	Days

5.2.1 Baseline Organic Carbon Emissions

The baseline assumption for grassland projects is that the project area would be converted to cropland absent the project activities. When grassland is converted to cropland, carbon emissions occur through the loss of stored soil organic carbon over time. There is an immediate loss of soil carbon when the soil is tilled (9), followed by potentially decades of loss until a new equilibrium is reached. Determining the exact nature of the converted land use (crop rotation, tillage practices, fertilization, ongoing management) is complex, uncertain, and subjective. The Reserve has adopted a modeled, composite approach to determining organic carbon emissions from the baseline scenario for grassland projects. Refer to Appendix B for the development of

[57] Certain parameters required for project eligibility and quantification are contained in a separate document, *Grassland Project Parameters*, available at: http://www.climateactionreserve.org/how/protocols/grassland/.

the emission factors used in this quantification and the companion tables for the baseline emission factors.

Equation 5.3. Baseline Organic Carbon Emissions from Soil and Belowground Biomass Loss

$$\boldsymbol{OC_{BL}} = \sum_{S} \left(\frac{\boldsymbol{BEF_{OC,s}} \times \boldsymbol{Area_s}}{\mathbf{1000}} \right)$$

Where, Units

OC_{BL}	=	Baseline quantity of organic carbon emissions from soil and belowground biomass	tCO_2e
S	=	Total number of strata	
S	=	Individual stratum	
$BEF_{OC,s}$	=	Annual baseline emission factor for organic carbon in stratum *s* (refer to companion tables,[58] selecting the appropriate stratum and time category)	kg CO_2e/ac/yr
$Area_s$	=	Area of project in stratum *s*	acres
1000	=	Conversion factor	kg/t

5.2.2 Baseline N_2O Emissions

The use of fertilizer for crop cultivation results in emissions of nitrogen in the form of N_2O, which is a potent GHG.[59] Using emission factors developed with the composite modeling approach described in Appendix B, baseline emissions of N_2O are estimated for each stratum.

Equation 5.4. Baseline N_2O Emissions

$$\boldsymbol{N_2O_{BL}} = \sum_{s}^{S} \left(\frac{\boldsymbol{BEF_{N_2O,s}} \times \boldsymbol{Area_s} \times \boldsymbol{GWP_{N_2O}}}{\mathbf{1000}} \right)$$

Where, Units

N_2O_{BL}	=	Baseline emissions of N_2O	tCO_2e
$BEF_{N2O,s}$	=	Annual baseline emission factor for N_2O emissions in stratum *s* (refer to companion tables,[58] selecting the appropriate stratum and time category)	kg N_2O/ac/yr
$Area_s$	=	Area of the project in stratum *s*	acres
GWP_{N2O}	=	100-year global warming potential of N_2O (refer to Table 5.1).	CO_2e/N_2O
1000	=	Conversion factor	kg/t

5.2.3 Baseline CO_2 Emissions from Fossil Fuels

The conversion of grassland to cropland, as well as the ongoing cropland management activities, involves the use of fossil fuels for vehicles and equipment. This usage results in direct emissions of CO_2. Using emission factors developed with the composite modeling approach described in Appendix B, baseline emissions of CO_2 for fossil fuel usage are estimated for each

[58] Certain parameters required for project eligibility and quantification are contained in a separate document, *Grassland Project Parameters*, available at: http://www.climateactionreserve.org/how/protocols/grassland/.
[59] For additional details regarding the pathways of N_2O emissions due to fertilizer use, refer to the Reserve's Nitrogen Management Protocol, available online: http://www.climateactionreserve.org/how/protocols/nitrogen-management/.

stratum. If the project is located in a jurisdiction where GHG emissions from mobile sources are subject to a binding emissions cap (such as California[60]), then those projects may not claim emission reductions for this source, and must use a value of zero for $CO_{2,BL}$.

Equation 5.5. Baseline CO_2 Emissions from Fossil Fuel

$$CO_{2,BL} = \sum_{s}^{S} \left(BRC_{CO_2,s} \times \frac{10.15}{1000} \times Area_s \right)$$

Where,			Units
$CO_{2,BL}$	=	Baseline emissions due to fossil fuel combustion	tCO_2e
$BRC_{CO2,s}$	=	Annual baseline rate of fossil fuel consumption for stratum *s* (refer to companion tables,[61] selecting the appropriate stratum and time category)	gal/ac/yr
10.15	=	Emission factor for diesel (distillate fuel #2)[62]	kg CO_2/gal
1000	=	Conversion factor	kg/t

5.2.4 Discount Factors

There are two discount factors that are applicable to the quantification of baseline emissions, DF_{conv} and DF_{σ}. DF_{conv} represents the uncertainty of using a standardized financial additionality threshold to represent the likelihood of the baseline conversion scenario. As the cropland premium decreases, uncertainty around the likelihood of baseline conversion increases. Equation 5.6 explains how to determine the value of this discount based on the value of the cropland premium for the county in which the project area is located (found in the companion tables[63]). In Equation 5.2, this discount is applied to the entire estimate of baseline emissions. As stated in Section 3.3.1.1, if more than 10% of the project acres are in a different county, eligibility (including the value of DF_{conv}) must be assessed separately for that county.

Equation 5.6. Discount Factor for the Uncertainty of Baseline Conversion

$$DF_{conv} = \left(1 - \frac{CP - FT_l}{FT_u - FT_l} \right) \times 50\%$$

Where,			Units
DF_{conv}	=	Discount factor for the uncertainty of baseline conversion	%
CP	=	Cropland premium for the county where the project is located	%
FT_l	=	Lower threshold for financial additionality (Section 3.3.1.1)	%
FT_u	=	Upper threshold for financial additionality (Section 3.3.1.1)	%
50%	=	Maximum value of DF_{conv}	

DF_{σ} is meant to embody the uncertainty contained within the modeling of the baseline emission factors. The baseline emissions quantified in this protocol are discounted to account for increasing uncertainty about input assumptions and model outputs into the future. Uncertainty

[60] Additional information regarding the California cap-and-trade program is available at: http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm.
[61] See the Reserve's Grassland Protocol webpage at: http://www.climateactionreserve.org/how/protocols/grassland/
[62] 40 CFR Part 98 Subpart C Table C-1.
[63] See the Reserve's Grassland Protocol webpage at: http://www.climateactionreserve.org/how/protocols/grassland/.

arises due to anticipated but unknown shifts in practices in, among other things, tillage, cropping, and nitrogen management, and the interaction of agricultural systems with a changing climate. Model inputs and outputs are expected to accurately reflect baseline conditions in early years, but have greater uncertainty in future years. Accordingly, the quantification of baseline emissions is discounted , with the discount increasing through time in accordance with increasing uncertainty. The value of DF_σ for a given year is found in the separate file containing the companion tables.[64] If the modeling exercise is updated in the future, it is likely that this discount schedule would reset back to 1% for new projects that would use the updated emission factors. The discount factor is assigned based on the year of the beginning date of the reporting period (i.e., a reporting period which begins on May 9, 2019 would apply the discount listed for 2019 for an entire 12-month reporting period, even though a portion of the period is in the calendar year 2020).

5.3 Quantifying Project Emissions

Project emissions are actual GHG emissions that occur within the GHG Assessment Boundary as a result of the project activity. Project emissions must be quantified every reporting period on an *ex post* basis. In certain cases where these emissions are determined to be *de minimis*,[65] this protocol specifically allows for the Project Owner to use an alternative estimation methodology. Unless otherwise specified, project emission equations cover the entire reporting period, regardless of whether it covers a full year.

Equation 5.7. Project Emissions

$$\boldsymbol{PE = BU_{PR} + FF_{PR} + FE_{PR} + GR_{PR} + LE}$$

Where,

			Units
PE	=	Project emissions, rounded to the nearest whole number	tCO_2e
BU_{PR}	=	Emissions from burning in the project scenario (Equation 5.8)	tCO_2e
FF_{PR}	=	Emissions from fossil fuel and electricity use in the project scenario (Equation 5.9)	tCO_2e
FE_{PR}	=	Emissions from organic fertilizer use in the project scenario (Equation 5.10)	tCO_2e
GR_{PR}	=	Emissions from livestock grazing in the project scenario (Equation 5.11)	tCO_2e
LE	=	Leakage emissions (Equation 5.12)	tCO_2e

5.3.1 Project Emissions from Burning

The project scenario for a grassland project may involve periodic burning, either prescribed or accidental. Regardless of the reason for the fire, the combustion of aboveground biomass results in emissions of CO_2, CH_4, and N_2O. The CO_2 emissions from grass burning are considered biogenic and are excluded from this quantification. The project emissions of CH_4 and N_2O must be estimated using Equation 5.8.

[64] Certain parameters required for project eligibility and quantification are contained in a separate document, *Grassland Project Parameters*, available at: http://www.climateactionreserve.org/how/protocols/grassland/.

[65] For the purposes of this protocol, emissions are *de minimis* if they are less than the relevant materiality threshold when applied to the overall calculation of emission reductions. The materiality threshold for projects is defined in the Verification Program Manual, available online at: http://www.climateactionreserve.org/how/verification/verification-program-manual/.

Equation 5.8. Project Emissions from Burning

$$BU_{PR} = \sum_{S}\left[\left(Area_{burn,s} \times DM_s \times \frac{2.3}{1000000} \times GWP_{CH_4}\right) + \left(Area_{burn,s} \times DM_s \times \frac{0.21}{1000000} \times GWP_{N_2O}\right)\right]$$

Where,			Units
BU_{PR}	=	Emissions from burning in the project scenario	tCO_2e
S	=	Total number of strata	
s	=	Individual stratum	
$Area_{burn,s}$	=	Area of stratum *s* that was burned	acres
DM_s	=	Amount of aboveground dry matter in stratum *s* (refer to companion tables,[66] selecting the appropriate stratum and time period)	kg/acre
2.3	=	Emission factor for methane from biomass burning (6)	g/kg dry matter
0.21	=	Emission factor for nitrous oxide from biomass burning (6)	g/kg dry matter
GWP_{CH4}	=	100-year global warming potential for methane (Table 5.1).	tCO_2e/tCH_4
GWP_{N2O}	=	100-year global warming potential for nitrous oxide (Table 5.1)	tCO_2e/tN_2O
1000000	=	Conversion factor	g/t

5.3.2 Project Emissions from Fossil Fuel and Electricity Use

In the case that the project activities include the use of mobile or stationary equipment or vehicles that consume fossil fuels or electricity, these project emissions are estimated using Equation 5.9. However, if the project can demonstrate that the total value of FF_{PR} is reasonably expected to be *de minimis* (i.e., less than the relevant materiality threshold[67]), these emissions may be estimated through a conservative method proposed by the Project Owner and deemed acceptable by the verifier.

[66] See the Reserve's Grassland Protocol webpage at: http://www.climateactionreserve.org/how/protocols/grassland/.
[67] Materiality thresholds for Reserve projects are specified in the Reserve Verification Program Manual, available at: http://www.climateactionreserve.org/how/verification/verification-program-manual/.

Equation 5.9. Project Emissions from Fossil Fuels and Electricity

$$FF_{PR} = \frac{\sum_f \left(QF_f \times PEF_{FF,f}\right)}{1000} + \frac{(QE \times PEF_{EL})}{1000}$$

Where,

			Units
FF_{PR}	=	Carbon dioxide emissions due to fossil fuel combustion and electricity use in the project scenario	tCO_2e
QF_f	=	Quantity of fossil fuel type *f* consumed	volume
$PEF_{FF,f}$	=	Project emission factor for fossil fuel type *f* (refer to companion tables)[68]	$kgCO_2$/volume fossil fuel
1000	=	Conversion factor	kg/t
QE	=	Quantity of electricity consumed during the reporting period	MWh
PEF_{EL}	=	Carbon emission factor for electricity used, referenced from the most recent U.S. EPA eGRID emission factor publication.[69] Projects shall use the annual total output emission rates for the subregion where the project is located	kg CO_2/MWh

5.3.3 Project Emissions from Organic Fertilizer Use

Certain grasslands may see ecosystem improvements or possibly even enhanced carbon sequestration (not credited under this protocol) following the addition of organic soil amendments (10). In the case that the project activities include the application of organic fertilizer (such as compost or manure), the project emissions of N_2O are estimated using Equation 5.10. This equation quantifies the total direct and indirect emissions of N_2O related to the application of organic fertilizers through the use of project-specific activity data and default emission factors. Additional information regarding the default emission factors used in the next two equations can be found in Appendix C.

Accounting for leaching is required for counties where, on average, the annual precipitation exceeds 80% of annual potential evapotranspiration. This protocol assigns the leaching factor based on an analysis carried out for the annual U.S. GHG Inventory which identifies the probability of leaching on non-irrigated land for every county (13). The results of this analysis are displayed in Figure 5.2 and are contained within the county-level companion tables.[70] Project Owners should refer to Figure 5.2 and the companion tables to determine if their project must account for leaching.[71] Accounting for leaching is also required for any projects which employ irrigation on the project area during the reporting period.

[68] This information can be found in the *Grassland Project Parameters*, document available at: http://www.climateactionreserve.org/how/protocols/grassland/.
[69] Available online at: http://www.epa.gov/cleanenergy/energy-resources/egrid/
[70] Ibid.
[71] Ibid.

Figure 5.2. U.S. Counties Where Nitrogen Leaching is Expected to Occur

Equation 5.10. Project Emissions from Fertilizer Use

$$FE_{PR} = \left(\sum_{C} QF_{PR,c} \times NC_c\right) \times (0.012 + Leach) \times \frac{44}{28} \times \frac{GWP_{N_2O}}{1000}$$

Where,			Units
FE_{PR}	=	Direct and indirect nitrous oxide emissions from organic fertilizer use in the project scenario	tCO_2e
C	=	Total number of types of organic fertilizer applied, other than manure from grazing livestock	
$QF_{PR,c}$	=	Quantity of fertilizer type *c* applied	kg
NC_c	=	Nitrogen content of fertilizer type *c*	kg N/kg
0.012	=	Default factor representing the direct emission factor of N_2O from organic fertilizer, the fraction of N which is volatilized, and the indirect emission factor for N volatilization and deposition	
Leach	=	Default factor for the fraction and emission factor for N_2O emissions due to leaching. Equal to **0.00225** for projects that are required to use this factor, and **0** for all other projects. Refer to the companion tables[72] to determine whether leaching must be quantified for the county where the project is located.[73] The 0.00225 factor must also be used when irrigation is employed.	
44/28	=	Molar mass ratio of N_2O to N	kg N_2O/kg N_2O-N
GWP_{N2O}	=	100-year global warming potential for N_2O (Table 5.1)	tCO_2e/tN_2O
1000	=	Conversion factor	kg/t

[72] Certain parameters required for project eligibility and quantification are contained in a separate document, *Grassland Project Parameters*, available at: http://www.climateactionreserve.org/how/protocols/grassland/.
[73] If the project area includes land in more than one county, and the companion tables specify that leaching must be accounted for in any of the given counties, then leaching must be accounted for across the entire project area.

5.3.4 Project Emissions from Grazing

It is likely that grasslands projects include livestock grazing on the project area in the project scenario, leading to enteric methane and manure (methane and nitrous oxide) emissions that would not exist in the baseline scenario. These emissions are quantified using Equation 5.11 and the guidance in Box 5.3. For the purposes of this equation, the "grazing season" is defined as the period of time between the first and last grazing days of the reporting period.

Equation 5.11. Project Emissions from Livestock Grazing

$$GR_{PR} = N_2O_{MN} + CH_{4,MN} + CH_{4,ENT}$$

Where,			Units
GR_{PR}	=	Project emissions from grazing activities in the project area	tCO_2e
N_2O_{MN}	=	N_2O emissions from manure deposited by grazing animals	tCO_2e
$CH_{4,MN}$	=	CH_4 emissions from manure deposited by grazing animals	tCO_2e
$CH_{4,ENT}$	=	CH_4 emissions from enteric fermentation in grazing animals	tCO_2e

$$N_2O_{MN} = \sum_L \left(AGD_l \times Nex_l \times (0.022 + Leach)\right) \times \frac{44}{28} \times \frac{GWP_{N_2O}}{1000}$$

Where,			Units
L	=	Total number of livestock categories in the project scenario	
AGD_l	=	Animal grazing days for livestock category *l* (see Box 5.3)	animal days
Nex_l	=	Nitrogen excreted by grazing animals in livestock category *l*	kg N/head/day
0.22	=	Default factor representing the emission factor of nitrogen from manure, the fraction of N which is volatilized, and the emission factor for N volatilization. Additional details can be found in Appendix C.	
Leach	=	Default factor for the fraction and emission factor for N_2O emissions due to leaching. Equal to **0.00225** for projects which are required to use this factor, and **0** for all other projects. Refer to the companion tables to determine whether leaching must be quantified for the county where the project is located.[74, 74] The 0.00225 factor must also be used when irrigation is employed.	
44/28	=	Molar mass ratio of N_2O to N	N_2O/N
GWP_{N2O}	=	100-year global warming potential for N_2O (Table 5.1)	CO_2e/N_2O
1000	=	Conversion factor	kg/t

$$CH_{4,MN} = \sum_L \left(AGD_l \times VS_l \times B_{0,l}\right) \times \frac{MCF_{PRP} \times \rho_{CH_4} \times GWP_{CH_4}}{1000}$$

Where,			Units
VS_l	=	Volatile solids excreted by grazing animals in category *l*	kg VS/animal/day
$B_{0,l}$	=	Maximum methane potential for manure from category *l*	m^3 CH_4/kg VS
MCF_{PRP}	=	Methane conversion factor for pasture/range/paddock manure management, dependent on average temperature during grazing season	%
ρ_{CH4}	=	Density of methane at 1 atm and the average temperature during the grazing season	kg/m^3
GWP_{CH4}	=	100-year global warming potential for CH_4 (Table 5.1)	CO_2e/CH_4

$$CH_{4,ENT} = \sum_L \left(AGD_l \times PEF_{ENT,l}\right) \times \frac{GWP_{CH_4}}{1000}$$

Where,			Units
$PEF_{ENT,l}$	=	Project emission factor for enteric methane emissions from livestock category *l* in the project State[74]	kg CH_4/head/day

[74] Default emission factors and parameters can be found in a separate document, *Grassland Project Parameters*, available at: http://www.climateactionreserve.org/how/protocols/grassland/.

Box 5.3. Determining Animal Grazing Days (AGD_l)

Equation 5.11 requires the use of parameter AGD_l, which represents the total number of days that were grazed by a single category of animals. This is the sum of the number of days each animal category was grazed during the relevant time period. A simplified example is below:

Animal Category	Population	Grazing Days	Animal Grazing Days
Bulls	100	240	24,000
Beef Cows	200	240	48,000
Beef Replacements	40	240	9,600

Note: the numbers in this table are fictional used only for illustrative purposes

If the population of each category is not stable over the grazing period, a reasonable approach shall be applied to estimate AGD_l for each category over the relevant time period.

5.3.5 Project Emissions Due To Leakage

Avoided grassland conversion projects would result in leakage if the project activities result in the conversion of other grassland outside of the project area. This would cause the “avoided” baseline emissions to simply shift and occur elsewhere, thus never actually being avoided. The extent to which this occurs depends on the economics of crop production. The project emissions due to leakage represent the probability that the avoided baseline emissions will occur outside of the project area due to the project activities. Calculating a precise value for this probability is both complex and uncertain. As this protocol relies on default baseline assumptions which are composites of multiple baseline scenarios, it is not possible to determine a precise leakage value for each specific project.

Estimates of the leakage effects of grassland conservation are variable. Several studies have examined the Federal Conservation Reserve Program (CRP) to assess “slippage” (leakage) caused by conservation of arable land. One study determined the slippage effect of CRP enrollment to be 20% (i.e., for every 100 acres that are conserved, 20 acres are converted elsewhere) (12). A later study found no slippage effect from CRP enrollment (13). A third study determined that there is a range from 17.5% to 20.6%, depending upon the number of acres enrolled (higher enrollment led to higher slippage), as well as the elasticity of supply of nitrogen fertilizer (inelastic fertilizer supply led to higher slippage) (14). Lastly, another study, attempting to address the disagreement between the first two, used satellite imagery to attempt to estimate the magnitude of this effect, and came up with estimates that ranged from 3% to 11% (15). This is all to say that estimates of leakage from CRP enrollment, a reasonable proxy for avoided grassland conversion, range from 0% to 20%, with evidence to support various values in the middle of that range. Thus, the Reserve has taken a conservative approach, assuming a 20% leakage effect from grassland projects.

Equation 5.12. Project Emissions from Leakage

$$\boldsymbol{LE = 0.2 \times BE}$$

Where,			Units
LE	=	Leakage emissions during the reporting period	tCO_2e
0.2	=	Leakage discount factor	
BE	=	Baseline emissions during the reporting period	tCO_2e

5.4 Ensuring Permanence of GHG Emission Reductions

If a reversal occurs during a reporting period (see Section 3.5), the reversal must be compensated for by retiring CRTs. Specific requirements depend on the whether the reversal was avoidable or unavoidable, as described below. Reversal compensation requirements do not apply to emission reductions unrelated to carbon stored in the project area soils (e.g., CH_4 and N_2O).

Identification of a reversal is a binary decision based on area; either an area is subject to a reversal or not. For example, if the Grassland Owner decides to plow and cultivate a 10-acre portion of the project area, that entire 10-acre portion shall be considered to have experienced a complete and avoidable reversal. If an area is subject to a reversal, then the quantity of soil carbon reversed is considered to be equal to total number of CRTs issued for reversible emission reductions on that specific portion of the project area. For the purposes of this protocol, reversible emission reductions are those related to the avoided loss of organic carbon in soil and belowground biomass (Equation 5.3) for which CRTs were issued for reporting periods during the 100 years prior to the date of the reversal. The quantity of CRTs that must be retired is determined using Equation 5.13.

Equation 5.13. Quantifying Reversals

$$\boldsymbol{Rev} = \left(\boldsymbol{OC_{BL,rev,RP}}\right) \times \left(\mathbf{1} - \boldsymbol{DF_{conv}}\right)$$

Where,			Units
Rev	=	Quantity of emissions due to the reversal	tCO_2e
$\boldsymbol{OC_{BL,rev,RP}}$	=	Baseline emissions due to the loss of organic carbon in soil and biomass for all reporting periods	tCO_2e
DF_{conv}	=	Discount factor for the uncertainty of baseline conversion	

$$\boldsymbol{OC_{BL,rev,RP}} = \sum_{s,rp}^{RP}\left(\left(\boldsymbol{OC_{BL,s,rp}} \times \frac{\boldsymbol{Area_{rev,s}}}{\boldsymbol{Area_s}}\right) \times \left(\mathbf{1} - \boldsymbol{DF_{\rho,rp}}\right) \times \left[\mathbf{1} - \left(\boldsymbol{Y_{s,rp}} \times \mathbf{0.01}\right)\right]\right)$$

Where,			Units
RP	=	Total number of reporting periods for which CRTs have already been issued to the project	years
s	=	Individual stratum	
rp	=	Specific project reporting periods	
$OC_{BL,s,rp}$	=	Baseline emissions due to the loss of organic carbon and biomass in stratum *s* during reporting period *rp*	tCO_2e
$Area_{rev,s}$	=	Area of stratum *s* affected by the reversal	acres
$Area_s$	=	Total project area in stratum *s*	acres
$DF_{\rho,rp}$	=	Discount factor for the uncertainty of modeling future management practices and climatic conditions for reporting period *rp*	
$Y_{s,rp}$	=	Total number of years that have elapsed since the first day of the reporting period *rp* until the first day of the reporting period when the reversal occurred and, for which CRTs were previously issued for stratum *s*	years
0.01	=	Simplified annual atmospheric impact of avoided GHG emissions in a given year	tCO_2e/tCO_2e

5.4.1 Avoidable Reversals

Requirements for avoidable reversals are as follows:

1. If an avoidable reversal is identified during annual monitoring, the Project Owner must give written notice to the Reserve within thirty days of identifying the reversal. Additionally, if the Reserve determines that an avoidable reversal has occurred, it shall deliver written notice to the Project Owner.
2. Within thirty days of receiving the avoidable reversal notice from the Reserve, the Project Owner must provide a written description and explanation of the reversal to the Reserve, including a map of the specific area that is affected.
3. Within four months of receiving the avoidable reversal notice, the Project Owner must transfer to the Reserve a quantity of CRTs from its Reserve account equal to the size of the reversal as calculated in Equation 5.13.
    a. The surrendered CRTs must be those that were issued to the grassland project, or that were issued to other grassland projects registered with the Reserve. If there is not a sufficient quantity of grassland CRTs available for compensation, as determined by the Reserve, CRTs issued to a forest project registered with the Reserve are acceptable.
    b. The surrendered CRTs shall be retired by the Reserve and designated in the Reserve software as compensating for an avoidable reversal.

5.4.2 Compensating for Unavoidable Reversals

Requirements for unavoidable reversals are as follows:

1. If the Project Owner determines there has been an unavoidable reversal, it must notify the Reserve in writing of the unavoidable reversal within 30 days of identifying the reversal.
2. The Project Owner must explain the nature of the unavoidable reversal, including a map of the specific area affected, and provide an estimate of the size of the reversal using Equation 5.13.

If the Reserve determines that there has been an unavoidable reversal, it shall retire a quantity of CRTs from the Reserve Grassland Buffer Pool equal to the size of the reversal in metric tons of CO_2.

5.4.3 Contributing to the Grassland Buffer Pool

For each reporting period, the Project Owner must transfer a quantity of credits (determined by Equation 5.14) to the Reserve Grassland Buffer Pool at the time of credit issuance. Credits that enter the buffer pool are never returned to the project directly (except as specified for credits related to $Risk_{SV}$), but instead are held in trust for the benefit of all registered grassland projects, to be used as compensation for unavoidable reversals, as described in Section 5.4.2. Equation 5.14 shall be used to calculate the buffer pool contribution for the project during the reporting period.

The risk of an unavoidable reversal to a grassland project is extremely low. Fires would not typically release the carbon that is stored underground. Catastrophic floods would typically only occur in areas that have already been screened out by the eligibility criteria. Volcanic activity is exceedingly rare in the conterminous U.S., and does not occur in the areas where grassland projects typically occur. Due to the fact that the risk of unavoidable reversals is not significantly differentiated by location or land management, the Reserve has decided to adopt a default buffer pool contribution for all projects that is intended to insure against all types of unavoidable reversals.

In addition to the default contribution, projects may be obligated to make additional contributions to the buffer pool in certain situations. Where the Project Owner has elected to employ a Contract PIA, an additional contribution is required to reflect risks from financial failure; the value of $Risk_{FF}$ in Equation 5.14 shall be 0.1. Where the Grassland Owner has elected to employ a Recorded PIA, and has elected to allow the PIA to be subordinated to subsequent deed restrictions (such as a mortgage), an additional contribution is required to reflect risks from financial failure. If the property owner has employed Recorded PIA Subordination Clause Type 1, the value of this risk is 0. If the property owner has employed Recorded PIA Subordination Clause Type 2, the value of this risk is 0.1.[75] An exception to these rules is made for cases where the Project Owner is a land trust with accreditation through the Land Trust Accreditation Commission,[76] in which case the value of $Risk_{FF}$ shall be 0, regardless of the particular format of the PIA.

Site visits during verification are not mandatory for grassland projects. However, there is risk associated with a project that has never been visited for the purposes of a third-party verification. The Reserve believes that this risk is low enough that the site visit during verification has been made optional. However, an additional buffer pool contribution must be made to account for the increased risk (designated as "$Risk_{SV}$" in Equation 5.14). For each project that has never had a site visit during verification, the value of $Risk_{SV}$ shall be 0.05 until such time that a site visit verification occurs.[77] At that time, the CRTs contributed to the buffer pool due to this requirement shall be returned to the project in the form of either a reduced buffer pool contribution in future reporting periods or a lump sum refund of CRTs from the buffer pool, subject to agreement between the Project Owner and the Reserve. The amount of CRTs to be returned shall be determined by calculating what the buffer pool contributions would have been had the value of $Risk_{SV}$ been 0 for the previous reporting periods. If a site visit occurs during the initial verification, the value of $Risk_{SV}$ shall be 0 for the entire crediting period. This applies equally to individual projects as well as projects participating in a cooperative. For example, if a cooperative contains 10 projects and site visits occur on only 2 of them during the initial verification, the remaining 8 projects are subject to the increased buffer pool contribution, until such time that a site visit is carried out for those projects. If a project is expanded after a site visit has occurred, the value of $Risk_{SV}$ shall return to 0.05 for subsequent verifications until such time that either:

a) The project developer can demonstrate to the satisfaction of the subsequent verification body that the previous site visit was sufficiently thorough to be applied to the new project area, in whole; or,
b) Another site visit occurs at the new portion(s) of the expanded project area.

[75] The Project Implementation Agreements are available at: http://www.climateactionreserve.org/how/protocols/grassland/. Details on the buffer pool contribution related to subordination of the Recorded PIA are found in Exhibit E.
[76] Information regarding the Land Trust Accreditation Commission and the requirements for accreditation can be found at: http://www.landtrustaccreditation.org/.
[77] The reporting period during which the site visit occurs shall be the first reporting period not subject to the additional buffer pool contribution.

Equation 5.14. Buffer Pool Contribution to Insure Against Reversals

$$BP = Risk_{rev} \times OC_{BL}$$

Where, Units

BP	=	Project contribution to the buffer pool	tCO_2e
$Risk_{rev}$	=	Risk of reversals, as determined below	%
OC_{BL}	=	Baseline quantity of organic carbon emissions from soil and biomass (Equation 5.3)	tCO_2e

$$Risk_{rev} = 1 - [(1 - 0.02) \times (1 - Risk_{FF}) \times (1 - Risk_{SV})]$$

Where, Units

0.02	=	Default risk of unavoidable reversals, applicable to all projects[78]	fraction
$Risk_{FF}$	=	Additional risk related to financial failure, the value is either 0 or 0.1, as described above.	fraction
$Risk_{SV}$	=	Risk of misstatement by projects which have not had a site visit by a third-party verifier. The value is either 0 or 0.05.	fraction

As there are only three risk categories that contribute to $Risk_{rev}$, one of which is mandatory, there are ten possible project scenarios, leading to four possible values for this parameter. The potential project scenarios and the resulting value of $Risk_{rev}$ are listed in Table 5.3.

Table 5.3. Possible Values of $Risk_{rev}$

Default Risk	PIA	Project Owner	$Risk_{FF}$	Site Visit	$Risk_{SV}$	$Risk_{rev}$
0.02	Contract PIA	Accredited land trust	0	Yes	0	**0.020**
0.02	Contract PIA	Accredited land trust	0	No	0.05	**0.069**
0.02	Contract PIA	Other	0.1	Yes	0	**0.118**
0.02	Contract PIA	Other	0.1	No	0.05	**0.162**
0.02	Recorded PIA, Type 1 Subordination Clause	Any	0	Yes	0	**0.020**
0.02	Recorded PIA, Type 1 Subordination Clause	Any	0	No	0.05	**0.069**
0.02	Recorded PIA, Type 2 Subordination Clause	Accredited land trust	0	Yes	0	**0.020**
0.02	Recorded PIA, Type 2 Subordination Clause	Accredited land trust	0	No	0.05	**0.069**
0.02	Recorded PIA, Type 2 Subordination Clause	Other	0.1	Yes	0	**0.118**
0.02	Recorded PIA, Type 2 Subordination Clause	Other	0.1	No	0.05	**0.162**

[78] Based on discussion between and among Reserve staff and external stakeholders regarding the risks of unavoidable reversals to grassland projects. Such risks were determined to be low, but also not zero.

6 Project Monitoring

The Reserve requires a Monitoring Plan to be established for all monitoring and reporting activities associated with the project. The Monitoring Plan serves as the basis for verifiers to confirm that the monitoring and reporting requirements in this section and Section 7 have been and continue to be met, and that consistent, rigorous monitoring and record keeping is ongoing at the project site. The Monitoring Plan must cover all aspects of monitoring and reporting contained in this protocol and must specify how data for all relevant parameters in Table 6.1 are collected and recorded.

At a minimum, the Monitoring Plan shall include a description of ownership of both the property and the emission reductions; the methods and frequency of data acquisition; a record keeping plan (see Section 7.3 for minimum record keeping requirements), and the role of individuals performing each specific monitoring activity. The Monitoring Plan should include QA/QC provisions to ensure that data acquisition and recordkeeping are carried out consistently and with precision.

Finally, the Monitoring Plan must include procedures that the Project Owner follows to ascertain and demonstrate that the project at all times passes the legal requirement test and the Regulatory Compliance Test (Section 3.3.2 and 3.6, respectively).

Project Owners are responsible for monitoring the performance of the project.

6.1 Monitoring Ongoing Eligibility

To maintain eligibility on an ongoing basis, grassland projects must demonstrate that the project area has not been converted into another land use during the reporting period. If the project verification includes a physical site visit, that satisfies the requirements of this section. Otherwise, Project Owners shall refer to the guidance in Section 5.1.3 for guidance on documenting land use in the project area.

6.2 Monitoring Grazing

Livestock grazing is allowed in the project scenario. While low to moderate levels of grazing intensity may have a beneficial effect on the grassland ecosystem and net soil carbon storage (16), overgrazing can be detrimental to both the storage of soil carbon (17) and the health of the grassland ecosystem (18). Project grazing must be limited to moderate levels of intensity, balancing stocking rates with forage production and accounting for site characteristics, including climate variability (especially periods of drought), range condition, slope, distance from water, and the needs of the particular animals (19) (20).

Grassland projects must employ a mechanism to detect and prevent overgrazing on project lands, which is tailored to the specific conditions of their project and its ecosystem. It is up to each project developer to determine the appropriate means to safeguard the project against overgrazing. The project developer must obtain Reserve approval for the particular administrative means they will use to ensure project land is not overgrazed. Such approval must be obtained prior to listing of the project, and any changes to the mechanism must be approved by the Reserve prior to the completion of verification activities in a given reporting period.

The mechanism in question should include requirements for monitoring and enforcement, as well as identify the entity or entities that are responsible for such enforcement. The entity empowered to enforce this mechanism must be an entity (or entities) other than the Reserve or project verifier, and can be a third-party to the offset project (e.g., the easement holder, in certain cases). Project developers shall include in their monitoring plan full details of the administrative mechanism they are employing to safeguard against over-grazing.

For each reporting period, Project Owners must provide both a quantitative and qualitative accounting of grazing activities for the reporting period. In terms of quantitative data, projects must document the type of livestock being grazed and the total animal grazing days for each type (see Box 5.2). The livestock shall be categorized according to the categories in the *Grassland Project Parameters* spreadsheet.[79] These data are used for the parameter AGD_l in Equation 5.11. The frequency of monitoring and the form of the documentation is not prescribed by this protocol. In terms of qualitative reporting, project developers shall include in their monitoring report a description of grazing activity for the reporting period and whether this conforms to the administrative mechanism in place to guard against overgrazing. Written confirmation from the entity or entities providing oversight with respect to this administrative mechanism should be provided to the verifier, that no overgrazing has occurred during the verification period. The verifier shall use professional judgment to confirm with reasonable assurance that the quantification of project emissions from grazing is conservative, that effective monitoring of grazing has been maintained in accordance with this administrative overgrazing mechanism, and that no overgrazing has been detected using this administrative mechanism.

Examples of documentation that may suffice to demonstrate the quantitative grazing monitoring requirements may include (this list is not comprehensive nor is it intended to define sufficiency of documentation):

- Grazing logs (kept daily, weekly, or monthly) that specify the animal categories, populations, and grazing locations
- Animal purchase and sale records, assuming all animals are grazed on the project area
- Grazing management plan, assuming maximum allowable grazing activity

CRTs will not be issued for any reporting period during which it is determined that there has been a violation of the administrative mechanism to prevent overgrazing. In addition, the Reserve may conduct additional review to confirm that a reversal has not occurred due to overgrazing.

6.3 Monitoring Project Emission Sources

For fossil fuels and electricity emissions (Equation 5.9), if the Project Owner can demonstrate that the total value of $CO_{2,PR}$ is reasonably expected to be *de minimis* (i.e., less than the relevant materiality threshold), these emissions may be estimated through a conservative method proposed by the Project Owner and deemed acceptable by the verifier. If not required for the alternative method, the monitoring of fossil fuels and electricity as described in this section is not required.

Otherwise, for each reporting period, the Project Owner must provide documentation for the following parameters used for the quantification of project emissions:

- Total acres burned and cause(s) of fire(s)
- Animal grazing days by livestock category

[79] Available at: http://www.climateactionreserve.org/how/protocols/grassland/.

- Mass of organic fertilizer applied (other than manure from grazing), by type
- Nitrogen content of organic fertilizer applied, by type
- Purpose, type, and quantity of fossil fuels used (e.g., tractor, diesel, 100 gallons)
- Purpose, source, and quantity of electricity (e.g., electric fence, MROW grid, 100 kWh)

For projects that employ additions of organic fertilizer (beyond the manure from on-site grazing of livestock), it is strongly encouraged that the project develop a nutrient management plan. Nutrient management plans should consider the principles contained in NRCS Conservation Practice Standard 590 for Nutrient Management.[80] Where a project also incorporates irrigation and/or grazing, such activities should be taken into account in developing any nutrient management plan for the project. Development of and adherence to a nutrient management plan is not required, but is strongly recommended.

6.4 Monitoring Ecosystem Health

As described in Section 3.7, grassland projects are subject to forces, both natural and cultural, active and passive, that could impair the long-term health and functioning of the rangeland system. Thus, it is required that projects undergo a periodic assessment of rangeland health according to the assessment protocol described in the Bureau of Land Management's Technical Reference 1734-6, "Interpreting Indicators of Rangeland Health" (21).[81] A rangeland health assessment must be submitted for review during one of the first two project verifications. Subsequent assessments may occur as frequently as desired by the Project Owner, with a minimum frequency of once every six years.[82] These assessments are only required during the crediting period, and are not required during the permanence period, although it is strongly recommended that the practice be continued on a voluntary basis. If the project area is already subject to periodic rangeland health assessments according to TR 1734-6, then the most recent assessment may be submitted during the initial project verification, provided that it is dated no more than six years prior to the end of the initial reporting period.

The reference conditions for the project area may be determined using the appropriate Ecological Site Description (ESD).[83] If the ESD does not contain specified reference conditions for the project area, they may be developed following the guidance in TR 1734-6. The rangeland health assessment must be conducted by an appropriately-trained individual. The result of the assessment is the rating of 17 different metrics by the severity of their departure from the expected reference condition, categorized into five levels:

1. None to Slight
2. Slight to Moderate
3. Moderate
4. Moderate to Extreme
5. Extreme to Total

The Reserve understands that heterogeneity of ecosystems, land use history, and land management practices mean that it is likely that the project area exhibits at least slight deviation

[80] Available at: http://www.nrcs.usda.gov/Internet/FSE_DOCUMENTS/stelprdb1046896.pdf.
[81] The assessment protocol, associated documents, and information regarding training opportunities are available online at: http://jornada.nmsu.edu/monit-assess/manuals/assessment (accessed 10/14/16).
[82] The result of this schedule is that if a project elects to follow the most relaxed verification schedule (once every six years), there will be at least one rangeland health assessment during every verification period.
[83] An ESD may be obtained from the USDA NRCS at: https://esis.sc.egov.usda.gov/Welcome/pgESDWelcome.aspx (accessed 10/14/16).

from the reference condition for at least one, if not several, rangeland health metrics. Projects are not required to meet reference conditions for rangeland health metrics.

For any metric that is assessed to be at the third level (“Moderate”), the Project Monitoring Plan must be updated prior to the next verification to reflect planned management changes to address that metric, with a minimum goal of preventing further departure from the reference condition. A preferred goal would be a return to reference condition.

For any metric that is assessed to be at the fourth or fifth levels (“Moderate to Extreme” or “Extreme to Total”) of departure from the reference condition, the Project Monitoring Plan must be updated prior to the next verification to reflect planned management changes to address that metric, with a goal of improving that metric toward reference condition. The subsequent rangeland health assessment must show improvement in these metrics. If a project does not improve (or declines) in these metrics at the next assessment, the Project Owner must notify the Reserve, which shall determine whether the project is eligible for crediting for the current reporting period. Projects that can demonstrate rangeland health impairment occurred despite reasonable, good-faith efforts in land management may not need to forfeit credits. However, significant degradation in rangeland health could be considered a reversal, despite the lack of a specific disturbance event. Refer to Section 3.7 for additional information regarding the consequences of significantly degraded rangeland health.

Management planning for rangeland health should explicitly include management of livestock grazing.

The requirements of this section may be satisfied through alternative assessment methods with written approval from the Reserve. Potential alternatives for complying with this requirement include (this list is not comprehensive nor is it intended to define sufficiency):

1. Use of an alternative assessment protocol which employs a robust sampling design which avoids or reduces bias in the selection of sample plots, assesses widely recognized metrics for ecosystem health, is/was developed with input from relevant experts, and is applied consistently over time; or,
2. Use of advanced remote sensing techniques, coupled with a clear, scientific evidence to support their use for this purpose. Such remote sensing must be of a sufficiently high resolution to detect ecosystem degradation at a scale which would be obvious from direct observation.

6.5 Monitoring Project Cooperatives

There can be gains in efficiency through centralized monitoring for project cooperatives. A Cooperative Developer may organize their monitoring plan such that information from individual projects is collected and processed together. However, all information and documentation must be organized in such a manner that the verifier can assess that the requirements of this protocol have been met for each individual project. For example, it is acceptable to submit a single spreadsheet of grazing data for the cooperative, but the grazing data for each individual project must still be clearly defined within that spreadsheet.

6.6 Monitoring Parameters

Prescribed monitoring parameters necessary to calculate baseline and project emissions are provided in Table 6.1.

Table 6.1. Grassland Project Monitoring Parameters

Eq. #	Parameter	Description	Data Unit	Calculated (C) Measured (M) Reference (R) Operating Records (O)	Measurement Frequency	Comment
General Project Parameters						
	Project Definition	Must confirm project land use has not changed		R, O	Each reporting period	Information used to asses that the project area remains as grassland.
	Eligibility	Must satisfy all requirements of the Eligibility section		N/A	Each reporting period	Information used to assess satisfaction of the requirements of Section 3.
	Regulations	Project Owner attestation of compliance with regulatory requirements relating to the project	All applicable regulations	N/A	Each reporting period	Information used to: 1) Demonstrate ability to meet the legal requirement test – where regulation would prevent conversion of project area. 2) Demonstrate compliance with associated environmental rules, e.g., criteria pollutant limits.
Equation 5.3, Equation 5.4	S	Total number of strata relevant to the project area	strata	R	Once[84]	Information used to determine acres assigned to each relevant stratum.
Equation 5.1	ER	Emission reductions	tCO_2e	C	Per reporting period	Emission reductions are quantified once per reporting period per project. May be summed for reporting of a project cooperative.
Equation 5.5	Area	Area of the entire project	acres	M	Once[84]	The project area is measured using GIS.
Equation 5.3, Equation 5.4	$Area_s$	Area of project in stratum *s*	acres	M	Once[84]	The area of each stratum is measured using GIS.

[84] This parameter would only change if a portion of the project area was subsequently removed from the project and excluded from future quantification or if the project area was expanded.

Eq. #	Parameter	Description	Data Unit	Calculated (C) Measured (M) Reference (R) Operating Records (O)	Measurement Frequency	Comment
Baseline Emission Calculation Parameters						
Equation 5.1, Equation 5.2, Equation 5.12	BE	Baseline emissions	tCO_2e	C	Per reporting period	Calculated based on default factors.
Equation 5.2, Equation 5.3, Equation 5.14	OC_{BL}	Baseline emissions due to loss of organic carbon from soil and belowground biomass	tCO_2e	C	Per reporting period	Calculated for each stratum using default emission factors.
Equation 5.2, Equation 5.4	N_2O_{BL}	Baseline emissions of nitrous oxide	tCO_2e	C	Per reporting period	Calculated for each stratum using default emission factors.
Equation 5.2, Equation 5.5	$CO_{2,BL}$	Baseline emissions of carbon dioxide	tCO_2e	C	Per reporting period	Calculated for each stratum using default consumption rates.
Equation 5.2, Equation 5.6, Equation 5.13	DF_{conv}	Discount factor for the uncertainty of conversion	%	R	Once	The value of this uncertainty is based on the performance standard test.
Equation 5.2, Equation 5.13	DF_{σ}	Discount factor for the uncertainty of modeling future management practices and climatic conditions	%	R	Per reporting period	The value of this uncertainty is related to the amount of time that has passed since the baseline modeling was completed.
Equation 5.2	Pro	Pro-rating factor	%	C	Per reporting period	For reporting periods which do not cover an entire year
Equation 5.3	CP	Cropland premium for the project site county	%	R	Once[85]	The cropland premium for the project site county may be referenced from the companion tables.[86]

[85] If a new county is added due to project expansion, then this value needs to be updated.
[86] Certain parameters required for project eligibility and quantification are contained in a separate document, *Grassland Project Parameters*, available at: http://www.climateactionreserve.org/how/protocols/grassland/.

Eq. #	Parameter	Description	Data Unit	Calculated (C) Measured (M) Reference (R) Operating Records (O)	Measurement Frequency	Comment
Equation 5.3	$BEF_{OC,s,y}$	Annual baseline emission factor for organic carbon	kg CO_2e/ac/yr	R	Per reporting period	Default factor based on stratum.
Equation 5.4	$BEF_{N2O,s}$	Annual baseline emission factor for N_2O emissions in stratum *s*	kg N_2O/ac/yr	R	Per reporting period	Default factor based on stratum.
Equation 5.5	BRC_{CO2}	Annual baseline rate of consumption of diesel fuel due to cultivation activities	gal/ac/yr	R	Per reporting period	Default consumption rate based on stratum.
Equation 5.5	EF_{FF}	Emission factor for diesel fuel	kg CO_2/gal	R	Per reporting period	Default value for all projects.
Project Emission Calculation Parameters						
Equation 5.7	PE	Project emissions	tCO_2e	C	Per reporting period	Actual emissions in the project area during the reporting period.
Equation 5.7, Equation 5.8	BU_{PR}	Emissions from burning in the project scenario	tCO_2e	C	Per reporting period	Calculated only in the case of a fire during the reporting period.
Equation 5.7, Equation 5.9	FF_{PR}	Emissions from fossil fuels and electricity in the project scenario	tCO_2e	C	Per reporting period	Calculated only if fossil fuels or electricity are used for the project during the reporting period.
Equation 5.7, Equation 5.10	FE_{PR}	Emissions from fertilizer use in the project scenario	tCO_2e	C	Per reporting period	Calculated only if fertilizer is applied on the project area during the reporting period.
Equation 5.7, Equation 5.11	GR_{PR}	Emissions from livestock grazing in the project scenario	tCO_2e	C	Per reporting period	Calculated only if livestock grazing occurs on the project area during the reporting period.
Equation 5.7, Equation 5.12	LE	Emissions from leakage in the project scenario	tCO_2e	C	Per reporting period	Based on a default factor for leakage.
Equation 5.8	$Area_{burn,s}$	Area of stratum *s* that was burned	acres	O	Per fire event	Estimated through either remote sensing or on-site measurement.

Eq. #	Parameter	Description	Data Unit	Calculated (C) Measured (M) Reference (R) Operating Records (O)	Measurement Frequency	Comment
Equation 5.8	DM_s	Amount of aboveground dry matter in stratum *s*	kg/ac	R	Per reporting period	Default factor based on stratum.
Equation 5.9	QF_f	Quantity of fossil fuel type *f* consumed	volume	O	Per reporting period	Includes fossil fuels consumed for any activities on the project area.
Equation 5.9	$PEF_{FF,f}$	Project emission factor for fossil fuel type *f*	kg CO_2/volume fuel	R	Per reporting period	Default emission factors provided.
Equation 5.9	QE	Quantity of electricity consumed during the reporting period	MWh	O	Per reporting period	Includes any electricity consumed on the project area.
Equation 5.9	PEF_{EL}	Emission factor for electricity consumed	kg CO_2/MWh	R	Per reporting period	Referenced from the most recent U.S. EPA eGRID emission factor publication.[87] Projects shall use the annual total output emission rates for the subregion where the project is located.
Equation 5.10	C	Total number of types of organic fertilizer applied, other than manure from grazing livestock	Categories	O	Per reporting period	Must be documented if fertilizer is applied on the project area during the reporting period.
Equation 5.10	QF_{PR}	Quantity of organic fertilizer type *c* applied	kg	O	Per reporting period	Must be documented if fertilizer is applied on the project area during the reporting period.
Equation 5.10	NC_c	Nitrogen content of fertilizer type *c*	kg N/kg fertilizer	O	Per reporting period	Must be documented if fertilizer is applied on the project area during the reporting period.

[87] Available online at: http://www.epa.gov/cleanenergy/energy-resources/egrid/.

Eq. #	Parameter	Description	Data Unit	Calculated (C) Measured (M) Reference (R) Operating Records (O)	Measurement Frequency	Comment
Equation 5.10, Equation 5.11	Leach	Default factor for the fraction and emission factor for N_2O emissions due to leaching	N/A	R	Once[88]	Default factor based on the county where the project area is located. Default factor also be used when irrigation employed in project reporting period.
Equation 5.11	N_2O_{MN}	N_2O emissions from livestock grazing	tCO_2e	C	Per reporting period	Based on AGD for each livestock category using default emission factors.
Equation 5.11	$CH_{4,MN}$	CH_4 emissions from manure	tCO_2e	C	Per reporting period	Based on AGD for each livestock category using default emission factors.
Equation 5.11	$CH_{4,ENT}$	CH_4 emissions from enteric fermentation	tCO_2e	C	Per reporting period	Based on AGD for each livestock category using default emission factors.
Equation 5.11	L	Total number of livestock categories	Categories	O	Per reporting period	Documented for every reporting period where livestock are grazed on the project area.
Equation 5.11	AGD_l	Animal grazing days for livestock category *l*	Animal days	O	Per reporting period	Documented for every reporting period where livestock are grazed on the project area.
Equation 5.11	Nex_l	Nitrogen excreted by animals in livestock category *l*	kg N/animal grazing day	R	Per reporting period	Default factors based on livestock category and project state.
Equation 5.11	VS_l	Volatile solids excreted by animals in livestock category *l*	kg VS/animal grazing day	R	Per reporting period	Default factors based on livestock category and project state.
Equation 5.11	$B_{0,l}$	Maximum CH_4 potential for manure from animal category *l*	m^3 CH_4/kg VS	R	Per reporting period	Default factors based on livestock category.

[88] If a new county is added due to project expansion, then this value needs to be updated.

Eq. #	Parameter	Description	Data Unit	Calculated (C) Measured (M) Reference (R) Operating Records (O)	Measurement Frequency	Comment
Equation 5.11	MCF_{PRP}	CH_4 conversion factor for pasture/range/paddock manure management	%	R	Per reporting period	Default value based on average ambient temperature during the grazing season.
Equation 5.11	ρ_{CH4}	Density of CH_4 at 1 atm pressure and the average ambient temperature during the grazing season	kg/m^3	R	Per reporting period	Based on average ambient temperature during the grazing season.
Equation 5.11	$PEF_{ENT,l}$	Project emission factor for enteric methane emissions from livestock category *l*	kg CH_4/animal grazing day	R	Per reporting period	Default factors based on livestock category and project state.
Equation 5.13	Rev	Quantity of emissions due to a reversal	tCO_2e	C	Per reversal event	Any event, avoidable or unavoidable, which causes a loss of belowground organic carbon results in a reversal of CRTs which have been issued. Reversals must be quantified and compensated for.
Equation 5.13	Y	Number of years for which CRTs have already been issued	years	O	Per reversal event	The magnitude of a reversal is related to the affected area and the number of CRTs which have already been issued.
Equation 5.13	$OC_{BL,rev,rp}$	Baseline emissions of organic carbon in soil and biomass in reporting period *y* for the acres affected by the reversal	tCO_2e	C	Per reversal event	The quantity of CRTs related to belowground organic carbon affected by the reversal.
Equation 5.14	BP	Buffer pool contribution	tCO_2e	C	Per reporting period	Based on risk rating for the project.
Equation 5.14	$Risk_{rev}$	Risk of unavoidable reversals	%	C	Per reporting period	Includes a default risk plus additional project-specific risks.

Eq. #	Parameter	Description	Data Unit	Calculated (C) Measured (M) Reference (R) Operating Records (O)	Measurement Frequency	Comment
Equation 5.14	$Risk_{FF}$	Risk related to financial failure	%	R	Once, unless the PIA is updated to change the subordination clause	The value is determined based on the specific subordination clause that is included in the PIA. Details can be found in Exhibit E of the PIA.
Equation 5.14	$Risk_{SV}$	Risk related to site visit schedule	%	R	Per reporting period	The value is determined based on whether the project or cooperative adheres to the recommended minimum site visit schedule.

7 Reporting Parameters

This section provides requirements and guidance on reporting rules and procedures. A priority of the Reserve is to facilitate consistent and transparent information disclosure across projects.

7.1 Time Periods for Reporting

Table 7.1 summarizes the various time periods that are relevant to AGC projects. Project Owners should recognize that recurring periods (such as reporting periods or verification periods) must always be contiguous, such that there are no gaps between recurring periods. CRTs can only be issued upon approval of a verification report by the Reserve.

Table 7.1. Guide to Relevant Time Periods for Grassland Projects

Description	Time Period	Protocol Section
Project lifetime	Up to 150 years	2.2
Conservation easement term	Perpetual	2.2
Pre-project land use history	No less than 10 years prior to project start date	2.2
Crediting period	No more than 50 years following project start date	3.4
Reporting period (first)	No more than 24 months	7.4
Reporting period (subsequent)	No more than 12 months	7.4
Verification period (first)	First reporting period	7.4
Verification period (subsequent)	No more than 6 reporting periods	7.4
Permanence period	100 years following crediting period	3.5
Monitoring period (easement enforcement)	No more than 6 years	7.5.1
Monitoring period (outside of easement enforcement)	No more than 3 years	7.5.2
Verification period (outside of easement enforcement)	No more than 15 years	7.5.2

7.2 Project Documentation

Project Owners must provide the following documentation to the Reserve in order to register a grassland project:

- Project Submittal form (or Cooperative Submittal form)*
- Property ownership documentation*
- Project conservation easement
- Project Implementation Agreement
- Project area map (this map is public; it is only required to show the outer extent of the project area and is not required to be in a georeferenced format)*
- Signed Attestation of Title form
- Signed Attestation of Voluntary Implementation form
- Signed Attestation of Regulatory Compliance form
- Verification Report
- Verification Statement

** Denotes items that are required at the time of project submittal.*

Project Owners must provide the following documentation for each verification period during the crediting period in order for the Reserve to issue CRTs for quantified GHG reductions:

- Verification Report
- Verification Statement
- Signed Attestation of Title form
- Signed Attestation of Voluntary Implementation form
- Signed Attestation of Regulatory Compliance form
- Signed Project Implementation Agreement (for the initial verification) or signed, amended Project Implementation Agreement (for subsequent verifications)
- Georeferenced project boundary map (this map is private; it must delineate the actual polygons of the eligible project area, and must be a shapefile or KML format)

Documentation requirements for the Permanence Period are explained in Section 7.5.

At a minimum, the above project documentation (except as noted) is available to the public via the Reserve's online registry. Further disclosure and other documentation may be made available on a voluntary basis through the Reserve. Project submittal forms can be found at http://www.climateactionreserve.org/how/program/documents/.

7.3 Record Keeping

For purposes of independent verification and historical documentation, Project Owners are required to keep all information outlined in this protocol for a period of 10 years after the information is generated or 7 years after the last verification. This information is not publicly available, but may be requested by the verifier or the Reserve.

System information the Project Owner shall retain includes:

- Detailed, georeferenced project maps (created per guidance in Section 2.2.1)
- Ongoing monitoring reports or documentation related to the conservation easement
- All data inputs for the calculation of the project emission reductions, including all required sampled data
- Documentation of the continued conservation of the grassland cover in the project area (see Section 6.1)
- Copies of all permits, Notices of Violations, and any relevant administrative or legal consent orders dating back at least 3 years prior to the project start date
- Executed Attestation of Title, Attestation of Regulatory Compliance, and Attestation of Voluntary Implementation forms
- Onsite fossil fuel use records, if applicable
- Onsite grid electricity use records, if applicable
- Grazing management plan, if applicable
- Nutrient management plan, if applicable
- Grazing management records
- Fertilizer use records, if applicable
- Documentation of fires, if applicable
- Results of annual CO_2e reduction calculations
- Initial and annual verification records and results

7.4 Reporting Period and Verification Cycle

The reporting period is the length of time over which GHG emission reductions from project activities are quantified. Project Owners must report GHG reductions resulting from project activities during each reporting period. A reporting period may not exceed 12 months in length, except for the initial reporting period, which may cover up to 24 months. The Reserve accepts verified emission reduction reports on a sub-annual basis, should the Project Owner choose to have a sub-annual reporting period and verification schedule (e.g., monthly, quarterly, or semi-annually). However, it is recommended that projects follow a calendar year reporting schedule to simplify the application of the quantification and monitoring requirements. Reporting periods must be contiguous; there must be no gaps in reporting during the crediting period of a project once the first reporting period has commenced.

The verification period is the length of time over which GHG emission reductions from project activities are verified. The initial verification period for a grassland project is limited to one reporting period. Subsequent verification periods may cover up to six reporting periods. It is required that a project verification occur at least every six years during a project's crediting period. CRTs will not be issued for reporting periods that have not been verified. Project Owners may choose to verify more frequently than every six reporting periods. For any reporting period that ends prior to the end of the verification period (i.e., years 1-5 of a 6 year verification period), an interim monitoring report must be submitted to the Reserve no later than 90 days following the end of the relevant reporting period. The interim monitoring report shall contain a summary of ownership (describing the entities and relationships detailed in Section 2.3), evidence of land use (as described in Section 5.1.3), and basic documentation of land management activities and project emissions during the relevant reporting period.[89] See Section 7.5 for guidance on reporting and verification activities after the crediting period is concluded.

To meet the verification deadline, the Project Owner must have the required verification documentation (see Section 7.2) submitted within 12 months of the end of the verification period. The end date of any verification period must correspond to the end date of a reporting period. No more than six reporting periods (a maximum of 72 months) can be verified at once during the project's crediting period.

7.5 Reporting and Verification of Permanence

When the crediting period for a grassland project ends, the project enters the permanence period. Per Section 3.5, the project area must be monitored to ensure against reversals for a period of 100 years following the last issuance of CRTs related to carbon pools at the project site (i.e., soil organic carbon). During the permanence period, no emission reductions are claimed and no new credits are issued. Projects may elect to begin the permanence period prior to the end of their maximum allowable crediting period by notifying the Reserve in writing prior to their next reporting deadline. This monitoring can take different forms depending on the terms of the conservation easement which binds the project area. In any case, monitoring must continue through the permanence period to confirm that no reversals have occurred, and the results of this monitoring must be reported to the Reserve periodically. There are two categories of monitoring scenarios: projects may either be monitored as part of their easement monitoring activities, or they may be monitored specifically for the carbon project. In both cases, the required periodic monitoring reports shall, at a minimum, contain the following:

[89] A template monitoring report is available at: http://www.climateactionreserve.org/how/program/documents/.

- Evidence to support the conclusion that no reversals have occurred on the project area since the previous reported time period
- Information related to ongoing activities on the site, including grazing
- Updated information related to ownership of the property, the easement, and the rights to the soil carbon

In certain cases (see Section 7.5.1) these reports are not required to be verified, but in all cases they must be reviewed and approved by the Reserve in order for the terms of the PIA to be satisfied. Project emissions are not quantified during the permanence period. If a reversal is identified, it must be reported to the Reserve and the guidance in Section 5.4 regarding compensation for reversals shall apply.

7.5.1 Monitoring through Easement Activities

If a project area is subject to the terms of a Qualified Conservation Easement (Section 3.5.1) which includes provisions for ongoing monitoring and specific mechanisms for enforcement, such monitoring activities may be considered sufficient for the purposes of this protocol. The Project Owner must submit a monitoring report at least every six years (i.e., this report is due no later than 72 months after the end date of the previous verification or monitoring period, whichever is relevant). The Reserve maintains the right to determine whether the terms of a conservation easement are sufficient to meet the requirements of this section. An easement may be amended at any time to meet these requirements, subject to approval by the Reserve. If the monitoring is not carried out according to the terms of the easement or the monitoring reports are not received by the Reserve, the Project Owner may be in breach of the PIA.

7.5.2 Monitoring for Carbon Separately

If the conservation easement does not contain monitoring and enforcement terms that satisfy Section 7.5.1, the Project Owner must continue monitoring and reporting activities through other means. Projects must prepare and submit a monitoring report to the Reserve at least every 3 years (i.e., this report is due no later than 36 months after the end date of the previous verification or monitoring period, whichever is relevant). These monitoring reports shall be verified at least every fifteen years, although verification may be more frequent. The verification deadlines described in Section 7.4 shall apply.

7.6 Joint Reporting of Project Cooperatives

Project cooperatives carry out a certain amount of joint effort for reporting. While the quantification section shall be applied to each project independently, the results may be collected and reported together to the Reserve by the Cooperative Developer. Reports and documentation may be combined for efficiency, but it must be possible to trace the evidence for the emission reductions from each individual project.

In the management of a cooperative, certain documents are required to be submitted for each individual project, while certain other documents may be submitted once for the entire cooperative. Table 7.2 details which documents belong to which category. The Cooperative Developer shall submit all documentation through their Reserve account. Once the verification report is registered, CRTs shall be issued to the Project Owner account associated with each project in the cooperative.

Table 7.2. Document Management for Project Cooperatives

May Apply to the Cooperative	Must be Submitted for Each Individual Project[90]
▪ Cooperative Submittal form ▪ Verification Report ▪ Verification Statement	▪ Property ownership documentation ▪ Attestation of Title form ▪ Attestation of Voluntary Implementation form ▪ Attestation of Regulatory Compliance form ▪ Project maps

7.6.1 Cooperative Verification Cycle

The verification period for the entire cooperative must end on the same date, unless a project reaches the end of its crediting period during the verification period. In that case, it is acceptable for that project to end reporting prior to the end of the cooperative's verification period. However, during a project's first verification as a member of a cooperative, it may begin reporting at a date that is different from other projects in the cooperative. It is likely that each project in a cooperative has a different start date, and thus during the initial verification for a cooperative each project begins reporting on a different date. The initial verification period shall cover a single reporting period, and the initial reporting period may be up to 24 months in length. Although the individual projects begin their reporting periods on different dates, they shall all end on the same date, such that subsequent verifications of the cooperative will cover the same length of time for every project. When a project joins a cooperative that has already undergone verification, that project's next reporting period must not begin prior to the end of the cooperative's previous verification period, but it may begin at a date that is later than the beginning of the cooperative's next reporting period. Table 7.3 describes various cooperative scenarios and the resultant outcomes for their respective verification cycles.

If an individual project within a cooperative is unable to meet the requirements of this protocol for one or more reporting periods, that project may report zero credits for that time period and continue to be verified as part of the cooperative. For reporting periods where a project claims zero credits, the verifier shall confirm that project emissions were not greater than baseline emissions, and that no reversals occurred. Additional guidance regarding zero-credit reporting periods can be found in the Reserve Offset Program Manual.[91]

Table 7.3. Example Cooperative Verification Scenarios

Example Scenario	Resulting Verification Cycle
1. Cooperative X contains two projects: Project A has a start date of 1/1/15 and Project B has a start date of 7/22/15.	The initial verification period for the cooperative would cover 1/1/15 – 12/31/16. Project A would report for the entire period, while Project B would report only for 7/22/15 – 12/31/16.
2. Project C wishes to join Cooperative X. Project C has a start date of 5/9/17.	The next reporting period for the cooperative is 1/1/17 – 12/31/17. The first reporting period for Project C would be 5/9/17 – 12/31/17.

[90] These documents for individual projects may be electronically combined into a single PDF (e.g., one digital file may contain the individual Attestation of Title forms for every project in the cooperative).
[91] Available at: http://www.climateactionreserve.org/how/program/program-manual/.

Example Scenario	Resulting Verification Cycle
3. Project D wishes to join Cooperative X. Project D has a start date of 1/1/16 and has not yet gone through verification.	There are two options: *Option i*: The project may undergo verification as a standalone project for the period 1/1/16 – 12/31/16, then subsequently join the cooperative for future reporting. *Option ii*: The project may join the cooperative immediately, taking a zero-credit reporting period for 1/1/16 – 12/31/16, and begin reporting on 1/1/17 with the cooperative's next verification period.
4. Project E wishes to transfer into Cooperative X from another, different cooperative, which has already undergone verification. The last verification period for Project E ended on 6/30/16.	There are two options: *Option i*: The project may undergo verification as a standalone project for the period 7/1/16 – 12/31/16, then subsequently join the cooperative for future reporting. *Option ii*: The project may join the cooperative immediately, taking a zero-credit reporting period for 7/1/16 – 12/31/16, and begin reporting on 1/1/17 with the cooperative's next verification period.

8 Verification Guidance

This section provides verification bodies with guidance on verifying GHG emission reductions associated with the project activity. This verification guidance supplements the Reserve's Verification Program Manual and describes verification activities specifically related to grassland projects.

Verification bodies trained to verify grassland projects must be familiar with the following documents:

- Reserve Offset Program Manual
- Climate Action Reserve Verification Program Manual
- Climate Action Reserve Grassland Protocol (this document)

The Reserve Offset Program Manual, Verification Program Manual, and protocols are designed to be compatible with each other and are available on the Reserve's website at http://www.climateactionreserve.org.

Only ANSI-accredited verification bodies trained by the Reserve for this project type are eligible to verify grassland project reports. Verification bodies approved under other protocol types are not permitted to verify grassland projects.[92]

8.1 Joint Verification of Project Cooperatives

Projects that participate in a project cooperative are verified together for every verification period. The Cooperative Developer has their own account on the Reserve through which they submit all documentation related to the cooperative. One set of verification documentation shall be submitted for the entire cooperative, but the project-specific attestations must be executed by the Project Owner for each project.

If the verifier cannot reach a positive verification opinion for one or more projects within a cooperative, the verification may still be completed, and emission reductions registered for the projects for which the verifier can reach a positive opinion. However, the verification of the cooperative as a whole cannot be approved by the Reserve unless an opinion is rendered on every project within the cooperative.

8.2 Standard of Verification

The Reserve's standard of verification for grassland projects is the Grassland Protocol (this document), the Reserve Offset Program Manual, and the Verification Program Manual. To verify a grassland project report, verification bodies apply the guidance in the Verification Program Manual and this section of the protocol to the standards described in Sections 2 through 7 of this protocol. Sections 2 through 7 provide eligibility rules, methods to calculate emission reductions, performance monitoring instructions and requirements, and procedures for reporting project information to the Reserve.

[92] Information about verification body accreditation and Reserve project verification training can be found on the Reserve website at http://www.climateactionreserve.org/how/verification/.

8.3 Monitoring Plan

The Monitoring Plan serves as the basis for verification bodies to confirm that the monitoring and reporting requirements in Section 6 and Section 7 have been met, and that consistent, rigorous monitoring and record keeping are ongoing at the project site. Verification bodies shall confirm that the Monitoring Plan covers all aspects of monitoring and reporting contained in this protocol and specifies how data for all relevant parameters in Table 6.1 are collected and recorded.

8.4 Verifying Project Eligibility

Verification bodies must affirm a grassland project's eligibility according to the rules described in this protocol. The table below outlines the eligibility criteria for grassland projects. This table does not present all criteria for determining eligibility comprehensively; verification bodies must also look to Section 3 and the verification items list in Table 8.2.

Table 8.1. Summary of Eligibility Criteria for a Grassland Project

Eligibility Rule	Eligibility Criteria	Frequency of Rule Application
Start Date	Projects must be submitted for listing no more than 12 months after the project start date	Once during first verification
Start Date	Recordation of a conservation easement, submittal of the project to the Reserve, transfer of the project area to Federal Government ownership, or execution of a notarized contract	Once during first verification
Location	Conterminous United States and tribal areas	Once during first verification
Location	Project strata must have a positive baseline emission factor for soil organic carbon during the reporting period	Every verification
Performance Standard	Project county must pass the financial threshold at the time of project submittal	Once during first verification
Performance Standard	Project area must pass the suitability threshold	Once during first verification
Legal Requirement Test	Signed Attestation of Voluntary Implementation form and monitoring procedures for ascertaining and demonstrating that the project passes the legal requirement test	Every verification
Credit and Payment Stacking	Projects must meet credit and payment stacking requirements and disclose all credits or payments received in relation to the project area	Every verification
Regulatory Compliance Test	Signed Attestation of Regulatory Compliance form and disclosure of all non-compliance events to verifier; project must be in material compliance with all applicable laws	Every verification
Project Implementation Agreement	The Project Owner must execute a PIA with the Reserve prior to the initial registration, and sign an amended PIA prior to each subsequent registration	Every verification

8.5 Core Verification Activities

The Grassland Protocol provides explicit requirements and guidance for quantifying the GHG reductions associated with the avoided conversion of grasslands to croplands. The Verification Program Manual describes the core verification activities that shall be performed by verification bodies for all project verifications. They are summarized below in the context of a grassland project, but verification bodies must also follow the general guidance in the Verification Program Manual.

Verification is a risk assessment and data sampling effort designed to ensure that the risk of reporting error is assessed and addressed through appropriate sampling, testing, and review. The three core verification activities are:

1. Identifying emission sources, sinks, and reservoirs (SSRs)
2. Reviewing GHG management systems and estimation methodologies
3. Verifying emission reduction estimates

Identifying emission sources, sinks, and reservoirs
The verification body reviews for completeness the sources, sinks, and reservoirs identified for a project, based on the guidance in Section 4.

Reviewing GHG management systems and estimation methodologies
The verification body reviews and assesses the appropriateness of the methodologies and management systems that the grassland Project Owner uses to gather data and calculate baseline and project emissions, based on the guidance in Sections 5 and 6.

Verifying emission reduction estimates
The verification body further investigates areas that have the greatest potential for material misstatements and then confirms whether or not material misstatements have occurred. This may involve site visits to the project area (or areas if verifying a project cooperative) to ensure the activities on the ground correspond to and are consistent with data provided to the verification body. In addition, the verification body recalculates a representative sample of the performance or emissions data for comparison with data reported by the Project Owner in order to double-check the calculations of GHG emission reductions.

8.5.1 Site Visits

Site visits during verification are strongly recommended, but are not mandatory for grassland projects. However, there is risk associated with a project that has never been visited for the purposes of a third-party verification. This risk is related to the lack of direct, physical inspection of the project area and personal, face-to-face interaction with the project participants, which are valuable components of typical offset project verification activities. The Reserve believes that this risk is low enough in the case of grassland projects that the site visit during verification has been made optional. However, an additional buffer pool contribution must be made to account for the increased risk for those projects which forego a site visit verification. Section 5.4.3 details how this contribution is determined. Although the site visit is optional, it may be carried out at the discretion of the Project Owner or the verifier.

When a site visit is carried out for the verification of a grassland project, the site visit may occur during the verification period or after its conclusion. During this visit the verifier confirms the eligibility of the existing land use, assess the accuracy of the project maps, assess the sources of project emissions, and assess the management and recordkeeping related to the project.

8.5.2 Desk Review Verification

For verifications that do not include a site visit, the verification body must follow the same standards and procedures, but is not required to physically visit the project site. Desk review verifications must achieve the same standard of reasonable assurance.

8.6 Grassland Verification Items

The following tables provide lists of items that a verification body needs to address while verifying a grassland project. The tables include references to the section in the protocol where requirements are further specified. The table also identifies items for which a verification body is expected to apply professional judgment during the verification process. Verification bodies are expected to use their professional judgment to confirm that protocol requirements have been met in instances where the protocol does not provide (sufficiently) prescriptive guidance. For more information on the Reserve's verification process and professional judgment, please see the Verification Program Manual.

Note: These tables shall not be viewed as a comprehensive list or plan for verification activities, but rather guidance on areas specific to grassland projects that must be addressed during verification.

8.6.1 Project Eligibility and CRT Issuance

Table 8.2 lists the criteria for reasonable assurance with respect to eligibility and CRT issuance for grassland projects. These requirements determine if a project is eligible to register with the Reserve and/or have CRTs issued for the reporting period. If any requirement is not met, either the project may be determined ineligible or the GHG reductions from the reporting period (or subset of the reporting period) may be ineligible for issuance of CRTs, as specified in Sections 2, 3, and 6.

Table 8.2. Eligibility Verification Items

Protocol Section	Eligibility Qualification Item	Apply Professional Judgment?
2.2	Verify that the project meets the definition of a grassland project	No
2.2.1	Verify that the project area, and subsequent modifications, have been correctly delineated on a map (or maps) that meets the requirements of the protocol	No
2.3	Verify ownership of the GHG reductions by reviewing Attestation of Title and accompanying documentation	No
2.3	Verify the project and/or cooperative structure is appropriate	No
3.2	Verify project start date	No
3.2	Verify accuracy of project start date based on documentation	Yes
3.2	Verify that the project has documented and implemented a Monitoring Plan	No
3.3, 3.4	Verify that the entire reporting period is within the crediting period for the project	No
3.3.1	Verify that the project meets the performance standard test	No
3.3.2	Confirm execution of the Attestation of Voluntary Implementation form to demonstrate eligibility under the legal requirement test	No

Protocol Section	Eligibility Qualification Item	Apply Professional Judgment?
3.3.2	Verify that the project Monitoring Plan contains a mechanism for ascertaining and demonstrating that the project passes the legal requirement test at all times	No
3.3.3	Confirm that disclosure has been made of any other credits or payments received in relation to the project area, and that these conform to the requirements of the protocol	No
3.5.1	Confirm that the Project Owner has executed a PIA with the Reserve	No
3.6	Verify that the project activities comply with applicable laws by reviewing any instances of non-compliance provided by the Project Owner and performing a risk-based assessment to confirm the statements made by the Project Owner in the Attestation of Regulatory Compliance form	Yes
6	Verify that monitoring meets the requirements of the protocol. If it does not, verify that a variance has been approved for monitoring variations	No

8.6.2 Quantification

Table 8.3 lists the items that verification bodies shall include in their risk assessment and recalculation of the project's GHG emission reductions. These quantification items inform any determination as to whether there are material and/or immaterial misstatements in the project's GHG emission reduction calculations. If there are material misstatements, the calculations must be revised before CRTs are issued.

Table 8.3. Quantification Verification Items

Protocol Section	Quantification Item	Apply Professional Judgment?
4	Verify that all SSRs in the GHG Assessment Boundary are accounted for (unless optional)	No
5	Verify that the emission factors are all correctly selected for the relevant parameters, both for baseline emissions and project emissions	No
5.1	Verify that the stratification procedures were carried out properly	Yes
5.2	Verify that the baseline emissions are properly aggregated (and pro-rated, if applicable)	No
5.2.1	Verify that the project employed the appropriate discount factors	No
5.3	Verify that the project emissions were calculated according to the protocol with the appropriate data	No
5.3.1	Verify that the Project Owner correctly monitored and quantified fires	No
5.3.2	Verify that the Project Owner correctly monitored, quantified, and aggregated fossil fuel use	Yes
5.3.3	Verify that the Project Owner correctly monitored and quantified fertilizer use	No
5.3.4	Verify that the Project Owner correctly monitored and quantified grazing activities	No
5.4	Verify that no reversals have occurred and that the correct contribution was calculated for the buffer pool	No

8.6.3 Risk Assessment

Verification bodies shall review the following items in Table 8.4 to guide and prioritize their assessment of data used in determining eligibility and quantifying GHG emission reductions.

Table 8.4. Risk Assessment Verification Items

Protocol Section	Item that Informs Risk Assessment	Apply Professional Judgment?
6	Verify that the project Monitoring Plan is sufficiently rigorous to support the requirements of the protocol and proper operation of the project	Yes
6	Verify that appropriate monitoring practices are in place to meet the requirements of the protocol	No
6	Verify that the individual or team responsible for managing and reporting project activities are qualified to perform this function	Yes
6	Verify that appropriate training was provided to personnel assigned to greenhouse gas reporting duties	Yes
6	Verify that all contractors are qualified for managing and reporting greenhouse gas emissions if relied upon by the Project Owner. Verify that there is internal oversight to assure the quality of the contractor's work	Yes
7.3	Verify that all required records have been retained by the Project Owner	No

8.6.4 Completing Verification

The Verification Program Manual provides detailed information and instructions for verification bodies to finalize the verification process. It describes completing a Verification Report, preparing a Verification Statement, submitting the necessary documents to the Reserve, and notifying the Reserve of the project's verified status.

9 Glossary of Terms

Accredited verifier	A verification firm approved by the Climate Action Reserve to provide verification services for Project Owners.
Additionality	Project activities that are above and beyond "business as usual" operation, exceed the baseline characterization, and are not mandated by regulation.
Anthropogenic emissions	GHG emissions resultant from human activity that are considered to be an unnatural component of the Carbon Cycle (i.e., fossil fuel destruction, de-forestation, etc.).
Biogenic CO_2 emissions	CO_2 emissions resulting from the destruction and/or aerobic decomposition of organic matter. Biogenic emissions are considered to be a natural part of the Carbon Cycle, as opposed to anthropogenic emissions.
Carbon rights	Legal ownership of carbon stored in pools located within the project area. Carbon rights may be separate from GHG reduction rights (defined below).
Carbon dioxide (CO_2)	The most common of the six primary greenhouse gases, consisting of a single carbon atom and two oxygen atoms.
CO_2 equivalent (CO_2e)	The quantity of a given GHG multiplied by its total global warming potential. This is the standard unit for comparing the degree of warming which can be caused by different GHGs.
Cooperative Developer	The entity responsible for management of a project cooperative. The Cooperative Developer may or may not be one of the Project Owners participating in the project cooperative.
Crediting period	The period of time over which CRTs may be quantified and registered under this protocol. For a grassland project, the crediting period may be a maximum of 50 years.
Cropland	Land whose management is primarily conducted through "cultural" treatments, such as human and/or mechanical labor, fertilization, irrigation, tillage, seeding, and/or planting. While cropland may include seasonal livestock grazing, at least a portion of the year it is specifically given over to cultivation of a crop which is intended to be harvested for off-site consumption.
Direct emissions	GHG emissions from sources that are owned or controlled by the reporting entity.
Easement monitoring report	Reports developed by an easement grantee that demonstrate easement terms have been met.
Emission factor (EF)	A unique value for determining an amount of a GHG emitted for a given quantity of activity data (e.g., metric tons of carbon dioxide emitted per barrel of fossil fuel burned).
Fossil fuel	A fuel, such as coal, oil, and natural gas, produced by the decomposition of ancient (fossilized) plants and animals.

Grassland	An area of land dominated by native or introduced grass species with little to no tree canopy. Other plant species may include legumes, forbs, and other non-woody vegetation. Tree canopy may not exceed 10% of the land area on a per-acre basis. For the purpose of this protocol, grassland may include managed rangeland and/or pastureland.
Greenhouse gas (GHG)	Carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), or perfluorocarbons (PFCs).
GHG reduction rights	Legal ownership of the GHG emission reductions resulting from avoided grassland conversion project activities on the project area during the reporting period. GHG reduction rights may be separate from carbon rights (defined above).
Grassland Owner	An individual or entity which has a right of ownership over a portion or all of the project area, or an ownership right whose exercise could reasonably be expected to impact soil carbon storage on a portion or all of the project area.
Grazing season	The period of time bounded by the first and last days of livestock grazing during the reporting period.
GHG reservoir	A physical unit or component of the biosphere, geosphere, or hydrosphere with the capability to store or accumulate a GHG that has been removed from the atmosphere by a GHG sink or a GHG captured from a GHG source.
GHG sink	A physical unit or process that removes GHG from the atmosphere.
GHG source	A physical unit or process that releases GHG into the atmosphere.
Global Warming Potential (GWP)	The ratio of radiative forcing (degree of warming to the atmosphere) that would result from the emission of one unit of a given GHG compared to one unit of CO_2.
Indirect emissions	Reductions in GHG emissions that occur at a location other than where the reduction activity is implemented, and/or at sources not owned or controlled by project participants.
Metric ton (t, tonne)	A common international measurement for the quantity of GHG emissions, equivalent to about 2204.623 pounds or 1.102 short tons.
Methane (CH_4)	A potent GHG with a GWP of 21, consisting of a single carbon atom and four hydrogen atoms.
MMBtu	One million British thermal units.
Mobile combustion	Emissions from the transportation of employees, materials, products, and waste resulting from the combustion of fuels in company owned or controlled mobile combustion sources (e.g., cars, trucks, tractors, dozers, etc.).
Non-reversible emission reductions	An emission reduction is not considered reversible if it represents the destruction or avoided emission of a GHG which does not rely on storage within a carbon pool. For example, the avoided emissions of N_2O due to cultivation activities are considered non-reversible.

Pastureland	An area of grassland which is managed through livestock grazing as well as other "cultural" treatments, such as human and/or mechanical labor, fertilization, irrigation, and/or seeding. For the purpose of this protocol, pastureland may not involve any level of tillage.
Permanence period	The period of time following the crediting period during which the Project Owner must continue monitoring, reporting, and verification activities under this protocol. The permanence period for a grassland project is 100 years following the last issuance of CRTs related to reversible emission reductions.
Project area	The area defined by the physical boundaries of the project activities. The project area only contains land which meets the eligibility requirements of this protocol.
Project baseline	A "business as usual" GHG emission assessment against which GHG emission reductions from a specific GHG reduction activity are measured.
Project Owner	An entity that has title to the emission reduction credits issued under this protocol and undertakes a GHG project, as identified in Section 2.2 of this protocol. The Project Owner may also be the Cooperative Developer and/or a Grassland Owner.
Rangeland	An area of grassland which is managed principally through the use of livestock grazing. For the purpose of this protocol, rangeland must meet the definition of grassland.
Reporting period	The length of time over which GHG emission reductions from project activities are quantified. Under this protocol, the reporting period can be no more than 12 months.
Reversible emission reductions	An emission reduction is considered reversible if it represents an avoided emission or enhanced sequestration of carbon which must be stored in a carbon pool. For example, the avoided emissions of soil organic carbon due to cultivation activities are considered reversible, and the carbon must be permanently maintained through conservation of the project area.
Shrub	A woody perennial plant, generally more than 1.5 feet and less than 16.5 feet in height at maturity and without a definite crown (24). Shrubs will usually have multiple stems no more than 3 inches in diameter (23).
Tree	A woody perennial plant, typically large and with a well-defined stem or stems carrying a more or less definite crown with the capacity to attain a minimum diameter at breast height of 5 inches and a minimum height of 15 feet with no branches within three feet from the ground at maturity (24).
Verification	The process used to ensure that a given participant's GHG emissions or emission reductions have met the minimum quality standard and complied with the Reserve's procedures and protocols for calculating and reporting GHG emissions and emission reductions.
Verification body	A Reserve-approved firm that is able to render a verification opinion and provide verification services for operators subject to reporting under this protocol.
Verification period	The length of time over which GHG emission reductions from project activities are verified. Under this protocol, the verification period can cover up to six reporting periods during the crediting period, and up to ten reporting periods during the permanence period.

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Appendix A Development of the Performance Standard

The Reserve assesses the additionality of projects through application of a performance standard test and a legal requirement test. The purpose of a performance standard is to establish a standard of performance applicable to all grassland projects that serves as a proxy for a significant threat of conversion of the project area to crop cultivation. If this standard is met or exceeded by the Project Owner, the project satisfies the criterion of “additionality.”[93]

A.1 Components of the Performance Standard Test

The Grassland Protocol performance standard test has two components:

1. Financial threshold
2. Suitability threshold

The intent of this two-part test is to create a standardized proxy for the complex decision-making process that leads to land use change. A project-specific approach would allow for the evaluation of all barriers to the project activity at the project site, but it would be fraught with subjectivity and uncertainty due to the counterfactual nature of the baseline scenario. Moreover, project-specific determinations of additionality tend to be very expensive and labor-intensive, thus rendering relatively low-volume projects, such as grassland projects, to be infeasible. While each individual component of the performance standard test would not, on its own, be a rigorous test of the additionality of the project, the Reserve believes that, taken as a whole with the other requirements for eligibility (e.g., location, legal surplus), the performance standard test does achieve such an outcome.

In addition to the two components of the performance standard test, projects are subject to a location-based emission reductions threshold, discussed in Section 3.1. Although this eligibility screen is not part of the performance standard test, it works in conjunction with the performance standard test to identify eligible projects.

A.1.1 Location-Based Emission Reductions Threshold

This component of the eligibility screening is quantitative. Its premise is that projects should only be eligible if, based on the quantification methodology used by this protocol, the project will generate creditable emission reductions. The main focus of this protocol is the avoided emission and permanent protection of soil organic carbon (SOC). Thus, SOC is the focus of the emission reductions threshold.

For the purposes of this protocol, the U.S. has been stratified in order to enable the development of baseline and project emissions estimates that correspond to local soil conditions, climatic conditions, starting condition, and agricultural practices. A stratum represents a unique combination of these variables. All baseline modeling was performed at the stratum level, enabling the resulting emissions estimates to represent relatively fine distinctions in the primary drivers of variation in emissions. In total, this protocol established emissions estimates for 1,002 total strata within the U.S. By stratifying the country in this manner, the emissions estimates used in this protocol provide greater local accuracy and representation than would emission estimates generated at a national scale or with fewer variables. These variables act as filters that each brings greater specificity to the emissions estimates by more

[93] See the Reserve Offset Program Manual for further discussion of the Reserve’s general approach to determining additionality: http://www.climateactionreserve.org/how/program/program-manual/.

precisely estimating the conditions of the project. Land is first broken down by climate and geography, then further delineated by the major soil type and texture, and finally evaluated based on the previous land use.

The following variables were used to stratify the U.S:

- Geography and associated climate
- Soil texture
- Previous land use

A.1.1.1 Geography and Associated Climate

The first level of stratification used in this protocol delineates land based on its geography and associated climate, due to these factors important influence over carbon pools and sources in both natural and managed ecosystems (8). Regional climate and geographic conditions are determined through the use of Major Land Resource Area (MLRA) designations, as defined by the U.S. Department of Agriculture, Natural Resources Conservation Services (9). These designations are used for a variety of policy and planning decisions, as they represent information about land suitability for farming and other purposes. As such, they constitute a land area that has similar physical and climatic characteristics. In total, there are approximately 280 MLRAs in the U.S. However, some of these MLRAs contain very little cropland or grassland feasible for conversion. Appendix B provides an overview of the methodology used to screen out certain MLRAs based on the absence of significant areas of grassland or cropland, and constraints on data availability and modeling confidence.

A.1.1.2 Soil Texture

Soil texture has a significant impact on land productivity and carbon dynamics through influences on soil fertility and water balance and on soil organic matter stabilization processes (10). Accordingly, the second level of stratification requires differentiating by soil texture. While successively finer delineations of soil type and texture would yield greater precision, this protocol limits the stratification of soils into three major classes of surface soil texture as defined by USDA. These are:

- Coarse
- Medium
- Fine

By adding soil texture to the stratification, the quantification is improved in two ways. First, the texture itself plays a considerable role in the carbon dynamics being modeled (27), allowing more refined and representative results. Second, defining the stratum with the soil texture limits the cropping systems and management practices that are modeled to those suitable to these soils by evaluating only those systems seen on other similar soils within the MLRA. Use of soil texture therefore gives greater precision to the crop system inputs and resulting model accuracy.

A.1.1.3 Previous Land Use

Initial carbon pools at project commencement will be significantly influenced by previous land uses. Additionally, soil quality at project initiation influences nutrient inputs and farming practices in the baseline scenario. Because this protocol allows for the avoided conversion of grasslands with somewhat varied histories, the third level of stratification requires grasslands to be delimited by the duration of time it has been in a grassland state. This protocol defines the following two categories for grasslands:

- Greater than 10, but less than 30 years continuous grassland or pastureland
- Greater than 30 years continuous, long-term permanent grassland or pastureland

To develop this threshold, the baseline scenario was modeled for a period of 50 years for each individual stratum. The outputs from the models were averaged over 10 year periods to smooth out any inter-annual variability and stochasticity inherent in the modeling. Due to the specific characteristics of the individual strata and the common management practices in those areas, some strata exhibit SOC loss after conversion to cropland, some do not, and some show consistent SOC gains. A stratum may only be eligible if we have an emission factor that shows a baseline loss of SOC for the first 10 year emission factor period. If the stratum shows baseline SOC gains for an emission factor period, then the project crediting period will end prior to that emission factor period. Table A.1 and Figure A.1 show a summary of the outcome of this test.

Table A.1. Summary of Strata Eligibility Based on Emission Reduction Potential

Categories	Number of Strata in Each Category
Total possible strata	1,668
Strata with no data for modeling	667
Strata with no emission reductions in first 10 years	331
Potentially eligible strata	670

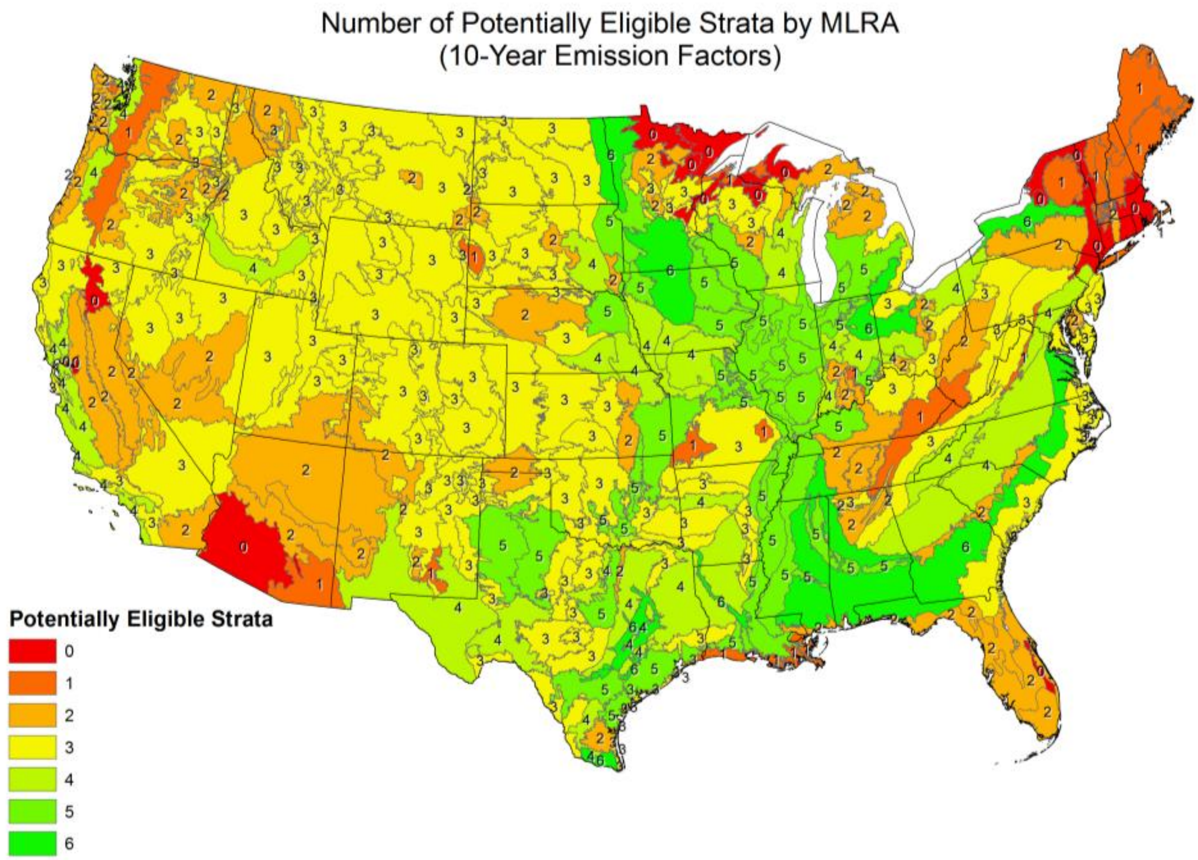

Figure A.1. Potentially Eligible Strata for Each MLRA

A.1.2 Financial Threshold

The first component of the performance standard test is a financial threshold. The concept is that the monetary incentive provided by offsets is needed to counteract the existing financial incentive to convert grassland to cropland. The incentive to convert to cropland is thus viewed as a barrier to the project. As a proxy for this financial incentive, the Reserve uses the concept of the "cropland premium." The cropland premium for a county value of the cash rent rate for cropland compared to the cash rent rate for pastureland. In other words, the cropland premium represents the increased value (either as a percentage or in absolute dollars per acre) of land that is converted from pasture to crop production.

This approach is also utilized by avoided conversion project type in the Reserve Forest Protocol,[94] which requires the Project Owner to obtain a certified real estate appraisal of the project area to identify the land's value as a forest (project scenario) and as the converted land use (baseline scenario). The percentage difference between these two must exceed 40% for eligibility and must exceed 80% to avoid the application of a discount, which is calculated on a sliding scale between the two thresholds.[95] The discount represents the uncertainty of the baseline conversion and recognizes that the threshold for the decision to convert will vary between landowners.

[94] Climate Action Reserve, Forest Project Protocol Version 3.3 (November 15, 2012). Section 3.1.2.3.
[95] Climate Action Reserve, Forest Project Protocol Version 3.3 (November 15, 2012). Equation 6.14.

A.1.2.1 Calculating the Cropland Premium

The rent rate data are collected through the annual cash rent survey of the USDA National Agricultural Statistics Service (NASS).[96] This dataset is robust and published on a regular, annual schedule. The cash rent survey provides a value, in dollars per acre, of the cash rent paid for non-irrigated cropland, irrigated cropland, and pastureland. The non-irrigated cropland rent rate is used as a proxy for the value of cropland. The pastureland rent rate is used as a proxy for the value of grassland. Cropland premiums were calculated by subtracting the average pastureland rent rate from the average non-irrigated cropland rent rates, then dividing by the average pastureland rent rate.

In order to smooth out inter-annual fluctuations and account for years with missing data, the financial threshold is based on an average of the cropland premium for the previous three years. If there are too few respondents in a particular county to ensure anonymity of the reported data, those counties are combined and averaged together by the NASS at the level of the Agricultural Statistics District (ASD) and identified in the data as "Other (Combined) Counties." Thus, where a county did not have a value listed for a particular rent category for a particular year, the average for the ASD for that year was used. If there was no ASD average reported, the value was left out. When averaging the rent values over the three year period, only years with reported values were considered (i.e., "no value" was not considered to equal zero). For projects with start dates during the calendar year 2015, rent rate data from 2012-2014 were used.

A.1.2.2 Setting the Threshold

Once the cropland premiums were determined, a policy decision was made as to where the threshold should be set. There are several options for how to consider the cropland premium as a proxy for the financial incentive to convert the project area. There were also several other decisions that ultimately influenced the threshold, such as the most appropriate geographic level of analysis (county, ASD, state, region) and the particular metric for the cropland premium (absolute $/acre or percent difference).

As the rent rate data are available at the county level, the Reserve chose to use this level for the analysis. Following the approach used in the Forest Protocol, the Reserve elected to continue to apply the financial threshold as a percent difference, rather than a dollar value, which limits the impact of other variables that affect land value. This approach is also used in the Avoided Conversion of Grasslands and Shrublands (ACoGS) methodology adopted by the American Carbon Registry, although that methodology does not rely on a standardized assessment of land value.

The Forest Protocol sets a threshold of 40% premium for eligibility, and 80% premium for undiscounted eligibility. The ACR ACoGS methodology sets a threshold of 40% premium for eligibility and 100% premium for undiscounted eligibility. The Reserve has elected to adopt the thresholds described in the ACoGS methodology. Cropland premiums between these two values are subject to a discount on a sliding scale, following the guidance in Equation 5.6.

Although the threshold will be applied to new rent rate data each year, the thresholds themselves will not change unless the Reserve carries out a new analysis and issues a new version of this protocol.

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[96] Information available at: http://www.nass.usda.gov/Surveys/Guide_to_NASS_Surveys/Cash_Rents_by_County/index.asp. Accessed October 13, 2014.

A.1.2.3 List of Eligible Counties

Once the threshold was determined, it was then applied to the rent rate data to determine the list of eligible counties. Following the procedures above, the Reserve determined the average cropland premiums for the most recent three year period (2012-2014). The financial thresholds were then applied to these data (Figure A.2). This exercise will be conducted as new rent rate data become available. For counties which are identified as having no data, a Project Owner may request that the Reserve examine the data for surrounding counties and determine whether the county may be considered eligible (and the appropriate value for DF_{conv}, if applicable). The revised list of eligible counties, along with their value for DF_{conv}, if applicable, will be published and be effective for new projects submitted during the following year. The current tables, as well as any future updates, are available by individual request (email to policy@climateactionreserve.org or call (213) 891-1444) or for download at: http://www.climateactionreserve.org/how/protocols/grassland/.

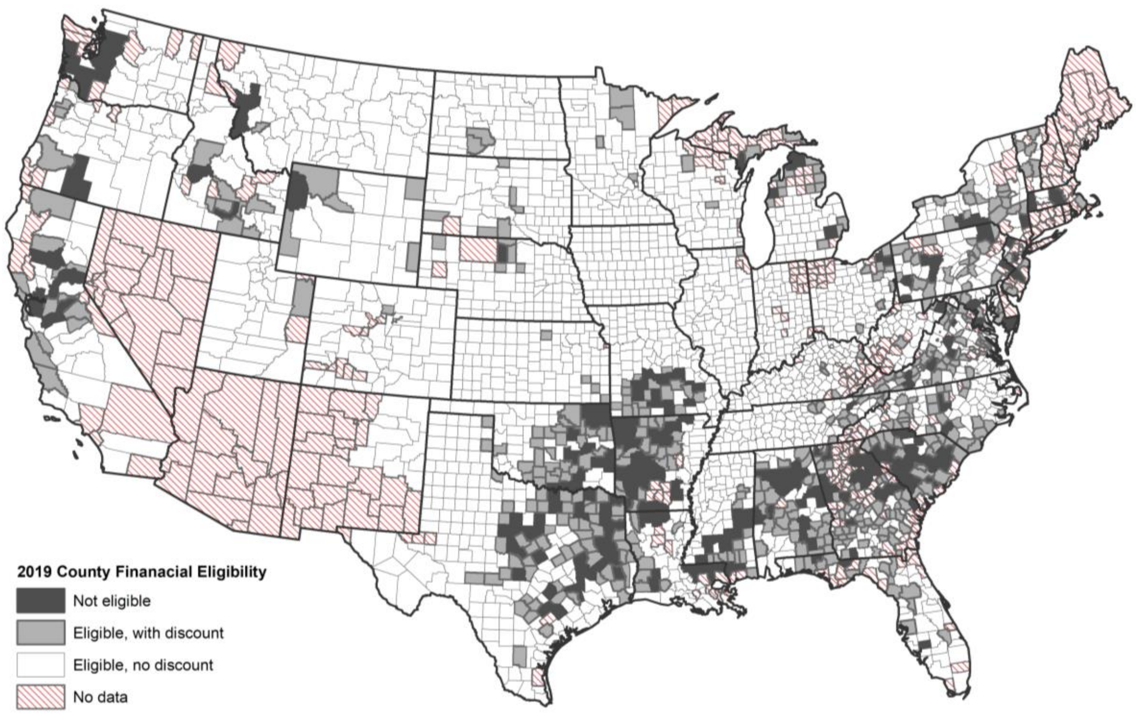

Figure A.2. Eligibility of Counties Based on the Financial Threshold for Additionality

A.1.3 Suitability Threshold

Projects should only be considered additional if the project area is actually suitable for conversion to crop cultivation. Otherwise, the baseline scenario is invalid, and the project area is not actually under threat of conversion to cropland. This is the premise behind the second component of the performance standard test: the suitability threshold. There are numerous parameters (slope, drainage, rockiness, etc.) that contribute to the overall suitability of a parcel for crop cultivation. The Natural Resources Conservation Service (NRCS) Land Capability Classification (LCC) system is widely used to simplify the description of land areas in regards to its suitability for cultivation (3). The Reserve has chosen to use the NRCS LCC system to assess the suitability threshold for grassland projects.

There are eight LCC classes, numbered I through VIII:

I. Soils have few limitations that restrict their use. (no subclasses)
II. Soils have some limitations that reduce the choice of plants or require moderate conservation practices. (all subclasses)
III. Soils have severe limitations that reduce the choice of plants or require special conservation practices or both. (all subclasses)
IV. Soils have very severe limitations that restrict the choice of plants, require very careful management, or both. (all subclasses)
V. Soils have little or no erosion hazard but have other limitations impractical to remove that limit their use largely to pasture, range, woodland, or wildlife food and cover. (subclasses w, s, c)
VI. Soils have severe limitations that make them generally unsuited to cultivation and limit their use largely to pasture or range, woodland, or wildlife food and cover. (all subclasses)
VII. Soils have very severe limitations that make them unsuited to cultivation and that restrict their use largely to grazing, woodland, or wildlife. (all subclasses)
VIII. Soils and landforms have limitations that preclude their use for commercial plant production and restrict their use to recreation, wildlife, or water supply or to esthetic purposes. (all subclasses)

In addition, there are four subclasses, indicated by letter:

(e) Erosion
(w) Excess wetness
(s) Problems in the rooting zone
(c) Climatic limitations

Crop cultivation is generally not recommended for land classified above Class IV (3). We have received stakeholder feedback that would push this threshold in both directions, some saying that no land above Class III should be cultivated, and others saying that they have seen Class V and VI land being actively converted. Recent research has supported this conclusion (3). The Reserve has chosen to rely on the general recommendation that classes above IV are not suitable for cultivation, while recognizing that land characteristics tend to be more heterogeneous than legal boundaries by allowing for small components of the project area to be Class V or VI.

To determine the appropriate minimum threshold for NICC I-IV soils as a percentage of the total project area, the Reserve assessed the NICC for existing, non-irrigated cropland, as well as the NICC for non-irrigated cropland that was identified as being newly-converted. The irrigation data were from the most recent (2012) version of the Moderate Resolution Imaging Spectroradiometer (MODIS) Irrigated Agriculture Dataset for the United States (MIrAD-US).[97] The cultivated lands data used in the assessment, known as the USDA Cultivated Layer, were obtained by request from the USDA NASS[98]; the public CDL data portal, CropScape, only offers the most recent version of the Cultivated Layer. The Cultivated Layer is a 5-year composite of all land that has been identified as cropland. To align with the MIrAD-US data, the 2012 Cultivated Layer (showing cropland from 2008-2012) was used. The data regarding which of these lands were considerednewly-converted croplands were obtained from researchers at the University of Wisconsin (24). These data are also based on the 2008-2012 Cropland Data Layers.

For each state, the data for cultivation, irrigation, MLRA, and soil map unit were combined using ArcMap. The resulting data layer identifies all of this information for each 250m x 250m pixel; thus the resolution of the analysis is 15.44 acres. The tables were then combined into one large table, allowing for assessment of each MLRA, regardless of political boundaries. The area for each MLRA that is cultivated but not irrigated is summed according to its NICC, allowing for a determination of the percentage of non-irrigated cropland in that MLRA which is classified as NICC I-IV. The analysis was also conducted for irrigated lands, using the ICC. For any MLRAs with insufficient data to develop either a NICC or ICC threshold, the default threshold will be 100%. This is a conservative approach given that those MLRAs do not show significant crop cultivation activity. Of course, projects will still have the option for the local, site-specific LCC assessment.

The same analysis was then conducted using only areas of newly-converted cropland (2008-2012). For areas with sufficient amounts of new cropland, the resulting values from the existing cropland and the newly-converted cropland were then averaged together to obtain the default value for the suitability threshold for that MLRA. This approach seeks to recognize that recent conversion trends may be different than historical conversion trends. In many places, the LCC of new cropland is higher than existing cropland (i.e., newly converted cropland may be considered of “marginal” quality for crop cultivation).

A.1.4 Complete Performance Standard Test

While neither of the individual components of this performance standard test (or the eligibility section as a whole) would represent a comprehensive test for additionality on their own, when considered together, along with the eligibility limitations arising from the baseline stratification and modeling, they function to provide a holistic assessment of the threat of conversion of grassland to cropland in different areas of the country.

[97] The MIrAD-US data are available at: http://earlywarning.usgs.gov/USirrigation.
[98] Information regarding the Cropland Data Layer and the Cultivated Layer is available at: https://www.nass.usda.gov/Research_and_Science/Cropland/SARS1a.php.

Appendix B Development of Standardized Parameters and Emission Factors

The approach outlined in this appendix was developed and executed by the Reserve's technical contractor WSP. The team consisted of Tim Kidman and Michael Mondshine at WSP, and Dr. Keith Paustian, Ernest Marx, Mark Easter, Ben Johkne and Stephen Williams at Colorado State University. The effort described here has resulted in a fixed collection of emission factors. The Reserve will seek to replicate this process at a later date in order to generate updated emission factors for AGC projects.

B.1 Introduction

This appendix describes the standardized assumptions used by the Reserve's technical contractor in modeling baseline GHG emissions from the conversion of grasslands to croplands. It also describes the modeling approach used by the Reserve's contractor to estimate the baseline emissions from soil processes, soil organic carbon, below-ground biomass, and fertilizer N_2O emissions using the DAYCENT model and a combination of national data sources. The methodology and standardized baselines are intended to provide accurate estimates of baseline emissions, give certainty over expected project outcomes, minimize project setup and monitoring costs, and reduce verification costs. The resulting emission rates, applied in the protocol as per acre emission factors, preclude the need for project-level modeling by Project Owners.

Modeling was performed using the same build of the DAYCENT model that is used for estimation of the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2013[99] (U.S. Inventory) compiled by EPA, and which is incorporated in USDA's entity level GHG quantification tool, COMET-Farm[100]. To compute the emissions associated with baseline conversion scenarios, the contractors utilized a DAYCENT model inputs database developed for the U.S. Inventory. The Inventory Database (IDB) was derived from national level soils and weather data sources, the USDA's Natural Resources Inventory (NRI) as well as ancillary data sets on actual agricultural management practices across the U.S. The NRI is a statistically robust stratified sampling design that includes land use and management data since 1979 at ca. 400,000 non-federal cropland and grassland locations.

The DAYCENT model (i.e., daily time-step version of the Century model) simulates cycling of carbon, nitrogen, and other nutrients in cropland, grassland, forest, and savanna ecosystems on a daily time step. This includes CO_2 emissions and uptake resulting from plant production and decomposition processes, and N_2O emissions from the application of synthetic and manure fertilizer, the retention of crop residues and subsequent mineralization, and mineralization of soil organic matter. DAYCENT simulates all processes based on interactions with location-specific environmental conditions, such as soil characteristics and climate.

[99] Available at: http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2014-Main-Text.pdf.
[100] Available at: http://cometfarm.nrel.colostate.edu.

B.2 Conceptual Overview

The approach to baseline determination and baseline modeling relies almost exclusively on geographic, historic, and physical characteristics of project parcels – most of which are publicly available in national geospatial databases – in assigning a baseline and associated emissions for any given project parcel. The methodology does not require project proponents to assert a single baseline cropping system, tillage, or management practice, support that assertion with detailed documentation, or justify why assertions represent reasonable baseline assumptions. Rather, this methodology establishes and dictates a composite baseline for any given parcel based on the practices documented on ecologically and geologically similar parcels using a variety of national databases. The methodology does not establish a single tillage practice, average fertilizer practice or other factors and use that as the baseline to model that single scenario to obtain baseline emission rates. Instead, the methodology acknowledges variability in practice, and the uncertainty associated with predicting future practice by assuming that there is a certain probability that the converted land could be managed in a variety of ways. The modeled management practices were generated based on survey data from land within the same eco-climatic region and soil type as the project parcel, based on the IDB and related data sources defined below.

Through this exercise 154,639 long term grassland points and 162,460 short term grassland points were modeled. The resulting emission rates for each stratum represent a weighted average of the potential practices on the parcel were it to be converted to cropland, with weighting based on the relative prevalence of each practice within the survey data. This approach to baseline determination eliminates subjectivity by standardizing the baseline determination based exclusively on stratification (see Section 5.1).

Similarly, the methodology does not require project proponents to execute complex biogeochemical process models. Instead, the methodology provides composite emission rates derived from these same biogeochemical process models utilizing geographic, soil, and cropping system assumptions representative of the project parcel.

Compared to the alternative in which project proponents would be responsible for asserting and documenting their baseline assumptions, and then conducting modeling themselves, this method has several important advantages, which are outlined in Section B.7.

B.3 Baseline Determination

The baseline for any given project parcel is defined probabilistically as a composite of the likely practices that might occur on that parcel were it to be converted from grassland to cropland.

The stratification regime defined in Section 5.1 of the protocol plays a fundamental role in establishing the range of practices and relative probabilities for baseline practice. Based on two of the three stratification elements – the Major Land Resource Area (MLRA) and the dominant surface soil texture from the Soil Survey Geographic Database (SSURGO) – the U.S. was first broken into individual super-strata (unique combinations of these two variables).[101] By first stratifying by MLRA and surface soil texture, the U.S. is effectively subdivided into land areas based on suitability to certain cropping systems and the practices associated with those systems in those geographies. Because MLRAs are based on agroecological classification, they define areas of similar climate, geomorphology, native vegetation and land management

[101] The third variable, previous land use, will be used later in the modeling of baseline emissions.

systems – all of which are the fundamental drivers of the biogeochemical processes involved in greenhouse gas emissions. Thus MLRAs are well-suited as stratification variables than other land area designations that are politically-based (e.g., states) or defined by a more limited set of criteria (e.g., NRCS Crop Management Zones (CMZ) based on farm management practices). By adding soil texture to the stratification, the quantification is improved in two ways. First, the texture itself plays a considerable role in the carbon dynamics being modeled (27), allowing more refined and representative results. Second, defining the stratum with the soil texture limits the cropping systems and management practices that are modeled to those suitable to these soils by evaluating only those systems seen on other similar soils within the MLRA. Use of soil texture therefore gives greater precision to the crop system inputs and resulting model accuracy.

For each unique super-strata, baseline practices were collected and estimated based on the real-world practices on agricultural land within the same super-stratum, as derived from the IDB, USDA National Resource Inventory (NRI), Economic Research Service Cropping Practice Survey (ERS), National Agricultural Statistics Service (NASS), and Natural Resources Conservation Service (NRCS) (29) (30).[102,103] These resources represent the best available data sources for agricultural practice in the U.S. A brief description of the relevant data sources is included below:

- **Inventory Database (IDB)**: Developed by Colorado State University as input data for the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2013 (13), the IDB is derived from a variety of data sources including SSURGO, NRI, CTIC, ERS, NASS (described below). The IDB describes typical management practices for distinct regions and soils at MLRA and county scales.
- **Major Land Resource Area (MLRA)**: Agro-ecological classification developed NRCS that defines areas of similar climate, geomorphology, native vegetation, and land management systems across the U.S.
- **Soil Survey Geographic Database (SSURGO):** Developed and managed by NRCS, the SSURGO database contains geographically linked information on soil properties including texture. SSURGO data were collected by the USDA National Cooperative Soil Survey, covering the states, commonwealths and territories of the U.S. It was generated from soil samples and laboratory analysis, and represents the finest resolution soil map data available in the U.S.
- **National Resource Inventory (NRI):** Developed and managed by NRCS, the NRI is a statistical survey of land use and natural resource conditions on non-federal U.S. lands. It provides data on the status, condition, and trends of land, soil, water and related resources. The NRI utilizes established inventory sites for repeated sampling to provide national representation.
- **Conservation Tillage Information Center (CTIC)**: Since 1989, CTIC has conducted annual county-level surveys of tillage practices, by crop. These data are used to estimate probabilities for tillage practices and tillage transitions, for IDB locations within the surveyed counties.
- **Economic Research Service:** Housed within the USDA, ERS gathers a variety of data on crop and livestock practices through the use of its annual Agricultural Resource Management Survey (ARMS). ERS provides both annual and trend data, illustrating

[102] USDA-NASS: https://www.nass.usda.gov/.
[103] USDA-NRCS (2012) *Energy Estimator: Tillage*, available at: http://ecat.sc.egov.usda.gov/.

shifts in agricultural practice. ERS contains data on nutrient management, irrigation practices, and conservation practices.

- **National Agricultural Statistics Service (NASS):** Data on annual county-average crop area and yields from NASS are used as a secondary data source for availability control of model outputs.
- **Natural Resource Conservation Service (NRCS)/Energy Tools:** Data related to the energy inputs required for cropland management, including planting, tillage, fertilization, and harvesting. (http://energytools.sc.egov.usda.gov/)

For each super-stratum combination of MLRA and soil texture, relevant variables about baseline conditions were established using these data sources, with specific variables pulled from each as defined in Table B.1. In many cases, these variables are linked. For example, IDB data are used to establish the various cropping sequences, and then each crop is assigned nitrogen application rate distributions based on regional ERS data. The methodology used to link data and determine practices within regions is based on the methodology used in the U.S. Inventory (13). For further detail on how these datasets are used to set appropriate conditions, please refer to the sections Agriculture and Land Use, Land-Use Change, and Forestry in the U.S. Inventory.

Table B.1. Derivation of Baseline Scenario Input Variables

Baseline Variable	Data Source	Methodology
Tillage practice	IDB, CTIC	Assignment of tillage practices established using CTIC data in each super stratum and associated expansion factors. County-level CTIC data were recalculated at the MLRA level, with practices assigned to simulations through use of NIDB area-weights.
Typical cropping sequence	IDB, NASS	Assignment of each cropping sequence established using IDB data in each super stratum and associated area-weights, based on the cropping sequence from 2000-2007, supplemented by NASS data.
Fertilizer N application	ERS, NASS	Crop-specific N rates assigned based on state-level statistics, subdivided by MLRA, based on the most recent five years period.
Application of other nutrients/organic matter	NRCS	Livestock manure application frequency and rates estimated based on NRCS data and adjusted for county-level estimates of manure availability, based on the most recent five years period.
Irrigation practice	IDB	Irrigated vs. non-irrigated status are specified for each IDB location, based on the most recent five years period. For irrigated land, full irrigation (i.e., no significant water stress) is modeled.
Fuel consumption	NRCS	Energy consumption for each cropland management practice, based on CMZ, tillage practice, and crop.

Table B.2 provides an illustrative overview of some of the crop system data elements that went into the establishment of the composite baseline conditions for any given super-stratum, and a highly simplified example distribution. Based on the cropping systems established from historic data, additional nutrient input data were applied based on ERS and NASS data. In addition to the cropping and management variables extracted from these data sources, the methodology employs IDB area-weights to appropriately weight each practice based on its representativeness across the landscape. IDB area-weights are based on the spatial resolutions of source data, including NRI expansion factors, SSURGO map unit areas, and spatial scales of fertilizer and tillage data. The IDB area-weights indicate the number of acres across the landscape that each IDB location point represents.

The baseline for this example super stratum would be, for example, 20% constructed from data point #1 which is a practice that includes the use of no till on irrigated land, and with a crop rotation of corn, soy, corn, soy, fallow. This is based on the existence of an IDB location with that practice and its area-weight (100) being 20% of the aggregate of IDB area-weights (500) within the super stratum.

Table B.2. Example Crop Systems and Resulting Probabilities in Baseline

IDB Data Point	Tillage Practice	Irrigation Practice	Cropping System	Area-weight	Probability
#1	No Till	Irrigated	Corn, soy, corn, soy, fallow	100	20%
#2	Conservation Till	Not Irrigated	Corn, soy, fallow, wheat, soy	150	30%
#3	Conservation Till	Irrigated	Wheat, fallow, wheat, wheat, fallow	50	10%
#4	Standard Till	Not Irrigated	Corn, soy, fallow, wheat, soy	200	40%

Using this methodology, each project parcel effectively has multiple baseline scenarios. One way to think about this approach would be that for every acre of a project in the above example, 0.2 acres would be converted according to practice #1, 0.3 acres according to practice #2, 0.1 acres according to practice #3, and 0.4 acres according to practice #4.

B.4 Modeling Approach

In order to model baseline emissions for use in quantifying emission reductions, the composite baseline practices defined in Section B.3 were combined with climatic and initial condition inputs. Local weather data inputs were based on values from the North America Regional Reanalysis Product (NARR).[104] Weather for each year in the future was modeled on actual weather from a year in the past (within the last 30 years). Thus, inputs such as temperature and precipitation should reflect recent trends. All modeling was performed using stochastic modeling techniques and the DAYCENT model to evaluate the change in carbon pools and emissions sources across multiple scenarios. More specifically, this was done by modeling the conversion to cropland of IDB locations throughout the U.S. that are currently categorized as grasslands. It includes analysis of the composite baselines defined in Section B.3 in a manner consistent with the compilation of the U.S. Inventory.

Modeling was conducted based on the strata delineated in Section 5.1 of the protocol, which include previous land use in addition to the variables used to define the super strata. For each stratum (unique combination of MLRA, soil texture, and previous land use), the following methodology was employed by utilizing the Colorado State University parallel computing capability, which includes dedicated database servers and a ca. 300 CPU computing cluster:

1. Grassland modeling points were pulled from the IDB or modified for modeling:

[104] NOAA/OAR/ESRL PSD, *North America Regional Reanalysis Product*, available at: http://www.esrl.noaa.gov/psd/.

   a. For long term grassland (30+ years), all 154,639 IDB locations that have been continuous grassland were selected.
   b. For short term grassland (10-30 years) a period of 12-28 years of grassland management preceding project implementation was randomly assigned and area-weighted to 162,460 IDB locations in continuous cropland.
2. Initial carbon pools at project start were established for each data point based on soil data and a long-term spin-up of the DAYCENT model using practices defined in the preceding step.
3. For the 30+ year grassland baseline scenario, each IDB location was modeled forward applying the baseline practices determined in Section B.3 through the DAYCENT model for 50 years. The baseline practices for each IDB location were pulled at random without replacement.
4. For the 10-30 year grassland baseline scenario, each IDB location was modeled forward applying the cropping practices associated with that point in the IDB through the DAYCENT model for 50 years.
5. For the project scenario, each IDB location was modeled forward applying a continuation of the management practices established for the U.S. national GHG inventory analysis.
6. DAYCENT output was summarized as average annual change or emission rates in ten year increments for the following:
   a. Soil organic carbon[105]
   b. N_2O emissions (direct and indirect)
7. The extracted emissions in ten year increments were area-weighted based on IDB area-weights and averaged across points within the strata and translated into average annual per acre emission rates applicable to corresponding ten year increments.

The resulting emission rates are provided by stratum in a tabular form and included as lookup tables[106] where they function as per acre emission factors. A sample of the table format is provided as Table B.3 below.

Table B.3. Sample Output of Emission Factor Table Format

Stratum	Annual Emission Factor (tCO_2e/acre)				
	Year 1-10	Year 11-20	Year 21-30	Year 31-40	Year 41-50

In addition to modeling baseline emissions, the DAYCENT modeling exercise was also performed to estimate project soil carbon emissions or sequestration, emissions from nitrous oxide, and dry matter estimates. The dry matter estimates are used in the quantification portion of this protocol to estimate CH_4 and N_2O emissions from burning on project lands.

Finally, fuel consumption was estimated by applying fuel consumption factors from the NRCS Energy Calculator to the practices modeled at each IDB location. The results from each IDB

[105] Other related pools including above- and below-ground biomass flow through this pool in the modeled carbon balance. Accordingly, this pool is intended to represent net system emissions or sequestration over longer time horizons such as the 50 years modeled in this exercise.
[106] See the Reserve's Grassland Protocol webpage at: http://www.climateactionreserve.org/how/protocols/grassland/.

location in the baseline scenario were area-weighted based on IDB area-weights to estimate fuel consumption per acre for each stratum.

B.5 Results

Over 317,099 individual grassland points were modeled to calculate composite emission rates based on 31.7 million point years. However, emission rates have been provided for only a subset of strata within the continental U.S. where data was available and deemed reliable. In order to maintain data integrity and robustness of modeling results, certain strata for which there was limited data were evaluated, but output results were not included in the published tables of emission rates. Specifically, strata with less than ten assigned IDB locations in grassland were excluded due to low sample size. Because strata include soil type (texture), the paucity of points in many cases (especially for coarse and fine soils) reflects the actual low occurrence of a particular soil type within a particular MLRA. Strata with 11-100 data points were considered to be of good availability, while those with more than 101 points were considered excellent data availability. The number of strata assigned to each category of data availability is summarized in Table B.4.

Table B.4. Stratum Availability

Count of strata deemed low availability (≤10 points), good availability (11-100 points), and excellent availability (>100 points)

	Fine		Coarse		Medium		Total Strata
	10-30 years	30+ years	10-30 years	30+ years	10-30 years	30+ years	
≤10 Points	89	70	70	54	45	26	**354**
11-100 Points	64	79	98	77	73	61	**452**
>100 Points	73	77	58	95	108	139	**550**
TOTAL	**226**	**226**	**226**	**226**	**226**	**226**	**1,356**

The maps in Figures B.1 through B.6 illustrate the distribution of the strata for which there was insufficient data to generate reliable emission rates (10 or fewer data points), and those for which there was good or excellent data availability.

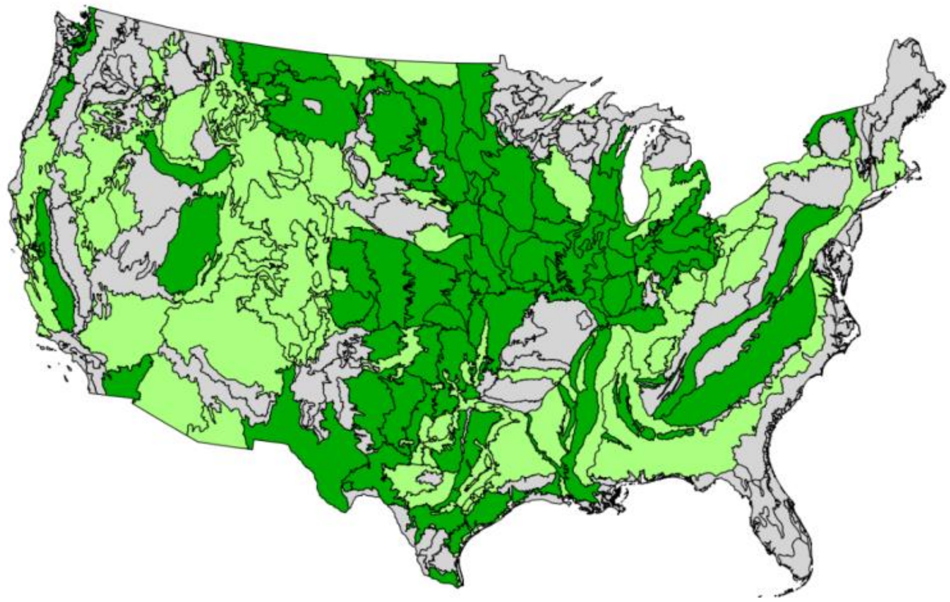

Figure B.1. Map of 10-30 Year Grassland Data Points on Fine Soils

Grey represents 10 or fewer points. Light green represents 11-100, and dark green represents greater than 100 data points. Emission rates have been provided for all green MLRAs.

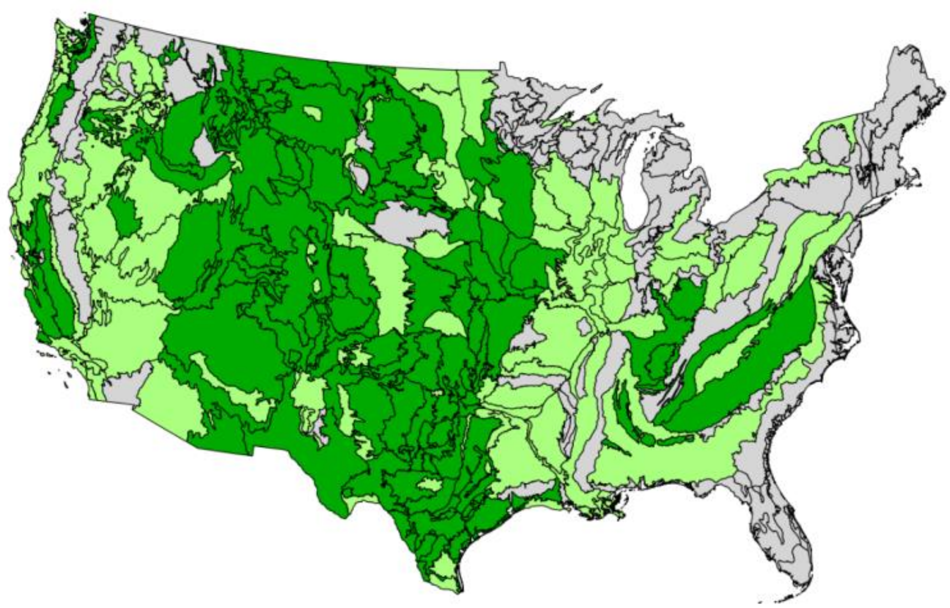

Figure B.2. Map of 30+ Year Grassland Data Points on Fine Soils

Grey represents 10 or fewer points. Light green represents 11-100, and dark green represents greater than 100 data points. Emission rates have been provided for all green MLRAs.

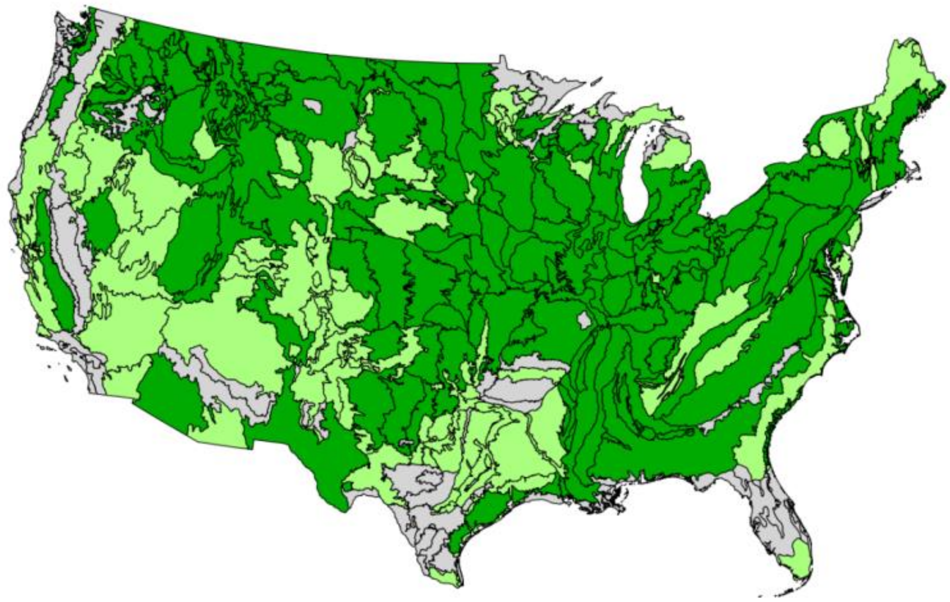

Figure B.3. Map of 10-30 Year Grassland Data Points on Medium Soils

Grey represents 10 or fewer points. Light green represents 11-100, and dark green represents greater than 100 data points. Emission rates have been provided for all green MLRAs.

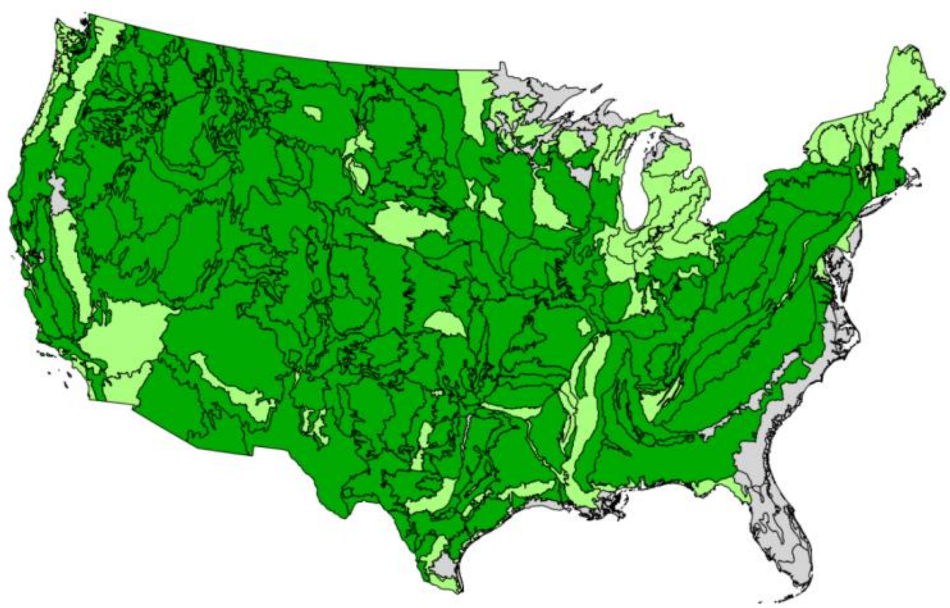

Figure B.4. Map of 30+ Year Grassland Data Points on Medium Soils

Grey represents 10 or fewer points. Light green represents 11-100, and dark green represents greater than 100 data points. Emission rates have been provided for all green MLRAs.

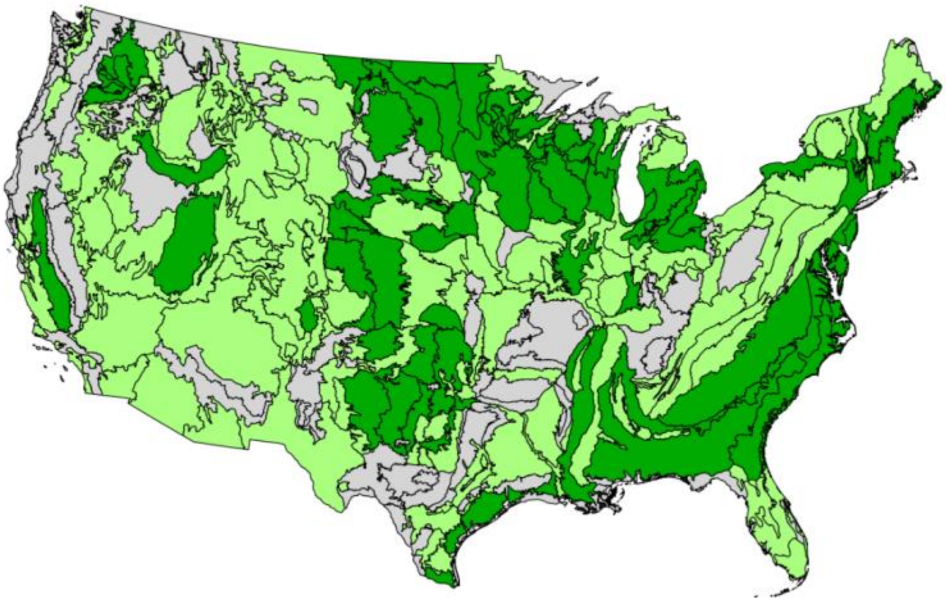

Figure B.5. Map of 10-30 Year Grassland Data Points on Coarse Soils

Grey represents 10 or fewer points. Light green represents 11-100, and dark green represents greater than 100 data points. Emission rates have been provided for all green MLRAs.

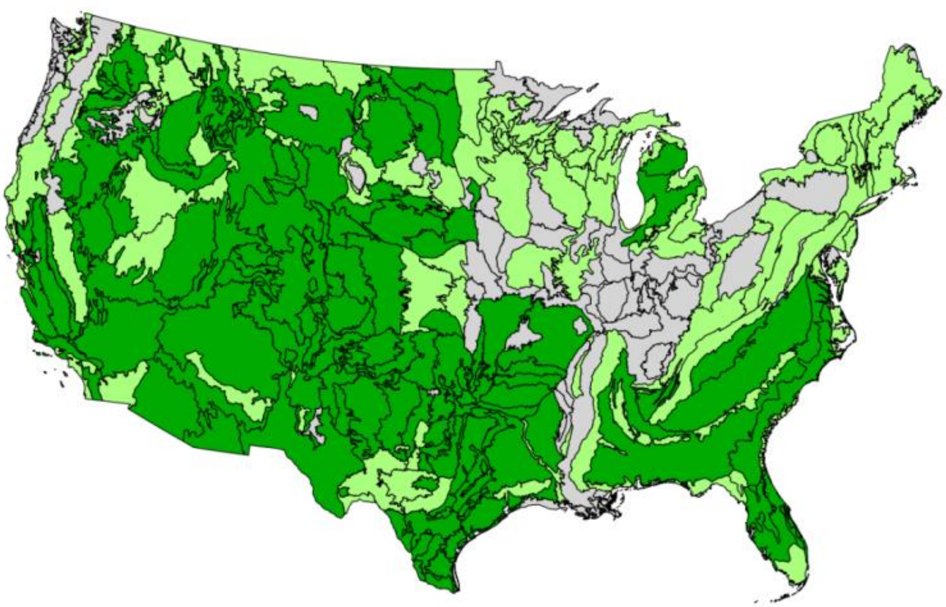

Figure B.6. Map of 30+ Year Grassland Data Points on Coarse Soils

Grey represents 10 or fewer points. Light green represents 11-100, and dark green represents greater than 100 data points. Emission rates have been provided for all green MLRAs.

Due to the size and complexity of the emission rate output tables, results are not provided in the protocol, but instead are available for download in Microsoft Excel format from the Reserve's website.[107] In addition to the emission rate tables, there is an additional file that contains summary statistics for each stratum for which modeling was performed, which is available upon request. Although many variables went into the inputs for each modeling run, this file displays the percent of land that was modeled as irrigated in each stratum, as well as the distribution of crops that contributed to the composite baseline.

B.6 Uncertainty

Although some level of uncertainty is inherent in any modeling exercise, there are several important uncertainties unique to the establishment of baseline conditions and modeling performed over a 50 year horizon. Several sources of uncertainty are particularly noteworthy:

- **Tillage Practice.** The use of no-till and conservation tillage practices in the U.S. has been increasing in recent decades, and this trend is expected to continue. The USDA ERS evaluated tillage data for a variety of crops and geographies across the U.S. and found that no-till has increased at a rate of 1.5% per year between 2000 and 2007, though there is considerable variation across crops and regions. No-till agriculture, particularly when practiced over a prolonged time, has the potential to lower soil carbon emissions or increase sequestration (31).
- **Fertilizer Use.** Inorganic and organic nitrogen are common inputs for many cropping systems in the U.S., and have considerable GHG impacts through both direct and indirect N_2O emissions. Nitrogen management best practices focus on minimizing excess nitrogen in the system by matching the rate, timing, placement, and source of nitrogen to the requirements of the crop system to efficiently utilize nitrogen and maximize crop yields. Despite data showing that nitrogen application rates on some crops have increased even since 1990 (e.g., corn, wheat) (32), emissions from this source may be flat or declining due to increased nitrogen use efficiency and yields. Shifts in practice and technology have the potential to reduce net N_2O emissions from fertilization per unit of yield.
- **Climate Change.** Over the coming decades, weather patterns across the country are expected to change in several ways. Temperatures are projected to rise; the intensity of the heaviest precipitation events is projected to increase; crop yields may be more strongly influenced by anomalous weather events; weeds, diseases and pests may increase crop stress; and other climate disruptions to agricultural production are projected to increase over the next 50 years (33). These impacts will vary considerably across regions, and will have varied impacts on agricultural GHG emissions.

During the workgroup consultation process, the concept of including shifts in tillage practice and fertilizer use within the modeling environment was evaluated. However, because of data and modeling limitations, uncertainty around inputs, and the assumptions required to conduct modeling that included these shifts, it was deemed more appropriate to account for the uncertainty outside of the modeling exercise rather than compromise the model's inherent strengths and data sources. Both tillage and nitrogen management practice will further interact with climate change and weather events, with the result being unknown net impacts to field-level GHG emissions. The quantification methodology includes a discount factor intended to conservatively address the uncertainty associated with these and other factors. The specific uncertainty related to these emission factors has not been quantified. In discussion with the contractor, the Reserve has set the discount as 1% per 10-year emission factor period. Thus, the discount increases as the time of quantification moves farther from the time the modeling

[107] See the Reserve's Grassland Protocol webpage at http://www.climateactionreserve.org/how/protocols/grassland/.

was completed. If the Reserve is able to update this modeling exercise at a later date, then the discount for uncertainty will be reset for the new emission factors.

B.7 Justification for a Standardized Baseline

This section provides a brief overview of the benefits associated with use of a highly standardized approach to baseline determination and quantification of baseline emissions.

B.7.1 Transaction Costs and Verifiability

One of the primary goals to standardization is to cut down to the extent practicable on project costs and verification complexity. If the project proponent is required to assert the baseline cropping system and management practice, this would necessitate considerable costs both in project development and verification. Existing protocols rely on resources such as appraisals, government surveys, and universities in establishing baseline cropping systems. While government surveys provide some insight into dominant crops in a region, they are not generally differentiated by relevant soil characteristics, and do not reveal detailed crop rotation information nor do they link across variables (e.g., crop rotations and tillage practices). Further, while appraisals are useful in establishing that land may have a higher value as “cropland” versus grassland, it is unclear that these appraisals would consider specific cropping systems, inputs and management practices. Instead, these appraisals may assess only the publicly available rent information on cropland in the region, itself a composite of multiple practices.

In short, relying on project proponent assertions would require considerable project proponent resources to identify and document the likely cropping system, provided it can reliably be done at all. Additionally, the asserted crop system would need to be verified by the verification body, adding additional costs and uncertainty. Alternatively, the standardized approach does not require the project proponent to assert a baseline cropping system or management practice at all, or the verifier to assure this data. The baseline scenario and emissions estimates are defined exclusively based on geographic, historic, and physical characteristics of the project parcels, most of which are publicly available in national geospatial databases.

B.7.2 Customizability and Opportunity for Gaming

One potential shortcoming of a standardized approach to baseline determination and baseline emissions modeling is that it limits the opportunity for projects to be customized. Greater project proponent input provides greater opportunity to reflect specific knowledge or greater detail. For example, there may be characteristics of the land (e.g., slope) or local market (e.g., proximity to processing) that cannot be captured in the standardized methodology that nonetheless can reasonably be expected to influence cropping or practice.

However, this shortcoming of standardization is also a potential benefit in the ability it provides to avoid gaming. For example, if emission rates for two cropping systems are different, then gaming could occur if project proponents take steps to establish the system with higher emissions as their baseline. Given the complexity of verification and the potential methodological flexibility due to varying levels of data availability that may need to be afforded project proponents in establishing the baseline practice, it is possible that this gaming could occur without detection. Use of standardized composite baselines essentially eliminates this gaming risk by basing stratification and the determination of baseline emissions purely on geographic, historic, and physical characteristics of project parcels, most of which are publicly available in national geospatial databases.

B.7.3 Future Uncertainty

While the uncertainty of knowing what may occur on grassland directly following conversion is obviously significant, the uncertainty about what may occur 10 years or 20 years hence is even greater. Given a crediting period of 50 years, it is therefore extremely important that the baseline determination and associated baseline emissions are not overly influenced by short-term considerations.

Means of evaluating the highest value cropping systems are highly dependent on short-term projections about commodity and crop prices, which are subject to change in the future. As such, even if one knew with certainty that a parcel would be converted to a given crop rotation and management practice tomorrow, there is no reasonable way to know that it would persist in that manner for 10 or 20 years. As such, it is more reasonable to treat each parcel as essentially a composite of a multitude of crop systems in the area reflecting longer term practices and trends.

Appendix C Default Parameters and Emission Factors

Most of the emission factors needed in this protocol can be found in the separate *Grassland Project Parameters* document, which can be downloaded from the protocol website.[108]

C.1 Development of Project Emission Factors for N_2O

To simplify the quantification of N_2O emissions from fertilizer and manure, the Reserve is relying on default values from the IPCC (6). Because of this, the full equation necessary for accounting for emissions from nitrogen volatilization and leaching can be collapsed and simplified by combining multiple constants into a single constant.

Equation 5.10 uses a value of 0.012 to represent direct emissions and emissions from the volatilization of fertilizer. This value is derived thusly:

$$\boldsymbol{A} = \boldsymbol{B} + (\boldsymbol{C} \times \boldsymbol{D})$$

Where,
A = Emission factor for direct and volatilized emissions of N_2O from organic fertilizer (0.012)
B = Emission factor for direction emissions of N_2O from organic fertilizer (0.01)
C = Fraction of organic fertilizer lost to volatilization (0.2)
D = Emission factor for N_2O due to volatilization and deposition (0.01)

Equation 5.10 uses a value of 0.00225 to represent emissions from the leaching of fertilizer. This value is derived thusly:

$$\boldsymbol{Leach} = \boldsymbol{E} \times \boldsymbol{F}$$

Where,
Leach = Default factor for the fraction and emission factor for N_2O emissions due to leaching (0.00225)
E = Fraction of organic fertilizer lost to leaching (0.3)
F = Emission factor for N_2O due to leaching (0.0075)

Equation 5.11 uses a value of 0.22 to represent direct emissions and emissions from the volatilization of manure nitrogen. This value is derived thusly:

$$\boldsymbol{G} = \boldsymbol{H} + (\boldsymbol{I} \times \boldsymbol{J})$$

Where,
G = Emission factor for direct and volatilized emissions of N_2O from manure (0.22)
H = Emission factor for direction emissions of N_2O from manure (0.02)
I = Fraction of organic fertilizer lost to volatilization (0.2)
J = Emission factor for N_2O due to volatilization and deposition (0.01)

Equation 5.11 uses a value of 0.00225 to represent emissions from the leaching of manure nitrogen. This value is the same as the leaching value derived for fertilizer, above.

[108] Default emission factors can be found in a separate document, *Grassland Project Parameters*, available at: http://www.climateactionreserve.org/how/protocols/grassland/.

Appendix D Legal Instruments

Registration of a grassland project under this protocol requires the use of a number of specific legal instruments. This appendix provides additional guidance on the intent and usage of these instruments, as well as any requirements for their use with a grassland project. Table D.1 lists the relevant legal instruments and their relatedprotocol sections.

Table D.1. Legal Instruments Relevant to Grassland Projects

Legal Instrument	When Required	Protocol Section(s)
GHG reduction rights contract	Required when ownership of GHG emission reduction rights are not determined in the conservation easement	2.3.2
Indemnification agreement	Required when there are multiple Grassland Owners who are not party to the legal instruments related to the project	2.3.2
Conservation easement	Required, unless project area is owned by the Federal government	2.2, 3.2
Qualified Conservation Easement	Required, unless project area is owned by the Federal government	3.5.1
Project Implementation Agreement	Required for all projects	3.5.2
Reserve attestations (title, voluntary implementation, regulatory compliance)	Required for all projects	2.3.2, 3.3.2, 3.6
Instruments associated with concurrently-joined conservation programs	Required only if the project area is enrolled in other conservation payment/credit programs	3.3.2.1

D.1 GHG Reduction Rights Contract

Purpose: This contract is required in order to clearly establish ownership over the GHG emission reductions associated with the grassland project. In order to meet the definition of a Project Owner, an entity must be able to demonstrate ownership of the GHG emission reductions associated with the project. Unless existing contracts specify otherwise, it is assumed that the Grassland Owner holds the rights to any GHG emission reductions that would be issued under this protocol. However, the recording of a conservation easement may create the expectation, on the part of the easement holder, that they hold ownership rights that include the GHG emission reductions. In addition, either the Grassland Owner or the easement holder may wish to transfer these rights to a third-party Project Owner. The grantee of the GHG Reduction Rights contract will be the Project Owner of record (the Account Holder) with the Reserve, and will be the entity to which the CRTs are issued upon successful registration of a reporting period. The Project Owner is also the entity who will execute the Project Implementation Agreement.

Parties involved: Grassland Owner, Project Owner, easement holder.

Timing: Ownership of the GHG emission reductions associated with the project activities must be documented during project verification.

Notes:

- May be a standalone document, or it may be incorporated into another legal document, such as the project's conservation easement. A standard, short form version is included as Exhibit B to the PIA.
- Must clarify the ownership of the GHG emission reductions at the time of their creation, rather than just the sale of those credits
- Must clearly define ownership of rights for GHG reductions related to the project activities
- Must be signed by the Grassland Owner, the easement holder, and the Project Owner.
- Must include clauses that specify steps to be taken if ownership changes for either the land, the GHG reduction rights, or the conservation easement
- Recommended inclusions:
    - Description of the project area
    - Description of the offset project and the offset project registry
    - Reference to the Grassland Protocol as the method of quantifying GHG emission reductions
    - Specific reference to sources of GHG emissions which are covered by GHG assessment boundary for the Grassland Protocol
    - Discussion of responsibilities in the event of a reversal (see Section 5.4)
    - Any potential exclusions (i.e., GHG or other benefits not covered by this contract)

D.2 Indemnification Agreement

Purpose: Where there may be multiple entities who could meet the definition of Grassland Owner, the Reserve must be indemnified against future GHG reduction claims by those entities which are not acting as Grassland Owner for the purposes of the protocol, and are not party to the GHG reduction rights contract.

Parties involved: Grassland Owner, Project Owner, Climate Action Reserve.

Timing: This agreement must be executed following the initial verification, prior to registration by the Reserve.

Notes: Must indemnify the Reserve in connection with any claims brought by other grassland owners or would-be grassland owners against the Reserve.[109]

D.3 Cooperative Contract

Purpose: For projects participating in a cooperative, this is a contract between the Project Owner and the Cooperative Developer. In general, this contract lays out the terms of the Project Owner's participation in the cooperative. However, its relevance for this protocol is its usefulness as a clear signal from the Project Owner of their intent to initiate a GHG offset project. This is particularly useful for determining the project start date, in order to ensure the additionality of the project.

Parties involved: Project Owner, Cooperative Developer.

Timing: If being used to denote the project start date, then the notarization date of this contract will be chosen by the Cooperative Developer as a date which will result in more efficient

[109] A sample indemnification agreement is available at: http://www.climateactionreserve.org/how/protocols/grassland/.

management of the cooperative. This date can be no earlier than the earliest recorded easement on any project in the cooperative.

Notes:

- This contract is only required for projects which wish to use it to denote the project start date. In those cases, this contract must be notarized

D.4 Qualified Conservation Easement (QCE)

Purpose: The conservation easement is the principle mechanism by which the project area is protected against land use change during the project period, and in perpetuity. The QCE is a label applied to a conservation easement whose terms either explicitly prevent reversals of CRTs by referencing the Grassland Protocol, or implicitly prevent reversals of CRTs by including land use limitations which are sufficient to prevent land use that would disturb soil carbon in the project area.

Parties involved: Grassland Owner, easement holder, Project Owner (optional).

Timing: In most cases, the execution of the QCE will denote the project start date. In all cases the QCE must be executed prior to completion of the initial verification.

Notes:

- It is recommended that the QCE also include clear discussion of both the carbon rights and the GHG emission reduction rights, as defined in Section 9 (see section above regarding the GHG emission reduction rights contract).
- It is required that the QCE include enforceable provisions for the ongoing monitoring of compliance with the terms of the easement.
- It is recommended that access rights be granted to the Project Owner and the Reserve for the purposes of monitoring and enforcing the provisions of the Protocol.
- If the project is at all likely to include livestock grazing, it is recommended that the QCE include prescriptive guidance for grazing management which explicitly limits grazing intensity.
- It is recommended that the QCE make reference to and incorporate the PIA.

D.5 Project Implementation Agreement (PIA)

Purpose: The PIA is a contract between the Reserve and the Project Owner which binds the Project Owner to the terms of the protocol, including the avoidance of and compensation for reversals, and the monitoring of the project during the permanence period. If the Grassland Owner is the Project Owner, they may elect to have the PIA recorded on the deed to the property, thus binding the landholder to the protocol and reducing the risk of uncompensated reversals.

Parties involved: Project Owner, Climate Action Reserve.

Timing: The PIA is executed during the initial verification of the project, prior to registration and CRT issuance. The terms of the PIA are applicable for 100 years following the issuance of CRTs. The PIA is updated at each subsequent registration in order to extend its term to cover the new CRT issuance, as well as to potentially reflect any changes in Project Ownership.

Notes:

- The Recorded PIA includes a clause specifying whether the PIA may be subordinated to any subsequent deed restrictions. The Project Owner will choose whether to use the Type I (not able to be subordinated) or the Type II (able to be subordinated) clause. Use of the Type II clause results in a value of 0.1 for the risk of financial failure in the calculation of the project's contribution to the risk buffer pool. Use of the Type I clause results in a value of 0 for this parameter.
- The Contract PIA, where the project area itself is not bound by the contract, always results in a value of 0.1 for the risk of financial failure in the calculation of the project's contribution to the risk buffer pool.

D.6 Reserve Attestations

Required attestations:

- Attestation of Title
- Attestation of Voluntary Implementation
- Attestation of Regulatory Compliance

Purpose: These attestations are legal documents whereby the Project Owner legally attests to the truth of the statements and facts necessary to support the conclusions of a positive verification report. The Attestation of Title confirms that the Project Owner is the legal owner of the rights to the GHG emission reductions represented by the CRTs which will be issued into their account. The Attestation of Voluntary Implementation confirms that the project passes the legal requirement test. The Attestation of Regulatory Compliance confirms that the project met the eligibility requirements of Section 3.6 during the reporting period(s).

Parties involved: Project Owner.

Timing: These attestations are completed during verification and apply to a specific period of time for which CRTs are to be issued. The Attestation of Title and Attestation of Regulatory Compliance are completed at every verification. The Attestation of Voluntary Implementation is only completed during the initial verification.

D.7 Other Instruments Associated with Concurrently-Joined Conservation Programs

Purpose: If a project area is enrolled in any other credit or payment program, the contracts or legal instruments associated with that program is relevant to the verification of the offset project. These contracts or instruments must be disclosed to the verifier during the verification process. The verifier shall assess each payment or crediting program against the guidance of Section #, conferring with the Reserve for guidance where appropriate.

Parties involved: Grassland Owner, others as relevant.

Timing: At every verification.

A.2.5 Rice Cultivation Project Protocol v1.1

CLIMATE ACTION RESERVE

Version 1.1 | June 3, 2013

Rice Cultivation

Project Protocol

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Abbreviations and Acronyms

CDM	Clean Development Mechanism
CH_4	Methane
CO_2	Carbon dioxide
CRT	Climate Reserve Tonne
CSV	California Sacramento Valley
DNDC	Denitrification-Decomposition biogeochemical process model
DOC	Dissolved organic carbon
DS	Dry seeding
EPA	Environmental Protection Agency
GHG	Greenhouse gas
GUI	Graphical user interface
HCP	Habitat Conservation Plan
IPCC	Intergovernmental Panel on Climate Change
ISO	International Organization for Standardization
lb	Pound
MT (t)	Metric ton (or tonne)
N_2O	Nitrous oxide
NRCS	Natural Resources Conservation Service of the USDA
RC	Rice cultivation
Reserve	Climate Action Reserve
SOC	Soil organic carbon
SHA	Safe Harbor Agreement
SSR	Source, sink, and reservoir
UNFCCC	United Nations Framework Convention on Climate Change
USDA	United States Department of Agriculture

1 Introduction

The Climate Action Reserve (Reserve) Rice Cultivation Project Protocol (RCPP) provides guidance to account for, report, and verify greenhouse gas (GHG) emission reductions associated with the implementation of rice cultivation practice changes that result in a decrease in methane emissions to the atmosphere.

The Climate Action Reserve is the most experienced, trusted and efficient offset registry to serve the California cap-and-trade program and the voluntary carbon market. With deep roots in California and a reach across North America, the Reserve encourages actions to reduce greenhouse gas emissions and works to ensure environmental benefit, integrity and transparency in market-based solutions to address global climate change. It operates the largest accredited registry for the California compliance market and has played an integral role in the development and administration of the state's cap-and-trade program. For the voluntary market, the Reserve establishes high quality standards for carbon offset projects, oversees independent third-party verification bodies and issues and tracks the transaction of carbon credits (Climate Reserve Tonnes) generated from such projects in a transparent, publicly-accessible system. The Reserve program promotes immediate environmental and health benefits to local communities and brings credibility and value to the carbon market. The Climate Action Reserve is a private 501(c)(3) nonprofit organization based in Los Angeles, California.

Project developers and aggregators that initiate rice cultivation (RC) projects use this document to quantify and register GHG reductions with the Reserve. The protocol provides eligibility rules, methods to calculate reductions, performance-monitoring instructions, and procedures for reporting project information to the Reserve. Additionally, all project aggregates receive annual, independent verification by ISO-accredited and Reserve-approved verification bodies. Guidance for verification bodies to verify reductions is provided in the Reserve Verification Program Manual and Section 8 of this protocol.

This protocol is designed to ensure the complete, consistent, transparent, accurate, and conservative quantification and verification of GHG emission reductions associated with a rice cultivation project.

2 The GHG Reduction Project

2.1 Background

Methane (CH_4), a potent GHG, can be formed as a by-product of microbial respiration reactions that occur when organic materials decompose in the absence of oxygen (i.e. under anaerobic conditions). In the United States, rice is almost exclusively grown on flooded fields.[1] When fields are flooded during rice cultivation, oxygen retained in soil pores is rapidly depleted by aerobic decomposition of organic plant residues in the soil, and the soil environment becomes anaerobic. Organic matter continues to decompose under anaerobic conditions, resulting in formation of methane gas. While as much as 60 to 90 percent of the CH_4 produced by the anaerobic microbes is oxidized within the soil by aerobic microbes, remaining un-oxidized CH_4 is transported from the soil to the atmosphere via diffusive transport through the rice plants and the floodwaters.[1]

The annual quantity of methane emitted to the atmosphere at a given rice field will depend on numerous factors related primarily to the water and plant residue management systems in place. Other contributing factors include fertilization practices (using organic vs. synthetic fertilizer), soil properties (type, temperature), rice variety, and other cultivation practices (i.e. tillage, seeding, and weeding practices).

According to the U.S. EPA, rice is currently cultivated in eight states (AR, CA, FL, LA, MS, MO, OK, TX), and rice cultivation is considered to be a relatively small source of CH_4 emissions in the U.S., with total 2009 emissions estimated to be 7.3 MMT CO_2e.[2] Nevertheless, opportunity exists to reduce the methane generated by rice cultivation through implementation of cultivation practice changes related to water and residue management. Management practice changes that decrease the amount of organic matter deposited in the soil, or decrease the amount of time a field is flooded, will typically reduce GHG emissions compared to baseline management practices.

Due to the complexities involved with accurately quantifying GHG emissions resulting from the biogeochemical interactions that occur in cropped rice field systems, this protocol relies on the application of the Denitrification-Decomposition (DNDC) biogeochemical process model for quantification of baseline and project GHG emissions to quantify associated emission reductions. Because of the significant geographic variability related to soil types, climate, and cultivation management practices, the DNDC model must be properly validated for the geographic area and for all relevant cultivation practices in order for the model to perform with an acceptable degree of certainty. Therefore, this protocol will apply only to the regions and practices for which the DNDC model has been explicitly validated with measured data. While this version of the RCPP is valid only in specified rice growing regions, the Reserve expects to periodically update the protocol to expand the geographic scope to include other U.S. rice growing regions as data and model calibration results become available. Currently, however, this protocol only applies to RC projects located in the California Sacramento Valley (CSV) rice growing region.

[1] U.S. EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks.
[2] Ibid.

2.1.1 Rice Cultivation Techniques

In the U.S. there are three dominant flooding systems for rice cultivation: continuous flood, pinpoint flood, and delayed flood.

1. **Continuous flood**: In a continuous flood system, fields are flooded prior to seeding. Once the flood is established, pre-germinated or sprouted seeds are sown (typically by aircraft) into a flooded field. These fields are then maintained in a flooded state until they are drained just before harvest.
2. **Pinpoint flood**: In the pinpoint flood system, pre-germinated seeds are sown into floodwater. The field is drained after seeding for several days to allow the roots to establish or "peg" in the soil. This drain period varies based on soil conditions and weather, but typically lasts for three to five days to enable the roots to establish. During this drain period, oxygen can permeate back into the soil. Once the rice seeds have pegged into the soil, the fields are re-flooded and maintained in flooded conditions until just before harvest.
3. **Delayed flood**: In a delayed flood system, fields are either dry seeded and irrigated for germination or water seeded using pre-germinated seeds that are sown directly into flooded fields, after which the fields are immediately drained. The fields are then kept drained for three to four weeks while the rice canopy is established. Once the canopy is established then the fields are flooded and remain flooded until the typical pre-harvest drain.

Producer decisions regarding which seeding method to use are targeted at selecting the method that will result in proper seedling emergence and lead to a uniform canopy. Seeding methods depend on soil type, weather conditions, and producer preferences. Differences in seeding methods for rice production relate to (a) dry versus water seeded, (b) drill seeding versus broadcast, and (c) use of stale seedbed or conventional seedbed.

1. **Water seeding**: Water seeding describes sowing of dry or soaked seed into a flooded field. It is usually implemented for any or all of the following reasons: red rice control, wet planting season, planting efficiency and earlier crop maturity.
2. **Dry seeding**: Dry seeding simply describes sowing seed into a dry seedbed by drilling or broadcasting. This method usually offers more flexibility in planting but may require more time to do so. This system is also weather dependent.

2.1.2 California Rice Cultivation Practices

In California's Sacramento Valley rice growing region (see Figure 2.1 below), continuous flood is the dominant water management technique.[3] Fields are typically flooded to a depth of 4 to 5 inches just prior to aerial seeding. While deeper flooding reduces weed pressures, it also can lead to poor stand establishment. Once the rice stand is established and the panicle initiation has occurred, many growers will increase the depth of the flood water to 8 inches. This helps with further weed control and protects the rice from cool nighttime temperatures that can lead to reduced yields. Occasionally, several weeks after seeding, fields are drained for one day to apply herbicide for weed control. This drain is short-lived and does not lead to drying of the soil surface and does not affect CH_4 emissions. Prior to harvest, water is drained from fields to allow fields to dry, as harvesting equipment cannot function as well on wet soil. The timing of pre-harvest field draining varies from field to field, and can influence total yields. The University of California Cooperative Extension recommends growers to drain their fields when the panicles

[3] Correspondence with Paul Buttner (CalRice).

are 100 percent “fully tipped and golden,” although fields are often drained earlier due to other contributing factors such as soil type (e.g. soils with high clay content require longer time for drying) and weather.

A continuous flooding and water seeded regime is estimated to be used on over 96 percent of the acreage in California.[4] A small fraction of the rice acreage is dry seeded in California. The flood for dry seeded rice starts approximately 25 to 30 days after seeding. During this period, fields are periodically irrigated to promote germination and stand establishment.

Rice straw can have a significant impact on GHG emissions. Timing of straw amendment/incorporation can impact GHG emissions by altering the timing and availability of substrate (dissolved organic carbon or DOC) released from the fresh straw to methanogens in the soil. The timing of the residue incorporation relative to the flooding period will impact total methane production, as will the availability of rice straw on the field. Rice straw incorporation is currently the dominant management practice in California.

Burning of rice straw was the prevailing management practice in California until 1991. Following the 1991 Rice Straw Burning Reduction Act, burning of rice straw decreased dramatically on an annual basis. By the 2001 growing season, burning of rice straw was permitted for disease control only with a cap of 25 percent of total rice acreage in the state burned annually. Currently, burning occurs on only 10 to 12 percent of rice acreage in California.[5]

Some growers bale rice straw for off-field uses. The current estimate for baling adoption in California is 2 to 6 percent of California rice acres per year.[6] This fluctuates slightly coincident with the various straw markets. Baling does not remove all of the rice straw following harvest. Due to operational constraints and the market for straw, baling typically removes between one and two tons of rice straw per acre, out of an average of about three tons of rice straw available per acre. Of the straw that is baled, much of the straw is sold to end-users, while the straw that goes un-used is typically left onsite. Presently, the majority of rice straw is sold for dairy heifer and beef cattle high roughage feed (estimated to be 75 to 85 percent), with some straw used for erosion control (15 to 25 percent), and very little sold for building construction. The straw that is baled and left onsite is typically composted in large static piles.

[4] Based on communication with P. Buttner (CalRice), R. Mutters, and L. Espino (University of California Cooperative Extension).
[5] Communication with Paul Buttner.
[6] Based on communication with P. Buttner (CalRice), R. Mutters, L. Espino, and G Nader (University of California Cooperative Extension).

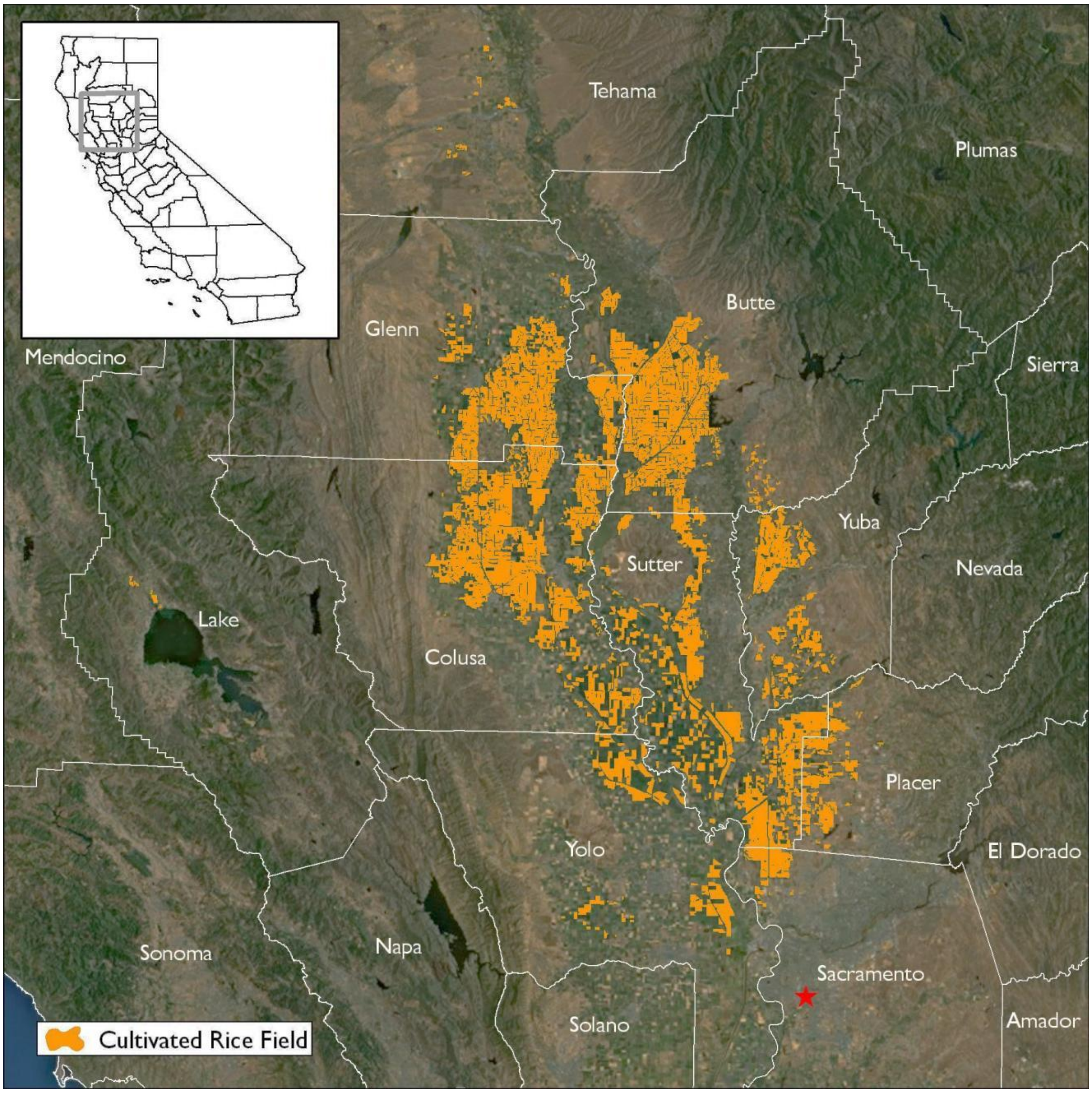

Figure 2.1. California's Sacramento Valley Rice Growing Region

2.2 Project Definition

For the purpose of this protocol, a GHG reduction project (project) is defined as the adoption and maintenance of one or more of the approved rice cultivation project activities[7] that reduce methane (CH_4) emissions. Specific project activities must be adopted and maintained on individual rice fields, with at least one approved project activity implemented on each individual field. Approved rice cultivation project activities may be implemented on a single field, known as a "single-field project," or may be implemented on two or more individual fields combined into a single project area, known as a "project aggregate." Specific requirements for project aggregates are outlined in Section 2.4 below. Physical boundaries for individual fields must be defined according to the requirements in Section 2.2.1.

[7] Note that a project is defined by the adoption of management changes; however, GHG reductions are quantified based on actual project performance in terms of reduced CH_4 emissions.

Practice changes described in Table 2.1 below are the approved project activities (by geographic scope).

Table 2.1. Approved Project Activities

Project Activity	Description	Geographic Scope
Dry seeding (DS) with delayed flood	Adoption of a dry seeding method that involves sowing of dry seeds into dry or moist (non-flooded[8]) soil with field flooding delayed until rice stand is established (typically 25 to 30 days after seeding). Dry seeding can be performed by spreading seeds onto the soil surface and transferring soil on top of the seeds or by drilling seeds into a prepared seedbed, a practice known as "drill seeding." Regardless of the dry seeding method utilized, the methane reductions occur due to the subsequent delay in flooding of the dry seeded field.	California
Post-harvest rice straw removal and baling (baling)	After harvest, rice straw residue is traditionally left on agricultural fields and incorporated into soil; however, rice straw can be removed by baling. Doing so reduces the net soil dissolved organic carbon and therefore decreases methane production from anaerobic decay over the winter season. Baled straw can be sold even though the market is currently small. In California, rice straw can be used for erosion control, animal bedding or as an alternative feed for cow and calf producers.[9]	California

2.2.1 Defining Field Boundaries

For the purposes of quantifying emission reductions with this protocol, a field must be defined as an area of rice cultivation across which management practices are homogenous.[10] Thus if management practices differ across a single rice paddy, the paddy would need to be divided into multiple "fields" corresponding to different management practices for the purpose of this protocol.

An individual rice field must be defined by the following criteria:[11]

1. The field must be under the direct management control of a single rice-producing legal entity.
2. The field area must be contiguous across field 'checks'.
3. Water management (flooding and drainage events) within the field boundary must be relatively homogenous across the field area during a reporting period. There is no set definition for homogeneous water management; however standard practice suggests that most rice fields have a flood-up duration across all field checks of less than 96 hours from start to finish (4 acre-inches per acre or more).[12]

[8] For the purposes of this protocol, non-flooded should be interpreted to mean that there is not standing water (1 inch or more) on the field.
[9] DANR, publication 8425.
[10] More specifically, to effectively quantify field-level emissions using the biogeochemical process model DNDC, the management practices (model inputs) must be homogeneous across the field.
[11] The Reserve believes that in most cases a field defined according to the specified criteria in this protocol will be compatible with a field as defined by the UDSA Farm Service Agency (FSA) Field I.D. protocols.
[12] Note that when recording the date of flood-up for modeling purposes, the date shall be equal to the date when the last field 'check' was flooded to approximately 4 inches or more. This is conservative.

4. Fertilizer management must be relatively homogenous. This criterion is met when application rates across the field do not vary by more than 15 percent of the average application rate for the entire field. During a reporting period, every fertilizer application event must be completed for the entire field on the same day with the same type of fertilizer. A field may have multiple fertilizer application events, as long as each application is homogenous (e.g. consistent rate, timing and type) across the field.
5. Crop residue management within the field boundary must be homogenous across the field area within a reporting period. For example, any burning or baling that occurs on a field must occur across the entire field; there can be no fields that have been partially burnt or baled.
6. The field must have at least five years of rice yield data available for DNDC model calibration.[13]

The above criteria shall be confirmed by the verification body using professional judgment when necessary. If a field does not meet the criteria above, the field shall be divided into sub-fields that meet the field definition criteria, and each sub-field shall be modeled and reported on separately.

2.2.2 Defining the Cultivation Cycle

For the purposes of this protocol, a cultivation cycle is defined as the period starting the day immediately after harvest of one rice crop and ending the last day of the next rice crop harvest the following calendar year. Since this protocol is only applicable to annual rice crops, the cultivation cycle is further defined as approximately 365 days. See Section 5.1 for guidance on how a reporting period is defined and Section 5.3 for guidance on requirements for modeling annual versus cultivation-cycle emissions.

2.3 The Project Developer

The project developer is an entity that has an active account in good standing on the Reserve, submits a project for listing and registration with the Reserve, and is ultimately responsible for all project reporting and verification. According to this protocol, project developers may also be project aggregators, and can represent one or more projects. Project developers/aggregators must be a legally constituted entity (e.g. a corporation, city, county, state agency, agricultural producer, or a combination thereof). An individual rice grower may serve as a project developer of a single-field project, project aggregator for his/her own fields, or as a project aggregator for a group of fields. Rice growers who elect to enroll in a project aggregate and not serve as a project developer are referred to as “project participants.” Project participants must have authority to make cultivation management decisions on their fields that are enrolled in the project aggregate. Project participants are also required to be a legally constituted entity (e.g. an individual, corporation etc.).

Project developers/aggregators act as official agents to the Reserve on behalf of project participants and are ultimately responsible for submitting all required forms and complying with the terms of this protocol. Project developers/aggregators manage the flow of ongoing monitoring and verification reports to the Reserve and may engage in other project development activities such as developing monitoring plans, modeling emission reductions, managing data collection and retention etc., or may hire technical contractors to perform these services on their

[13] USDA FSA Abbreviated Farm Records may be a useful resource for documenting historical yields and/or practices on a particular rice field, however these reports are not required to be used. Note that in this protocol yield refers to the weight of the rice before it is milled, so it includes the weight of the husks.

behalf. The scope of project developer/aggregator services is negotiated between the project participants and the project developer/aggregator and should be reflected in contracts between the project participants and the project developer/aggregator.

Project aggregators have the authority to develop their own internal monitoring, reporting, and other participation requirements for individual fields as they deem necessary, as long as these internal requirements do not conflict with any requirements outlined in this protocol.

Aggregators also have the discretion to exclude individual fields enrolled in their aggregate from participating in verification activities for any given reporting period; however, in such cases there can be no CRTs claimed by those fields in the aggregate total.

In all cases, the project developer/aggregator must attest to the Reserve that they have exclusive claim to the GHG reductions resulting from all fields in the project. The Project developer/aggregator must attest to this requirement by submitting a signed Attestation of Title form for single-field projects or Aggregator Attestation of Title[14] form for project aggregates, prior to the commencement of verification activities each time the project is verified (see Section 8). In the case of project activities taking place on leased fields (i.e. the project developer/participant is not the land owner, but rather a lessee), the project developer must notify the land owner with a Letter of Notification of the Intent to Implement a GHG Mitigation Project on the respective field. Sufficient evidence must be given to the verifier to demonstrate that such a letter was sent (e.g. evidencing the use of certified mail).

Although the aggregator must have exclusive claim to CRTs for the project to complete verification, this protocol does not dictate the terms for how that exclusive title will be established; allowing the aggregator, project participant, and land owner (if separate from the project participant) maximum flexibility for the terms of contracts between the respective parties.

As part of verification activities, verifiers shall review contracts and letters of notification as a means of confirming exclusive title to the CRTs. The Reserve will not issue CRTs for GHG reductions that are reported or claimed by entities other than the aggregator.

2.4 Project Aggregates

Incorporated into the RCPP is an option for project aggregation that aims to facilitate greater participation by farmers by leveraging economies of scale and technical expertise of aggregators. Through aggregation, technical complexities of the methodology and other potential barriers to adopting practice changes in agriculture may be overcome. Specifically, aggregators can acquire appropriate technical expertise, enabling them to implement and manage projects that fulfill protocol requirements on behalf of farmers. Aggregation allows for "economies of scale" within the methodology, in terms of streamlined requirements for individual farmers, while upholding rigorous standards at the level of the aggregate. This is primarily accomplished through pooling and sampling fields for verification activities. In addition, aggregation can help to increase the accuracy of GHG reduction estimates at a program level by encouraging greater participation, which reduces structural uncertainty within the DNDC model.

[14] The Reserve Aggregator Attestation of Title form is available at http://www.climateactionreserve.org/how/program/documents/.

2.4.1 Field Size Limits and Other Requirements

The project aggregate does not need to be comprised of contiguous fields, and can encompass fields located on one farming operation or distributed amongst different farms and/or producers.

There is no limit on the total number of rice acres enrolled in a project aggregate, assuming each individual field meets the requirements of Section 2.2.1. There are, however, limits on how large a single field may be, in relation to the total combined acreage in a project aggregate, as defined by Table 2.2 below. Field size limitations are in place to minimize the influence a single large field may have on a project aggregate's calculations.

Table 2.2. Maximum Field Size, as a Percent of Aggregate Acreage

Number of Fields in Aggregate	Maximum Acreage of a Single Field (% of Aggregate Acreage)
2	70%
3	50%
4	33%
5 or more	25%

2.4.2 Entering an Aggregate

Individual fields may join a project aggregate by being added to the aggregate's Project Submittal Form (if joining at aggregate initiation) or by being added through the New Field Enrollment Form (if joining once the aggregate is underway).

Single-field projects that have already been submitted to the Reserve may choose to join an existing aggregate at any time by submitting a Project Aggregate Transfer Form to the Reserve. The project aggregator will also need to submit a New Field Enrollment Form, listing that field. However, emission reductions for a given field may only be reported to one project in a given cultivation cycle. Thus in the case of a single-field project joining an aggregate during a cultivation cycle, the project developer must chose to either continue to report as an SFP for the remainder of the cultivation cycle or report the entire current cultivation cycle as part of the aggregate.

When a field enters an aggregate, the project aggregator must ensure that all other requirements for each field (as outlined in Sections 2.2, 2.3 and 2.4) continue to be met with all the necessary documentation on file.

2.4.3 Leaving an Aggregate

Fields must meet the requirements in this section in order to leave or change aggregates and continue reporting emission reductions to the Reserve. In all cases, emission reductions must be reported for a complete cultivation cycle, as defined in Section 2.2.2, and no CRTs may be claimed for a field that does not participate and report data for a full cultivation cycle.

Project activities on an individual field may be terminated and the field may elect to leave an aggregate at any time.

Individual fields may elect to leave an aggregate and participate as a single-field project for the duration of their crediting period. To leave an aggregate and become a single-field project, the project participant must open a project developer account on the Reserve and submit a Project

Submittal Form to the Reserve, noting both that it is a transfer project and the aggregate from where it transferred.

Fields can change aggregates during a crediting period if and only if:

1. The field changes ownership, tenant occupancy or management control during the crediting period and the new owner, tenant or manager has other fields already enrolled with a different aggregator
2. The original aggregate is terminated (e.g. goes out of business)
3. The aggregator breaches its contract with the project participant

Fields seeking to change aggregates during a crediting period under one of the above allowed circumstances must submit a Project Aggregate Transfer Form to the Reserve prior to enrolling in the new aggregate.

After completing the crediting period, a field may elect to enroll in a different aggregate when renewing for an additional crediting period.

2.4.4 Changes in Land Ownership, Management or Tenant Occupancy

A field in an aggregate may change ownership, tenant occupancy or management control during a crediting period, and remain in the project aggregate with uninterrupted crediting, if and only if the following criteria are met:

- The contract with the project aggregator is transferred from the old to the new project participant
- The new project participant submits a Field Management Transfer Form to the Reserve via their project aggregator prior to the beginning of the subsequent cultivation cycle
- Implementation of the approved management practices continues without change until the end of the current reporting period[15]

Where any of the criteria immediately above are not met, a field will forfeit the opportunity to generate CRTs for the cultivation cycle during which the ownership, tenant occupancy or management control change occurs. The field may re-enter the project aggregate at any time during the remainder of the five-year crediting period by fulfilling the three requirements above.

[15] See Section 5 for definition of reporting period.

3 Eligibility Rules

Projects must fully satisfy the following eligibility rules in order to register with the Reserve. The criteria only apply to projects that meet the definition of a GHG reduction project (Section 2.2).

Eligibility Rule I:	Location	→	*California*
Eligibility Rule II:	Project Start Date	→	*First day of cultivation cycle during which approved activity is implemented*
Eligibility Rule III:	Anaerobic Baseline Conditions	→	*Demonstrate baseline flooded rice cultivation practice*
Eligibility Rule IV:	Other Eligibility Conditions	→	*Demonstrate compliance with other eligibility criteria*
Eligibility Rule IV:	Additionality	→	*Meet performance standard*
		→	*Exceed regulatory requirements*
Eligibility Rule V:	Regulatory Compliance	→	*Compliance with all applicable laws*

3.1 Location

Projects must be located in approved rice growing regions for which the DNDC model has been validated against field measured methane emissions, and for which a regional performance standard has been developed and included in this protocol. Reductions from projects outside of the approved rice growing regions are not eligible to register with the Reserve at this time.

3.1.1 Rice Growing Regions

Currently, only the California rice growing region is approved under this protocol. Therefore, only RC projects located in California are eligible to register reductions with the Reserve. In the future, projects located in other parts of the United States or on U.S. tribal lands may be eligible to register reductions with the Reserve under this protocol as the DNDC model becomes validated in more regions.

3.1.2 High Carbon Content Soils

As the DNDC model has not been validated on soils with SOC content greater than 3 percent, fields that have soil with organic carbon content greater than 3 percent in the top 10 cm of soil are not eligible at this time. The organic carbon content of the field shall be determined by using SSURGO data or soil sampling in accordance with Appendix B, Step 1.4. Where SSURGO data on SOC content is not available to a depth of 10 cm for any given field, that field must use field measurements or data from the STATSGO database to determine eligibility.

3.1.3 Fields Using Nitrification/Urea Inhibitors and Controlled Release Fertilizers

The DNDC model has not been validated for use on fields that have been treated with nitrification inhibitors, urea inhibitors or controlled release fertilizers. Therefore, fields that have used such products in either the five year baseline period or a project year are not eligible under this protocol.

3.2 Project Start Date

In order to produce accurate GHG emission modeling results, the DNDC model used for calculating GHG reductions must be run for each annual cultivation cycle. A complete cultivation cycle begins with post-harvest residue management and culminates at the end of the rice crop harvest and thus may be slightly greater or less than 365 days depending on planting/harvest dates. More information on how to define a cultivation cycle is found in Section 2.2.2.

Each field has a unique start date, defined as the first day of a cultivation cycle during which one or more of the approved project activities are implemented at the field. Approved project activities initiated prior to the start date (i.e. during the baseline period) are permissible, but must be represented in the field's baseline; as such project activities must go beyond baseline practices in order to generate any additional emission reductions.

To be eligible, a field must submit as a single-field project or join an active or new aggregate before the end of the first cultivation cycle after the start date.[16] Fields may always be submitted for listing by the Reserve prior to their start date.

3.3 Crediting Period

The crediting period for fields under this protocol is five years. The crediting period is renewable up to three times (for a potential of 20 years of crediting). During the last six months of a field's crediting period, project developers/aggregators may apply for a field's eligibility under a second, third or fourth crediting period. During a crediting period, project reporting for each field must be continuous with no gaps between reporting periods. Reporting periods in which a field does not meet the performance standard (see Section 3.5) or is not included in the pool of fields potentially selected for verification, for any number of reasons, still count towards the five-year crediting period. If a project developer wishes to apply for another crediting period, the project must meet the requirements of the most current version of this protocol, including any updates to the Performance Standard Test (Section 3.5.1). The pre-project baseline for the initial crediting period shall be retained for any subsequent crediting periods.[17]

Crediting periods do not apply to project aggregates, but rather only to individual fields within a project aggregate and to single-field projects.

The Reserve will issue CRTs for GHG reductions quantified and verified according to this protocol for a maximum of four five-year crediting periods after the field's start date. Section 3.5.1 describes requirements for qualifying for a second, third, and fourth crediting period.

3.4 Anaerobic Baseline Conditions

All fields must demonstrate that previous rice cultivation practices prior to the field's start date resulted in anaerobic conditions. This requirement is met by demonstrating all the following criteria are met:

1. Each individual rice field has been under continuous rice cultivation for five cultivation cycles preceding the field's start date, with no more than one fallow season. In instances

[16] Fields are considered submitted when the project developer/aggregator has fully completed and filed with the Reserve the appropriate Submittal Form, or the New Field Enrollment form, available on the Reserve's website.
[17] This is known as a continuation of current practices baseline scenario, and is considered appropriate in the circumstances.

where a fallow season occurred, the field must have been under rice cultivation for five of the six years prior to the start date; and

2. Each individual rice field was flooded for a period of at least 100 days during each of the five rice-growing cultivation cycles preceding the field's start date. Fields that are unable to meet this requirement due to events beyond management control (e.g. drought conditions), can meet this requirement by demonstrating that 100 or more days of flooding is common practice for the field, and that drought conditions or other conditions beyond management control prevented normal flooding practices; and
3. Management records for each individual rice field are available for each of the past five rice-growing cultivation cycles preceding the field's start date. At a minimum, management records must include:
    - Annual rice yields
    - Planting and harvest dates
    - Flooding and draining dates
    - Fertilizer application dates and amounts

3.5 Additionality

The Reserve strives to register only projects that yield surplus GHG reductions that are additional to what would have occurred in the absence of a carbon offset market.

Projects must satisfy the following tests to be considered additional:

1. The Performance Standard Test
2. The Legal Requirement Test

3.5.1 The Performance Standard Test

Projects pass the Performance Standard Test by meeting a performance threshold, i.e. a standard of performance applicable to all RC projects, established by this protocol.

For this protocol, the Reserve uses practice-based thresholds, which serve as "best practice standards" for management practices governing methane emissions from rice cultivation. By meeting the performance threshold for a specific management activity, a rice field demonstrates that cultivation management exceeds the regional common practice standard for methane emissions management. Although multiple fields are submitted together in the case of a project aggregate, each participating field must separately pass the Performance Standard Test, for each approved project activity that is implemented on the field, in order to be eligible.

The performance standard research, summarized in Appendix D, reviewed common water management, residue management, and other RC management practices in the approved rice growing region.[18] Based on the performance standard analysis, the Reserve has developed Performance Standard Tests for each approved project activity, as defined in Section 2.2.

Table 3.1 below provides the Performance Standard Test for each approved project activity.

[18] Based on the geographic limitations imposed by data availability, only management data from California rice cropping systems were sufficiently analyzed in the performance standard for this protocol. The Reserve plans to expand the geographic scope of this protocol to other U.S. regions based upon future data availability and successful peer-reviewed DNDC model validation results.

Table 3.1. Approved Project Activities

Region	Approved Project Activity	Performance Standard Test	Justification
CA	Dry seeding with a delayed flood	A rice field passes the Performance Standard Test by implementing a dry seeding technique combined with delayed flooding.	Research indicates that dry seeding is currently practiced on less than 3 percent of the CA rice acreage.[19]
	Post-harvest rice straw removal and baling	A rice field passes the Performance Standard Test by implementing post-harvest rice straw removal and "baling."	Research indicates that residue removal (baling) is currently very limited and variable, occurring on an estimated 2 to 7 percent of the CA rice acreage. Despite initiatives launched by state agencies and private partnerships, the market for rice straw has not grown as expected.[19]

3.5.2 The Legal Requirement Test

All projects are subject to a Legal Requirement Test to ensure that the GHG reductions achieved by a project would not otherwise have occurred due to federal, state or local regulations, or other legally binding mandates. An RC project passes the Legal Requirement Test when there are no laws, statutes, regulations, court orders, environmental mitigation agreements, permitting conditions, binding contractual obligations or other legally binding mandates in place on the project start date (including, but not limited to, conservation management plans and deed restrictions) that require the adoption or continued use of any approved project activities on the project rice fields. Should a field initially pass the Legal Requirement Test, the field is eligible to earn CRTs from a project activity for the remainder of the five-year crediting period, regardless of changes in legal requirements.

To satisfy the Legal Requirement Test, project developers (including aggregators) must submit a signed Attestation of Voluntary Implementation form[20] prior to the commencement of verification activities for the first verification period. Aggregators must also submit a signed Attestation of Voluntary Implementation form on behalf of new project fields in the aggregate prior to the commencement of verification activities each time new fields join the project aggregate. Individual project participants who are part of a project aggregate are not separately required to attest to the voluntary nature of project activities to the Reserve. However, supporting documentation should be made available to the verifier during verification, if requested. In addition, the Aggregate Monitoring Plan (Section 6.2) must include procedures that the aggregator will follow to ascertain and demonstrate that all new fields in the project aggregate pass the Legal Requirement Test at the time of the field's start date.

As of the Effective Date of this protocol, the Reserve could identify no existing federal, state or local regulations that explicitly obligate rice producers to adopt the project activities approved under this protocol.

[19] See Appendix C for a summary of performance standard research.
[20] Form available at http://www.climateactionreserve.org/how/program/documents/.

3.5.3 Ecosystem Services Payment Stacking

When multiple ecosystem services credits or payments are sought for a single activity on a single piece of land, it is referred to as credit stacking or payment stacking, respectively.[21]

As of the Effective Date of this protocol, the Reserve did not identify any ecosystem service markets besides the carbon market that issues credits for the project activities included in this protocol.[22] As such, credit stacking does not need to be addressed by this protocol at this time.

The USDA Natural Resources Conservation Service (NRCS) provides payments for ecosystem services through programs like the Environmental Quality Incentives Program and the Conservation Stewardship Program. These are federal programs that are implemented at the state and local level. In California, NRCS Conservation Practice Standard (CPS) 344A – *Residue Management, Seasonal Rice Straw Residue* provides assistance to farmers to reduce the amount of rice straw residues on their fields through a variety of methods, including baling the rice straw residue,[23] and CPS 329 – *Residue and Tillage Management, No Till/Strip Till/Direct Seed* can provide support for dry seeding.[24]

CPS 344A and CPS 329 have primarily been used in California to fund other management practices besides baling and dry seeding.[25] Because baling and dry seeding are expensive, uncommon, and generally not already funded by NRCS programs, the use of NRCS payments to help finance either project activity under this protocol is allowed, except as specified below.

Stacking NRCS payments for baling under CPS 344A with CRTs for baling under this protocol is not allowed if a NRCS contract for baling on a project field was in place and the baling was completed prior to the project being submitted to the Reserve.

Stacking NRCS payments for dry seeding under CPS 329 with CRTs for dry seeding under this protocol is not allowed if dry seeding was specified in the conservation plan developed with NRCS for a project field and dry seeding was implemented prior to the project being submitted to the Reserve.

Note that if a field receives NRCS payments for any activity *other than* baling or dry seeding, those payments do not affect field eligibility, as the payments were awarded for different activities than those credited by this protocol and thus are not considered "stacked."

Furthermore, other fields owned by the farmer are eligible if they are not under agreement to receive NRCS funding for CPS 344A or CPS 329 activities that include project activities. Fields

[21] Cooley, David, and Lydia Olander (September 2011). "Stacking Ecosystem Services Payments: Risk and Solutions," Nicholas Institute for Environmental Policy Solutions, Duke University. NI WP 11-04. Available at: http://nicholasinstitute.duke.edu/ecosystem/land/stacking-ecosystem-services-payments/.

[22] The Reserve did identify a type of air quality offset that is issued in California under the Connelly-Areias-Chandler Rice Straw Phase-down Act of 1991 (Act); however, credits from the program are not issued for the project activities included in this protocol, but rather for reduced rice straw burning. The Reserve does not consider project participants receiving credits under both the Act and this protocol to be "stacking" credits.

[23] NRCS CPS 344A is available on the NRCS Field Officer Technical Guide website at http://efotg.sc.egov.usda.gov//efotg_locator.aspx. To find the appropriate standard, choose state, county, Section IV: Practice Standards and Specifications, and then the Conservation Practices folder.

[24] NRCS CPS 329 is available on the NRCS Field Officer Technical Guide website at http://efotg.sc.egov.usda.gov//efotg_locator.aspx. To find the appropriate standard, choose state, county, Section IV: Practice Standards and Specifications, and then the Conservation Practices folder.

[25] Personal communication with NRCS field personnel in California.

that have received CPS 344A or CPS 329 payments in the past (e.g. prior to the field's start date) but have not received payments for at least one year are also eligible.

Table 3.2. Payment Stacking Scenarios

Scenario		Is Project Eligible?	Is the Project Stacking?
1	Field under CPS 344A or 329 agreement that includes baling or dry seeding and agreement was signed *prior* to the project field's start date or submittal to the Reserve (whichever is earlier)	No	n/a
2	Field under NRCS CPS 344A or 329 agreement for activities that do not include baling or dry seeding	Yes	No
3	Field under NRCS agreement for any other CPS	Yes	No
4	Field under CPS 344A or 329 agreement that includes baling or dry seeding and agreement was signed *after* the project field's start date or submittal to the Reserve (whichever is earlier)	Yes	Yes
5	Field that received CPS 344A or 329 payment for the year prior to the project field's start date	No	n/a
6	Field that received CPS 344A or 329 payment in the past, but has not received payment for more than one year	Yes	No

For informational purposes, any other type of ecosystem service payment or credit received for activities on a project field must be disclosed by the project developer/aggregator to the verification body and the Reserve.

3.6 Regulatory Compliance

As a final eligibility requirement, project developers/aggregators must attest that activities on the project fields (including, but not limited to, project activities) do not cause material violations of applicable laws (e.g. air, water quality, water discharge, nutrient management, safety, labor, endangered species protection, etc.) prior to verification activities commencing each time a project is verified. To satisfy this eligibility requirement, the project developers/aggregators must submit a signed Attestation of Regulatory Compliance form[26] or an Attestation of Regulatory Compliance form on behalf of themselves or all enrolled project participants prior to the commencement of verification activities each time the project is verified. Project developers/aggregators are also required to disclose in writing to the verifier any and all instances of legal violations – material or otherwise – caused by activities on project fields.

If a verifier finds that activities on project fields have caused a material violation, then CRTs will not be issued for GHG reductions that occurred on the field during the period(s) when the violation(s) occurred. Individual violations due to administrative or reporting issues, or due to "acts of nature," are not considered material and will not affect CRT crediting. However, recurrent administrative violations directly related to activities on project fields may affect crediting. Verifiers must determine if recurrent violations rise to the level of materiality. If the verifier is unable to assess the materiality of the violation, then the verifier shall consult with the Reserve.

[26] Attestation of Regulatory Compliance form available at http://www.climateactionreserve.org/how/program/documents/.

Individual project participants who are part of a project aggregate are not required to attest to their status of regulatory compliance to the Reserve. However, the project aggregator is encouraged to have in place routine procedures for assessing field-level compliance. The verifier may request supporting documentation about the project aggregator's procedures or about specific fields and such information shall be made available to the verification body during verification, if requested.

3.6.1 California Rice Straw Burning Regulation

In California, rice producers are required to comply with the Connelly-Areias-Chandler Rice Straw Burning Reduction Act of 1991 and the subsequent regulations of the Conditional Rice Straw Burn Permit Program, which limit the amount of rice straw residue producers may burn in any given year. The 1991 Act required a phase down of rice straw burning in the Sacramento Valley over a ten-year period, starting in 1992. Since September 2001, the Conditional Rice Straw Burn Permit Program has limited rice straw burning to less than 25 percent of an individual grower's planted acreage, not to exceed 125,000 acres in the Sacramento Valley Basin. Initially, rice fields were only allowed to be burned for disease control, which required demonstration of the presence of significant levels of disease in order to secure a Conditional Rice Straw Burn Permit ("Burn Permit"). However, after 100 percent of rice fields were consistently found to have the "significant" level of disease, this requirement was eliminated. Today, rice producers must secure Burn Permits (for up to 25 percent of their rice acreage) in order to burn straw.[27]

When project developers in California sign the Attestation of Regulatory Compliance, they are attesting that they are also in compliance with this regulation and that they have secured the appropriate "Conditional Rice Straw Burn Permits" from the appropriate local air district. Wherever rice straw burning occurs, the project developer must demonstrate that the amount of burning was within legal limits, if legal limits exist such as in California, and that all necessary permits have been secured.

Burning of rice straw is assumed to be an activity that will occur occasionally under "business as usual" as a pest management strategy. As such, whenever burning occurs, project input parameters to the model (see Appendix B, Step 1) should be adjusted, to reflect the correct percentage of rice straw burned in both the baseline and the project. Additionally, it should be noted that rice straw burning is not an approved project activity; although an increase in rice straw burning may reduce methane emissions, it is not an eligible activity under this protocol, even in cases when an increase in rice burning may be permissible by law.

3.6.2 Regulations on Special-Status Species

Regulations exist at the federal, state, and local level to protect threatened and endangered species (i.e. "special-status species") of wildlife and their habitats. These regulations include the federal and many state-level Endangered Species Acts and the Migratory Bird Treaty Act. As a component of the federal Endangered Species Act, the U.S. Fish and Wildlife Service works with private landowners to develop Habitat Conservation Plans (HCP) and Safe Harbor Agreements (SHA). When in effect on a rice field, an HCP or SHA should be considered a legally binding mandate. Project developers/aggregators shall disclose to the verifier any instances when a field is not in compliance with HCP or SHA requirements.

[27] Regulations establishing the Conditional Rice Straw Burning Program can be found in the California Code of Regulations, Title 17, § 80156. More information can also be found on the California Air Resources Board webpage at http://www.arb.ca.gov/smp/rice/condburn/condburn.htm.

4 The GHG Assessment Boundary

The GHG Assessment Boundary delineates the GHG sources, sinks, and reservoirs (SSRs) that must be assessed by project developers in order to determine the net change in emissions caused by a rice cultivation project.[28]

The GHG Assessment Boundary encompasses all the GHG SSRs that may be significantly affected by project activities, including sources of CH_4 and N_2O emissions from the soil, biological CO_2 emissions and soil carbon sinks, and fossil fuel combustion GHG emissions. For accounting purposes, the SSRs included in the GHG Assessment Boundary are organized according to whether they are predominantly associated with an RC project's "primary effects" (i.e. changes in the RC project's soil dynamics, including the predominant CH_4 source but also N_2O emissions from the soil and biological CO_2 emissions) or its "secondary effects" (i.e. unintended changes in emissions due to on-field practice change or upstream/off-field changes in production)).[29] Secondary effects may include increases in mobile combustion CO_2 emissions associated with site preparation, as well as increased GHG emissions caused by the shifting of cultivation activities from the project area to other agricultural lands (often referred to as "leakage"). Projects are required to account for all SSRs that are included in the GHG Assessment Boundary regardless of whether the particular SSR is designated as a primary or secondary effect.

Note that primary emissions contain some 'indirect' emissions (e.g. N_2O emissions), while secondary effect emissions contain some modeled soil dynamics (e.g. SOC decreases associated with shifting rice production outside of the project area).

Figure 4.1 below provides a general illustration of the GHG Assessment Boundary, indicating which SSRs are included or excluded from the project boundary.

Table 4.1 provides a comprehensive list of the GHG SSRs that may be affected by an RC project, and indicates which SSRs must be included in the GHG Assessment Boundary.

Note that for SSRs 6 and 7, some scenarios may require quantification of the SSRs for the project only.

[28] The definition and assessment of sources, sinks, and reservoirs (SSRs) is consistent with ISO 14064-2 guidance.
[29] The terms "primary effect" and "secondary effect" come from WRI/WBCSD, 2005. *The Greenhouse Gas Protocol for Project Accounting*, World Resources Institute, Washington, DC. Available at http://www.ghgprotocol.org.

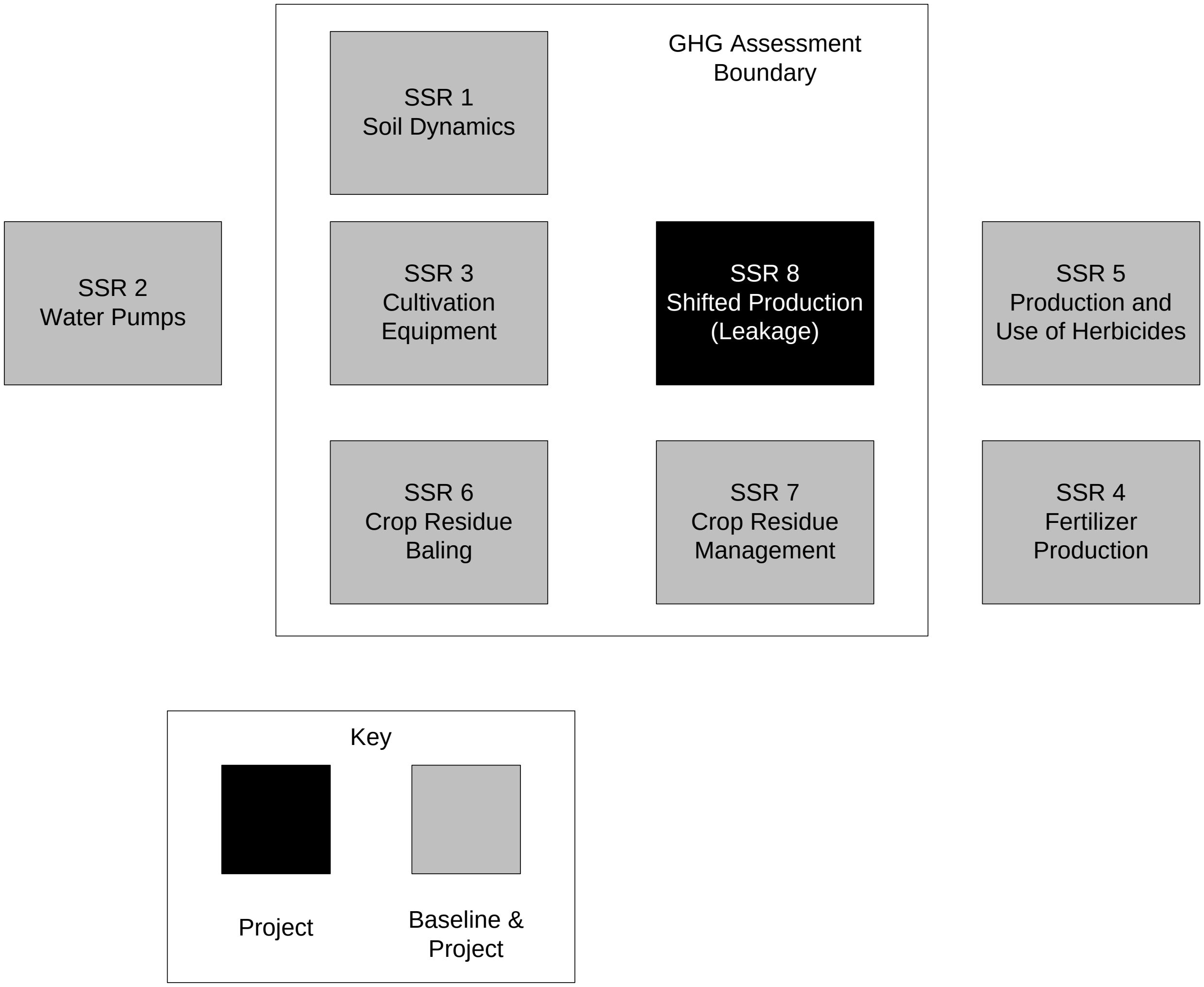

Figure 4.1. General illustration of the GHG Assessment Boundary

Table 4.1. Description of RC Project Sources, Sinks, and Reservoirs

SSR	Source Description	Gas	Included (I) or Excluded (E)	Quantification Method	Justification/Explanation
Primary Effect Sources, Sinks, and Reservoirs					
1. Soil Dynamics	Soil dynamics refer to the biogeochemical interactions occurring in the soil that produce emissions of CO_2 (biogenic), CH_4, N_2O, and changes in soil carbon stocks. GHG flux rates from soils are dependent on water management (including during seeding and after harvest), residue management, fertilizer application, and other site-specific variables	CO_2	I (if SOC decreased)	DNDC	Changes in soil carbon stocks resulting from project activity may be significant. Decreases in carbon stocks must be accounted for.
		CH_4	I	DNDC	The primary effect of an RC project is reduction in CH_4 emissions from soil due to reduced flooding and/or reduced organic residues available for decomposition.
		N_2O	I (if increased)	Direct: DNDC Indirect: DNDC and IPCC emission factors	A significant source affected by project activities if fertilizer application amounts and/or dates are changed, or seeding practice is altered. Increases in direct and/or indirect N_2O must be accounted for.
Secondary Effect Sources, Sinks, and Reservoirs					
2. Water Pumps	Indirect fossil fuel emissions from transport of water onto fields	CO_2	E	N/A	Excluded, as project activity is very likely to reduce or not impact the quantity of water used during the cultivation process as compared to baseline management.
		CH_4	E	N/A	Excluded, as this emission source is assumed to be very small.
		N_2O	E	N/A	Excluded, as this emission source is assumed to be very small.
3. Cultivation Equipment	Fossil fuel emissions increases from equipment used for field preparation, seeding, fertilizer/pesticide/herbicide application, and harvest	CO_2	I	Emission factors	Emissions may be significant if management is altered. Increased emissions due to project activity must be accounted for.
		CH_4	E	N/A	Excluded, as this emission source is assumed to be very small.
		N_2O	E	N/A	Excluded, as this emission source is assumed to be very small.
4. GHG Emissions from Fertilizer Production	GHG emissions from synthetic N fertilizer production	CO_2	E	N/A	Excluded, the very small increase in fertilizer demand due to RC projects is unlikely to have an effect on fertilizer production.
		CH_4	E	N/A	Excluded, as this emission source is assumed to be very small
		N_2O	E	N/A	Excluded, the very small increase in fertilizer demand due to RC projects is unlikely to have an effect on fertilizer production.

SSR	Source Description	Gas	Included (I) or Excluded (E)	Quantification Method	Justification/Explanation
5. GHG Emissions from Production and Use of Herbicides	Fossil fuel emissions from Herbicide production	CO_2	E	N/A	Excluded, the very small increase in herbicide demand due to RC projects is unlikely to have an effect on herbicide production.
		CH_4	E	N/A	Excluded, as this emission source is assumed to be very small
		N_2O	E	N/A	Excluded, as this emission source is assumed to be very small
6. Crop Residue Baling	Fossil fuel emissions from baling and transportation of baled rice straw for offsite use/management	CO_2	I	Baling emission factors	Emissions may be significant if residue management is altered. Increased emissions due to project activity must be accounted for.
		CH_4	E	N/A	Excluded, as this emission source is assumed to be very small.
		N_2O	E	N/A	Excluded, as this emission source is assumed to be very small.
7. Crop Residue Management	Fugitive emissions from aerobic or semi-anaerobic rice straw management (onsite or offsite)	CO_2	E	N/A	Emissions from rice straw burning are excluded as they are not considered likely to increase relative to baseline and are biogenic.
		CH_4	I	Emission factors	May be a significant source of fugitive CH_4 emissions, depending on management/use of rice straw.
		N_2O	E	N/A	Due to low N content of rice straw, changes in N_2O emissions from alternative rice straw management are likely insignificant.
8. GHG Emissions from Shifted Production (Leakage)	If project activity results in a statistically significant decrease in yield, rice production and associated GHG emissions may be shifted outside the project area	CO_2	I		If rice yield totaled over all fields in an aggregate are found to have statistically decreased due to project activity, the associated GHG emissions from shifted rice production must be estimated.
		CH_4	I		
		N_2O	I		

5 Quantification Overview

GHG emission reductions from an RC project are quantified by comparing actual project emissions to baseline emissions from rice cultivation. Baseline emissions are an estimate of the GHG emissions from sources within the GHG Assessment Boundary (see Section 4) that would have occurred in the absence of an RC project. Project emissions are actual GHG emissions that occur at sources within the GHG Assessment Boundary. Project emissions must be subtracted from the baseline emissions to quantify the project total net GHG emission reductions. GHG emission reductions are calculated for each individual field and summed together over the entire project area. The calculation approach in this section is applicable to single-field projects and aggregates.

The primary effect of an RC project is a reduction in methane emissions due to either (i) a decrease in duration of flooded conditions (switching to dry seeding with delayed flood), or (ii) a decrease in the availability of dissolved organic matter in the soil (residue baling). While there is directional certainty (i.e. it is likely that project cultivation changes will reduce methane emissions compared to the baseline scenario), the magnitude of reductions is highly variable and dependent on numerous other parameters related to field-scale management techniques, soil characteristics, and climatic conditions.

This protocol relies on the application of the DNDC model for quantification of baseline and project emissions from soil dynamics (SSR 1) defined in Section 4. Detailed requirements for accurate and consistent application of the DNDC model are provided in Appendix B. In addition to SSR 1, RC projects may result in unintended increases of GHG emissions from secondary effect SSRs. Section 5.5 provides the requirements for calculating those secondary GHG emissions resulting from the project activity that do not rely on use of the DNDC model. Total emission reductions from a field are equal to the combined primary effect emission reductions from SSR 1 for all fields in the project boundary, minus the increase in emissions from all other SSRs due to the project activity.

In addition to changes in CH_4, the DNDC model also provides estimates of nitrate leaching, and ammonia and nitric oxide emissions that are used to estimate the changes in indirect N_2O emissions associated with an RC project. The DNDC model also provides estimates of changes in SOC. If emissions of N_2O (both direct and indirect) increase or SOC decrease due to project activity, these emissions must be deducted from the emission reduction estimate. If N_2O (direct or indirect) emissions are reduced or SOC increased due to the project activity, these changes must be excluded from the emission reduction estimate.

5.1 Defining the Reporting Period

Under this protocol, project emission reductions must be quantified per cultivation cycle. The length of time over which GHG emission reductions are quantified is called a "reporting period". The length of time over which GHG emission reductions are verified is called a "verification period." For single-field projects, a verification period can cover multiple reporting periods (see Section 7.4.1). For aggregate projects, the verification period is limited to a single reporting period (i.e. a single cultivation cycle).

For single field projects, the reporting period shall be defined using the exact dates corresponding to the beginning and the end of the cultivation cycle for the particular field.

For an aggregate, the individual fields will likely have cultivation cycles that start on different dates, and the length of the cultivation cycle may be slightly more or less than a full 365 days for each individual field. Therefore, the reporting period must be uniformly defined for the aggregate for reporting purposes. For reporting reductions from each cultivation cycle to the Reserve, the aggregate reporting period shall be defined as starting on October 1 and ending on September 30 of the following year. This defined reporting period is for reporting purposes only; the emission reductions reported for the aggregate must include the emission reductions achieved over the complete cultivation cycle for each participating field in the aggregate.[30]

Note that in order to model emissions for any given cultivation cycle, it is necessary to model two full years of data, as each cultivation cycle spans across two calendar years. See Section 5.3 for guidance on how to reconcile modeling annual emissions with modeling emissions for the cultivation cycle.

5.2 Baseline Modeling Inputs

To set the baseline scenario inputs within the DNDC model for each cultivation cycle, the project developer must use field management data from five cultivation cycles prior. Given that two calendar years of data are required for every cultivation cycle being modeled (as set out in Section 5.3 below), inputs for the first baseline cultivation cycle must be derived from records starting in the fall of the fifth year prior to the start date and ending with the following rice harvest in the fall of the fourth year prior to the start date. The last baseline cultivation cycle in the crediting period shall include data from the fall of the year before the project started through to the rice harvest immediately preceding the project start date. In subsequent crediting periods, the baseline scenario will continue to be set using data from the five cultivation cycles immediately prior to the project.

5.3 Deriving Cultivation Cycle Emissions from Calendar-Year Modeling Results

It is important to note that the DNDC model operates on a calendar year, beginning on January 1 and ending on December 31. The model's daily output files use Julian days, where January 1 represents Julian Day 1, January 2 represent Julian Day 2, and December 31 represents Julian Day 365.[31] However, project developers must quantify emissions and emission reductions that occur during the reporting period of a given field, which is defined by the rice crop's cultivation cycle beginning in fall and running through the fall of the following year (e.g. October 1 to September 30). As such, for every instance in this protocol where the project developer is directed to model a cultivation cycle, the project developer must model two full calendar years, so as to capture the last two to three months in the first year, and the first nine to ten months in the following year that make up the relevant cultivation cycle.[32]

For ease of monitoring, reporting, and verification, the Reserve encourages project developers to use Julian Dates in addition to calendar dates wherever possible, but particularly when

[30] All emissions reductions from each field's cultivation cycle must be reported under the corresponding reporting period for the aggregate, even if the dates of the cultivation cycle and reporting period do not completely overlap. For any given field, emissions reductions achieved during a cultivation cycle may only be reported under a single aggregate reporting period.

[31] A Julian Day calendar provided by NASA is available at: http://www-air.larc.nasa.gov/tools/jday.htm.

[32] In determining project emissions, one strategy for economizing on required modeling runs is to conduct modeling only after input data for the entire two calendar years have been collected, i.e. at the end of the second calendar year, rather than at the end of the cultivation cycle. This will generate results for the initial 2-3 months of the subsequent cultivation cycle, avoiding the need to model the entire calendar year again.

reporting the first and last days of a cultivation cycle, as this will ease project accounting and reduce human error associated with model inputs.

5.4 Quantifying GHG Emission Reductions

The emission reductions for a project are calculated by subtracting the total secondary effect emissions (SE) from the total primary emission reductions (PER) (adjusted for uncertainty) for the entire project area. Equation 5.1 below provides the general emission reduction calculation, applicable to all projects.

Equation 5.1. Calculating GHG Emission Reductions

$$ER = PER - SE$$

Where,

			Units
ER	=	Total emission reductions from the project area for the reporting period	tCO_2e
PER	=	Total primary GHG emission reductions from soil dynamics (SSR 1) from each project during the reporting period adjusted for uncertainty (as calculated in Section 5.4.3)	tCO_2e
SE	=	Total secondary effect GHG emissions caused by project activity during the reporting period for each project (as calculated in Section 5.5)	tCO_2e

Table 5.1 below provides an overview of the key steps, calculations and equations necessary to quantify PER and SE emissions for each field and the project as a whole.

Table 5.1. Overview of Quantification Steps

STEP	OVERVIEW	EQUATION
1. Calculate primary emissions for baseline scenario and project scenario for each field	Calculate average cultivation cycle baseline and project scenario GHG values. This involves: ▪ Conducting 2,000 Monte Carlo runs of the DNDC model for both calendar years within which the cultivation cycle falls, for both the baseline and project scenarios (4 years total); ▪ Extracting data from DNDC modeling results corresponding to the cultivation cycle; ▪ Calculating cultivation cycle GHG parameter values for each Monte Carlo run; and ▪ Averaging these values across the 2,000 Monte Carlo runs for both the baseline and project scenarios.	Equation 5.2
2. Calculate primary effect emission reductions for each field (unadjusted for uncertainty)	Preliminary primary effect emission reductions for each field are calculated using results from the baseline and project modeling calculations in Step 1.	Equation 5.3
3. Calculate uncertainty-adjusted primary emission reductions for each field	Apply soil and structural uncertainty deductions to preliminary primary effect emission reductions for each field to calculate final primary effect emission reductions.	Equation 5.4

4. Calculate increased emissions from cultivation equipment	Choose from two alternative approaches to calculate emissions from increased fuel emissions from cultivation equipment.	Equation 5.5 or Equation 5.6
5. Calculate emissions from rice straw end use	Calculate emissions associated with changes in rice straw management, using default emission factors provided in Appendix A.	Equation 5.7
6. Calculate emissions from activity leakage	Calculate emissions associated with any shift in rice production outside of the project boundary, attributed to reductions in project yields.	Equation 5.8 Equation 5.9 Equation 5.10
7. Calculate total secondary effect emissions for the project	Sum together emissions from increased fossil fuel usage, alternative residue management activities, and activity leakage.	Equation 5.11

5.4.1 Step 1: Calculate Primary Emissions for Baseline and Project Scenarios for Each Field

This section provides guidance on how to use results from DNDC Monte Carlo modeling runs to calculate average cultivation cycle emissions for both the baseline and project scenarios for each field. These average cultivation cycle emissions are then input into Equation 5.3 to calculate primary emission reductions for each field. For the purposes of this protocol, the modeling of GHG emissions from soil dynamics under baseline and project scenarios must be performed using Version 9.5 of the DNDC model, which shall be obtained directly from the Reserve.

Detailed guidance is provided in Appendix B on how to undertake the modeling itself, extract relevant results and develop the necessary inputs for Equation 5.2 below. Specifically, Appendix B, Step 1 provides guidance to help project developers understand the necessary DNDC data input parameters; Step 2 instructs project developers on how to prepare input files and what to do in case of missing data; Step 3 instructs project developers on how to properly prepare DNDC for modeling; and Step 4 instructs project developers on how to undertake the modeling of emissions, extract relevant results and develop the values to be input into Equation 5.2 below.

In order to quantify primary emission reductions for each field, project developers shall first calculate annual baseline and project scenario GHG values using data extracted from DNDC modeling results.

For both the baseline and project scenarios, GHG emissions are calculated by performing 2,000 Monte Carlo runs of the DNDC model for each field, for each calendar year being modeled.[33]

For each of the 2000 Monte Carlo runs for a field, the project developer must extract GHG parameter values corresponding to the dates of the field's cultivation cycle (i.e. extracted from the appropriate range within each modeled calendar year). A single cultivation cycle value is then determined for each GHG parameter, by summing daily values (for emissions) or by

[33] As set out in Section 5.3, emissions will need to be modeled separately for four calendar years: the two calendar years that capture the baseline scenario cultivation cycle and the two calendar years that capture the project scenario cultivation cycle.

identifying the value on the last day of the cultivation cycle (soil carbon).These single values are then input into Equation 5.2 to be averaged across the 2,000 Monte Carlo runs in order to generate a single average value for each GHG parameter for the cultivation cycle. Refer to Step 4 in Appendix B for detailed guidance on how to perform these steps. Appendix C also provides more general guidance on how to use the DNDC model, including screen shots, step by step instructions, and advice on performing project feasibility analysis with the model. Further guidance can also be found in the *DNDC User's Guide*, available on the Reserve's RCPP webpage.[34]

The results of Equation 5.2 are a single average value for each of the direct emission parameters (N_2O, CH_4, and SOC content) and indirect emission parameters (NO_3 and NH_3+NO_x) that are used to calculate primary GHG reductions. Once these values are calculated for both the baseline and project scenarios, they are input into Equation 5.3, to calculate the total primary emission reductions for each field.

[34] A copy of the *DNDC User's Guide* can be found on the protocol webpage at http://www.climateactionreserve.org/how/protocols/rice-cultivation/.

Equation 5.2. Calculating GHG Emissions from Monte Carlo Runs for Field i

$$N_2O_i = \frac{\sum_{j=1}^{2000}\{(N_2O_{Dir,j,i} + (N_{Leach,j,i} \times 0.0075) + (N_{Vol,j,i} \times 0.01)\}}{2000} \times \frac{44}{28} \times 310$$

$$CH_{4_i} = \frac{\sum_{j=1}^{2000}\left(CH_{4_{j,i}}\right)}{2000} \times \frac{16}{12} \times 21$$

$$SOC_{LDcc,i} = \frac{\sum_{j=1}^{2000}\left(SOC_{LDcc,j,i}\right)}{2000} \times \frac{44}{12}$$

Where,			Units
N_2O_i	=	Average cultivation cycle direct and indirect N_2O emissions (for either the baseline or project scenario) from rice field *i*, equal to the average value of all Monte Carlo runs *j*	kg CO_2e/ha
j	=	*1, 2, 3 …2000* Monte Carlo runs	
$N_2O_{Dir,j,i}$	=	Cultivation cycle N_2O emissions from rice field *i* (for either the baseline or project scenario) from Monte Carlo run *j*	kg N_2O-N/ha
$N_{Leach,j,i}$	=	Cultivation cycle nitrate leaching loss from rice field *i* (for either the baseline or project scenario) from Monte Carlo run *j*	kg NO_3-N/ha
$N_{Vol,j,i}$	=	Cultivation cycle ammonia volatilization and nitric oxide emissions from rice field *i* (for either the baseline or project scenario)from Monte Carlo run *j*	kg NH_3-N + kg NO_x-N /ha volatized
44/28	=	Unit conversion from kg N_2O-N to kg N_2O	
310	=	Global warming potential of N_2O	
$CH_{4\ i}$	=	Average cultivation cycle CH_4 emissions (for either the baseline or project scenario)from rice field *i*, equal to the average value of all Monte Carlo runs *j*	kg CO_2e/ha
$CH_{4\ j,i}$	=	Cultivation cycle CH_4 emissions from rice field *i* (for either the baseline or project scenario) from Monte Carlo run *j*	kg CH_4-C/ha
16/12	=	Unit conversion of C to CH_4	
21	=	Global warming potential of CH_4	
$SOC_{LDcc,i}$	=	Average cultivation cycle final SOC, equal to the average value of all Monte Carlo runs *j,* of the soil organic carbon content of rice field *i* on the last day of the cultivation cycle (for either the baseline or project scenario)	kg CO_2e/ha
$SOC_{LDcc,j,i}$	=	SOC content of rice field *i* on the last day of the cultivation cycle (for either the baseline or project scenario) from Monte Carlo run *j*	kg SOC-C/ha
44/12	=	Unit conversion of C to CO_2	
0.0075	=	Emission factor for N_2O emissions from N leaching and runoff[35]	kg N_2O-N / kg NO_3-N
0.01	=	Emission factor for N_2O emissions from atmospheric deposition of N on soils and water surfaces and subsequent volatization[36]	kg N_2O-N / (kg NH_3-N + kg NO_x-N)

[35] IPCC Guidelines for National GHG Inventories (2006), Vol.4, Ch.11, Table 11.3.
[36] Ibid.

5.4.2 Step 2: Calculate Primary Emission Reductions for Each Field (Unadjusted for Uncertainty)

In order to calculate the total PER for each field (PER_i) (unadjusted for uncertainty), project developers must compare the baseline and project scenario results calculated in Step 1 for the key GHG parameters CH_4, N_2O, and SOC. Any decreases in N_2O or increases in SOC are excluded from the total PER_i results, as the protocol does not credit projects for such changes.

The calculations necessary to quantify PER_i are set out in Equation 5.3 below.

Equation 5.3. Total Primary Effect GHG Emission Reductions for each Field (Unadjusted for Uncertainty)

$$\boldsymbol{PER_i = \frac{\left\{(N_2O_{B,i} - N_2O_{P,i}) + (CH_{4_{B,i}} - CH_{4_{P,i}}) - (SOC_{LDBcc,i} - SOC_{LDPcc,i})\right\}}{1000} \times Area_i}$$

Where,

			Units
PER_i	=	Primary effect GHG emission reductions for field *i* ***** (unadjusted for uncertainty)	tCO_2e
$N_2O_{B,i}$	=	Average baseline cultivation cycle N_2O emissions for field *i*	kg CO_2e/ha
$N_2O_{P,i}$	=	Average project cultivation cycle N_2O emissions for field *i*	kg CO_2e/ha
$CH_{4\ B,i}$	=	Average baseline cultivation cycle CH_4 emissions for field *i*	kg CO_2e/ha
$CH_{4\ P,i}$	=	Average project cultivation cycle CH_4 emissions for field *i*	kg CO_2e/ha
$SOC_{LDBcc,i}$	=	Average SOC value on the last day of the baseline cultivation cycle for field *i*	kg CO_2e/ha
$SOC_{LDPcc,i}$	=	Average SOC value on the last day of the project cultivation cycle for field *i*	kg CO_2e/ha
$Area_i$	=	Area of field *i* in hectares	ha

***** In order to ensure that only reductions in CH_4 are credited on each field, the term ($N_2O_{B,i} - N_2O_{P,i}$), must be set equal to zero if it is > 0; and the term ($SOC_{LDBcc,i} - SOC_{LDPcc,i}$) must be set equal to zero if it is < 0.

5.4.3 Step 3: Calculate Uncertainty-Adjusted Primary Emission Reductions for each Field

When calculating PER, this protocol requires project developers to account for two types of uncertainty: model structural uncertainty and soil input uncertainty. Inherent in biogeochemical models (like DNDC) are uncertainties due to imperfect science in the models. This uncertainty is often referred to as model structural uncertainty, and roughly quantifies how well the model represents reality. Because physical and chemical properties of soil have a significant impact on CH_4 and N_2O production, consumption, and emissions, further variability and uncertainty is also introduced to the model in the sampling of soil data and the subsequent modeling of GHG emissions using such data. This is known as soil input uncertainty.

The protocol requires that project developers account for both types of uncertainty by applying the appropriate uncertainty deductions to the modeled primary emission reductions. The soil input uncertainty deduction must be calculated by project developers for each field based on results from DNDC to model baseline and project scenario emissions for that field. The model structural uncertainty deduction is provided by the Reserve. Further guidance on each type of uncertainty deduction is provided below.

5.4.3.1 Model Structural Uncertainty Deduction

Model structural uncertainty is quantified by comparing model estimates of greenhouse gases with measured emission estimates. The measured data are assumed to have no uncertainty (although measurements can have sources of uncertainties in practice). Project developers do not need to calculate the model structural uncertainty deduction, but instead obtain the appropriate structural uncertainty deduction from the Reserve at the time of verification.

Appendix C provides the structural uncertainty derivation procedure developed to adjust DNDC results for model structural uncertainty. To ensure conservativeness in estimates of project emission reductions, all projects must use the adjustments provided by the Reserve to account for structural uncertainty for Version 9.5 of the DNDC model, as specified in Equation 5.4.

Because there is ongoing field research actively collecting GHG emissions data for California rice, new data may become available for model validation. Periodically, as data become available, the calculation of model structural uncertainty and the table of structural uncertainty factors will be updated. Further, the factors decline as more fields implement rice cultivation projects. As such, the most up-to-date factors will be available on the Reserve website. Project developers must use the structural uncertainty deduction factor (μ_{struct}) for the appropriate reporting year that is published on the Reserve website at the time of verification.

5.4.3.2 Soil Input Uncertainty Deduction

Project developers must calculate an appropriate soil input uncertainty deduction using results from the same Monte Carlo analyses performed to model baseline and project emissions for each field. Detailed guidance on conducting Monte Carlo analyses and developing soil input uncertainty deductions is provided in Appendix B, Step 4 and Step 5 respectively.

5.4.3.3 Applying Uncertainty Deductions to Primary Emission Reductions

Once an appropriate soil input uncertainty deduction has been calculated, in accordance with Appendix B, Step 5.1, and an appropriate structural uncertainty deduction has been obtained from the Reserve, both deductions are applied to PER_i in order to calculate uncertainty adjusted total PER for each field. The application of the uncertainty deductions to PER_i is shown in Equation 5.4 below.

Equation 5.4. Applying Uncertainty Deductions to Primary Emission Reductions

$$\boldsymbol{PERud} = \sum_{i=1}^{m} \{(\mu_{\boldsymbol{inputs_i}} \times \boldsymbol{PER_i}) - \mu_{\boldsymbol{struct}}\}$$

Where,

			Units
PERud	=	Primary GHG emission reductions over the entire project area, accounting for uncertainty deductions	tCO_2e
m	=	Number of individual rice fields included in the project area	
$\mu_{inputs,i}$	=	Accuracy deduction factor for the cultivation cycle for individual rice field *i* due to soil input uncertainties, refer to Appendix B, Step 5.1	fraction
PER_i	=	Primary GHG emission reductions for field *i* (from Equation 5.3)	tCO_2e
μ_{struct}	=	Accuracy deduction from model structural uncertainty for the reporting period, values available on Reserve website	

5.5 Quantifying Secondary Effects

Secondary effect GHG emissions are unintentional changes in GHG emissions from the secondary SSRs within the GHG Assessment Boundary. Secondary effect emissions may increase, decrease or go unchanged as a result of the project activity. If emissions from secondary SSRs increase as a result of the project, these emissions must be subtracted from the total modeled primary emission reductions (as specified in Equation 5.1) for each reporting period on an *ex post* basis.

The total secondary effect GHG emissions are equal to:

- Increased CO_2 emissions from mobile combustion of fossil fuels by farm equipment used for field preparation, seeding, and cultivation (SSR 3, Step 4), plus
- CO_2 emissions from transport and processing of rice straw residues (SSR 6, Step 5), and methane emissions from aerobic or semi-anaerobic treatment/use of baled rice straw residue (SSR 7, Step 5), plus
- Emissions of CH_4 and CO_2 due to shifted rice production outside the project boundary (SSR 8, Step 6)

5.5.1 Step 4: Calculate Project Emissions from Onsite Fossil Fuel Combustion

Included in the GHG Assessment Boundary are secondary CO_2 emissions resulting from increased fossil fuel combustion for onsite equipment used for performing RC management activities related to seeding, fertilizer application, and herbicide application. Fossil fuel emissions from baling rice straw are incorporated into the emission calculation in Section 5.5.2 below and are not to be included when quantifying increased fossil fuel emissions per this section. Secondary emissions from cultivation equipment need not be quantified if there is no change in the type or hours of cultivation equipment usage due to implementation of the project (e.g. no new equipment used for dry seeding). But if the project management changes require new equipment or an increase in the operational hours for existing equipment, the CO_2 emissions from the increased fossil fuel combustion shall be calculated using either Equation 5.5 or Equation 5.6 below.

Two approaches are provided to calculate secondary emissions from cultivation equipment. Approach 1 calculates emissions based on the time needed for each rice cultivation related field operation, the horsepower required for this field operation, and a default emission factor for GHG emissions per horsepower-hours. Approach 2 calculates emissions based on the change in fuel consumption for field operations related to rice cultivation and a default emission factor for GHG emissions per unit of fuel consumed.

Approach 1 is designed to require minimal documentation. The project participant must provide manufacturer's specifications on the horsepower requirements for the new cultivation equipment used, and the time needed per hectare for implementation of the project-specific activity. The time needed to implement the activity should be reported based on work-hour records. However, lacking those records, they may be derived based on the average operation or ground speed of the equipment and the application width per pass (e.g. width of boom). Using Approach 1, project emissions from cultivation equipment are calculated using Equation 5.5.

Equation 5.5. Project Emissions from Cultivation Equipment (Approach 1)

$$\boldsymbol{SE_{FF,f}} = \left(\sum_{i}\left(\boldsymbol{EF_{HP-hr,P,i,f}} \times \boldsymbol{HP_{P,i,f}} \times \boldsymbol{t_{P,i,f}}\right) - \sum_{k}\left(\boldsymbol{EF_{HP-hr,B,k,f}} \times \boldsymbol{HP_{B,k,f}} \times \boldsymbol{t_{B,k,f}}\right)\right) \times \mathbf{10^{-6}}$$

If $\boldsymbol{SE_{FF,f}} < 0$, set $\boldsymbol{SE_{FF,f}}$ to 0

Where,

			Units
$SE_{FF,f}$	=	Increase in secondary emissions from a change in cultivation equipment on field *f*	Mg CO_2e/ha
$EF_{HP-hr,P,i,f}$	=	Emission factor for project operation *i* on field *f*. Default value is 1311 for gasoline-fueled operations and 904 for diesel-fueled operations[37]	g CO_2e/HP-hr
$HP_{P,i,f}$	=	Horsepower requirement for project operation *i* on field *f*	HP
$t_{P,i,f}$	=	Time required to perform project operation *i* on field *f*	hr/field
$EF_{HP-hr,B,k,f}$	=	Default emission factor for baseline operation *k* on field *f* Default value is 1311 for gasoline-fueled operations and 904 for diesel-fueled operations[38]	g CO_2e/HP-hr
$HP_{B,k,f}$	=	Horsepower requirement for baseline operation *k* on field *f*	HP
$t_{B,k,f}$	=	Time required to perform baseline operation *k* on field *f*	hr/field
10^{-6}	=	Converting g CO_2e to Mg CO_2e	

Optional Method (determination of *t*)
If time records are not available, use the method below in both baseline and project estimates.

$$\boldsymbol{t} = \frac{\mathbf{10000}}{(\boldsymbol{width} \times \boldsymbol{speed} \times \mathbf{1000})} \times \boldsymbol{A_f}$$

Where,

			Units
t	=	Time requirement for field operation	hr
10000	=	Area unit conversion	m^2/ha
width	=	Application width covered by equipment	m
speed	=	Average ground speed of the operation equipment	km/hr
1000	=	Length unit conversion	m/km
A_f	=	Size of field *f*	ha

Alternately, project participants may choose to quantify secondary emissions from changes in the use of cultivation equipment based on their fuel consumption records (see Equation 5.6, Approach 2, below). If insufficient fuel consumption records are available, Approach 1 must be used.

[37] California Air Resources Board, OFFROAD2007. Available at http://www.arb.ca.gov/msei/offroad/offroad.htm.
[38] Ibid.

Equation 5.6. Increased Emissions from Cultivation Equipment (Approach 2)

$$SE_{FF,f} = \frac{\sum_i [(FF_{RP,j} \times EF_{FF,j}]}{1000}$$

If $SE_{FF,f}$ < 0, set $SE_{FF,f}$ to 0

Where,			Units
$SE_{FF,f}$	=	Increase in secondary emissions from a change in cultivation equipment on field *f*	Mg CO_2e/ha
$FF_{RP,j}$	=	Total change in fossil fuel consumption for field *f* during the reporting period, by fuel type *j*	gallons
$EF_{FF,j}$	=	Fuel-specific emission factor. Default values are 17.4 for gasoline and 13.7 for diesel[39]	kg CO_2/gallon fossil fuel
1000	=	Kilograms per megagram	kg CO_2/Mg CO_2

5.5.2 Step 5: Calculate Project Emissions from Rice Straw Residue Management/Use

Project emissions from rice straw management consist of CH_4 produced from anaerobic or semi-anaerobic decay of the rice straw, and fossil fuel emissions that are used for swathing, raking, and baling of the rice straw. Depending on the end-use of the rice straw, the magnitude of the emissions will vary, but may be significant. If rice straw is unused and accumulates in piles on or near the farm, anaerobic decay will produce emissions that are quite significant, potentially outweighing the GHG benefits of baling the rice straw. Because the swathing, raking, and baling services are most often performed by third-party contractors, fossil fuel emissions from the swathing, raking, and baling process are estimated using conservative default factors.

For calculating the emissions from rice straw management and/or use, emission factors were developed for the following identified end-uses:[40]

- **Dairy replacement heifer feed:** Wheat straw is traditionally used in heifer feed. Rice straw can be used if it is cut to the right length. Quality of the straw (crude protein content, moisture content, etc.) must meet minimal standards before it can be used. There may be a significant effect on enteric fermentation from replacing wheat straw with rice straw due to feeding animals lower quality straw.

- **Beef cattle feed:** Rice straw is used by beef cattle operations as a dry matter supplement to pasture feeding during fall and winter. Cattle ranchers spread the large bales out on the range in fall and allow the cattle to feed on the bales. Quality of the straw (crude protein content, moisture content, etc.) must meet minimal standards before it can be used. There may be some effects on enteric fermentation by feeding lower quality straw.

- **Fiberboard manufacturing:** Rice straw may be used as an alternative to wood products for the manufacturing of fiberboard. The avoided emissions from harvest and transport of wood products very likely outweigh emissions from transporting rice straw.

[39] California Air Resources Board, OFFROAD2007. Available at http://www.arb.ca.gov/msei/offroad/offroad.htm.
[40] End-uses and descriptions referenced from ANR, 2010.

- **Spread out on bare soils as erosion control:** Rice straw is particularly valuable for erosion control since it is produced in an aquatic environment and does not pose a risk of introducing upland weeds like wheat or barley straw. When used for erosion control, rice straw will decompose aerobically because it is spread out on top soil, ensuring an oxygen rich environment during decomposition.

- **Other uses:** Rice straw may be used in small quantities for other uses, such as animal bedding, being stuffed into netted rolls for soil loss prevention, or for use in mushroom farming (among other potential uses). Because of a lack of detailed emissions data, straw that is sent to an end-use other than those specified above must use the default emission factor for 'unknown or other' end-uses in Appendix A.

Each field must use Equation 5.7 to calculate the project CH_4 emissions from the end-use of all baled rice straw. Because growers may not be able to track the end fate for some or all of the field rice straw, a conservative default factor can be used in place of an end-use specific default factor. If electing to use end-use specific factors, the project developer must collect and retain straw sales documentation to demonstrate rice straw end-use(s). See Section 6.4.3 for detailed baling monitoring requirements.

Projects must use the emission factor in Table A.1 in Appendix A corresponding to the appropriate end-use, or the default factor. If rice straw is unused and accumulates in piles on or near the field, the portion of rice straw that is left unused must be estimated, and the default factor for unused rice straw must be used to quantify the emissions from this source.

Equation 5.7. Emissions from Rice Straw End-Use

$$\boldsymbol{SE_{RM,i}} = (\boldsymbol{W_{RS,i}} \times \boldsymbol{EF_{SRB}}) + \sum_{\boldsymbol{U}} [\boldsymbol{W_{RS,U}} \times \boldsymbol{EF_U}]$$

Where,

			Units
$SE_{RM,i}$	=	Total secondary effect GHG emissions from alternative residue management for field *i*	tCO_2e
$W_{RS,i}$	=	Total weight of rice straw in dry tonnes that is swathed, raked, and baled on the field *i*	dry tonne
EF_{SRB}	=	Emission factor for increased fossil fuel emissions from swathing, raking, and baling. The emission factor shall be equal to 0.01 for all fields[41]	tCO_2e / dry tonne
$W_{RS,U}$	=	Weight of rice straw in dry tonnes with end-use *U*. The sum weight of rice straw for all end-uses must equal the total weight of rice straw baled on the field	dry tonne
EF_U	=	Emission factor from Table A.1 in Appendix A for end-use *U*	tCO_2e / dry tonne

[41] Emissions from swathing, raking, and baling the rice straw are likely to be similar to emissions from the avoided chopping and disking of the field. From University of California cost and return studies for rice (2007) and orchard grass hay (2006), conservative estimates of fuel usage were obtained for both scenarios. The emission factor assumes an increase in fuel usage equivalent to 2 gallons of diesel fuel per acre for the swathing, raking, and baling. Using EPA diesel emission factor of 8.78 kg CO_2 per gallon of diesel, and assuming 3 tonnes of rice straw per acre, the emissions increase from swathing, raking, and baling is estimated to be 5.85 kg CO_2 per tonne of rice straw.

5.5.3 Step 6: Calculate GHG Emissions from the Shift of Rice Production Outside of Project Boundaries (Leakage)

If rice yields decrease as a direct result of project activity, to be conservative it is assumed that the decrease in rice production causes a net increase in production elsewhere outside the project boundary. The emissions associated with this shift in production must be estimated if project related yield losses are statistically significant compared to historic and average yields. Although rice production in California and the U.S. is likely fairly inelastic in relation to price changes,[42] it is assumed for conservativeness that a statistically significant drop in rice yields due to project activities would result in an increase of production outside of the project boundary.

If a simple summation of project yield, or in the case of aggregate, the aggregate project area yields, shows that yields did not decrease compared to the average historic rice yield for the same area, then this protocol assumes leakage has not occurred and subsequently emissions associated with shifting production do not need to be estimated (i.e. the remainder of this section can be skipped).

In order to determine if rice yields have decreased across the project area during the cultivation cycle as a result of project activity, the annual yield from the project area must be compared to historical yields from the same project area. Because yields fluctuate annually depending on numerous climatic drivers, all yields are normalized to average annual county yields using USDA NASS statistics.[43]

The following procedure must be followed for each cultivation cycle to ensure that the yields from the project area have not declined due to project activity. The following procedure is applicable for a single field project. All project aggregates must apply the following procedure to the entire project area, defined as the sum of individual fields included in verification activities:

1. For the five rice cultivation years *t* prior to implementation of the project, normalize the rice yield of the field by the county average for that year, $\boldsymbol{y\_norm_t}$. If the project is an aggregate, calculate $\boldsymbol{y\_norm_t}$ for each of the historical years as the weighted average (by percent of field area) of all fields in the aggregate following Equation 5.8. The distribution of $\boldsymbol{y\_norm_t}$ will have five data points. If a fallow year is present in the baseline period, ignore that year for the purpose of calculating leakage for that particular field. As an additional year of historic yield should have been reported, the field with a fallow year should still have five data points.

[42] McDonald et al. (2002), Russo et al. (2008).
[43] Available at http://quickstats.nass.usda.gov.

Equation 5.8. Normalized Yield for Each Year *t*

For single-field projects: $\boldsymbol{y\_norm_t} = \frac{Y_{f,t}}{Y_{county,t}}$			
For aggregate projects: $\boldsymbol{y\_norm_t} = \sum_f \left(A_f \times \frac{Y_{f,t}}{Y_{county,t}} \right) / \sum_f A_f$			
Where,			Units
y_norm_t	=	Normalized yield for each year *t*	fraction
$Y_{f,t}$	=	Yield of field *f* in year *t*	Mg/ha
$Y_{county,t}$	=	County average yield in year *t*	Mg/ha
A_f	=	Size of field *f*	ha
If aggregates span multiple counties, $Y_{county,t}$ must correspond with the county in which field *f* is located.			

2. Take the standard deviation, ***s***, and mean of the $\boldsymbol{y\_norm_t}$ distribution:

$$s = stdev(y\_norm_t)$$

$$\overline{y\_norm_t} = average(y\_norm_t)$$

3. Calculate the minimum yield threshold below which normalized yields are significantly smaller than the historical average. This shall be done as follows:

$$y_{min} = \overline{y_{norm_t}} - 2.132 \times s$$

Where 2.132 is the t-distribution value with 95 percent confidence for a one-tailed test with four degrees of freedom (i.e. n is 5),[44] and ***s*** is the standard deviation of the $\boldsymbol{y\_norm_t}$ distribution, as calculated in Step 2.

4. For the present cultivation cycle, normalize the yield of each field by the county average for the growing season for the year, and, if the project is an aggregate, calculate the weighted average for all fields in the aggregate to get $\boldsymbol{y\_norm_{t0}}$ using Equation 5.8 above and replacing ***t*** with $\boldsymbol{t_0}$, i.e. the year of the present reporting period.

5. For every year of the crediting period, calculate $\boldsymbol{y\_norm_{t0}}$ and compare this value to ***y_min***. If $\boldsymbol{y\_norm_{t0}}$ is smaller than ***y_min***, it must be assumed that emissions increased outside of the project area. The aggregate must account for increased emissions as specified in Equation 5.9 below. Alternatively, if $\boldsymbol{y\_norm_{t0}}$ is larger than ***y_min*** then no emissions associated with shifts in production are assumed to occur and therefore do not need to be calculated.

[44] The t-distribution value of 2.132 = t(0.05, n – 1), where n is 5, and n-1 degrees of freedom is 4. There should always be five data points when performing this calculation in the RCPP as there shall always be 5 years of rice yield data for a given field.

Equation 5.9. GHG Emissions Outside the Project Boundary

$$SE_{PS} = \left(1 - \frac{y\_norm_{t_0}}{y\_min}\right) \times \frac{\sum_i \left(N_2O_{B,i} + CH_{4_{B,i}} - \Delta SOC_{B,i}\right)}{1000}$$

Where,

			Units
SE_{PS}	=	Total secondary effect GHG emissions for the project aggregate from production shifting outside of the project boundary	tCO_2e
y_norm_{t0}	=	Sum of yields for the current cultivation cycle normalized to the county averages	fraction
y_min	=	Minimum yield threshold below which normalized yields are significantly smaller than the historical average	fraction
$N_2O_{B,i}$	=	Baseline cultivation cycle direct and indirect N_2O emissions from rice field *i*, equal to the average of the values of all Monte Carlo runs *j*	kg CO_2e/ha
$CH_{4\ B,i}$	=	Baseline cultivation cycle CH_4 emissions from rice field *i*, equal to the average of the values for all Monte Carlo runs *j*	kg CO_2e/ha
$\Delta SOC_{B,i}$	=	Change in SOC content of rice field *i* during the baseline cultivation cycle, as calculated in Equation 5.10 below	kg CO_2e/ha
1000	=	kg per tonne	kg CO_2/tCO_2

Note: Guidance on how to calculate $N_2O_{B,I,}$ and $CH_{4\ B,I}$ values is provided in Appendix B, Step 4.2, and guidance on how to calculate the $\Delta SOC_{B,I}$ value is provided below.

5.5.3.1 Accounting for Change in Soil Organic Carbon

Unlike N_2O and CH_4 emissions, the baseline SOC value cannot be used as an input in Equation 5.9 as it does not itself represent emissions. Rather, the change in SOC over a given baseline cultivation cycle ($\Delta SOC_{B,i}$) must be calculated using Equation 5.10 below.

In order to calculate $\Delta SOC_{B,i}$, the project developer must calculate the change in SOC that occurred over the relevant baseline cultivation cycle. The project developer must extract the SOC value corresponding to the first Julian day of the baseline cultivation cycle from the first baseline year being modeled and the last Julian day of the baseline cultivation cycle from the second baseline year being modeled.[45] Per Equation 5.10, the project developer must then subtract the SOC value on the first day of the cultivation cycle from the SOC value on the last day of the cultivation cycle. The results must then be converted into CO_2e. This process must be repeated for the 2,000 Monte Carlo runs, and then averaged to determine the appropriate $\Delta SOC_{B,i}$ value to be used in Equation 5.9.

[45] See Section 5.3 for detailed guidance on using two calendar years of modeling for a single cultivation cycle.

Equation 5.10. Change in Soil Organic Carbon in the Baseline Cultivation Cycle

$$\Delta SOC_{B,i} = \frac{\sum_{j=1}^{2000} SOC_{LDBcc} - SOC_{FDBcc}}{2000} \times \frac{44}{12}$$

Where, Units

$\Delta SOC_{B,i}$	=	Change in SOC content of rice field *i* during the baseline cultivation cycle	kg CO_2e/ha
SOC_{LDBcc}	=	SOC stock value on the last day of the baseline cultivation cycle (i.e. the day harvest is complete)	kg C/ha
SOC_{FDBcc}	=	SOC stock value on the first day of the baseline cultivation cycle (i.e. the day after the previous year's harvest is complete)	kg C/ha
44/12	=	Unit conversion of C to CO_2e	

5.5.4 Step 7: Calculate Total Secondary Emissions from Project Activity

Once all of the sources of relevant secondary emissions have been accounted for, the project developer shall calculate total secondary emissions using Equation 5.11 below. The total secondary effect emissions calculated in Equation 5.11 are then input into Equation 5.1 (in Section 5.4) to calculate the total emission reductions for the project.

Equation 5.11. Total Secondary Effect Emissions from Project Activity

$$SE = \sum_{i} (SE_{FF,i} + SE_{RM,i}) + SE_{PS}$$

Where, Units

SE	=	Total secondary effect emissions	tCO_2e
$SE_{FF,i}$	=	Total secondary effect GHG emissions from increased fossil fuel combustion for field *i*, as calculated in Section 5.5.1 (Step 4)	tCO_2e
$SE_{RM,i}$	=	Total secondary effect GHG emissions from alternative residue management for field *i*, as calculated in Section 5.5.2 (Step 5)	tCO_2e
SE_{PS}	=	Total secondary effect GHG emissions for each project from production shifting outside of the project boundary, as calculated in Section 5.5.3 (Step 6)	tCO_2e

6 Project Monitoring

The Reserve requires that Monitoring Plans and Reports be established for all monitoring and reporting activities associated with the project. Under this protocol, two distinct types of Monitoring Plans and Reports must be developed: aggregate level and field level.

A field serial number must appear in the file name of all monitoring records for each distinct field and kept in accordance with this protocol (see Section 7.1.1 for details on how to create field serial numbers).

6.1 Single-Field Monitoring Plan

The Single-Field Monitoring Plan (SFMP) will serve as the basis for verification bodies to confirm that the monitoring and reporting requirements in this section and Section 7 are met for single-field projects, and that consistent, rigorous monitoring and record keeping is ongoing at the project field. The SFMP must be developed and maintained by the project developer. The SFMP must outline procedures on how all of the data included in the Single-Field Report, particularly the parameters in Table 6.1 and Table 6.2, will be collected, recorded, and managed, as specified below and in Section 7.2.1 (see Section 7.3.1 for minimum record keeping requirements). It is the responsibility of the project developer to ensure that the SFMP meets all requirements specified and is kept on file and up-to-date for verification.

The SFMP will outline the following procedures:

- How the GIS shape file and/or KML file will be created
- How the crediting period, verification schedule, and quantification results will be tracked for each field included in the project aggregate
- How to ensure that the project developer holds title to the GHG emission reductions as required in Section 2.3
- Procedures that the project developer will follow to ascertain and demonstrate that the project field at all times passes the Legal Requirement Test and Regulatory Compliance (Section 3.5.2 and 3.6 respectively)
- A plan for detailed record keeping and maintenance that meet the requirements for minimum record keeping in Section 7.3.1
- The frequency of data acquisition
- The frequency of sampling activities
- The role of individuals performing each specific activity, particularly monitoring and sampling
- QA/QC provisions to ensure that data acquisition is carried out consistently and with precision

6.2 Aggregate Monitoring Plan

The Aggregate Monitoring Plan (AMP) will serve as the basis for verifiers to confirm that the project aggregate tracking requirements have been and will continue to be met for each reporting period. The AMP must be developed and maintained by the aggregator. The AMP must outline procedures on how all of the data included in the Aggregate Report will be collected and managed, as specified below and in Section 7.2.2 (see Section 7.3.2 for minimum record keeping requirements).

The AMP will outline the following procedures:

- How the GIS shape file and/or KML file will be created for each field
- How the crediting period, verification schedule, and quantification results will be tracked for each field included in the project aggregate
- How to ensure that the title to the GHG emission reductions has been conferred to the aggregator as required in Section 2.3 for each field in the aggregate
- Procedures that the aggregator will follow to ascertain and demonstrate that all fields in the project aggregate at all times pass the Legal Requirement Test and Regulatory Compliance (Section 3.5.2 and 3.6 respectively)
- A plan for detailed record keeping and maintenance that meet the requirements for minimum record keeping in Section 7.3.2
- The role of individuals performing each specific activity
- QA/QC provisions to ensure that data collected from the field level, according to data acquisition requirements outlined in the Field Monitoring Plan (FMP) described below, is carried out consistently and with precision at the aggregate level

6.3 Field Monitoring Plan for Project Participants in an Aggregate

The Field Monitoring Plan (FMP) will serve as the basis for verifiers to confirm that the monitoring and reporting requirements in Sections 6 and 7 are met at each field in a project aggregate, and that consistent, rigorous monitoring and record keeping is ongoing at each field. The FMP must cover all aspects of monitoring and reporting contained in this protocol and must specify how data for all relevant parameters in Table 6.1 and Table 6.2 are collected and recorded at each field.

One FMP must be developed for each project participant. If a project participant has multiple fields enrolled in the aggregate, only one FMP is required as long as it addresses the monitoring requirements at each field. The FMP can be developed by the project participant or the aggregator, depending on the arrangement specified in contractual agreements. It is the responsibility of the aggregator to ensure that the FMP meets all requirements specified, and is kept on file and up-to-date for verification.

At a minimum the FMP shall stipulate:

- The frequency of data acquisition
- The frequency of sampling activities
- The role of individuals performing each specific monitoring and sampling activity
- A record keeping plan (see Section 7.3.2.2 for minimum record keeping requirements)
- QA/QC provisions to ensure that data acquisition is carried out consistently and with precision

6.4 Field Data

All fields, whether enrolled in a project aggregate or participating as a single-field project, must monitor the necessary DNDC input data and field management data as specified below. All field-level data and information specified in Sections 6.4.1, 6.4.2, 6.4.3, and 6.4.4 must be collected and retained for verification purposes.

6.4.1 General Field Tracking Data

- Either a GIS shape file or a KML file clearly defining the field boundary (or boundaries), as defined in Section 2.2.1, of each distinct field that is part of the project (Note: project developers may wish to provide verifiers with additional GIS shape files with underlying information about how fields were stratified, e.g. further delineate where management activities are homogenous, how field boundaries map to legal parcels, etc.).
- The coordinates of the most north-westerly point of the field, reported in degrees to four decimal places[46] (to be used for creating field serial numbers)
- The serial number of the field, constructed as specified in Section 7.1.1
- The start date of the field
- Disclosure of any material and immaterial regulatory violations, with copies of all Notices of Violations (NOVs) included in the report
- A list of the project activities implemented on the field during the cultivation cycle
- Field rice yield during the relevant project cultivation cycle and all five baseline cultivation cycles

6.4.2 Field Management Data

The following management data must be collected and retained at each field for each cultivation cycle during the reporting period:

- Planting preparation description and date
- Planting date and method
- Fertilization types, amounts (used in both the baseline scenario cultivation cycle and the project scenario cultivation cycle, and application dates[47]
- Flooding[48] and drainage[49] dates (during the growing season and during post-harvest period)
- Begin and end date of harvesting on the field
- Post-harvesting residue management (e.g. burning, incorporation or baling) description and dates
- Amount of herbicides applied for the baseline scenario cultivation cycle and the project scenario cultivation cycle[50]
- All DNDC input files and output files in *.csv file format
- A summary of all data inputs where permissible deviations from using DNDC or default parameters sourced from UC Davis[51] has occurred (i.e. using field data in place of DNDC defaults for calibration purposes), a justification for any such deviation and appropriate supporting evidentiary material

[46] Longitude reported in degrees to four decimal places provides a spatial resolution of about 11 meters, the resolution of the latitude is slightly less than that.
[47] Amounts of fertilizer used in the baseline scenario cultivation cycle do not need to be verified.
[48] For each field, the flood date shall be equal to the date that the first ‘check’ began filling.
[49] For each field, the drainage date shall be equal to the date that the last ‘check’ began draining.
[50] Amounts of herbicide used in the baseline scenario cultivation cycle do not need to be verified.
[51] This information can be sourced directly from UC Davis. See http://ucanr.edu/sites/UCRiceProject/.

6.4.3 Project Activity Data and Documentation

To corroborate field management assertions, each field must collect and retain the following documentation.

Dry Seeding with Delayed Flood:

- Seeding equipment purchase or rental records, and/or seeding service contracts/agreements/receipts
- At least four time-stamped digital photographs per field ‘check’ taken from various vantage points no more than 15 days after seeding. The pictures must clearly show an establishing stand with no standing water present
- At least four time-stamped digital photographs per field ‘check’ taken from various vantage points during flood-up. The pictures must clearly show the established stand

Rice Straw Baling:

- Baling equipment purchase or rental records, and/or baling service agreements/receipts
- At least four time-stamped digital photographs per field ‘check’ taken from various vantage points during the swathing, raking, and baling process. Pictures must clearly show the baled hay post-baling
- Log of baling process, recorded at the time of baling, including:
    - Date(s) that each stage of the swathing, raking, and baling process commenced and ended
    - Number of acres baled
    - Quantity of rice straw removed
    - Quantity of rice straw left unused in piles at or near the field
    - List of equipment used
    - Height of the cutting bar used
    - Name of third-party baling service provider (if applicable)
- End-use of rice straw (if using an end-use specific emission factor). All sales contracts or receipts for the rice straw must be retained for verification purposes

6.4.4 Field Monitoring Parameters

Prescribed monitoring parameters, including those specific to DNDC as well as additional parameters necessary to calculate baseline and project emissions, are provided below in Table 6.1 and Table 6.2, respectively. Field monitoring parameters and DNDC input parameters must be determined according to the data source and frequency specified in the tables. Note that verifiers will also need to verify that defaults provided by DNDC for additional parameters not listed in the tables have not been altered. Further guidance on all of the DNDC input parameters can be found in Appendix B, Step 1.1.

Table 6.1. DNDC Model Input Parameters

Parameter	Description	Data Unit	Calculated (c) Measured (m) Reference(r) Operating Records (o)	Measurement Frequency	Comment
Climate	GPS location of field	° decimal to four places	m	Once per project	
	Atmospheric background NH_3 concentration	μg N/m^3	r	Once per crediting period	Source: National Atmospheric Deposition Program data or data from UC Davis.
	Atmospheric background CO_2 concentration	ppm	r	Once per crediting period	Source: National Atmospheric Deposition Program data or data from UC Davis.
	Daily precipitation	cm	m	Daily	Source: Nearest CIMIS station
	Daily maximum temperature	°C	m	Daily	Source: Nearest CIMIS station
	Daily minimum temperature	°C	m	Daily	Source: Nearest CIMIS station
	N concentration in rainfall	mg N/l or ppm	r	Once per crediting period	Source: National Atmospheric Deposition Program data or data from UC Davis.
Soils**	Land-use type	type	m	Once per project	
	Clay content	0-1	m/r	Annual	Source: Measured or SSURGO
	Bulk density	g/cm^3	m/r	Annual	Source: Measured or SSURGO
	Soil pH	value	m/r	Annual	Source: Measured or SSURGO
	SOC at surface soil	kg C/kg	m/r	Annual	Source: Measured or SSURGO
	Soil texture	type	m/r	Annual	Source: Measured or SSURGO
Crop	Planting date	date	m	Annual	Famer records
	Harvest date	date	m	Annual	Famer records
	C/N ratio of the grain	ratio	m/r	Once per variety	Can use default *.dnd file values or defaults derived from UC Davis Jenkins Lab
	C/N ratio of the leaf + stem tissue	ratio	m/r	Once per variety	Can use default *.dnd file values or defaults derived from UC Davis Jenkins Lab
	C/N ratio of the root tissue	ratio	m/r	Once per variety	Can use default *.dnd file values or defaults derived from UC Davis Jenkins Lab
	Fraction of leaves + stem left in field after harvest	0-1	m	Annual	Farmer records
	Maximum yield	kg dry	m	Annual	Farmer records

Parameter	Description	Data Unit	Calculated (c) Measured (m) Reference(r) Operating Records (o)	Measurement Frequency	Comment
		matter/ha			
	Number of tillage events	number	o	Annual	Farmer records
	Date of tillage events	date	o	Annual	Farmer records
	Depth of tillage events	cm (select from 7 default depths) †	o	Annual	Farmer records
Tillage	Number of fertilizer applications	number	o	Annual	Farmer records
	Date of each fertilizer application	date	o	Annual	Farmer records
	Application method	surface / injection	o	Annual	Farmer records
Fertilization	Type of fertilizer	type*	o	Annual	Farmer records
	Fertilizer application rate	kg N/ha	o	Annual	Farmer records (field average if using variable rate applications)
	Number of organic applications per year	number	o	Annual	Farmer records
	Date of application	date	o	Annual	Farmer records
	Type of organic amendment	type	o	Annual	Farmer records
Manure amendment[52] (if used)	Application rate	kg C/ha	o	Annual	Farmer records
	Amendment C/N ratio	ratio	o	Annual	DNDC defaults or Farmer records
	Number of irrigation events	number	o	Annual	Farmer records
	Date of irrigation events		o	Annual	Farmer records
	Irrigation type	Must use the 'flood' default type	o	Annual	Farmer records
Irrigation	Irrigation application rate	mm	o	Annual	Farmer records
	Date of flood-up for growing season	date	o	Annual	Farmer records
	Date of drain for crop harvest	date	o	Annual	Farmer records
	Date of flood-up for winter flooding (if applicable)	date	o	Annual	Farmer records

[52] DNDC allows for data on any soil amendment to be input into the model, and provides default parameters (i.e. C/N ratio) for several types of soil amendments. See Appendix B Step 1.4 for further guidance.

Parameter	Description	Data Unit	Calculated (c) Measured (m) Reference(r) Operating Records (o)	Measurement Frequency	Comment
Flooding	Date of drain for winter flooding (if applicable)	date	o	Annual	Farmer records

† 0, 5, 10, 20, 30, 50 cm.
* DNDC accepts seven types of fertilizers: Urea, Anhydrous Ammonia, Ammonium Nitrate, Nitrate, Ammonium Bicarbonate, Ammonium Sulfate and Ammonium Phosphate.
‡ Flood, sprinkler or surface drip tape.
** Soil parameters for DNDC are for the properties of the top layer of the soil profile. If look up values from the NRCS SSURGO database are not used, then data taken from field samples is required.

Table 6.2. Field Monitoring Parameters

Equation Reference	Parameter	Description	Data Unit	Calculated (c) Measured (m) Reference(r) Operating Records (o)	Measurement Frequency	Comment
Equation 5.1	ER	Total emission reductions from the project area for the reporting period	tCO_2e	c,m	Cultivation cycle	
Equation 5.1 Equation 5.3 Equation 5.4	PER	Total primary GHG emission reductions	tCO_2e	c,m	Cultivation cycle	
Equation 5.1 Equation 5.11	SE	Total secondary effect GHG emission reductions	tCO_2e	c,m	Cultivation cycle	
Equation 5.2 Equation 5.3	N_2O_i	Average cultivation cycle direct and indirect N_2O emissions from rice field *i*, equal to the average of the values of all Monte Carlo runs *j*	kg CO_2e/ha	c	Cultivation cycle	Note: In Equation 5.3 this parameter contains additional subscript denoting whether it pertains to the baseline or project scenario cultivation cycles.

Equation Reference	Parameter	Description	Data Unit	Calculated (c) Measured (m) Reference(r) Operating Records (o)	Measurement Frequency	Comment
Equation 5.2 Equation 5.3	$CH_{4\ i}$	Average cultivation cycle CH_4 emissions from rice field *i*, equal to the average of the values for all Monte Carlo runs *j*	kg CO_2e/ha	c	Cultivation cycle	Note: In Equation 5.3 this parameter contains additional subscript denoting whether it pertains to the baseline or project scenario cultivation cycles.
Equation 5.2 Equation 5.3	$SOC_{LDcc,i}$	Average cultivation cycle final soil organic carbon content of rice field *i* on the last day of either the baseline or project scenario cultivation cycle, equal to the average of the values for all Monte Carlo runs *j*	kg CO_2e/ha	c	Cultivation cycle	Note: In Equation 5.3 this parameter contains additional subscript denoting whether it pertains to the baseline or project scenario cultivation cycles.
Equation 5.2	$N_2O_{Dir,j,i}$	N_2O emissions from rice field *i* from Monte Carlo run *j*	kg N_2O-N/ha	c	Cultivation cycle	
Equation 5.2	$N_{Leach,j,i}$	Nitrate leaching loss from rice field *i* from Monte Carlo run *j*	kg NO_3-N/ha	c	Cultivation cycle	
Equation 5.2	$N_{Vol,j,i}$	Ammonia volatilization and nitric oxide emissions from rice field *i* from Monte Carlo run *j*	kg NH_3-N + kg NO_x-N /ha volatized	c	Cultivation cycle	
Equation 5.3	$Area_i$	Area of the rice field *i*	ha	m	Cultivation cycle	
Equation 5.4	PERud	Total primary GHG emission reductions from the entire project, corrected for uncertainty deductions	tCO_2e	c,m	Cultivation cycle	
Equation 5.4	μ_{struct}	Accuracy deduction from model structural uncertainty		r	Cultivation cycle	Values will be made available on Reserve website
Equation 5.4	$\mu_{inputs,i}$	Accuracy deduction factor for individual rice field *i* due to input uncertainties	fraction	c	Cultivation cycle	As calculated in Appendix B Step 5.1

Equation Reference	Parameter	Description	Data Unit	Calculated (c) Measured (m) Reference(r) Operating Records (o)	Measurement Frequency	Comment
Equation 5.5 Equation 5.11	$SE_{FF,i}$	Total secondary effect GHG emissions from increased fossil fuel combustion for field *i*	tCO_2e	c	Cultivation cycle	As calculated in Section 5.5
Equation 5.5	$EF_{HP\text{-}hr,i,f}$	Emission factors for fossil fuel emissions	g CO_2e/HP-hr	r	Cultivation cycle	
Equation 5.5	$HP_{i,f}$	Horsepower requirement for machinery operated *i* on field *f*	HP	r	Cultivation cycle	
Equation 5.5	$t_{i,f}$	Time required to perform operation *i* on field *f*	hr/field	m	Cultivation cycle	Note: Additional subscript is used to denote whether the parameter is used in the baseline or project scenario. In the baseline scenario, *j* is replaced by the letter *k*.
Equation 5.5 Equation 5.8	A_f	Size of field	ha	m	Cultivation cycle	
Equation 5.6	FF_j	Total change in fossil fuel consumption for field *f*, by fuel type *j*	gallons	m	Cultivation cycle	
Equation 5.7	$W_{RS,i}$	Total weight of rice straw in dry tonnes that is swathed, raked, and baled on the field *i*	dry tonne	m	Cultivation cycle	
Equation 5.7	EF_{SRB}	Emission factor for increased fossil fuel emissions from swathing, raking, and baling	tCO_2e / dry tonne	r	Cultivation cycle	
Equation 5.7	$W_{RS,U}$	Weight of rice straw in dry tonnes with end-use *U*. The sum weight of rice straw for all end-uses must equal the total weight of rice straw baled on the field	dry tonne	m	Cultivation cycle	
Equation 5.7 Table A.1	EF_U	Emission factor for end-use *U*	tCO_2e / dry tonne	r	Cultivation cycle	From Table A.1 in Appendix A

Equation Reference	Parameter	Description	Data Unit	Calculated (c) Measured (m) Reference(r) Operating Records (o)	Measurement Frequency	Comment
Equation 5.8	$Y_{f,t}$	Yield of field *f* in year *t*	Mg/ha	m	Cultivation cycle	
Equation 5.8	$Y_{county,t}$	County average yield in year *t*	Mg/ha	c	Cultivation cycle	
Equation 5.8 Equation 5.9	y_norm_t	Normalized yield for each year *t*	fraction	c	Cultivation cycle	
Equation 5.9	y_min	Minimum yield threshold below which normalized yields are significantly smaller than the historical average	fraction	c	Cultivation cycle	
Equation 5.9 Equation 5.10	$\Delta SOC_{B,i}$	Change in soil organic carbon content of rice field i during the baseline cultivation cycle	kg CO_2e/ha	c	Cultivation cycle	
Equation 5.10	SOC_{LDBcc}	Soil organic carbon stock value on the last day of the baseline cultivation cycle (i.e. the day harvest is complete)	kgC/ha	c	Cultivation cycle	
Equation 5.10	SOC_{FDBcc}	Soil organic carbon stock value on the first day of the baseline cultivation cycle (i.e. the day after the previous year's harvest is complete)	kgC/ha	c	Cultivation cycle	
Equation 5.11	$SE_{RM,i}$	Total secondary effect GHG emissions from alternative residue management for field *i*	tCO_2e	c	Cultivation cycle	As calculated in Section 5.5
Equation 5.11	SE_{PS}	Total secondary effect GHG emissions for the project aggregate from production shifting outside of the project boundary	tCO_2e	c	Cultivation cycle	As calculated in Section 5.5

7 Reporting and Record Keeping

This section provides requirements and guidance on reporting rules and procedures. A priority of the Reserve is to facilitate consistent and transparent information disclosure among project developers.

A field serial number must appear in the file name of all monitoring records for each distinct field and kept in accordance with this protocol (see Section 7.1.1 for details on how to create field serial numbers).

7.1 Project Submittal Documentation

For each rice cultivation project, project developers/aggregators must provide the following documentation to the Reserve in order to submit an RC project for listing on the Reserve.

- Project Submittal form
- Project Submittal *.csv file

The Project Submittal form is the same for both single-field projects and aggregates. Both single-field and aggregate projects are also required to submit a Project Submittal *.csv file, which shall include the initial "List of Enrolled Fields"; each field's serial number (according to Section 7.1.1 below), county and state; and the names of project participants for each field. In the case of a single-field project, the List of Enrolled Fields shall include only the single field. The List of Enrolled fields for aggregate projects shall include all fields enrolled in the aggregate at the time of submittal. Aggregate projects are required to update the List of Enrolled Fields prior to commencement of verification activities (i.e. prior to submission of the NOVA/COI), to include all fields actually enrolled in the aggregate at that point (e.g. if fields have been added or removed from the aggregate between submittal and contracting a verifier [53]). The list must also be updated prior to each subsequent verification.

Project submittal forms can be found at http://www.climateactionreserve.org/how/program/documents/.

7.1.1 Determining Field Serial Numbers

The field serial number, which must be included in the List of Enrolled Fields, shall be determined by the following algorithm, with each element separated by a dash (-):

First state postal abbreviation, followed by the first letter of the County, followed by degrees of the most north-western point of the field (latitude then longitude, both reported to four decimal places), followed by the acreage of the field.[54] (Example: CA-*B-39.6123-121.5332-76* would be a 76 acre field in Butte County, CA.)

7.2 Annual Reports and Documentation

Once a project has been listed, project developers must provide the following documentation to the Reserve in order to register an RC project. This documentation must be submitted to the

[53] See the Reserve Verification Program Manual at http://www.climateactionreserve.org/how/program/program-manual/.

[54] Because all fields are located in the United States, the latitude will always be positive (i.e. degrees north of the equator), and longitude will always be negative (i.e. degrees west of the Prime Meridian). Therefore, in the example serial number, the field in Butte County California is at *+39.6123º latitude, and -121.5332º longitude.*

Reserve within 12 months of the end of each reporting period in order for the Reserve to issue CRTs for quantified GHG reductions.

The following documentation is required of both single-field projects and aggregates:

- Signed Attestation of Regulatory Compliance form
- Signed Attestation of Voluntary Implementation form (initial verification only for single-field projects; aggregates, see guidance in Section 3.6)
- Signed Attestation of Title form or Aggregator Attestation of Title form[55]
- Annual reports (as outlined in Sections 7.2.1 and 7.2.2)
- Verification Report
- Verification Statement

With the exception of the annual reports, all of the above project documentation will be available to the public via the Reserve's online registry. Further disclosure (e.g. of the annual reports) and other documentation may be made available on a voluntary basis through the Reserve, at the request of the project developer.

In the event that a project participant transfers from one aggregate to a different aggregate, the new aggregator is responsible for submitting a Field Management Transfer form, which requires the project participant's signature, to the Reserve prior to the beginning of the subsequent reporting period. The new aggregator should also make sure to obtain and have on file all necessary documentation for the new field, as required by this protocol.

Project forms can be found at http://www.climateactionreserve.org/how/program/documents/.

7.2.1 Single-Field Report

For each cultivation cycle, project developers of single-field projects must include the following information in an annual report submitted to the Reserve as a *.csv file:

- The field serial number (see Section 7.1.1)
- The acreage of the field (acres)
- Start date of the field
- Whether the field had previously been enrolled in an aggregate
    - If so, include the name of the project aggregate and dates of enrollment
- The field's emission reduction calculation results for the current verified cultivation cycle (both corrected and uncorrected for model uncertainty)

7.2.2 Aggregate Report

For each cultivation cycle, all aggregate-level monitoring information must be included in an annual Aggregate Report that is submitted to the Reserve as a *.csv file, with accompanying documentation, at verification. The Aggregate Report must contain a list of all fields and the following information for each field:

- The field serial number (see Section 7.1.1)
- The acreage of the field (acres)

[55] Although the single-field project will submit the general Attestation of Title form, aggregators will be required to submit an Aggregator Attestation of Title form, which will include language attesting to the fact that the aggregator has not and will not knowingly allow a third party (e.g. project participant) to provide false, fraudulent, or misleading data or statements.

- Start date of the field
- Date field enrolled in the aggregate
  - Including a flag specifying whether the field is a new addition to the aggregate in the particular year
- Current status of field (active, terminated, transferred to a different aggregate) as well as a description of any notable changes in management control and/or management practices
- Name of project participant associated with the field
- A flag for which fields had site visit or desktop verifications, or were unverified, in the previous reporting period
- The emission reduction calculation results for each field (both uncorrected and corrected for uncertainty) for that calculation period
- The total verified emission reductions for the aggregate (corrected for model structural uncertainty and any deductions due to errors or misrepresentations at the verified fields)

7.2.3 Field Report

For each cultivation cycle, all fields within an aggregate must submit an annual Field Report to the aggregator. This report is not submitted to the Reserve. Although the Reserve encourages participants to submit a Field Report in the form of a *.csv file, the format of the report is at the discretion of the aggregator.

At a minimum, the Field Report is required to include the following:

- A signed statement by the project participant attesting to the fact that all statements and data contained therein are true and accurate
- Field management data (as specified in Section 6.4.2)
- Project activity data (as specified in Section 6.4.3)

7.3 Record Keeping

For purposes of independent verification and historical documentation, project developers are required to keep all information outlined in this protocol for a period of 10 years after the information is generated or seven years after the last verification. This information will not be publicly available, but may be requested by the verifier or the Reserve.

7.3.1 Record Keeping for Single-Field Projects

The project developer shall retain the following records and documentation, as well as documentation to substantiate the information in the annual Single-Field Report and all field-level data and calculations. These records include:

- Contractual arrangements with each project participant and/or land owner (if applicable)
- Copies of letters of notification sent to land owners, including the dates letters were sent
- GIS or KML shape files clearly defining the field boundary, as defined in Section 2.2.1
- Northwestern latitude/longitude coordinates of field (to four decimal places)
- Serial number of field (according to the guidance in Section 7.1.1)
- Data inputs for the calculation of the project emission reductions, including all required sampled data and all DNDC input files (*.dnd files)
- Copies of all DNDC output files (*dnd files)
- Copies of air, water, and land use permits relevant to project activities; Notices of Violations (NOVs) relevant to project activities; and any administrative or legal consent orders relevant to project

- Executed Attestation of Title, Attestation of Regulatory Compliance, and Attestation of Voluntary Implementation forms
- Field management data (as specified in Section 6.4.2)
- Onsite fossil fuel use records
- Fertilizer purchase records
- Project activity data (as specified in Section 6.4.3), including:
    - All time-stamped digital photographs of the seeding, flooding, and baling activities
    - Rice baling logs
    - Rice straw sales receipts or contracts (if applicable)
    - All maintenance records relevant to the farm equipment and monitoring equipment
- Rice sales/milling records
- Copies of soil laboratory statements and the Soil Sampling Log (Appendix B, Step 1.4) for any sampled soil parameters
- Results of CO_2e annual reduction calculations
- Initial and annual verification records and results

7.3.2 Record Keeping for Project Aggregates

7.3.2.1 Aggregate-Level Record Keeping

The aggregator shall retain the following records and documentation, as well as documentation required by Section 6 to substantiate the information in the annual Aggregate Report. System information must be retained for each field, but collected and managed at the aggregate level. These records include all:

- Contractual arrangements with each project participant and/or land owner
- Copies of letters of notification sent to land owners, including the dates letters were sent
- GIS or KML shape files clearly defining the field boundaries, as defined in Section 2.2.1, of each distinct field in the aggregate
- Northwestern latitude/longitude coordinates for each field (to four decimal places)
- Serial numbers for each field (according to the guidance in Section 7.1.1)
- Data inputs for the calculation of the project emission reductions, including all required sampled data and all DNDC input files (*.dnd files)
- Copies of all DNDC output files (*.dnd files)
- Copies of air, water, and land use permits relevant to project activities; Notices of Violations (NOVs) relevant to project activities; and any administrative or legal consent orders relevant to project activities
- Executed Aggregator Attestation of Title, Attestation of Regulatory Compliance, and Attestation of Voluntary Implementation forms
- Results of CO_2e annual reduction calculations
- Initial and annual verification records and results

7.3.2.2 Field-Level Record Keeping

The project developer/aggregator shall retain the following records and documentation, as well as documentation required in Section 6.4 for each field.

- Field management data (as specified in Section 6.4.2)
- Onsite fossil fuel use records
- Fertilizer purchase records

- Project activity data (as specified in Section 6.4.3), including:
  - All time-stamped digital photographs of the seeding, flooding, and baling activities
  - Rice baling logs
  - Rice straw sales receipts or contracts (if applicable)
  - All maintenance records relevant to the farm equipment and monitoring equipment
- Rice sales/milling records
- Copies of soil laboratory statements and the Soil Sampling Log (Appendix B, Step 1.4) for any sampled soil parameters

7.4 Reporting Period and Verification Cycle

Though the requirements for reporting periods vary slightly between single field projects and aggregates, reporting periods generally correspond to a single year-long cultivation cycle. Aggregate projects undergo verification annually, while single field projects may choose from multiple flexible options for the verification cycle upon completing the first verification as detailed below.

Project developers/aggregators must report GHG reductions resulting from project activities for all fields during each reporting period, which represents a complete cultivation cycle. A complete cultivation cycle may be slightly greater or less than 365 days for each field depending on planting/harvest dates.

The reporting period must be uniformly defined for the aggregate. Thus, for reporting purposes, the aggregate reporting period shall always be defined as starting on October 1 and ending on September 30 of the next year. Each field must quantify their emission reductions for its entire cultivation cycle, and the aggregate reductions must be reported on the uniform reporting period. For project aggregates, no more than one reporting period can be verified at once.

Both reporting periods and cultivation cycles must be contiguous; there can be no time gaps in reporting during the crediting period of an aggregate or single field project once the initial reporting period has commenced.[56] Because a single reporting period spans two calendar years (from fall of one year to late summer/fall of the next year), a single "vintage" must be assigned for reporting purposes. The calendar year in which the rice crop is harvested is used as the vintage year for the reporting cycle. For instance, all GHG reductions from a cycle beginning in fall 2012 and ending with harvest in late summer 2013 shall be assigned a 2013 vintage.

7.4.1 Additional Reporting and Verification Options for Single-Field Projects

For single-field projects, however, there are three verification options to choose from, which provide the project developer more flexibility and help manage verification costs associated with RC projects. The project developer may choose from these additional options after a project has completed its initial verification and registration.

A project developer may choose to use one option for the duration of a project's crediting period. Regardless of the option selected, reporting periods must be contiguous; there may be no time gaps in reporting during the crediting period of a project once the initial reporting period has commenced.

[56] An entire aggregate can willingly forfeit CRTs for an entire cultivation cycle in accordance with the zero-credit reporting period policy in section 3.3.3 of the Reserve Program Manual, available at http://www.climateactionreserve.org/how/program/program-manual/.

If a single-field project joins a project aggregate, that field is immediately subject to the verification schedule of the aggregate moving forward.

If a field exits a project aggregate to become a single-field project, that project is subject to the reporting and verification requirements of an initial reporting and verification period. In other words, that single-field project's first verification as a single-field project may not take advantage of Options 2 or 3, below.

7.4.1.1 Initial Reporting and Verification Period

The reporting period for projects undergoing their initial verification and registration cannot exceed one complete cultivation cycle. Once a project is registered and has had at least one complete cultivation cycle of emission reductions verified, the project developer may choose one of the verification options below.

7.4.1.2 Option 1: Twelve-Month Maximum Verification Period

Under this option, the verification period may not exceed one complete cultivation cycle, which may be slightly greater or less than 365 days. Verification with a site visit is required for CRT issuance.

7.4.1.3 Option 2: Twelve-Month Verification Period with Desktop Verification

Under this option, the verification period cannot exceed one complete cultivation cycle. However, CRTs may be issued upon successful completion of a desktop verification as long as: (1) Site visit verifications occur at two-year intervals; and (2) The verification body has confirmed that there have been no significant changes in selected project activities, field management or ownership and/or management control of the field since the previous site visit. Desktop verifications must cover all other required verification activities (i.e. a full desktop verification of the Single-Field Report).

Desktop verifications are allowed only for a single 12-month verification period in between 12-month verification periods that are verified by a site visit.

7.4.1.4 Option 3: Twenty-Four Month Maximum Verification Period

Under this option, the verification period cannot exceed two complete cultivation cycles (approximately 730 days or 24 months) and the project monitoring plan and Single-Field Report must be submitted to the Reserve for the interim cultivation cycle's reporting period. The project monitoring plan and report must be submitted for projects that choose Option 3 in order to meet the annual documentation requirement of the Reserve program. They are meant to provide the Reserve with information and documentation on project operations and performance. They also demonstrate how the project monitoring plan was met over the course of the first half of the verification period. They are submitted via the Reserve online registry, but are not publicly available documents. The monitoring plan and report shall be submitted within 30 days of the end of the reporting period.

Under this option, CRTs may be issued upon successful completion of a site visit verification for GHG reductions achieved over a maximum of 24 months. CRTs will not be issued based on the Reserve's review of project monitoring plans or reports. Project developers may choose to have a verification period shorter than 24 months.

8 Verification Guidance

This section provides verification bodies with guidance on verifying GHG emission reductions associated with the project activity. This verification guidance supplements the Reserve's Verification Program Manual and describes verification activities specifically related to RC projects.

Verification bodies trained to verify RC projects must be familiar with the following documents:

- Climate Action Reserve Program Manual
- Climate Action Reserve Verification Program Manual
- Climate Action Reserve Rice Cultivation Project Protocol

The Reserve Program Manual, Verification Program Manual, and project protocols are designed to be compatible with each other and are available on the Reserve's website at http://www.climateactionreserve.org.

Only ISO-accredited verification bodies with lead verifiers trained by the Reserve for this project type are eligible to verify RC project reports. Verification bodies approved under other project protocol types are not permitted to verify RC projects. Information about verification body accreditation and Reserve project verification training can be found on the Reserve website at http://www.climateactionreserve.org/how/verification/.

In addition, all verification bodies must have an accredited Professional Agronomist or Certified Crop Advisor on the verification team in order to verify RC projects.

8.1 Preparing for Verification

The project developer is responsible for coordinating all aspects of the verification process, coordinating with the verification body, project participants (in the case of a project aggregate), and the Reserve, and submitting all necessary documentation to the verification body and the Reserve.

The project developer is responsible for selecting a single verification body for the entire project or project aggregate for each reporting period. The same verification body may be used up to six consecutive years (the number of consecutive years allowed, according the Reserve Verification Program Manual[57]). Verification bodies must pass a conflict-of-interest review against the project developer, and in the case of project aggregates, all project participants and the aggregator. Consequently, the submitted List of Enrolled Fields must be updated by the aggregator prior to the conflict of interest review.

Each year, project developers of single-field projects must make the Single-Field Report, which is submitted to the Reserve annually, and the Single-Field Monitoring Plan available to the verification body. These documents must meet the requirements in Sections 6 and 7.

In project aggregates, each year, project participants must submit all field data to the aggregator according to the guidelines in Sections 6 and 7. Aggregators must make all Field Monitoring Plans, the Aggregate Monitoring Plan, DNDC output files and the Aggregate Report available to the verification body.

[57] Available at http://www.climateactionreserve.org/how/verification/verification-program-manual/.

In all cases, the above documentation should be made available to the verification body after the NOVA/COI process is complete.

Aggregators may assist project participants in preparing documents for verification and in facilitating the verification process. The scope of these services is determined by the specific contract between project participants and the aggregator. However, the ultimate responsibility for monitoring reports and verification compliance is assigned to the aggregator.

For project aggregates, a field is considered verified if it is in the pool of fields for which site visits or desktop verifications are conducted, even if not selected for either a site visit or desktop verification. As a preliminary step in preparing for verification, the aggregator may choose to exclude fields from the pool of fields that may be selected for verification activities. Aggregators must report to the verification body all instances of field exclusion. The excluded fields shall be removed from the acreage totals and from field numbers used to determine field eligibility and verification sampling methodologies (in Section 8.2) and are therefore not considered verified.

8.2 Verification Schedule for Single-Field Projects

Single-field projects are comprised of exactly one field, and as such, there is no sampling methodology to select the fields undergoing verification. The single-field project shall be verified according to the verification schedule outlined below.

This protocol provides project developers three verification options, Sections 8.2.1 to 8.2.3, for a single-field project after its initial verification and registration in order to provide flexibility and help manage verification costs associated with rice projects. For each option, verification bodies may need to confirm additional requirements specific to this protocol, and in some instances, utilize professional judgment on the appropriateness of the option selected.

The actual requirements for performing a site visit verification and desktop verification are the same. A desktop verification is equivalent to a full verification, without the requirement to visit the site. A verification body has the discretion to visit any site in any reporting period if the verification body determines that the risks for that field warrant a site visit.

8.2.1 Option 1: Twelve-Month Maximum Verification Period

Option 1 does not require verification bodies to confirm any additional requirements beyond what is specified in the protocol.

8.2.2 Option 2: Twelve-Month Verification Period with Desktop Verification

Option 2 requires verification bodies to review the documentation specified in Section 7.4.1.3 in order to determine if a desktop verification is appropriate. The verifier shall use their professional judgment to assess any changes that have occurred related to project data management systems, equipment or personnel and determine whether a site visit should be required as part of verification activities in order to provide a reasonable level of assurance on the project verification. The documentation shall be reviewed prior to the NOVA/COI renewal submitted to the Reserve, and the verification body shall provide a summary of its assessment and decision on the appropriateness of a desktop verification when submitting the NOVA/COI renewal. The Reserve reserves the right to review the documentation provided by the project developer and the decision made by the verification body on whether a desktop verification is appropriate.

8.2.3 Option 3: Twenty-Four Month Maximum Verification Period

Under Option 3 (see Section 7.4.1.4), verification bodies shall look to the project monitoring report submitted by the project developer to the Reserve for the interim 12-month reporting period as a resource to inform its planned verification activities. While verification bodies are not expected to provide a reasonable level of assurance on the accuracy of the monitoring report as part of verification, the verification body shall list a summary of discrepancies between the monitoring report and what was ultimately verified in the List of Findings.

8.3 Verification Sampling and Schedule for Project Aggregates

Guidelines for verification sampling of the aggregate and the aggregate's verification schedule are different for "small aggregates," "large single-participant aggregates," and "large multi-participant aggregates." This approach allows a consistent application of verification requirements across all aggregates regardless of size or number of participants.

In all cases, the verification schedule shall be established by the verification body using random sampling, according to the verification schedule and sampling methodologies outlined in Sections 8.3.1, 8.3.2, and 8.3.3. These sampling methodologies establish the minimum verification frequencies; the verification body may at any time add fields beyond the minimum number required for site visit and/or desktop verification and may use verifier judgment to determine the number of additional fields and method for selecting fields if a risk-based review indicates a high probability of non-compliance. The verification sampling requirements are mandatory regardless of the mix of entry dates represented by the group of fields in the project aggregate.

The initial site visit verification schedule for a given year shall be established after the completion of the NOVA/COI process and prior to the commencement of any verification activities. This is meant to allow for the aggregator and verification body to work together to develop a cost-effective and efficient site visit schedule. Specifically, once the sample fields designated for a site visit have been determined, the verification body shall document all fields selected for planned site visit verification and provide a list to the aggregator and the Reserve. The aggregator shall be responsible for informing project participants of their selection for a planned site visit. Following this notification, the aggregator shall supply the verification body with all the required documentation to demonstrate field-level conformance to the protocol. When a verification body determines that additional sampling is necessary, due to suspected non-compliance, however, a similar level of advance notice may not be possible.

Aggregators and project participants shall not be made aware, in advance, of which fields' data will be subject to desktop verification in a given year.

Regardless of the size of an aggregate, if the aggregate contains any fields that did not pass site visit verification the year before and wish to re-enter the aggregate, those fields must have a full verification with site visit for the subsequent reporting period. These fields must be site visited *in addition* to the verification sampling methodology and requirements outlined below in Sections 8.3.1, 8.3.2, and 8.3.3.

For the purposes of verification, a "small aggregate" is defined as an aggregate comprised of 10 or fewer fields, regardless of the number of project participants. Small aggregates will meet fixed site visit and desktop verification frequency requirements based on a verification schedule determined by the verifier, in compliance with Section 8.3.1 of this protocol.

A "large single-participant aggregate" is defined as an aggregate comprised of more than 10 fields all managed by one single project participant. For large single-participant aggregates, fields will be randomly selected for site visit and desktop verification, according to the sampling method in Section 8.3.2, which is based on a non-linear scale where the relative fraction of fields undergoing verification activities gets smaller as the aggregate size gets larger.

A "large multi-participant aggregate" is defined as an aggregate comprised of more than 10 fields and more than one project participant. For large multi-participant aggregates, participants and their fields will be randomly selected for site visit and desktop verification, according to the sampling method in Section 8.3.3, which is based on a non-linear scale where the relative fraction of participants undergoing verification activities gets smaller as the aggregate size, in terms of number of participants, gets larger.

In all cases, when determining the sample size for site visits and desktop verifications, the verification body shall round up to the nearest whole number.

The actual requirements for performing a site visit verification and desktop verification are the same. A desktop verification is equivalent to a full verification, without the requirement to visit the site. A verification body has the discretion to visit any site in any reporting period if the verification body determines that the risks for that field warrant a site visit. Any site visits initiated at the discretion of a verifier shall be in addition to the required site visit verification schedule.

8.3.1 Verification Schedule for Small Aggregates

8.3.1.1 Site Visit Verification Schedule for Small Aggregates

Each field in a small aggregate shall undergo initial site visit verification within the first two cultivation cycles for each crediting period. In the first year of the aggregate or in subsequent years when new fields enter the aggregate, a minimum of 30 percent of the newly enrolled fields shall complete the initial site visit verification in their first year of enrollment.

In addition, site visit verifications must be conducted on a schedule such that:

- Each field in the aggregate must successfully complete a minimum of two site visit verifications per crediting period (e.g. the initial site verification in addition to one more)
- A minimum of 20 percent of the fields in the aggregate shall be site verified in any given year, selected at random

8.3.1.2 Desktop Verification Schedule for Small Aggregates

In any given year, a number of desktop verifications of field data must be conducted, with the number inversely related to the number of fields undergoing a site visit that year. Specifically, the number of desktop verifications (**D**) shall equal 50 percent of the number of fields (**n**) in the aggregate that will not receive a site visit that year, rounding up in the case of an uneven number of fields. In other words,

$$\boldsymbol{D = \frac{(n - S)}{2}}$$

Where,

n	=	Number of fields in the aggregate
S	=	Number of site visits
D	=	Number of desktop verifications

Fields shall not be selected for a desktop verification in years that the field is undergoing a site visit. If a site visit is planned for a field randomly selected for a desktop verification, the verification body will continue randomly drawing additional fields until the total number selected for a desktop verification reaches the value of **D** per the equation above.

8.3.2 Verification Schedule for Large Single-Participant Aggregates

In contrast to small aggregates, it is possible that a field in a large aggregate is never verified, either via site visit or desktop verification, during its entire crediting period. Therefore, random sampling is a particularly important component of enforcement.

8.3.2.1 Sampling for Site Visit Verification for Large Single-Participant Aggregates

The verification body determines the number of enrolled fields that must be randomly selected for site visit verification in a given year. The required number of site visits (**S**) shall equal the square root of the total number of fields (**n**) enrolled in the large single-participant aggregate that year (i.e. $\boldsymbol{S} = \sqrt{\boldsymbol{n}}$ rounded up to the nearest whole number).

8.3.2.2 Sampling for Desktop Verification for Large Single-Participant Aggregates

In addition to site visit verifications, verification bodies shall randomly select a sample of fields to undergo a desktop verification (**D**) equal to two times the square root of the total number of fields in the aggregate.

Fields shall not be selected for a desktop verification in years that the field is undergoing a site visit. If a site visit is planned for a field randomly selected for a desktop verification, the verification body will continue randomly drawing additional fields until the total number selected for a desktop verification reaches the square root of the total number of fields in the aggregate.

8.3.3 Verification Schedule for Large Multi-Participant Aggregates

The random sampling methodology shall be applied first at the project participant level and then at the field level. A random sampling methodology will be applied for site visit and desktop verification selection. However, the verification body shall select fields for site visits first as described in Section 8.3.3.1 and desktop verifications second as described in Section 8.3.3.2.

In contrast to small aggregates, it is possible that a field in a large aggregate is never verified, either via site visit or desktop verification, during its entire crediting period. Therefore, random sampling is a particularly important component of the enforcement mechanism.

8.3.3.1 Sampling for Site Visit Verification for Large Multi-Participant Aggregates

The verification body shall determine the number of project participants that must be randomly selected for a site visit in a given year, as follows:

$$\boldsymbol{S} = \left(\mathbf{1} + \left(\frac{\boldsymbol{P}}{\mathbf{500}}\right)\right) \times \sqrt{\boldsymbol{P}}$$

Where,

S	=	Number of project participants that must receive site visits
P	=	Number of project participants in the aggregate

The verification body shall randomly select (**S**) project participants to receive site visits that year.

The verification body shall select which fields of the selected project participants will receive a site visit. For project participants with six enrolled fields or fewer, the verification body shall site visit at least 50 percent of the fields, selected at random. For project participants with more than six fields enrolled in the aggregate, the verification body shall site visit at least 33.3 percent of the fields, selected at random.

A minimum of the square root of the total number of fields in the aggregate must be site visited. If this number is not met after following Steps 1 to 3, then the verification body shall randomly select one additional project participant and the sample of fields, according to Step 2 and 3 above, and repeat this until the number of site visits meets this minimum requirement. Note that Step 3 must be completed in full and therefore could result in a greater number of fields selected for site visits than the minimum requirement.

8.3.3.2 Sampling for Desktop Verification for Large Multi-Participant Aggregates

In addition to site visit verifications, each year verification bodies shall also randomly select fields to undergo a desktop verification of their field data. Verification bodies shall randomly select a sample of fields to undergo a desktop verification equal to two times the square root of the total number of fields in the aggregate (rounded up to the next whole number).

Fields shall not be selected for a desk-audit in years that the field is undergoing a site visit. If a site visit is planned for a field randomly selected for a desktop verification, the verification body will continue randomly drawing additional fields until the total number selected for a desktop verification reaches the square root of the total number of fields in the aggregate.

8.4 Standard of Verification

The Reserve’s standard of verification for RC projects is the Rice Cultivation Project Protocol (this document) and the Reserve Program Manual and Verification Program Manual. To verify a RC project aggregate, verification bodies apply the guidance in the Verification Program Manual and this section of the protocol to the standards described in Sections 2 through 7 of this protocol. Sections 2 through 7 provide eligibility rules, methods to calculate emission reductions, performance monitoring instructions and requirements, and procedures for reporting project information to the Reserve.

8.5 Monitoring Plan

The Aggregate Monitoring Plan and Field Monitoring Plan serve as the basis for verification bodies to confirm that the monitoring and reporting requirements in Sections 6 and 7 have been met, and that consistent, rigorous monitoring and record keeping is ongoing by the aggregator and all enrolled fields. Verification bodies shall confirm that the Monitoring Plan covers all aspects of monitoring and reporting contained in this protocol and specifies how data for all relevant parameters in Table 6.1 and Table 6.2 are collected and recorded.

8.5.1 Annual Reports

The single-field project’s project developer must annually submit field data for single-field projects to the Reserve. The Single-Field Report will consist of a *.csv file and attachments, as described in Section 7.2.1. Verification bodies must review the Single-Field Report to confirm project information and data collected according to the SFMP.

The project aggregate must annually submit an Aggregate Report to the Reserve. The report will consist of a *.csv file and attachments, as described in Section 7.2.2. Verification bodies must review the Aggregate Report to confirm project information and data collected according to the AMP.

The verification body will need to review field data during desktop verifications of randomly selected fields in an aggregate. The field data must be made available to the verification body in order to confirm field-level information collected according to the FMP.

8.6 Verifying Eligibility at the Field Level

Verification bodies must affirm each project field's eligibility during site visit and/or desktop verifications according to the rules described in this protocol. Table 8.1 below outlines the eligibility criteria for each project field. This table does not present all criteria for determining eligibility comprehensively; verification bodies must also look to Section 3 and the verification items list in Table 8.2.

Table 8.1. Summary of Eligibility Criteria for a Rice Cultivation Project

Eligibility Rule	Eligibility Criteria	Frequency of Rule Application
Start Date	The first day of the cultivation cycle, which begins immediately after completion of a rice crop harvest, in which one or more of the approved project activities is adopted at the field. Projects must be submitted for listing before the end of the first cultivation cycle in which the project activity is implemented.	Once during first verification
Location	All fields must be located in the California rice growing region.	Once during first verification
	Must not include fields with SOC greater than 3% in the top 10 cm.	Every verification
	Must not include fields that have been treated with nitrification inhibitors, urea inhibitors or controlled release fertilizers.	Every verification
Anaerobic Baseline	All fields must demonstrate that previous rice cultivation practices resulted in anaerobic conditions.	Once during first verification
Performance Standard	The field passes the Performance Standard Test for at least one of the approved project activities.	Every verification
Legal Requirement Test	Signed Attestation of Voluntary Implementation form and monitoring procedures for ascertaining and demonstrating that the project passes the Legal Requirement Test.	Single Field Project: once during first verification Aggregate: once during first verification and once during first verification for new fields that have joined aggregate
Legal Title to CRTs	Aggregator Attestation of Title to CRTs.	Every verification
Regulatory Compliance	Signed Attestation of Regulatory Compliance form and disclosure of all non-compliance events to verification body; project must be in material compliance with all applicable laws.	Every verification

8.7 Core Verification Activities

The RCPP provides explicit requirements and guidance for quantifying the GHG reductions associated with the implementation of approved RC management practice changes on project fields. The Verification Program Manual describes the core verification activities that shall be performed by verification bodies for all project verifications. They are summarized below in the context of an RC project, but verification bodies must also follow the general guidance in the Verification Program Manual.

Verification is a risk assessment and data sampling effort designed to ensure that the risk of reporting error is assessed and addressed through appropriate sampling, testing, and review. The three core verification activities are:

- Identifying emission sources, sinks, and reservoirs
- Reviewing GHG management systems and estimation methodologies
- Verifying emission reduction estimates

Identifying emission sources, sinks, and reservoirs for each field
The verification body reviews for completeness the sources, sinks, and reservoirs identified for a single-field project or project aggregate, ensuring that all relevant secondary effect SSRs for each field are identified.

Reviewing GHG management systems and estimation methodologies at the field level
The verification body reviews and assesses the appropriateness of the methodologies and management systems that are used to gather data and calculate baseline and project emissions for each field.

Reviewing GHG management systems and estimation methodologies at the aggregate level
The verification body reviews and assesses the appropriateness of the methodologies and management systems that the project aggregator uses to gather data and calculate baseline and project emissions on the aggregate level.

Verifying emission reduction estimates at the field level
The verification body further investigates areas that have the greatest potential for material misstatements and confirms whether or not material misstatements have occurred for all fields undergoing verification. This involves site visits to a random sample of project fields, according to the sampling methodology outlined in Section 8.3.2.1, to ensure systems on the ground correspond to and are consistent with data provided to the verification body, combined with a random sample of desktop verifications of remaining project fields according to Section 8.3.2.2. In addition, the verification body recalculates a representative sample of the performance or emissions data from fields for comparison with data reported by the project aggregator in order to confirm calculations of GHG emission reductions.

Verifying emission reduction estimates at the aggregate level
The verification body further investigates areas that have the greatest potential for material misstatements at the aggregate level, including whether the appropriate modeling structural uncertainty factors (Section 5.4.3) and yield-loss statistical tests (Section 5.5.3) have been performed for the aggregate.

8.8 Project Type Verification Items

The following tables provide lists of items that a verification body needs to address while verifying a RC project. The tables include references to the section in the protocol where requirements are further specified. The table also identifies items for which a verification body is expected to apply professional judgment during the verification process. Verification bodies are expected to use their professional judgment to confirm that protocol requirements have been met in instances where the protocol does not provide (sufficiently) prescriptive guidance. For more information on the Reserve's verification process and professional judgment, please see the Verification Program Manual.

Note: These tables shall not be viewed as a comprehensive list or plan for verification activities, but rather guidance on areas specific to RC projects that must be addressed during verification.

8.8.1 Project Eligibility and CRT Issuance

Table 8.2 lists the criteria for reasonable assurance with respect to eligibility and CRT issuance for RC project aggregates. These requirements determine if the aggregate is eligible to register with the Reserve and/or have CRTs issued for the reporting period. If any single requirement is not met, either for one or more fields, then the entire aggregate may be determined ineligible or the GHG reductions from the reporting period (or subset of the reporting period) may be ineligible for issuance of CRTs, as specified in Section 3.

Table 8.2. Eligibility Verification Items

Protocol Section	Eligibility Qualification Item	Apply Professional Judgment?
2.2	Verify that all verified fields meet the definition of an RC project	Yes
2.3	Verify ownership of the reductions by reviewing Aggregator Attestation of Title	No
2.3	Verify ownership of the reductions by reviewing Letters of Notification and contracts between aggregators, project participants, and land owners	No
3.2	Verify project start date for all fields	No
3.2	Verify accuracy of project start date for all verified fields based on operational records	Yes
3.3	Verify that each field is within the 5-year crediting period (or a subsequent 5-year crediting period)	No
3.4	Verify that the management records at each verified field are adequate to document the anaerobic baseline requirements	No
3.4	Verify that all verified fields have a SOC content less than 3% in the top soil	No
3.5.1	Verify that each field meets the Performance Standard Test	No
3.5.2	Confirm execution of the Attestation of Voluntary Implementation form to demonstrate eligibility under the Legal Requirement Test	No
3.5.3	Verify that any ecosystem service payment or credit received for activities on a project field has been disclosed and is allowed to be stacked	No
3.6	Verify that the project activities at all verified fields comply with applicable laws by reviewing any instances of non-compliance provided by the aggregator and performing a risk-based assessment to confirm the statements made by the project developer in the Attestation of Regulatory Compliance form	Yes

Protocol Section	Eligibility Qualification Item	Apply Professional Judgment?
6.1, 6.2, 6.3	Verify that the project Monitoring Plan contains a mechanism for ascertaining and demonstrating that all fields pass the Legal Requirement Test at all times	No
6.1, 6.3, 6.4	Verify that field-level and aggregate-level monitoring meets the requirements of the protocol. If it does not, verify that a variance has been approved for monitoring variations	No

8.8.2 Quantification

Table 8.3 lists the items that verification bodies shall include in their risk assessment and re-calculation of the GHG emission reductions. These quantification items inform any determination as to whether there are material and/or immaterial misstatements in the project aggregate GHG emission reduction calculations. If there are material misstatements, the calculations must be revised before CRTs are issued.

Table 8.3. Quantification Verification Items

Protocol Section	Quantification Item	Apply Professional Judgment?
4	For each field, verify that all SSRs in the GHG Assessment Boundary are accounted for, particularly secondary effect emissions	No
5.4.2	For the aggregate, verify that all field emission reductions are summed correctly, and that the structural uncertainty factor is properly applied	No
5.4.3.3 and Appendix B Step 5	For each field, verify that the soil input uncertainty discount is quantified and applied correctly	No
5.5.1	Verify that the aggregator correctly monitored, quantified and aggregated fossil fuel and electricity use changes	Yes
5.5.2	For each field, verify that baled rice straw end-uses are properly characterized, and the appropriate emission factors are used	Yes
5.5.3	For the aggregate, verify that the statistical test for reduced yield is properly performed, and that increased emissions outside the project boundary are properly quantified for significant yield losses	No
Appendix B Step 1.2	For each field, verify that the project parameters and the static parameters are represented by the appropriate data and the DNDC input files are accurate for the baseline modeling and the project modeling	Yes
Appendix B Step 1.2	For each field, verify that the baseline and project emission models have the same static parameters, and that the project model adequately represents the project activities during the cultivation cycle	No
Appendix B Step 2.1	Confirm that the missing data substitution methodology has been applied correctly	Yes
Appendix B Step 3	For each field, verify that the DNDC model is adequately calibrated to historical yields, and that the 20-year historical calculation was run correctly	Yes
Appendix B Step 4	For each field, verify that the Monte Carlo analysis was performed correctly for the baseline and project modeling runs for each field	No

8.8.3 Risk Assessment

Verification bodies will review the following items in Table 8.4 to guide and prioritize their assessment of data used in determining eligibility and quantifying GHG emission reductions.

Table 8.4. Risk Assessment Verification Items

Protocol Section	Item that Informs Risk Assessment	Apply Professional Judgment?
6	Verify that all contractors are qualified to perform the duties expected. Verify that there is internal oversight to assure the quality of the contractor's work	Yes
6.1, 6.2, 6.3	Verify that the project has documented and implemented the Single-Field Monitoring Plan or Aggregate Monitoring Plan, and all necessary Field Monitoring Plans	No
6.1, 6.2, 6.3	Verify that the project monitoring plans are sufficiently rigorous to support the requirements of the protocol and proper operation of the project	Yes
6.4	Verify that appropriate monitoring data is measured or referenced accurately	No
6, 7	Verify that the individual or team responsible for managing and reporting project activities are qualified to perform this function	Yes
6, 7	Verify that appropriate training was provided to personnel assigned to GHG reporting duties	Yes
7.2	Verify that the Single-Field Report or Aggregate Report was uploaded to the Reserve software	No
7.2, 7.3	Verify that field data has been gathered by project participants and made available to the aggregator	No
7.3	Verify that all required records have been retained by the project developer	No

8.9 Successful and Unsuccessful Verifications

Successful verification of each field in the sample of fields selected for site visit and desktop verifications results in the crediting of all fields participating in the entire project aggregate, as calculated by the aggregator according to the quantification methodology in Section 5.

Verification may uncover any number of material and immaterial errors at the field, project participant or aggregate level, and the extent to which an error was propagated through the aggregate can affect whether a verification is determined to be "unsuccessful."

8.9.1 Field-Level and Project Participant-Level Errors

If material issues arise during verification of a participating field, verification bodies shall issue Corrective Action Requests, as needed. The aggregator will need to work with the project participant to independently address the issues and required corrective actions using the same process taken with standalone projects. These are described in the verification guidance of this protocol and the Reserve Verification Program Manual. If the error can be corrected at the field level and is the type of error which will not be propagated across an individual participant's fields or the entire aggregate, then the error shall be corrected and the field verification shall be considered successful. Errors shall be considered immaterial at the field level if they result in a discrepancy that is less than 5 percent of the total emission reductions quantified for that field.

If verification of a field reveals material non-compliance with the protocol, and no corrective action is possible, that field shall receive a negative verification and no CRTs shall be issued for that field, effectively removing the field from the aggregate for that year. When verification is unsuccessful for a participating field, the verification body must verify additional fields until the total number of successful verifications reaches the required number (as described in Section 8.2), starting with fields managed by the same participant, as follows. If the project participant managing the unsuccessfully verified field also manages other fields enrolled in the aggregate, the verification body shall site visit a minimum of two additional fields or 50 percent of the remaining unverified fields, whichever is larger, that are managed by that project participant. If the verification of the additional fields is also unsuccessful, no CRTs shall be issued for any of the fields managed by the project participant.

Deliberate non-compliance may result in disqualification of the project participant including all of their enrolled fields. Additionally, if the project participant failing verification and their negatively verified fields re-enter the aggregate the following year, each of the fields that failed verification the previous year shall be required to undergo a site visit, in addition to the minimum sampling requirements in Section 8.2.

Whenever a project participant receives a negative verification for all of their enrolled fields, the verification body shall use their professional judgment and a risk-based assessment to determine whether sampling additional project participants for site visit verification, beyond the minimum requirements of this protocol, is necessary to verify the entire aggregate to a reasonable level of assurance.

8.9.1.1 Cumulative Field-Level Error of Sampled Fields

Total errors and/or non-compliance shall be determined for the sampled fields and the offset issuance for those fields corrected, as required, by the Verification Program Manual. Should the aggregated error and/or non-compliance rate for the sampled fields be less than 5 percent, CRT issuance for fields not subjected to site visit or desktop verification shall be equal to the amount reported by the aggregator. However, if the aggregated percent error and/or non-compliance rate (i.e. the percentage of verified fields failing verification) for sampled fields is greater than 5 percent, CRT issuance for fields not subjected to site visit or desktop verification shall be reduced by the total amount of aggregated percent error or non-compliance rate.

8.9.2 Aggregate-Level Errors

If verification reveals a potential systemic error, which may be propagated out to the aggregate level (e.g. a qualitative error with regard to the model input parameters or a quantitative error repeated in multiple field-level model runs), the verification body shall use their professional judgment to sample additional fields, as necessary, to determine whether the error is truly systemic. Systemic errors must be corrected at the aggregate level.

8.10 Completing Verification

The Verification Program Manual provides detailed information and instructions for verification bodies to finalize the verification process. It describes completing a Verification Report, preparing a Verification Statement, submitting the necessary documents to the Reserve, and notifying the Reserve of the project’s verified status.

9 Glossary of Terms

Accredited verifier	A verification firm approved by the Climate Action Reserve to provide verification services for project developers.
Additionality	Practices that are above and beyond "business as usual" operation, exceed the baseline characterization, and are not mandated by regulation.
Aggregator	A project developer responsible for a project comprising multiple fields.
Anaerobic	Pertaining to or caused by the absence of oxygen.
Anthropogenic emissions	GHG emissions resulting from human activity that are considered to be an unnatural component of the Carbon Cycle (i.e. fossil fuel destruction, deforestation, etc.).
Biogenic CO_2 emissions	CO_2 emissions resulting from the destruction and/or aerobic decomposition of organic matter. Biogenic emissions are considered to be a natural part of the Carbon Cycle, as opposed to anthropogenic emissions.
Carbon dioxide (CO_2)	The most common of the six primary greenhouse gases, consisting of a single carbon atom and two oxygen atoms.
CO_2 equivalent (CO_2e)	The quantity of a given GHG multiplied by its total global warming potential. This is the standard unit for comparing the degree of warming which can be caused by different GHGs.
Direct emissions	Greenhouse gas emissions from sources that are owned or controlled by the reporting entity.
Effective date	The date of initial adoption of this protocol by the Reserve Board: December 14, 2011.
Emission factor (EF)	A unique value for determining an amount of a greenhouse gas emitted for a given quantity of activity data (e.g. metric tons of carbon dioxide emitted per barrel of fossil fuel burned).
Field checks	Low dikes that are employed by rice farmers to control water distribution to their fields.
Fossil fuel	A fuel, such as coal, oil, and natural gas, produced by the decomposition of ancient (fossilized) plants and animals.
Greenhouse gas (GHG)	Carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), or perfluorocarbons (PFCs).
GHG reservoir	A physical unit or component of the biosphere, geosphere or hydrosphere with the capability to store or accumulate a GHG that has been removed from the atmosphere by a GHG sink or a GHG captured from a GHG source.

GHG sink	A physical unit or process that removes GHG from the atmosphere.
GHG source	A physical unit or process that releases GHG into the atmosphere.
Global warming potential (GWP)	The ratio of radiative forcing (degree of warming to the atmosphere) that would result from the emission of one unit of a given GHG compared to one unit of CO_2.
Indirect emissions	Reductions in GHG emissions that occur at a location other than where the reduction activity is implemented, and/or at sources not owned or controlled by project participants.
Metric ton or "tonne" (MT, t)	A common international measurement for the quantity of GHG emissions, equivalent to about 2204.6 pounds or 1.1 short tons.
Methane (CH_4)	A potent GHG with a GWP of 21, consisting of a single carbon atom and four hydrogen atoms.
Mobile combustion	Emissions from the transportation of materials, products, waste, and employees resulting from the combustion of fuels in company owned or controlled mobile combustion sources (e.g. cars, trucks, tractors, dozers, etc.).
Project baseline	A "business as usual" GHG emission assessment against which GHG emission reductions from a specific GHG reduction activity are measured.
Project developer	An entity that undertakes a GHG project.
Stationary combustion source	A stationary source of emissions from the production of electricity, heat or steam, resulting from combustion of fuels in boilers, furnaces, turbines, kilns, and other facility equipment.
Verification	The process used to ensure that a given participant's GHG emissions or emission reductions have met the minimum quality standard and complied with the Reserve's procedures and protocols for calculating and reporting GHG emissions and emission reductions.
Verification body	A Reserve-approved firm that is able to render a verification statement and provide verification services for operators subject to reporting under this protocol.

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Appendix A Parameter Look-Up Tables

Rice Straw End-Use Emission Factors

The emission factors included in Table A.1 below were derived based on the conservative use of best available information regarding emissions associated with the transport and decay of rice straw given various end-use scenarios. Transportation energy use data came primarily from California rice straw time and motion studies[58] that examined, through survey responses within the industry, the costs associated with collection, storage, and transport of rice straw to various end-uses (primarily for use as cattle feed). Because of the uncertain nature of these emissions factors, the Reserve consistently applied conservative assumptions to estimate each emission factor, as described in the footnotes to Table A.1. A conservative default factor for ‘unknown’ or ‘non-specified’ offsite management has been included for cases where the ultimate fate of the rice straw is unknown.

Table A.1. Rice Straw End-Use Emission Factors

Rice Straw End-Use	Emission Factor (tCO_2e/t baled straw)
Unknown (or ‘other’ offsite management)	0.083 [1]
Dairy and Beef Cattle Feed	0.075 [2,4]
Fiberboard Manufacturing	0 [5]
Spread on Bare Soils for Erosion Control	0.012 [2,3]
Unused (left piled/stacked onsite)	0.210 [6]
1. Using survey responses from California rice baling experts, end-use emission factors were determined for each of the expert’s estimates of the current rice straw end-use market. The most conservative estimate was used for this emission factor. The scenario that is used assumes that close to 100% of rice straw goes to Dairy and Beef Cattle Feed, with negligible amounts going to other end-uses. The resulting estimate of 75 kg CO_2e/t of baled straw was increased by 10% for conservativeness 2. Transportation emissions per MT of rice straw are estimated as being 13.14 kg CO_2e using the following assumptions:[58] a. Bales are transported 200 km b. Average truck capacity of 16 MT rice straw c. Diesel fuel efficiency of 6 MPG d. The emission factor for Diesel Fuel Use is 10.15 kg CO_2e/gal[59] 3. Anaerobic decay is unlikely because the straw is spread across the landscape, therefore maximizing oxygen availability during decomposition 4. Change in enteric emissions may occur due to low nutritional quality of rice straw. It is assumed for conservativeness that the enteric CH_4 conversion factor is increased by 1% due to switching to low-digestible food (2006 IPCC *Guidelines for National Greenhouse Gas Inventories*, Vol. 4, pg. 10.30). Emission factor assumes a calorific value of dry rice straw of 15 MJ/kg (Putun et al., 2004), and an energy content of CH_4 of 55.65 MJ/kg (2006 *IPCC Guidelines for National Greenhouse Gas Inventories*, Vol. 4, pg. 10.32) 5. Rice straw replaces wood products for manufacturing of fiber board	

[58] Transport distance and truck capacity assumptions are conservative estimates based on information from time and motion studies in California (Jenkins et al. (2000), Table 3).
[59] US EPA (2008) Climate Leaders Greenhouse Gas Inventory Protocol Core Module Guidance: Direct Emissions from Mobile Combustion Sources, Appendix B, pg 26.

Avoidance of harvesting and transport of wood products provides likely net-positive GHG benefits 6. Equal to the IPCC default emission factor for aerobic composting (0.10 kg CH_4/t input). Low N residues (such as rice straw) would have discounted fugitive emissions compared with other compostable organic residues (Brown et al., 2008).	

Appendix B Step by Step Guide to Modeling RCPP Emissions Using DNDC

This protocol relies on the application of the DNDC model for quantification of baseline and project emissions from soil dynamics (SSR 1) defined in Section 4. Detailed requirements for accurate and consistent application of the DNDC model are provided in this appendix. Table B.1 below provides an overview of the process to model primary GHG emissions for this protocol using DNDC, as well as references to additional guidance.

Table B.1. Overview of DNDC Modeling

STEP	DNDC MODELING OVERVIEW	ADDITIONAL INFORMATION
Step 1: Become familiar with necessary DNDC inputs		
Step 1.1 Overview of DNDC site input parameters	This section introduces two typologies used to categorize DNDC input parameters.	*DNDC User's Guide* (Version 9.5) Appendix C
Step 1.2 Defining project inputs and static inputs	This section provides guidance on how to classify DNDC inputs as either project inputs or static inputs and where to source data for such inputs depending on their classification.	
Step 1.3 Climate input parameters	This section provides guidance on climate input parameters.	
Step 1.4 Soil input parameters	This section provides guidance on soil input parameters, including further guidance on: ▪ Using soil inputs from the SSURGO database ▪ Using soil inputs from field samples	
Step 1.5 Cropping input parameters	This section provides guidance on cropping input parameters, including multiple subcategories of cropping inputs: crop, tillage, fertilization, manure amendments, irrigation and flooding.	
Step 2: Prepare input files		
Step 2.1 Missing climate or soil data	This section provides a methodology to substitute data in the event that discrete climate or soil data is missing.	
Step 2.2 Historical modeling	This section provides guidance on how to prepare the necessary historical data needed to model emissions and to calibrate the DNDC model.	*DNDC User's Guide* (Version 9.5) Appendix C
Step 2.3 Preparing DNDC input files	This section provides guidance on how to create separate input files for the baseline and project scenarios, that each contains data from both the baseline year and the project scenario.	*DNDC User's Guide* (Version 9.5) Appendix C
Step 3: Calibrate the DNDC model		
Calibrating the DNDC model	This section provides guidance on how to prepare DNDC for modeling by undertaking the calibration exercises.	*DNDC User's Guide* (Version 9.5) Appendix C

Step 4: Model emissions using DNDC		
Step 4.1 Modeling emissions using Monte Carlo simulations	This section provides guidance on how to conduct Monte Carlo simulations using the DNDC model, in order to calculate primary emissions for the baseline and then repeat the process to calculate primary emissions for the project scenario.	*DNDC User's Guide* (Version 9.5) Appendix C
Step 4.2 Extracting DNDC modeling results for calculating emission reductions	This section provides guidance on how to extract data from DNDC Monte Carlo run results and use that data to calculate primary emission reductions for each of the baseline and project scenarios respectively.	
Step 5 Calculate the soil input uncertainty deduction		
Calculating soil input uncertainty	This section provides guidance on how to use the results of the same Monte Carlo runs used to model emissions in order to calculate the soil input uncertainty deduction for each field.	Appendix C

Step 1.1 Overview of DNDC Site Input Parameters

The DNDC model must be properly parameterized with appropriate field-level data related to climatic drivers, soil characteristics and data on various rice cultivation management actions. DNDC's Graphical User Interface (GUI) divides the parameters required for modeling GHG emissions into three main categories: climate, soil, and cropping inputs. Within the cropping input parameter classification are six additional subcategories, for a total of eight parameter categories. For the purposes of quantifying emission reductions under this protocol, these DNDC input parameter categories are classified into two types; static input parameters and project input parameters. The distinction denotes whether data for those parameters must be sourced from the project scenario cultivation cycle only or both the project scenario cultivation cycle and the baseline scenario cultivation cycle. This classification is not reflected in the GUI, but rather explained and detailed in the protocol. Determining what parameters are categorized as "static" versus "project" input parameters is discussed in Appendix B Step 1.2.

When entering data into DNDC, project developers first use the DNDC GUI. Once a particular dataset has been entered into the GUI, the data should be saved as an input file. Whenever the project developer wishes to re-enter this field's data into the model in the future, he/she should do so by selecting this input file to be input into the model. The input file is also one of a number of digital resources that is necessary for monitoring, reporting, and verification (as discussed further in Sections 6, 7, and 8). The input files created by project developers contain data on all of the parameters required by DNDC, except for climate data. Separate input files are created for climate data in accordance with the formatting requirement stipulated in Appendix B Step 1.3 on climate input parameters. However, the input file can reference the relevant climate data files required to model the desired scenario, allowing DNDC to automatically draw climate data from existing data files. Project developers need to ensure they reference the 20 historical climate input files in correct order (i.e. the five historical years, repeated four times, in that specific order). Additional guidance on use of input files can be found in the User's Guide for the DNDC Model Version 9.5 and in Appendix B of this protocol. Additional guidance on the requirements for the historical 20 year period can be found in Appendix B Step 2.3.

Once project developers become familiar with the DNDC model, they can more efficiently alter the input text files manually so that most data will not need to be input using the DNDC GUI.

Some values will still need to be manually input into the DNDC GUI each time, as described in the sections below.

No DNDC default parameters shall be altered (i.e. values changed or data input where no values existed), unless explicitly directed to do so by this protocol. This can result in an incorrect parameterization of the DNDC model.

This section outlines which of these parameters are 'project' input parameters and which are static. The section then gives further guidance on the DNDC input parameters, according to the climate, soil and cropping DNDC GUI classification.

Table B.2 provides an overview of all of the DNDC input parameter subcategories and identifies which contain project and/or static inputs.

Table B.2. Overview of DNDC Input Parameters

Parameter	Static or Project Input Parameter?	Description	Source of Data for Project Cultivation Cycle Scenario	Source of Data for Baseline Cultivation Cycle Scenario
Climate	Static	Climatic variables	Project scenario cultivation cycle	Project scenario cultivation cycle
Soil	Static	Soil conditions	SSURGO data or, where unavailable, from project scenario cultivation cycle soil samples	SSURGO data or, where unavailable, from project scenario cultivation cycle soil samples
Cropping	Static	Cropping systems and cycles – rotations, etc.	Project scenario cultivation cycle	Project scenario cultivation cycle
Crop	Project/ Static	(1) Types of crops (2) Planting/harvest dates (3) Crop residue management (4) Crop physiology/phenology (DNDC default values used)	Project scenario cultivation cycle and DNDC defaults or values obtained from the UC Davis Jenkins Lab[60]	Residue Management = PROJECT input, taken from baseline scenario cultivation cycle All other inputs = STATIC inputs, taken from project scenario cultivation cycle and DNDC defaults or values obtained from the UC Davis Jenkins Lab[61]
Tillage	Project	Timing and method	Project scenario cultivation cycle	Baseline scenario cultivation cycle
Fertilization	Project	Must choose manual application	Project scenario cultivation cycle	Baseline scenario cultivation cycle
Manure amendment	Static	Timing, type and amount of soil amendments	Project scenario cultivation cycle	Project scenario cultivation cycle

[60] This information can be sourced directly from UC Davis. See http://ucanr.edu/sites/UCRiceProject/.
[61] Ibid.

Irrigation	Static	Use the DNDC default irrigation index value of 1	Project scenario cultivation cycle	Project scenario cultivation cycle
Flooding	Project	Must use irrigation option (Control 1) to input data	Project scenario cultivation cycle	Baseline scenario cultivation cycle

Step 1.2 Defining Project Inputs and Static Inputs

For the purposes of this protocol, all DNDC model inputs are classified into two types: project inputs and static inputs. As stated above, the distinction denotes whether data for those parameters must be sourced from the project scenario cultivation cycle only or both the project scenario cultivation cycle and the baseline scenario cultivation cycle.

Project inputs are those that relate to the management parameters that are being changed as a result of the project activity. Project inputs to the DNDC model are the only parameters that may vary when modeling baseline and project emissions to determine the GHG reductions related to the field's management change. For example, when modeling dry seeding, the only change would be the dates for when flooding up occurred (and perhaps added irrigation events to get germination), but other project inputs may remain unchanged (and thus be treated as static inputs). All other inputs that are used to parameterize the model are referred to hereafter as static inputs because once determined for a field for a given cultivation cycle, these inputs must remain unchanged when modeling baseline versus project emission scenarios over the reporting period.

Static inputs may change from year to year, and therefore must be set using measured data from the cultivation cycle of the reporting period undergoing quantification. However, the value for a static input for any single cultivation cycle is assumed to be the same for both project and baseline scenarios.

Table B.3 lists all of the project input parameters.

Table B.3. List of Baseline Project Inputs

Baseline Practice	Project Input
Flooding at seeding	Dates of flooding relative to the planting date (other than winter flooding)
Residue Management	Fraction of straw removed after harvest (0 if no straw removed)
Fertilizer	Dates of all fertilizer applications
	Rate, type of fertilizer and application method for each fertilizer application
Tillage	Dates and depth of all tillage events for preparing the fields for planting and post-harvest residue management

Step 1.3 DNDC Climate Input Parameters

Table B.4 summarizes the climate parameters for which data must be input into DNDC by project developers to model emission reductions.

Table B.4. Climate Parameters

Input Parameters	Unit	Default or Site-Specific?
Jday (Julian day)[62]	Day of year	Site-specific
MaxT (maximum temperature)	°C	Site-specific
MinT (minimum temperature)	°C	Site-specific
Precipitation	cm/day	Site-specific
Humidity	%	Site-specific
Wind speed (daily average)	meters/second/day	Site-specific
N concentration in rainfall	Mg	Default
NH_3 background atmospheric concentration	µg N/m^3	Default
CO_2 background atmospheric concentration	ppm	Default

Seasonal weather can significantly affect methane emissions and, hence, the reduction in methane emissions due to project activities. Weather during the cultivation cycle will impact decisions made regarding the planting and harvesting dates and therefore impacts the length of the growing season. The following requirements for determining climate parameter inputs for each cultivation cycle calculation must be met:

- Daily climate data must come from a weather station that is located maximally 20 miles away, or the nearest station to the field if there are none within 20 miles. If the project area is located in California, it is recommended to use weather data from the nearest CIMIS weather station (http://wwwcimis.water.ca.gov).[63]
- Weather data for the five years preceding the start of the crediting period must be collected. Weather data for the 20-year historic period modeling run (see Appendix B Step 2.3) must be set by repeating this five-year weather data set four times.
- Daily values of maximum temperature, minimum temperature, precipitation, relative humidity and wind speed must be collected and formatted according to DNDC's climate file mode 6 format (see Table B.5 below).
- Default values for N concentration in rainfall, NH_3 background concentration and CO_2 background concentration shall be obtained from the National Atmospheric Deposition Program.[64] Project developers shall select an appropriate default value based on any given day during the first reporting period, which shall be used for the entire crediting period.

Data for N concentration in rainfall, NH_3 background concentration and CO_2 background concentration, are input directly into the DNDC GUI and will thus be contained in input files created by DNDC. Data for the remaining climate input parameters can only be input into the model via the use of climate input files that the project developer must create. When creating the climate input files for these variables, the data must be ordered in the precise manner set out in Table B.4 above, as outlined in the DNDC GUI file format default field. In other words, data needs to be input in text files in the following format: Jday, MaxT, MinT, Precipitation, Humidity, Wind Speed, Humidity.

[62] A Julian Day calendar provided by NASA can be viewed here: http://www-air.larc.nasa.gov/tools/jday.htm. See also Section 5.3.
[63] Note that not all weather stations include data on all the requisite parameters, in particular wind speed and relative humidity, and so may not be a suitable source of climate data.
[64] See http://ucanr.edu/sites/UCRiceProject/. For the NADP see: http://nadp.sws.uiuc.edu/.

For example, the data for the first four days would appear in the input file looking as follows:

Table B.5. Required Formatting for Climate Input Files

1	14	12.1	5.2	4	0.028	0.032	0.048
2	18	11.1	6.2	4	0.029	0.031	0.042
3	13	10.1	7.2	4	0.023	0.033	0.047
4	12	11.1	8.2	5	0.025	0.032	0.048

Step 1.4 DNDC Soil Input Parameters

Table B.6 summarizes the soil parameters for which data must be input into DNDC by project developers to model emission reductions.

Table B.6. DNDC Soil Input Parameters

Input Parameters	Unit	Default or Site- Specific?
Clay content	Fraction	Site-specific
Bulk density	g/cm^3	Site-specific
Soil pH	pH	Site-specific
Soil organic carbon (SOC) at surface soil (0-10 cm)	kg C/kg soil	Site-specific
Soil texture	Fraction	Default

Some soil parameters affect methane emissions to a significant extent. Therefore, for each of the individual rice fields, values for the input parameters listed in Table B.6 must be obtained either from the USDA NRCS SSURGO data set, or based on soil measurements. The Reserve strongly advises project developers to use the SSURGO database, as this will avoid the resource expenditure needed for soil sampling and may reduce the uncertainty surrounding soil sampling results.

Data for the first four soil input parameters listed in Table B.6 needs to be sourced from the SSURGO database. A default soil texture input shall be selected from a drop down menu directly within the DNDC GUI. Project developers must choose a value from the drop down menu that most closely corresponds to the clay content fraction in the soil. Once entered into the DNDC GUI, data for all soil input parameters appears in the relevant DNDC input file.

Note that there are multiple additional soil data input points in the DNDC GUI for which default parameters are provided by DNDC. Unless specifically stated above, such defaults should not be altered.

Further guidance is given below regarding the use of soil data obtained from either the SSURGO database or field sampling.

Using Soil Data Inputs from the SSURGO Database

If the NRCS SSURGO soil database is used, then project developers must calculate the soil parameters for each project field on an area-weighted basis. Figure B.1 below illustrates this concept for a rice field in Yolo County.

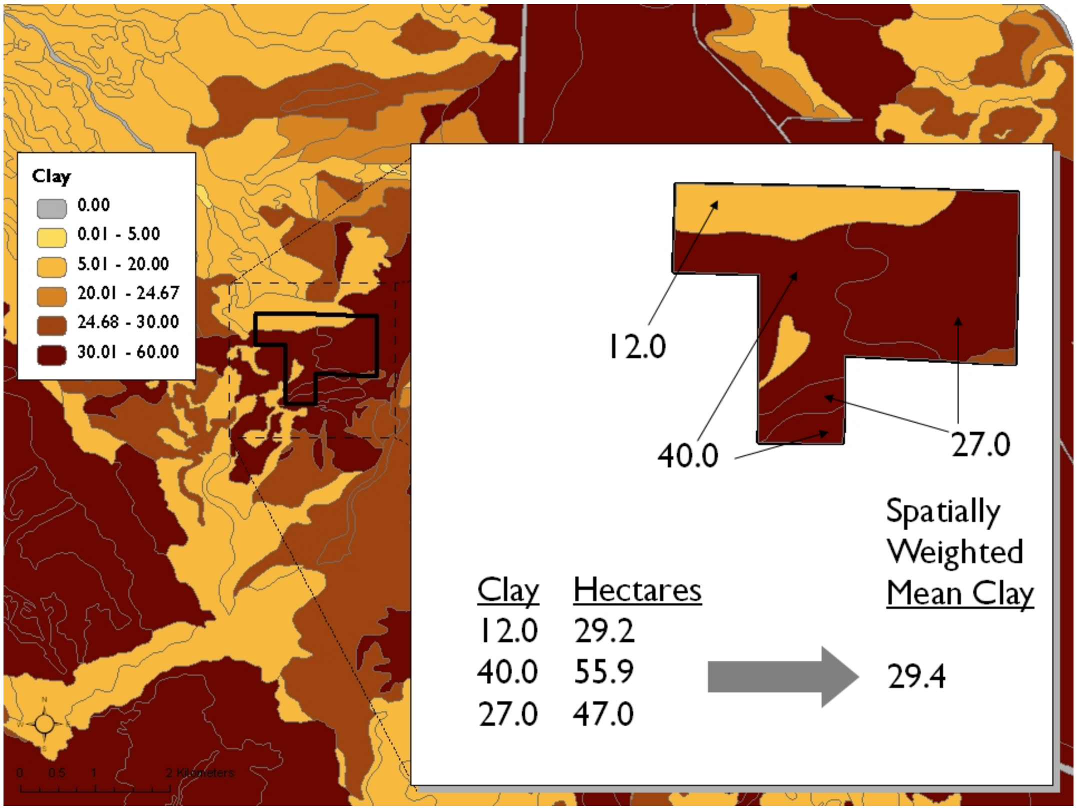

Figure B.1. Example of Soil Parameter Area-Weighting using SSURGO Data

Using Soil Inputs from Samples

If using soil measurements, data may not be older than 10 years prior to the field project start date and must meet the criteria for soil sampling outlined below. Official soil laboratory statements must be available during the verification process.

DNDC requires inputs of soil organic carbon content, soil bulk density, pH and clay fraction of the top 10 cm. If collecting samples for analysis (i.e. not using SSURGO data), the following procedure must be used for each field:

- Samples must be collected at a depth of 0-10 cm
- Samples must be collected using a core method
- 20 samples must be collected for the entire field
- To ensure spatial independence of soil properties, use a random sampling pattern
- Samples should be combined into one composite sample
- The GPS coordinates and depth at each sampling location must be recorded
- The combined 0-10 cm samples must be tested for all parameters
- Soil samples must be analyzed by a certified soil laboratory

A suggested mass of soil of at least 500 g should be collected from each depth for the initial (i.e. time zero) sampling. Future soil sample mass can be adjusted for the assessments being conducted.

Soil samples should be kept cool in the field and during transport. Samples should be maintained at 4°C as much as possible during processing. Samples should be sent to a soil lab for measurement of SOC, clay fraction, pH and bulk density.

For each field sampling event, a Soil Sampling Log must be developed, including the following information:

- Date of sampling event
- Description of the core method and compositing procedure
- The GPS coordinates of each sampling location
- The core depth of each sample
- The name/address of the third-party soil sampling contractor (if applicable)
- The name/address of the certified soil laboratory used for analysis

Step 1.5 DNDC Cropping Parameter Subcategories: Management Parameters

Cropping input parameters capture data on the approved project activities, and are therefore crucial in modeling emissions under this protocol. As set out in Appendix B Step 1.1, the Cropping input parameter category is made up of six subcategories, namely Crop, Tillage, Fertilization, Manure Amendment, Irrigation and Flooding.

Table B.7 summarizes the six subcategories of cropping parameters, referred to as crop management parameters, for which data must be input into DNDC by project developers to model emission reductions.

Table B.7. DNDC Cropping Parameters by Subcategory

Crop Input Parameters	Unit	Default or Site-Specific?
Planting date	Date	Site-specific
Harvest date	Date	Site-specific
C/N ratio of the grain	Ratio	Default
C/N ratio of the leaf + stem	Ratio	Default
C/N ratio of the root tissue	Ratio	Default
Fraction of leaves + stem left in field after harvest	Fraction	Site-specific
Maximum biomass (yield)	kg dry matter/ha/yr	Site-specific
Thermal degree days (TDD)	°C	Default
Biomass fraction	Fraction	Default
Water demand	g water/g dry matter	Default
Tillage Input Parameters		
Number of tillage events	Number	Site-specific
Date of tillage events	Date	Site-specific
Depth of tillage events	cm	Site-specific
Fertilization Input Parameters	**Unit**	
Number of fertilizer applications	Number	Site-specific
Date of each fertilizer application	Date	Site-specific
Application method	Surface/injection	Site-specific
Type of fertilizer	Type	Site-specific
Fertilizer application rate	kg N/ha	Site-specific
Manure Amendment Input Parameters		
Number of organic applications per year	Number	Site-specific

Date of application	Date	Site-specific
Type of organic amendment	Type	Default
Application rate	kg C/ha	Site-specific
Amendment C/N ratio	Ratio	Site-specific
Irrigation Input Parameters		
Number of irrigation events	Number	Site-specific
Date of irrigation events	Date	Site-specific
Irrigation types	Types	Default
Amount of water applied	cm	Site-specific
Flooding Input Parameters		
Date of flood-up for growing season	Date	Site-specific
Date of drain for crop harvest	Date	Site-specific
Date of flood-up for winter flooding (if applicable)	Date	Site-specific
Date of drain for winter flooding (if applicable)	Date	Site-specific

Crop Input Parameters

Default values for biomass fraction at maturity, biomass C/N ratio at maturity (i.e. C/N ratio of grain, leaf+stem, and root tissue, respectively), water demand and N fixation index are provided within DNDC for most rice cultivars and can be found in the “C:\DNDC\Library\Lib_crop” directory. The “crop.lst” file provides the look-up table for each crop. Where DNDC defaults are not available for the particular rice cultivar in use on a given field, data for biomass fraction, biomass C/N ratio, water demand[65] and N fixation index[66] should be obtained from UC Davis Jenkins Lab. The Thermal degree days value, defined as the cumulative air temperature from seeding to maturity of the crop, will need to be manually input based on default values sourced from UC Davis Jenkins Lab.[67]

The maximum biomass parameter is site-specific and refers to the maximum grain yield (measured in kg dry matter/ha/yr) which has been recorded for each field for the given cultivation cycle. Once this value is set in the GUI, the model will automatically create maximum biomass values for leaf, stem and root. Maximum yields are used in model calibration (see Appendix B Step 3) and in modeling emissions (see Appendix B Step 4).

When entering the fraction of leaves and stem left in the field after harvest, the project developer must ensure they provide sufficient evidence to their verifier to demonstrate their chosen value is appropriate. The provision of time/date stamped photographs of the height of the cutting blades used, close up photos of the residues in the field etc., may be helpful in this regard.

Tillage Input Parameters

The number and date of tillage events needs to be set based on field observations. The depth of tillage events parameter is set based on defaults provided in the DNDC GUI. When setting the depth of tillage events in DNDC, the project developer must set the value closest to the tillage method they used. The project developer needs to retain sufficient evidence to demonstrate to

[65] Water demand represents the amount of water needed for the crop to produce a unit of dry matter of biomass (in g water/ g dry matter).
[66] While the default N fixation index is 1 for non-legume crops, it must be calculated for legume crops, such as rice. The N fixation index is equal to the ratio (total N content in the plant)/(plant N taken from soil).
[67] This information can be sourced directly from UC Davis. See http://ucanr.edu/sites/UCRiceProject/.

their verifier that they have chosen an appropriate default value. Photographic evidence and interviews with relevant staff may be useful in this regard.

Fertilization Input Parameters

The number, date, method and rate of fertilizer application events need to be set based on field observations. DNDC accepts seven types of fertilizers: urea, anhydrous ammonia, ammonium nitrate, nitrate, ammonium bicarbonate, ammonium sulfate, and ammonium phosphate. Where a project developer has used a fertilizer that combines several of these products, they will need to ensure that they enter the correct amount of each of these types of fertilizers. This information can typically be found on fertilizer packaging or by contacting the manufacturer, an agronomist, or a university agricultural extension officer.

Manure Amendment Input Parameters

DNDC allows for data on any soil amendment to be input into the model, and provides default parameters (i.e. C/N ratio) for several types of soil amendments. Project developers must use the DNDC default values for the soil amendments listed, unless no suitable DNDC defaults are provided. If no suitable DNDC default value is provided, project developers must provide verifiers with sufficient material to justify the use of any alternative value.

Irrigation Input Parameters

The number, date, and rate of irrigation events need to be set based on field observations. Project developers must select the “flood irrigation” type within the DNDC GUI, as this is the only type relevant to rice cultivation.

Flooding Input Parameters

The date of all flooding events needs to be set based on field observations. Note that flooding events that carry over from December to January of the next year must be set to end on December 35 in the DNDC GUI in order to be recorded correctly in the model.

Step 2.1 Missing Climate or Soil Data

The DNDC model will crash if instructed to run without a full set of data for each input parameter. In situations where portions of the climate or soil input data are missing, the project developer must apply the data substitution methodology outlined in this section. This methodology may also be used for periods when the project developer can show that the data are available but known to be corrupted or inaccurate (and where the corruption/inaccuracy can be verified with reasonable assurance). For periods when it is not possible to use the data substitution procedure below to fill gaps, no emission reductions may be claimed.

Missing Climate Data

The method used to correct or complete missing climate data depends on a number of factors, including:

- The length of time that data were missing
- Availability of data from alternative sources
- The climate variable that is being corrected

For gaps in climate data that do not exceed 14 days, project developers shall use the average value of the previous and following 14 days from the same source of data. For gaps that are longer than 14 days, project developers shall use data for that same region from another source, or data from the nearest alternative weather station.

Missing Soil Data

If using SSURGO data for soil input parameters and data is missing in relation to one or more parameters, then project developers shall use data from the STATSGO database for those missing data. If data to replace the missing data is not available from the STATSGO database, then data must be sourced from field samples.

If using field samples for all soil inputs, and some data is missing, the project developer must either resample for those parameters or use data from the SSURGO database. Where SSURGO data is unavailable, data from the STATSGO database may be used.

Step 2.2 Historical Modeling

When preparing DNDC for modeling (i.e. calibrating the model, as discussed in Step 3 below) and when using DNDC to model emissions for both the project and baseline scenarios, historical data must be input into the model. This is necessary to ensure DNDC has adequate background data to accurately model emissions. The rules for using historical data depend on whether the data is being used for calibration or for modeling emissions.

When performing calibration, five years of historical data from the years immediately prior to the start date of the project must be used. No baseline or project scenario data are needed for calibration (other than for observed yield, as set out in Step 3 below). The same 5 years of data from the 5 years prior to the start of the project will be used as the historical period for the duration of the project.

When modeling emissions, each time DNDC is run to calculate either the baseline scenario or project scenario emissions for a given cultivation cycle, it must be run using data from the cultivation cycle being modeled as well as 20 years of historical data, for a total of 21 years of data. The input parameters for the 20-year historical period are set by repeating all parameters from the five years before the start of the project four times.

Additional guidance on using input files to create this 20-year historical period is provided in Appendix C and the *DNDC User's Guide* Version 9.5. Table B.8 below provides an overview of this process.

Table B.8. Schematic of Modeling and Calibration Periods

<table>
<tr><th>Year
-20 to -15*</th><th>Year
-15 to -10*</th><th>Year
-10 to -5*</th><th>Year
-5 to 0</th><th>Year
0 to 5</th><th>Year
5 to 10</th></tr>
<tr><td colspan="4">Historical Period</td><td colspan="2" rowspan="2">Crediting Period</td></tr>
<tr><td colspan="4">Model Equilibration</td></tr>
<tr><td colspan="3"></td><td>Crop Yield Calibration</td><td>Crediting Period 1</td><td>Crediting Period 2</td></tr>
</table>

Source: Figure adapted from Proposed VCS Methodology: Calculating Emission Reductions in Rice Management Systems.
* Represented by repeating historical parameter values for years -5 to 0.

Step 2.3 Preparing DNDC Input Files

As indicated in the Step 2.2 guidance above, each time DNDC is used to model emissions for either the baseline or project scenario, it requires 21 years of data. Inputting the requisite 21 years of data can be done using a single input file.

When entering data into DNDC, project developers first use the DNDC GUI. Once a particular dataset has been entered into the GUI, the data should be saved as an input file. Whenever the project developer wishes to re-enter this field's data into the model in the future, he/she should do so by selecting this input file to be input into the model. The input file is also one of a number of digital resources that is necessary for monitoring, reporting, and verification (as discussed further in Sections 6, 7, and 8).

The input files created by project developers contain data on all of the parameters required by DNDC, except for climate data. Separate input files are created for climate data in accordance with the formatting requirement stipulated in Appendix B Step 1.3 on climate input parameters. However, the input file can reference the relevant climate data files required to model the desired scenario, allowing DNDC to automatically draw climate data from existing data files. Project developers need to ensure they reference the 20 historical climate input files in correct order (i.e. the five historical years, repeated four times, in that specific order). Additional guidance on use of input files can be found in the User's Guide for the DNDC Model (Version 9.5) and in Appendix C of this protocol. Additional guidance on the requirements for the historical 20 year period can be found in Appendix B Step 2.2.

Once project developers become familiar with the DNDC model, they can more efficiently alter the input text files manually so that most data will not need to be input using the DNDC GUI. Some values will still need to be manually input into the DNDC GUI each time, as described in the sections below.

No DNDC default parameters shall be altered (i.e. values changed or data input where no values existed), unless explicitly directed to do so by this protocol. This can result in an incorrect parameterization of the DNDC model.

Step 3 Calibrating the DNDC Model

Prior to modeling baseline and project emissions for the first reporting period for each field, the DNDC model must be calibrated in order for the model to attain equilibrium in certain critical variables for which empirical data are lacking, such as the sizes and quality of the different carbon pools, and the inorganic nitrogen contents of soil pore water. This calibration step only needs to be performed once for the duration of the project, for each field.

Proper parameterization of soil physical conditions (which drive soil moisture dynamics) and crop simulation play a crucial role in modeling C and N biogeochemistry and N_2O emissions. Through transpiration and N uptake as well as depositing litter into soil, plant growth regulates soil water, C and N regimes, which in turn determine a series of biogeochemical reactions impacting soil carbon dynamics and CH_4 and N_2O emissions.

Users shall calibrate the DNDC crop model for cropping systems to be included in the project. Figure B.2 outlines the steps for crop calibration.

When undertaking the calibration process, the majority of data on soil input parameters comes from the historical baseline period (i.e. the five years immediately prior to the project start date):

- Maximum grain yield (kg dry matter/ha) shall be set based on the highest observed yield in the five year historical baseline period
- TDD value shall be manually input based on data obtained from UC Davis Jenkins Lab[68]
- Soil texture class shall be manually set based on the observed clay fraction in the soil

The remaining soil values shall be set manually based on DNDC defaults. Where DNDC defaults are not available for the particular rice cultivar in use on a given field, defaults shall be obtained from UC Davis Jenkins Lab.[69]

The steps for crop calibration are outlined below. Calibrating the DNDC model is an iterative process. To carry out the calibration process, the project developer must first run a five year simulation using data from the historical baseline period for that field. Once the simulation has been run, the project developer must then extract crop yields for the five years from the annual summary file. The project developer shall compare the difference between modeled outputs and observed yield for those five years. The maximum biomass and the thermal degree day parameters of the DNDC model must be manually adjusted so that DNDC predicts the maximum recorded yield during the five years before the start of the project with a maximal relative Root Mean Squared Error (RMSE) of 10 percent of the observed mean.

To achieve this calibration, the project developer must use the following process for the single year out of the historic five years that had the maximum observed rice yield.

1. **Adjust maximum biomass parameter:**
    a. Enter observed maximum biomass
    b. Provide more than adequate fertilization (i.e. use the auto-fertilization option in DNDC)
    c. Provide more than adequate irrigation (i.e. use the irrigation index mode and set the index to 1)
    d. Run the year (or rotation) with the actual local climate/soil conditions
    e. Check the modeled grain yield – the difference between the modeled and the recorded yields during the five years before the start of the project observed grain yield should be within a maximal relative Root Mean Squared Error (RMSE) of 10 percent of the observed mean. If the difference is greater than 10 percent, keep repeating steps (i) and/or (ii) below, until the result is below 10 percent. It is suggested that the user should alter the maximum biomass value by a percentage similar to the observed difference, in order to arrive at a properly calibrated result:
        i. If the difference is greater than 10 percent and the modeled grain yield is less than the actual yield, increase the maximum biomass parameter
        ii. If the difference is greater than 10 percent and the modeled grain yield is greater than the actual yield, decrease the maximum biomass parameter

2. **Adjust cumulative thermal degree days (TDD):** Check the modeled maturity date which can be found in the "Day_FieldCrop.csv" file.[70] The modeled maturity date must be brought to within seven days of the harvest date, for the model to be effectively

[68] This information can be sourced directly from UC Davis. See http://ucanr.edu/sites/UCRiceProject/.
[69] Ibid.
[70] This file will only be available in the site results if the "record daily results" option is selected on the climate tab of the DNDC Graphical User Interface (GUI).

calibrated.[71] The last column of this file, "GrainC," shows daily grain weight (kg C/ha); the maturity date can be inferred by checking the last day where there is an increase in grain weight (i.e. the first day where the grain weight levels off):

a. If the modeled maturity date is more than seven days later than the harvest date, you will need to reduce the TDD value
b. If the modeled maturity date is more than seven days earlier than the harvest date, you will need to increase the TDD value

Figure B.2 below illustrates this calibration process.

[71] It is not necessary for the difference between observed and modeled TDD to be within seven days for each of the five historical years, but rather that the average over the five years be within seven days.

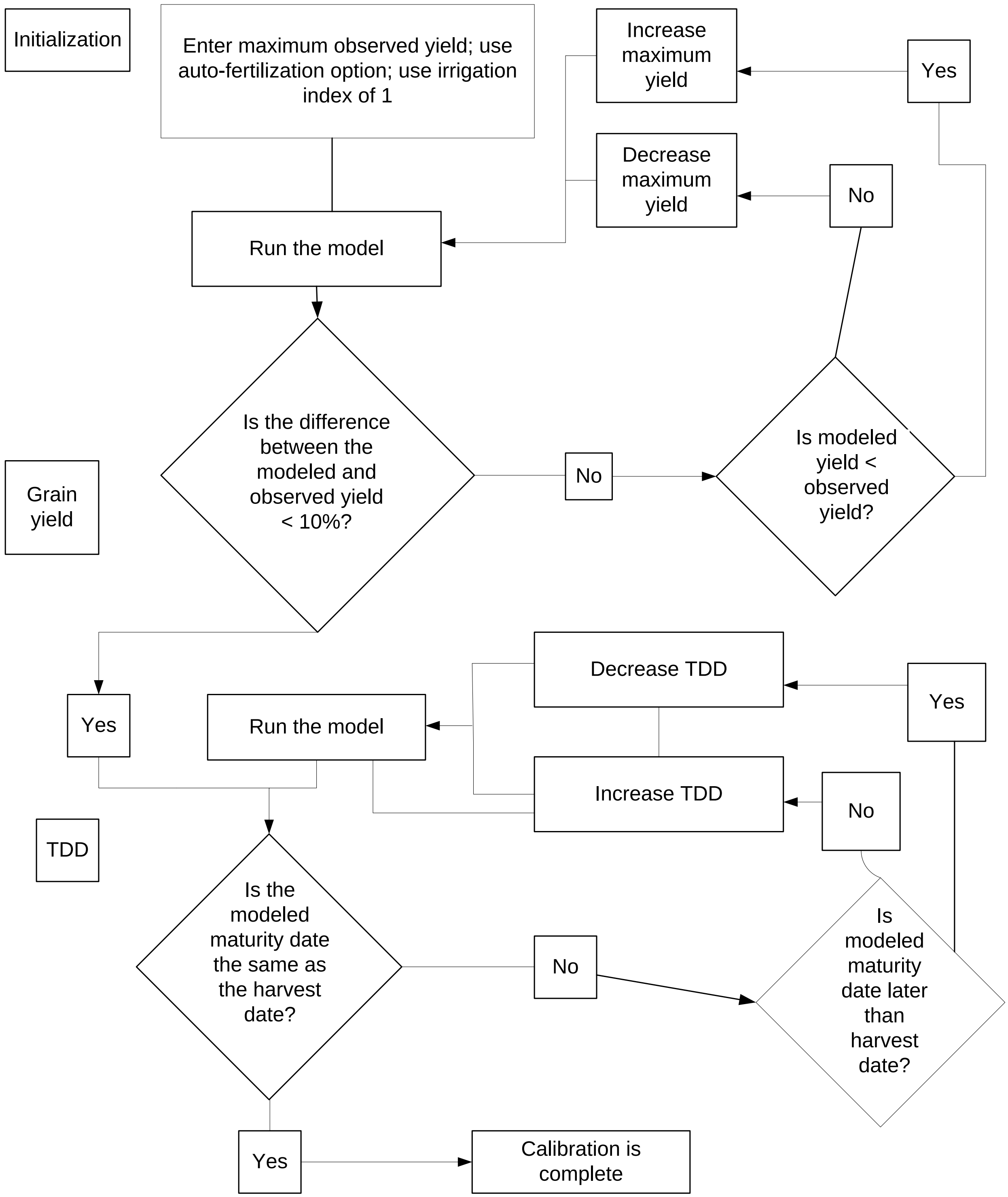

Figure B.2. Calibrating the DNDC Model

Step 4.1 Modeling Emissions using Monte Carlo Simulations

To calculate emissions reductions, project developers need to first model emissions from the baseline scenario and then model emissions from the project scenario. These emissions are compared to calculate associated emission reductions. This section outlines the process for modeling the emissions.

For this protocol, the DNDC model must be run using Monte Carlo batch runs to calculate emission estimates for a given cultivation cycle. A full set of 2,000 Monte Carlo runs must be performed for each calendar year within the baseline scenario and then a full set of 2,000 Monte Carlo runs must be performed for each calendar year within the project scenario.

Monte Carlo simulations are a class of computational algorithm that rely on repeated random sampling within a set range of input values to compute results. Monte Carlo simulations are particularly useful when there is uncertainty with respect to data inputs, as thousands of runs can be performed quickly, an average result determined, and the variance in results calculated. The duration of each Monte Carlo run should be the same as the duration of the cultivation cycle for the field (i.e. approximately 365 days).The Monte Carlo runs are accomplished by running DNDC in batch mode with each entry in the batch file list representing a separate Monte Carlo run (see *DNDC User's Guide* Version 9.5, for more information).

For each field, a Monte Carlo simulation of 2,000 model runs shall be performed for each calendar year within both the baseline cultivation cycle and the project cultivation cycle corresponding to the current reporting period. For each of these 2,000 baseline cultivation cycle and 2,000 project scenario cultivation cycle runs, the project developer needs to input data for both the 20-year historical period and the cultivation cycle being modeled (see Appendix B Step 1.2 for further guidance on sourcing data for project and static input parameters). Once the Monte Carlo simulation has been run using 21 years of data, results from the modeling of the 20 year historical period shall be ignored; only the results from the 21st year (i.e. the cultivation cycle in either the project scenario or the baseline scenario being modeled), are used.

It should be noted that modeling 21 years, as instructed, can be done using one single input file. Refer to Appendix B Step 2.3 and the *DNDC User's Guide* Version 9.5 for further guidance on developing input files, Appendix B Step 1.2 for guidance on sourcing data for project and static input parameters and Appendix B Step 2.3 for guidance on how to set a 20-year historical baseline period appropriate to each crediting period.

Once the Monte Carlo simulations are complete, results are recorded in a *.csv file. The name of the file shall be the site name as entered into DNDC. Project developers are strongly encouraged to use naming conventions for DNDC files based on the field serial number methodology described in Section 7.1.1.

Note that DNDC saves the results from each Monte Carlo batch run into both annual summary files and daily summary files. When quantifying emission reductions and calculating the soil input uncertainty deduction, results need to be extracted from the daily results files, and only for those dates that fall within each field's cultivation cycle.

Specifying Monte Carlo Analysis Soil Input Uncertainty

This protocol allows project developers the choice of using soil survey data (i.e. SSURGO) or field soil samples to estimate soil conditions. The method for parameterizing DNDC for Monte

Carlo analyses depends on whether SSURGO or directly measured soil data are used as inputs.

If NRCS SSURGO soil survey data[72] are used for setting soil parameter values, then default uncertainty estimates shall be set based on the uncertainty estimates and probability distribution functions (PDF) listed in Table B.9. For each soil stratum, the mean value shall be calculated as the area-weighted sum of the representative values for all of the relevant SSURGO data.

Table B.9. Uncertainty Estimates and Probability Distribution Functions for Soil Parameters

Parameter	PDF	Uncertainty
Bulk density	Log-normal	+/- 0.1 g/cm^3
Clay content	Log-normal	+/- 10%
SOC	Log-normal	+/- 20%
pH	Normal	+/- 1 pH unit

Source: Selected from http://www.abdn.ac.uk/modelling/cost627/Questionnaire.htm.

If field measurements are used, then the uncertainty level for each soil parameter shall be +/- 10 percent of the mean at a 90 percent confidence level.

Step 4.2 Extracting DNDC Modeling Results for Calculating Emission Reductions

The DNDC GUI creates estimates of primary emissions that occurred over the given year being modeled; however the model uses emission factors not employed by this protocol. Therefore, it is important that project developers do not extract emissions estimates from the DNDC user interface, but instead extract data from the daily *.csv files to manually generate emission results for the baseline and projects scenarios separately, using the emission factors stipulated in Equation 5.2.

It is also important that project developers understand that the entire modeling process must be undertaken twice for each cultivation cycle being modeled, once for the calendar year within which the cultivation cycle starts, and again for the subsequent calendar year in which the cultivation cycle ends. Section 5.3 provides further explanation of the need to model two calendar years of emission reductions for each cultivation cycle.

At the conclusion of a modeling exercise (for either the baseline or project scenario), the project developer extracts data from 2,000 separate results files for the 21st year being modeled, [73] for each calendar year being modeled. Specifically, from the daily *.csv files, project developers shall extract the direct GHG emission parameter values (N_2O, CH_4, and SOC content), and the indirect parameter values (NO_3 and NH_3+NO_x). The SOC and CH_4 values (expressed in DNDC as SOC and CH_4*flux* respectively) shall be extracted from the Day_SoilC file. Data on all of the nitrogen-related parameters (i.e. N_2O, NO_3, and NH_3+NO_x) shall be extracted from the Day_SoilN file.

The DNDC *.csv files contain data for each of the Julian days being modeled for a calendar year (i.e. approximately 365 days of data in each results file). From each of the 4,000 results files (2,000 from each calendar year), the project developer must extract data for only those dates

[72] See http://soils.usda.gov/survey/geography/ssurgo/.
[73] As explained in Step 4.1, the first 20 years of data/results are for historical modeling only.

that fit within the field's cultivation cycle. The results for the cultivation cycle are then added together (for all parameters except SOC; SOC values are taken only for the last Julian day in the cultivation cycle), such that the project developer has a single value for each GHG parameter for the cultivation cycle, for each of the 2,000 Monte Carlo runs. Once these values have been generated they must be averaged according to Equation 5.2 in Section 5.4.1. At the end of this process, the project developer has a single value for each key GHG parameter, representing the average value for that parameter for the cultivation cycle across all of the Monte Carlo runs.

This process must be repeated for both the baseline scenario and the project scenario.

Step 5 Calculating Soil Input Uncertainty

Project developers shall sum together primary emissions for the baseline scenario (CH_{4B} + N_2O_B + $\Delta SOC_{B,I}$),[74] and then sum together primary emissions for the project scenario (CH_{4P} + N_2O_P + ΔSOC value for the project scenario).[75] The input uncertainty ($\mu_{inputs,i}$) for greenhouse gas emissions due to uncertainty in soil input parameters for field *i* shall be calculated as the half-width of the 90 percent confidence interval of the difference between the baseline and project scenario cultivation cycle primary emissions, where the primary emissions for each Monte Carlo run *j* are expressed as a percent of the mean GHG cultivation cycle emissions of field *i.*

The soil input uncertainty deduction is used in Equation 5.4 to correct the total modeled primary emission reductions for soil input uncertainty.

Further guidance on the development of soil input uncertainty deductions is provided in Appendix C.

[74] Using CH_{4B} and N_2O_B from Equation 5.3 and $\Delta SOC_{B,I}$ from Equation 5.10, with each parameter converted into CO_2 equivalents.
[75] Using CH_{4P} and N_2O_P from Equation 5.3 and deriving a ΔSOC value for project scenario, in the same manner as the baseline ΔSOC value is derived in Equation 5.10, with each parameter converted into CO_2 equivalents.

Appendix C RCPP General Quantification Guidance

Quantification Guide Index:

Introduction

This appendix is intended to be a practical guide for users of the DNDC model. As such, this appendix includes information that is not strictly needed for this protocol (for instance guidance on using the DNDC model for pre-project feasibility analyses).

This guide describes the use of the DNDC model for the Reserve Rice Cultivation Project Protocol (RCPP). This guide assumes a basic familiarity with the model and its use and is meant to be used in conjunction with the *User's Guide for the DNDC Model* (Version 9.5) (*DNDC User's Guide*), which explains the background mechanics of the model as well as the functionality of the DNDC graphical user interface (GUI).

Development of Ex Ante Input Data and Assessment of Offset Potential

Prior to developing rice offset projects, project developers may want to assess opportunities prior to implementing projects. Such assessments are not required for this protocol. This assessment entails several steps, including collection of current agricultural management data, *ex ante* modeling of general baseline emissions and a suite of mitigation options, and first order assessment of economic feasibility of the mitigation measures.

The first step in developing rice offset projects and applying the DNDC model to evaluate the potential magnitude of emission reductions requires collection of basic rice management data (plant/harvest dates, flooding/irrigation and tillage practices, fertilizer use, etc). Collection of soils and climate data for DNDC modeling is discussed below.

Farmers decisions regarding when to plant rice, how much fertilizer to apply, when to till the soils, when to flood and when to harvest are driven by a combination of factors including commodity prices, prices of resources (e.g. fertilizer) and weather patterns. Over a crop season it is possible that farmers have a good estimate of commodity prices and cost of inputs. However, climatic conditions and associated impacts on agricultural management decisions are difficult to predict prior to the growing season. We also know that management practices and weather both have a significant impact on greenhouse gas (GHG) emissions from agricultural soils.

Given the reliance on weather patterns for decisions regarding agricultural management practices, the *ex ante* modeling is based on an estimation of what the growers think they will do in the future. The *ex ante* input data on management (see detailed discussion below on DNDC model inputs) for the baseline scenario should be based on recent management practices to satisfy both the performance standard criteria and simplify *ex ante* calculations. Once the baseline management practices are set, the project developers can assess what eligible mitigation measures they wish to implement by running DNDC with those changes in management that are both economically viable and have potential to reduce GHG emissions. Later in this document we present an example of the mechanics in using DNDC to evaluate potential offset management changes.

Once a project is implemented, the project developer must collect all of the necessary input data for running the DNDC model. These data are collected through the growing season to insure that the data reflect exactly what the farmer did. The change in approved practice changes implemented by the project must be represented in the model inputs. The key to reliable and genuine project modeling is to define what and how management practices are changed under the project scenario.

Collection of Climate Data for DNDC Modeling

The DNDC model requires daily data on maximum and minimum temperature, precipitation and average wind speed. In California, these data can be collected from the CIMIS (California Irrigation Management Information System) network of weather stations.

Collection of Climate and Soil Data for DNDC Modeling

DNDC requires inputs of soil organic carbon content, soil bulk density, pH and clay fraction of the top 10 cm. Data on soil conditions for a given field can either be collected from existing soil surveys (NRCS SSURGO) or through direct measurement. The RCPP describes some general guidelines on soil sampling for measuring soil properties for DNDC model simulations.

Calculation of Input for *Ex Post* Offset Calculations

The *ex ante* calculations are just an estimate of the potential reductions from implementing one or more of the approved project activities. The *ex post* calculations, performed in accordance with Section 5.4.1 of the RCPP, determines the primary effect GHG reductions that occur on a field due to RC project activity. Once a farmer implements a project and changes management practices from what they would have done in the “baseline,” the baseline becomes a fictitious scenario that represents what the grower “would have done” in the absence of the RC project.

The *ex post* model simulations are done for both the project management practices (what was actually done and recorded by the project) and the “baseline” management. The baseline management practices are the same as the project except for the specific changes in management selected for the project (e.g. those management practices that are recognized as approved project activity practices in Section 2.2 of the RCPP). Because *ex post* calculations represent the real reductions achieved at the field over the course of a complete cultivation cycle, actual weather data must be used for the *ex post* model simulations.

Example: Assessing Impact of Input Uncertainties on Modeled Offsets

This section describes how to calculate the impact of input uncertainties on DNDC modeled emission reductions following the procedures summarized in Section 5.4.2 of the RCPP. Input uncertainty must be quantified when using the DNDC model because the DNDC model can be sensitive to changes in input parameters, specifically changes in soil conditions. The Monte Carlo Input Uncertainty assessment models the GHG emissions thousands of times for a specific field, with each model run using slightly different soil parameters. The soil parameters for each Monte Carlo run are randomly selected based on the probability distribution function (PDF) expected for each soil input used to parameterize the model. Project developers can choose to use either the SSURGO database or field sampling to characterize the soil input parameters.

The following example demonstrates the Monte Carlo modeling approach described in Appendix B Step 4.1 of the RCPP. To apply this method for assessing the impact of uncertainty of soil conditions, the first step entails defining a possible range and probability distribution of the soil conditions. For this example, we use soil databases developed by the U.S. Department of Agriculture Natural Resources Conservation Services (USDA NRCS). The general approach is to assume some variability in site soil attributes (clay fraction, organic matter fraction, bulk density, and pH) as modeled in the USDA NRCS SSURGO soil model. Using a Monte Carlo simulation, one must model identical crop management practices and meteorological conditions while varying soil conditions through the expected range of conditions. The current uncertainty tool in DNDC allows users to run thousands of model simulations in a Monte Carlo mode for most input parameters. However, the current tool in the model assumes an *even* distribution (PDF) for each parameter. The RCPP requires the Monte Carlo run to assume a *log-normal* distribution of each of the soil attributes as well as some amount of correlation between them. The three steps for running the model in Monte Carlo mode can be described as:

- An analysis of correlation between the four soil attributes. In the development of the RCPP an analysis of SSURGO soil data for over 6000 rice fields was completed to develop default correlation coefficients for key soil input parameters. The default correlation coefficients are provided in Table C.1 below.
- Programmatic generation of DNDC inputs based on the Monte Carlo method and pre-defined correlation coefficients.
- Running the DNDC model in site mode using the batch processing option and synthesizing the results.

We demonstrate this approach in two ways; the first assumes no correlation between soil parameters, which is conservative since we know that there is significant correlation between soil parameters. The second set of Monte Carlo runs utilized correlation statistics as part of the sampling procedure.

Soil attributes are stored within the SSURGO database according to the following relationships:

Horizon	Contains soil attribute data (low, representative, and high values) based on an assessment of soil field conditions
⇩	[one to many]
Component	The basic soil type (roughly equivalent to soil series) – soil components have many horizons and have no explicit spatial location
⇩	[one to many]
Map Unit	The smallest mapped polygon in the SSURGO model – soil map units have many components of varying fractions

To assess correlation among soils in rice growing areas of California, all map units intersecting rice fields as mapped in the California Department of Water Resources land use database were selected. From this selection, we identified all soil components contained within the map units. Soil attribute data came from the top horizon for each component. Thus, the final database represents all soil horizons intersecting rice fields.

Pearson correlation coefficients we calculated for each set of pairs for representative values of the four soil attributes:

Table C.1. Soil Correlation Coefficients

	Clay fraction	OM fraction	Bulk Density	pH
Clay Fraction	1	-	-	-
OM Fraction	0.139	1	-	-
Bulk Density	-0.526	-0.685	1	-
pH	0.263	0.098	-0.126	1

The Monte Carlo simulation should randomly generate 2,000 numbers for each of the four soil properties with the correlation matrix and with each following a log-normal distribution. This can be done by using the Cholesky decomposition of the correlation matrix to transform a set of standard-normal random numbers in the logarithm space. The representative value are used as the mean, while the low and high values are transformed into log space and treated as a range of +/- 3 standard deviations. This will result in four sets of 2,000 correlated random numbers, normally distributed. The soil properties, other than pH, are then calculated by taking the exponent of the numbers.

The DNDC model should then be run as a batch using the DNDC site mode (see *DNDC User's Guide*). To demonstrate this, we ran two scenarios (one with a winter flood, one without a winter flood) for a single field as follows:

- Rice planted May 1, harvested September 11
- Tillage on April 23, April 26, April 27, April 29, and September 15
- Fertilizer on April 30 (injected anhydrous ammonia), May 1 (surface application of $(NH_4)_2HPO_4$), May 26 (surface application of $(NH_4)_2SO_4$)
- Flooded from May 1 to September 1
- Winter flood from November 15 to January 31 (only for the winter flood scenario)
- Rice straw burned once every eight years

These results indicate the modeled methane emissions and net GHG emissions are quite sensitive to soil conditions. At 90 percent confidence interval, the range in modeled CH_4 and net

GHG emissions were significant (over 14 percent in both baseline and project simulations) (see Table C.2 below). However, the impact of soil uncertainties on modeled changes in emissions from baseline to project conditions were quite small (<3 percent). Figure C.1 below shows the histogram of the Monte Carlo simulation results for the case assuming no correlation between soil input parameters. It is clear for this baseline and project scenario, that uncertainty in soil input parameters impacted both baseline and project modeled emissions in a similar degree. Accounting for correlation between soil input parameters reduced uncertainties. The table below summarizes these results.

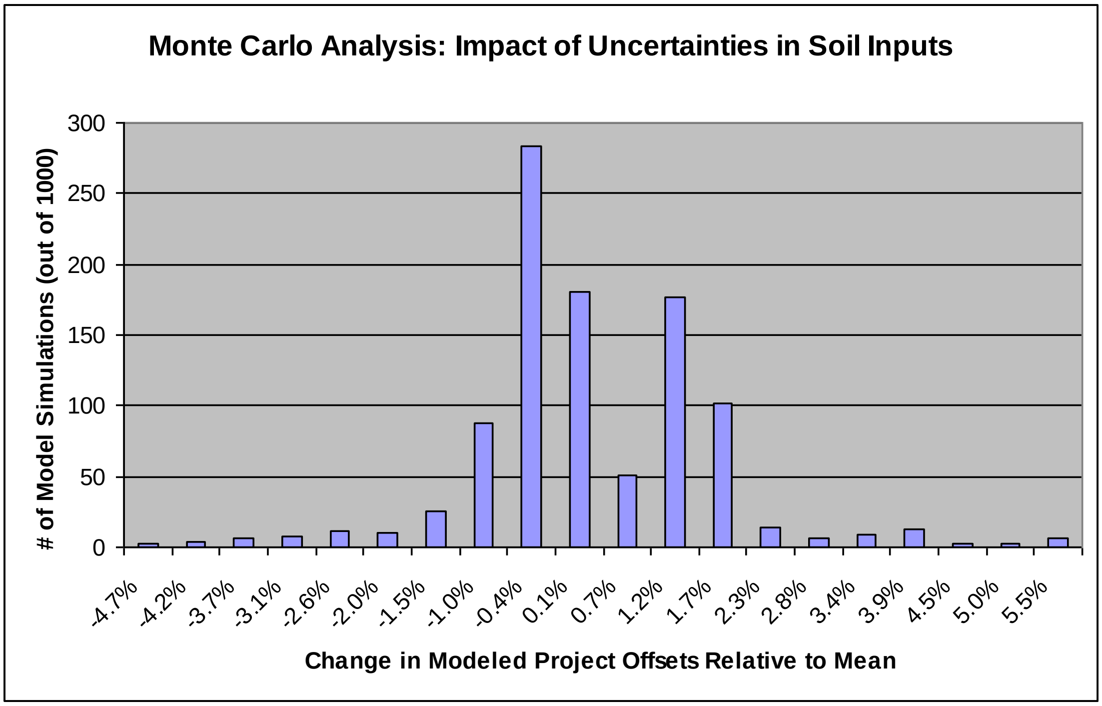

Figure C.1. Change in Modeled Offsets Based on Running Monte Carlo Analysis on Soil Input Uncertainty

Table C.2. Uncertainty in Modeled GHG Emissions and Change in Emissions at 90 Percent Confidence Interval due to Uncertainty in Soil Values

	Assuming No Correlation in Soil Input Parameters		Accounting for Correlation of Soil Input Parameters	
	CH_4 GWP (90% CI / Mean)	Total GHG GWP (90% CI / Mean)	CH_4 GWP (90% CI / Mean)	Total GWP (90% CI / Mean)
Baseline	14.7%	14.4%	14.0%	13.7%
Project	18.5%	20.0%	17.5%	19.1%
Baseline-Project	**1.0%**	**2.2%**	**0.2%**	**1.4%**

DNDC Modeling Overview

This section of the guide is a general overview of the modeling process to give the user a sense of the steps involved in evaluating various land management scenarios. It presents material on gathering input data for the model, using the DNDC GUI to enter data, setting up appropriate soil conditions for the model, calibrating parameters for crops, viewing results, and estimating model uncertainty.

Sources of Data

Prior to running the DNDC model, numerous input data are required, including information on soil, meteorology (climate), and management practices. As DNDC looks principally at soil dynamics, accurate soil parameters are critical: at a minimum, users should gather precise data for soil organic matter content (kg C/kg soil), bulk density (g/cm^3), soil texture (soil clay fraction can be used as a proxy here), and pH. Daily meteorological data for the modeling timeframe should include maximum and minimum air temperatures (°C) and precipitation (cm).

Creating Site Input Files

Once the user has gathered natural conditions and management information for the site, DNDC input files can be created using the DNDC GUI. The user will enter information for the following twelve thematic areas:

- Site
- Climate
- Soil
- Farming rotation management
- Crop
- Tillage
- Fertilization
- Manure amendment[76]
- Irrigation
- Flooding
- Plastic mulch (not relevant for RCPP)
- Grazing and cutting (not relevant for RCPP)

For a step-by-step guide to data input, the user may refer to the *DNDC User's Guide*, Section III-1.1.

Crop Model Calibration

Crop simulation plays a crucial role in modeling carbon and nitrogen biogeochemistry in and greenhouse gas emissions from the agroecosystems. DNDC default parameters for California rice are provided. Where DNDC defaults are not available for the particular rice cultivar in use on a given field, alternative values for defaults prescribed by this protocol may be obtained from the UC Davis Jenkins Lab.[77] The parameters for soil crop simulation are:

- ***Maximum biomass (kg C/ha)*:** The maximum biomass productions for grain, leaves and stems (non-harvest above ground biomass), and roots under optimum growing conditions (namely, maximum biomass assuming no N, water or growing degree day limitations). The unit is kg C/ha (1 kg dry matter contains 0.4 kg C). If local data are not available, then California default values must be used.
- ***Biomass fraction*:** The grain, leaves and stem, and root fractions of total rice biomass at maturity.
- ***Biomass C/N ratio*:** Ratio of C/N for grain, leaves and stem, and roots at maturity.

[76] DNDC allows for data on any soil amendment to be input into the model, and provides default parameters (i.e. C/N ratio) for several types of soil amendments. Users must adopt the DNDC default values for the soil amendments listed, unless no suitable DNDC defaults are provided. Where no DNDC default is provided or alternative values are believed to be more appropriate, users may provide verifiers with sufficient material to justify the use of any such alternative data.
[77] This information can be sourced directly from UC Davis.

- ***Thermal degree days (°C)***: Cumulative air temperature from seeding until rice maturity.
- ***Water demand (g water/g dry matter)***: Amount of water needed for the rice crop to produce a unit of dry matter of biomass (also known as transpiration efficiency).
- ***N fixation index***: The default number is 1 for non-legume crops. For legume crops, the N fixation index is equal to the ratio of total plant N content to plant N taken from soil. For rice, this value must be set at 1.

Default values for N deposition, NH_3 background and CO_2 concentration should be obtained from the National Atmospheric Deposition Program data or data from UC Davis Jenkins Lab.[78] The TDD value will need to be manually input based on a default value found in a look up table derived from UC Davis Jenkins Lab. The remaining soil values will need to be set manually based on DNDC defaults and can be found in the "C:\DNDC\Library\Lib_crop directory." The "crop.lst" file provides the look-up table for crop numbers for each crop. In addition to the crop libraries included with DNDC, the Crop Creator feature (see "Tools" tab on DNDC user interface) allows the user to create a new crop library (by entering in all of the parameters listed above) or modify an existing crop library. Figure C.2, below, shows the DNDC Crop Creator interface. For information on using the Crop Creator, the user may refer to *DNDC User's Guide*, Section III-2.3. The crop creator tool can be used to develop the input parameters for a new rice variety. Where DNDC defaults are not available for the particular rice cultivar in use on a given field, defaults may be obtained from UC Davis Jenkins Lab.

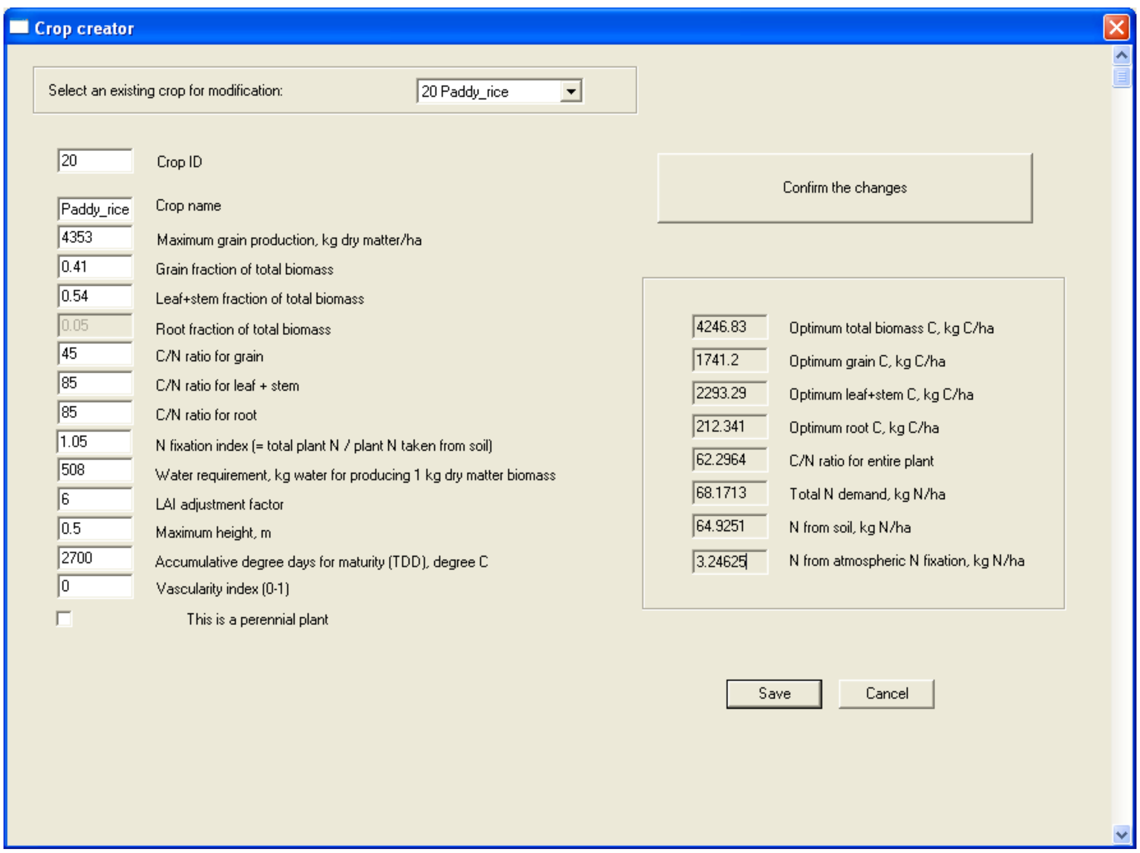

Figure C.2. DNDC Crop Creator

[78] This information can be sourced directly from UC Davis. See http://ucanr.edu/sites/UCRiceProject/.

To use the model according to the RCPP, the user must calibrate the DNDC crop model based on actual site conditions. At least five years of observed crop yields should be used for setting maximum rice grain yield (kg C/ha). In addition, for the particular rice variety used, the biomass fraction (% grain and % leaf and stem), and biomass C/N ratio for grain, leaves and stem, and roots should be obtained from the look up tables derived from UC Davis Jenkins lab.[79] DNDC default parameters which can be found in the "C:\DNDC\Library\Lib_crop" directory. DNDC provided default values or defaults sourced from UC Davis must be used for all of these parameters except the maximum biomass parameter, which must be manually set in the model based on historical yields. Biomass fraction and C/N ratios are typically constant for a cultivar, so if no DNDC default value can be found for the particular cultivar used on a given field, an alternative default value can be sourced from UC Davis (see Appendix B Step 1.4 for RCPP requirements). The steps for crop calibration are outlined in Appendix B Step 3.

Running the Model and Viewing Results

Once soil and crop calibration are complete, input parameters are entered, and input files are saved for later use, the model can be run. For details on running the model, the user may refer to the *DNDC User's Guide*, Section III-1.3. Model run results can be viewed either through the DNDC GUI or in text files saved to the user's hard-drive. Results in the DNDC GUI give a quick overview of results by year for crop(s), nitrogen, carbon, water, and greenhouse gas emissions. Viewing results via the GUI is described in detail in the *DNDC User's Guide*, Section III-1.4.

Daily and annual results are saved in text file format so that they can be retrieved and reprocessed with any spreadsheet or word processor tools (e.g. Microsoft Excel or OpenOffice Calc). Daily results include information on crop growth, soil carbon and nitrogen pools and fluxes, soil climate, and water budget. In addition, summarized annual results are saved in report and tabular format. Text file results are described in detail in the *DNDC User's Guide*, Section IV-1.

Greenhouse Gas Emissions Scenarios: Overview

This appendix provides an overview of the GHG emission evaluation process using DNDC. While this document is not intended to be used to select the actual scenarios to be used, we provide some background material here on the general effects of parameter changes in DNDC and a brief discussion of trade-offs between management practices, GHG emission, and crop yield. In addition, we describe the general framework for the ideal approach to scenario evaluation.

General Effects of Model Parameter Changes

The user should consider what GHG mitigation options make sense for their particular application and set-up DNDC modeling appropriately. Seeking input from local experts and surveying literature specific to the system of interest is the preferred approach. This section (and the accompanying tables in the appendix) provides a very general overview of methane mitigation options.

Reductions to CH_4 emissions fall into four categories: changes to soil character, organic matter management, crop/plant management, and flooding. Changes to soil character (such as by converting wetland soils to upland crop) often affect other GHG emissions such as C sequestration or N_2O emissions. Crop or plant management and organic matter management

[79] This information can be sourced directly from UC Davis. See http://ucanr.edu/sites/UCRiceProject/.

are typically effective in wetlands soils. Changes to flooding regime are often the most feasible option, but can also influence N_2O emissions.

Modeling Potential Project Scenarios

Ideally, each scenario should be run for the same time period, using the same site characteristics for several years (five or more): because of climate-related interannual variability, emissions and yields can vary significantly from year to year. Running the model for several years will ensure a reasonable average. If a multi-year run is not possible, a Monte Carlo simulation may provide better results. Due to the use of annual reporting periods, this protocol requires the use of Monte Carlo simulations to reduce model uncertainty.

The general process for evaluating scenarios is as follows (a specific example can be found in the Case Studies section):

- Create baseline input files for DNDC (including *.dnd file and climate files)
- Create management alternatives based on approved project activities
- Run baseline and project management scenarios
- Import text results into spreadsheet software (e.g. Microsoft Excel or OpenOffice Calc) and generate mean annual per hectare values (in CO_2 equivalents) for the principal parameters;
    - Change to soil organic carbon (ΔSOC)
    - Methane (CH_4)
    - Nitrous oxide (N_2O)
- Sum CO_2 equivalents to derive total annual GHG emissions (zeroing out any net emission reductions from SOC or N_2O, as reductions to these gases are not credited in the RCPP)
- Useful graphs might include:
    - Bar chart comparing total GHG emissions by scenario
    - Bar chart comparing grain yield by scenario

Case Study: Paddy Rice

In this section we will provide a step-by-step example of an evaluation of management scenarios for a 20.8 hectare rice paddy in California. In this case, we are using data from an actual field, with six years of detailed management, meteorological and atmospheric, and soils data. Here is the baseline management scenario:

- Single crop: rice
- No removal of crop residue
- Tillage prior to and after cropping
- Fertilizer applications prior to and after planting
- Flooded field from late May through early September
- Winter flood from December through February/March

Entering Input Data

As one would do with any DNDC model site run, we will begin by entering all of the site, soil, and cropping information available to us; this initial set-up will form the basis for the crop calibration process and the baseline run. Figure C.3 shows the basic site information and climate information for our rice paddy. Climate files were created based on data from a nearby agricultural weather station. Nitrogen concentration from rainfall was generated from data from a nearby monitoring station and represents annual average total deposition averaged over the six years.

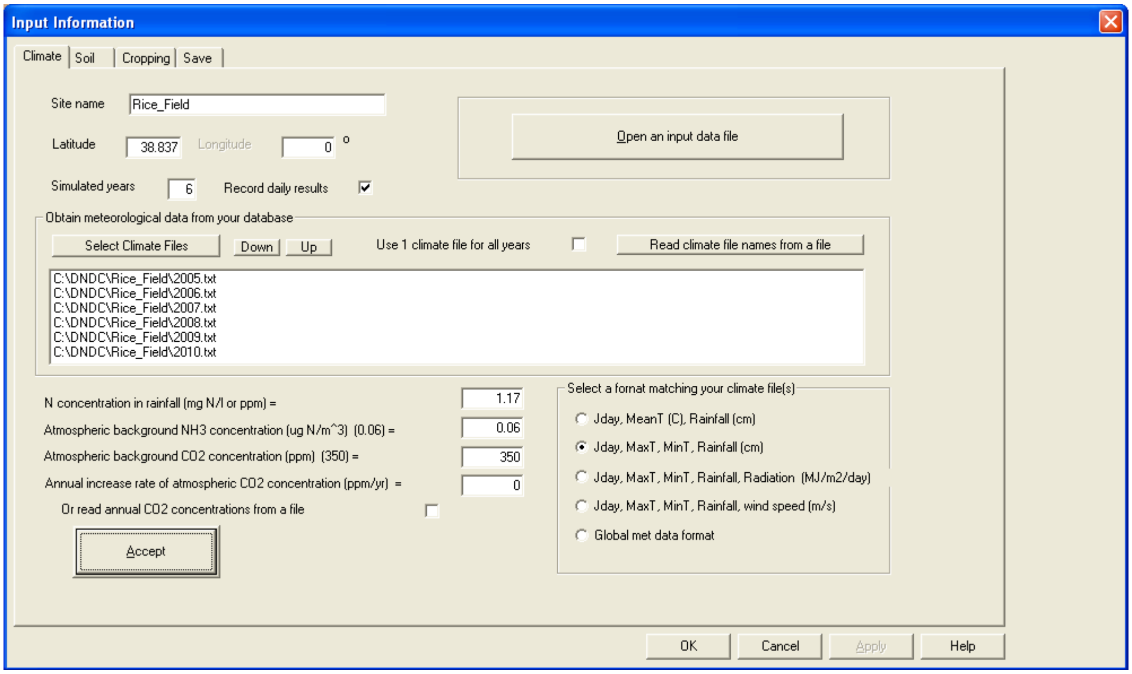

Figure C.3. Rice Site and Climate Input

Figure C.4 shows the soil data for our rice field based on site soil sampling. In this case we have data for the land use type (rice paddy), clay fraction (0.31), bulk density (1.45 g/cm^3), soil pH (7.5), and surface soil organic carbon (0.75 percent). For the rest of the parameters we will use the DNDC defaults.

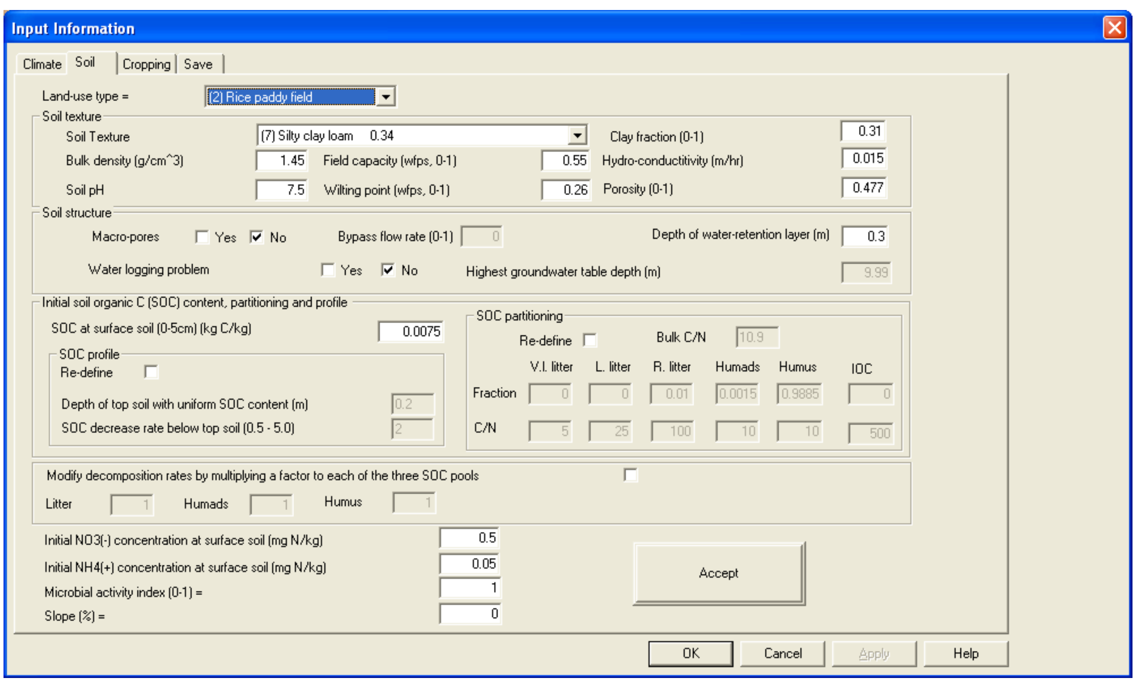

Figure C.4. Rice Soil Input

Next we will setup the cropping systems for our rice paddy. Figure C.5 shows how our cropping systems will be arranged for our six-year time period. The total years of the model run will be six years (based on the input in the Climate/Site tab); since each year of the run will have slightly different parameters, we will set these up as six different cropping systems (i.e. "Number of cropping systems applied…" should be set to 6) each of which lasts one year (i.e. "Duration of this cropping system…" should be set to 1 for each year).

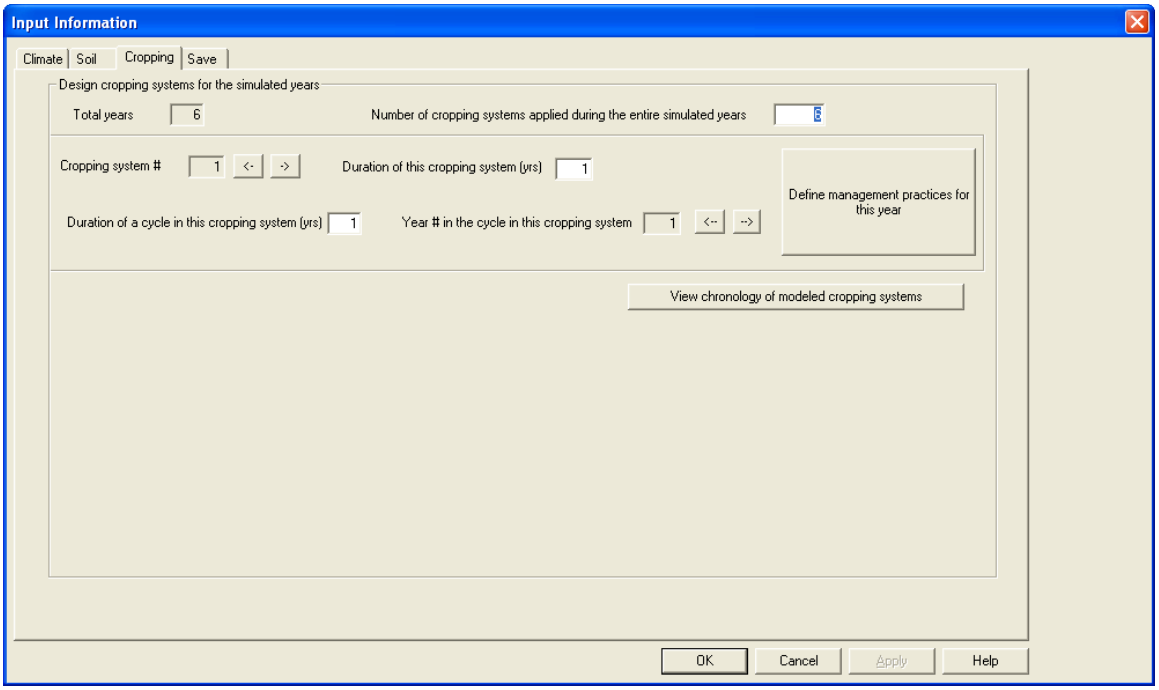

Figure C.5. Rice Cropping Systems

For this demonstration, we will show a single cropping system (year 1) as entered into DNDC (Figure C.6 through Figure C.8). The user can enter the cropping information for years 2 through 6 based on the information shown in Table C.3.

Table C.3. Rice Cropping System Information

Year	2005	2006	2007	2008	2009	2010
Cropping System	**1**	**2**	**3**	**4**	**5**	**6**
Plant Date	5/19	6/1	5/22	5/22	5/21	5/30
Harvest Date	10/12	10/30	10/15	10/13	10/29	11/12
Tillage 1	5/12 – 10 cm	5/25 – 10 cm	5/15 – 10 cm	5/15 – 10 cm	5/14 – 10 cm	5/23 – 10 cm
Tillage 2	5/13 – 10 cm	5/26 – 10 cm	5/16 – 10 cm	5/16 – 10 cm	5/15 – 10 cm	5/24 – 10 cm
Tillage 3	5/14 – 0 cm	5/27 – 0 cm	5/17 – 0 cm	5/17 – 0 cm	5/16 – 0 cm	5/25 – 0 cm
Tillage 4	10/18 – 5 cm	11/5 – 5 cm	10/21 – 5 cm	10/19 – 5 cm	11/4 – 5 cm	11/18 – 5 cm
Tillage 5	10/19 – 5 cm	11/6 – 5 cm	10/22 – 5 cm	10/20 – 5 cm	11/5 – 5 cm	11/19 – 5 cm
Fertilization 1	5/14 - 114.33 kg N/ha Urea	5/27 - 112.09 kg N/ha Urea	5/17 - 116.57 kg N/ha Urea	5/17 - 121.05 kg N/ha Urea	5/16 - 134.5 kg N/ha Urea	5/25 - 146.83 kg N/ha Urea
	injected to 10 cm	injected to 10 cm	injected to 10 cm	injected to 10 cm	injected to 10 cm	injected to 10 cm
Fertilization 2	6/29 – 168.13 kg N/ha Ammonium Sulfate	7/13 - 168.13 kg N/ha Ammonium Sulfate	7/25 - 168.13 kg N/ha Ammonium Sulfate	-	6/25 - 168.13 kg N/ha Ammonium Sulfate	7/4 – 196.15 kg N/ha Ammonium Sulfate
	applied to surface	applied to surface	applied to surface	-	applied to surface	applied to surface
Fertilization 3	-	-	-	-	7/10 – 196.15 kg N/ha Ammonium Sulfate	7/17 – 168.13 kg N/ha Ammonium Sulfate
	-	-	-	-	applied to surface	applied to surface
Flood Date	5/15/2005	5/27/2006	5/17/2007	6/11/2008	6/20/2009	5/24/2010
Drain Date	9/8/2005	9/24/2006	9/15/2007	9/10/2008	9/22/2009	10/2/2011
Additional Info				two "flushes" this year, entered as single day floods on 5/17 and 6/2	two "flushes" this year, entered as single day floods on 5/23 and 6/7	
Winter Flood Date	12/1/2005	12/1/2006	12/1/2007	12/1/2008	12/1/2009	12/1/2010
Winter Drain Date	2/28/2006	2/28/2007	2/28/2008	2/28/2009	3/15/2010	3/15/2011
Leak Rate	0.08	0.08	0.08	0.08	0.08	0.08
Yield (kg/ha)	9,796	9,097	10,882	8,980	10,087	7,220
Yield (kg C / ha)	3,918	3,639	4,353	3,592	4,035	2,888

Figure C.6 shows crop information for year 1. In this case we have entered crop type (paddy rice), planting dates, and fraction of leaves and stems left in the field (assumed to be all of the crop residue or 100 percent). In addition, in preparation for the crop calibration process we have entered in the maximum biomass for grain based on our measured data (4,353 kg C/ha) and the biomass C/N ratio from field measured data – we have accepted the default values for the rest of the crop parameters for now.

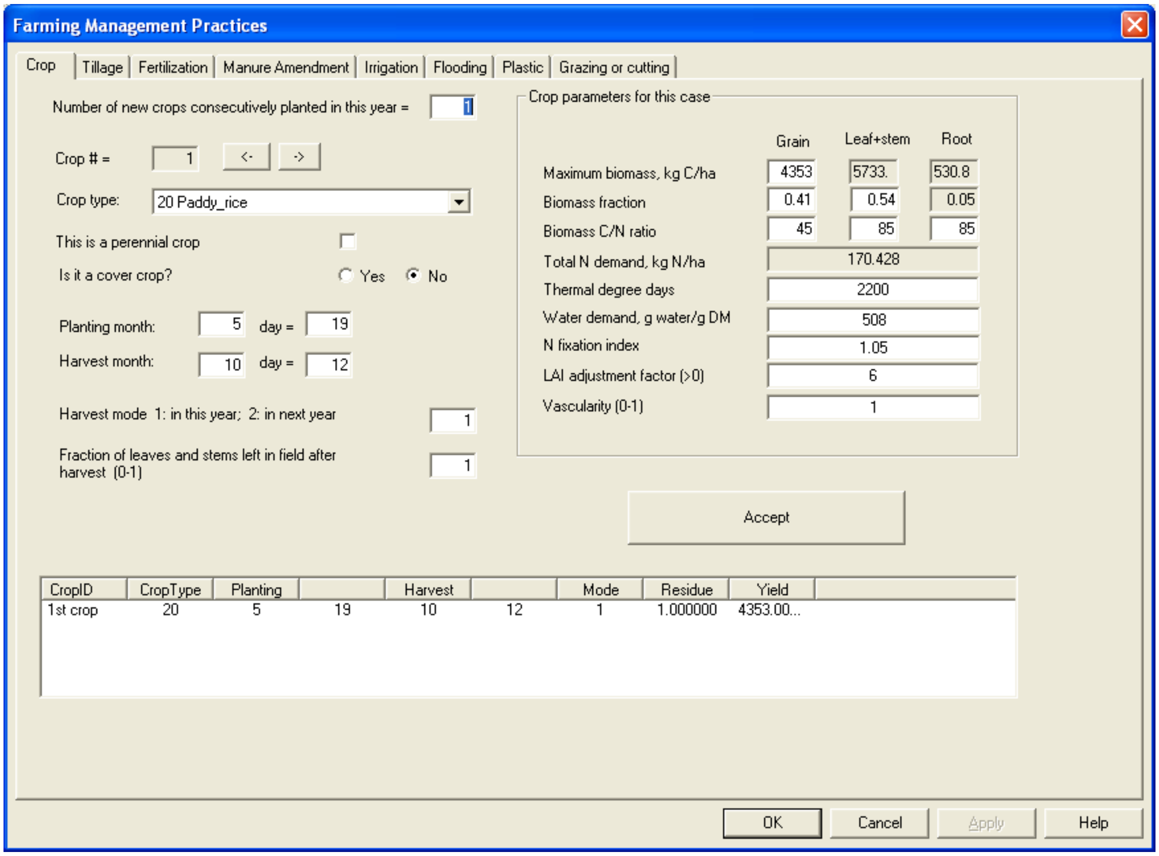

Figure C.6. Rice Farming Management Practices – Crop

Figure C.7 shows tillage practices. We have entered in all five applications and their associated dates and methods.

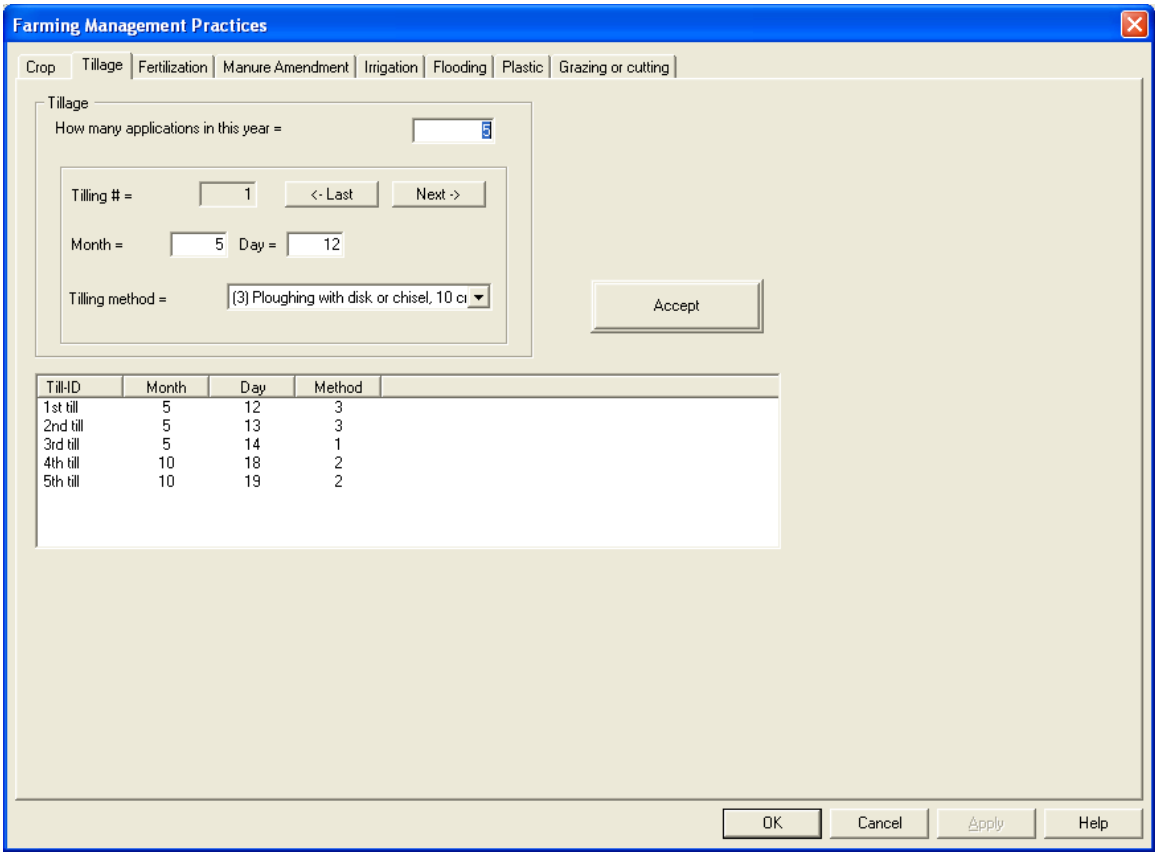

Figure C.7. Rice Farming Management Practices – Tillage

Figure C.8 shows fertilizer applications. We have entered in two applications and their associated dates, depths, and amounts.

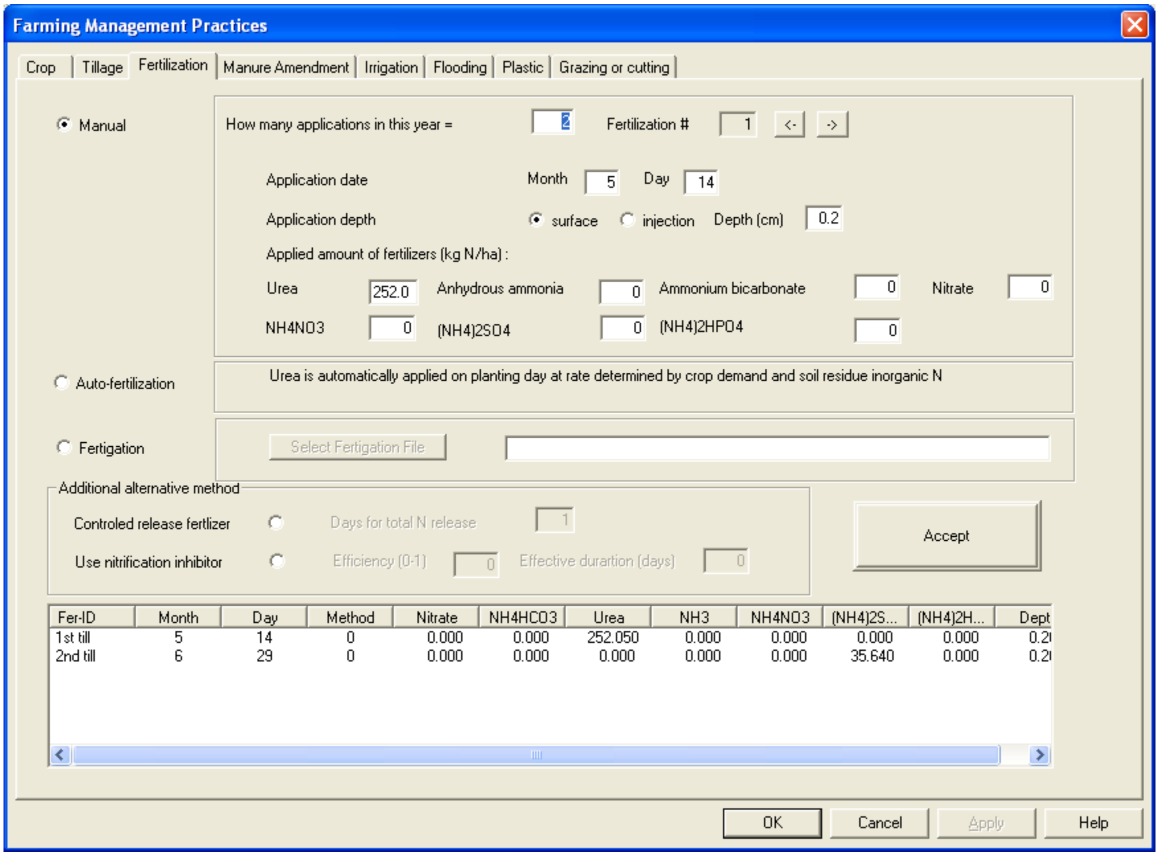

Figure C.8. Rice Farming Management Practices – Fertilization

Figure C.9 shows flooding management. We have entered in two floods (one seasonal and one winter flood) and their associated start and end dates as well as a leak rate of 0.08.

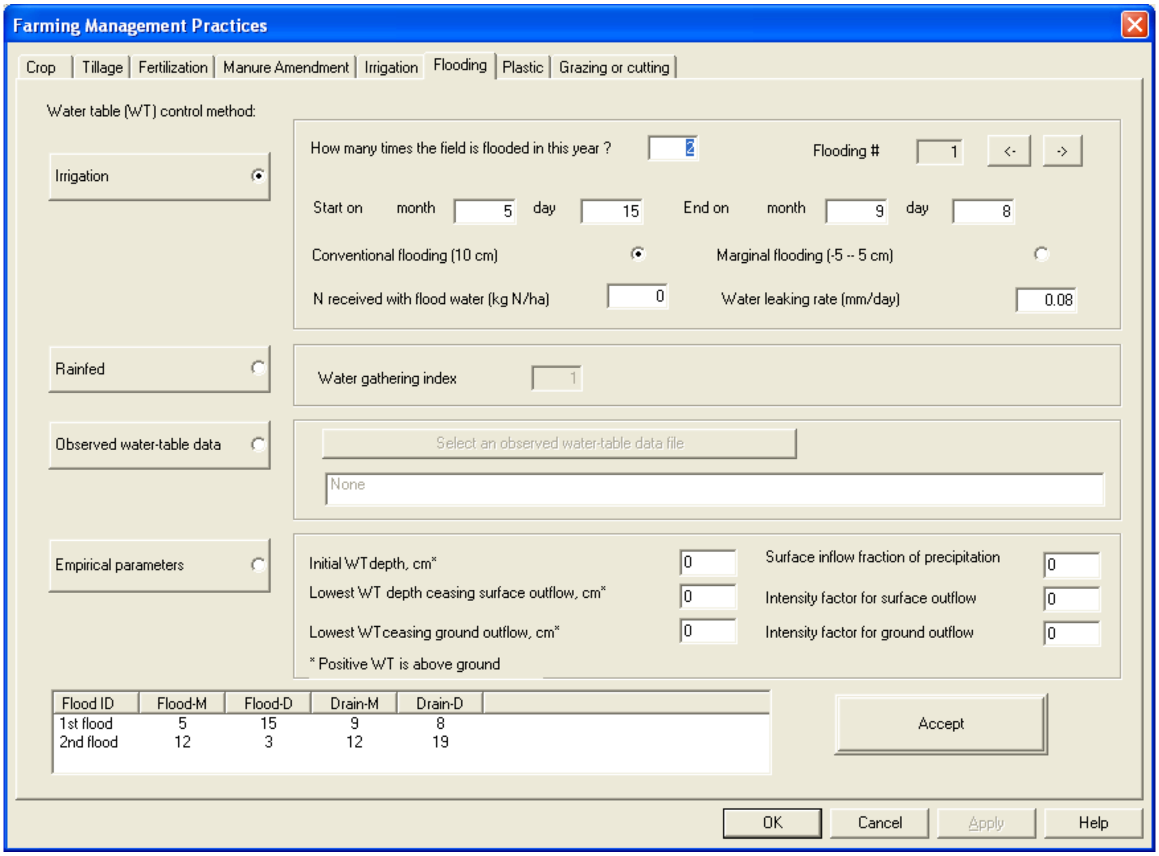

Figure C.9. Rice Farming Management Practices – Flooding

Since the farming management practices for this particular paddy do not involve any manure amendments, irrigation, plastic applications, or grazing/cutting, we will not enter any information on these tabs. The user should ensure that no residual information remains on these tabs from previous model runs.

When all of the information is entered, the user should save the results to a *.dnd file – we will call this "Baseline.dnd"; this file can be used later to set-up alternative management scenarios or to re-run model results.

Crop Model Calibration

The model can now be run to prepare for the crop model calibration – this can be done on the main DNDC screen by clicking the site mode "Run" button. Results are put in the "C:\DNDC\Result\Record\Site" directory.

To review the first iteration of the crop calibration process, we need to compare the modeled yield with measured yield. Modeled yield can be found in "Multi_year_summary.csv" in the "Yield_GrainC" field. These values can be compared with measured yields as in Table C.4. In this case, the maximum absolute difference between measured and modeled yields is large (48 percent) so we will opt to run another iteration with adjusted crop parameters.

Table C.4. Rice Crop Model Calibration – Iteration 1

Year	DNDC Yield (Yield_GrainC)	Measured Yield	Absolute Difference	Absolute Difference Percent
1	4,041	3,918	123	3%
2	4,012	3,639	373	10%
3	4,134	4,353	219	5%
4	3,266	3,592	326	9%
5	3,506	4,035	529	13%
6	4,266	2,888	1,378	48%

We will start the calibration process by modeling a single year: the year with the maximum measured yield (year 3). We will create the run using all of the site characteristics (climate, soil, and known crop parameters), and, as suggested in step 1 of the calibration process, we will use optimal fertilization (i.e. use the auto-fertilization setting). When this iteration is run, grain yield is 4,264 kg C/ha/y; a difference of only two percent. Since this difference is small, we will use the maximum measured yield as the maximum biomass parameter.

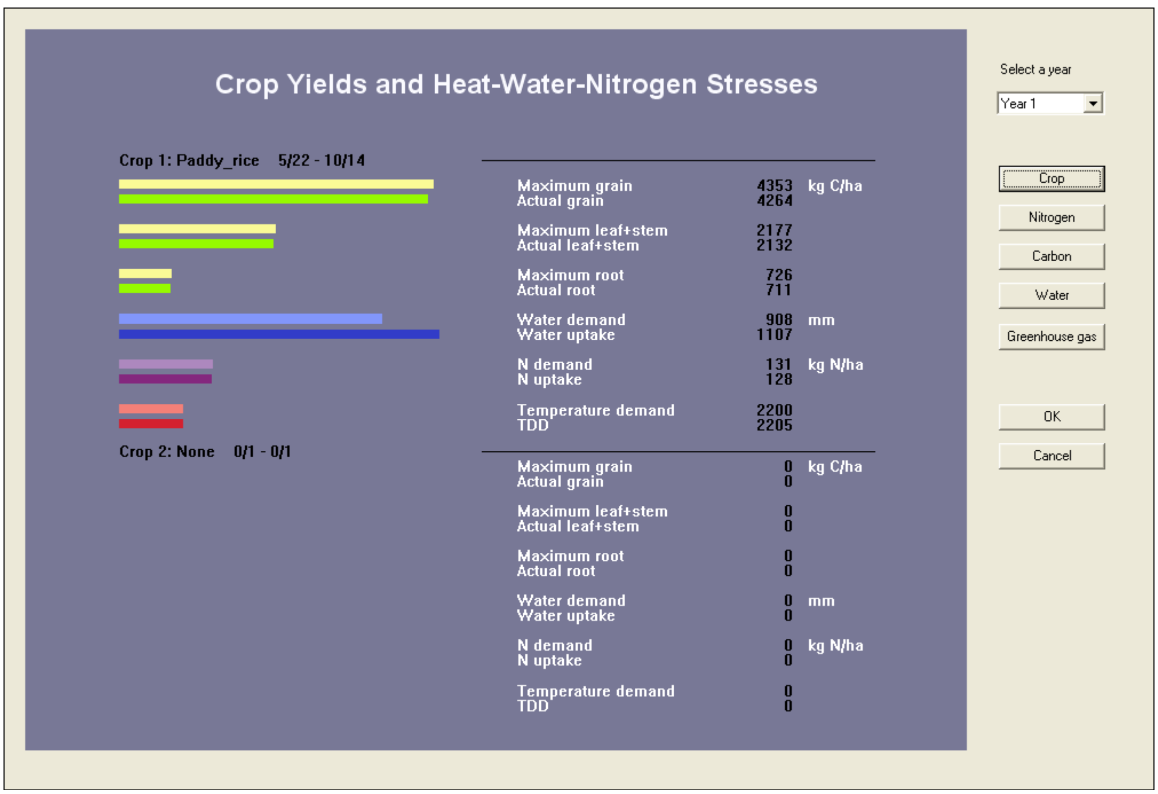

Figure C.10. Rice Crop Yields - Iteration 1

Next, we will check the modeled grain maturity date in the “Day_FieldCrop.csv” file: grain matures on day 238 (August 26) – this appears to be too early as the maturity date should be approximately the same date as the seasonal flood drain date (September 15). By increasing the thermal degree days parameter from 2,200 to 2,700 and re-running the model, we arrive at a more reasonable maturity date (day 260 or September 17).

Since there is no irrigation for paddy rice crops we can skip step 3 of the calibration process. We can now make one minor adjustment to the baseline scenario based on the calibration process: change the crop thermal degree days parameter from 2,200 to 2,700.

Creating Alternative Management Scenarios

For this rice paddy example we will look at two scenarios:

- Water seeded rice with all crop residue left onsite, with a winter flood (the baseline scenario)
- Dry seeded rice with all crop residue left onsite, with a winter flood (the dry seeded scenario)

To do this, we will make a copy of the baseline scenario (“Baseline.dnd”) to be adjusted for the alternative scenarios. Each file can be renamed to represent a scenario. We will use the following file names:

- “Baseline.dnd”
- “DrySeeded.dnd”

There are two ways to change the parameters in each *.dnd file. The first is through the DNDC GUI. For a complicated, multi-year run, this is straightforward and a less error-prone method. Users who familiarize themselves with the *.dnd file format (see *DNDC User’s Guide*, Section III-1.2) may be able to make these same changes in a text editor.

We will go through the revision process for the above-listed scenarios here (“DrySeeded.dnd”).

Here are the key changes to the baseline to create the dry seeded scenario:

- Site name ⟶ dry seeded[80]
- Adjust the timing of the flood-up period relative to seeding, shift from May 17 to June 12
- Add two irrigation events (May 23 and June 1)

Open the “DrySeeded.dnd” scenario on the DNDC Input Information dialogue (click on “Open an input data file”). The site name can be changed on the Climate tab of the Input Information dialogue. We will call this scenario “DrySeeded.”

For each of the cropping systems (years), we will change the flooding information. Baseline flooding is shown in Figure C.11. And, since we are shifting to dry seeding, we will shift the second flood start date from May 17 to June 12 (see Figure C.12).

[80] Project developers will eventually be running these scenarios in batch mode, so it is important that the site name be changed so that project developers will be able to distinguish the various results from each other.

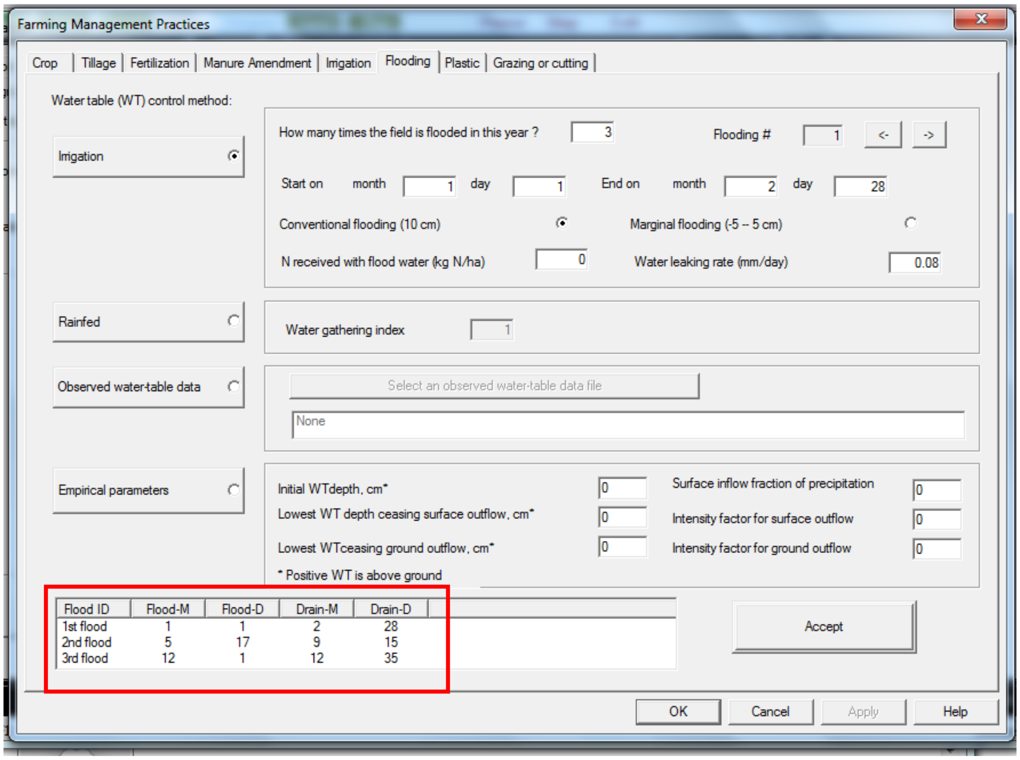

Figure C.11. Baseline to Flooding

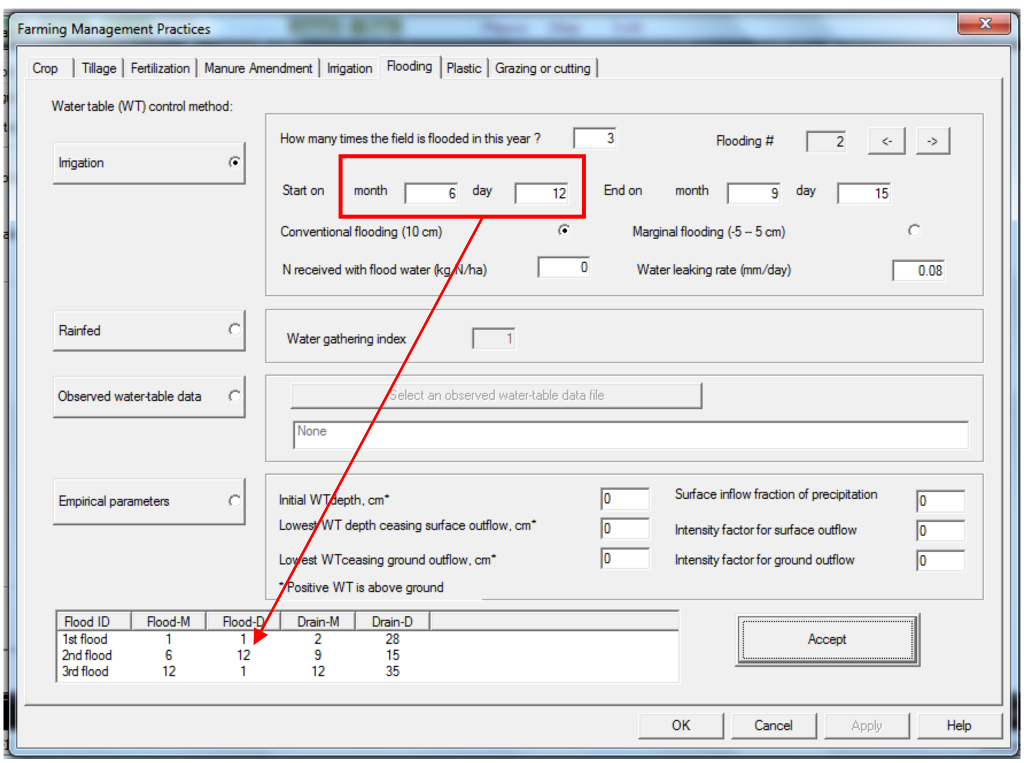

Figure C.12. Dry Seeding Flooding

In addition to a shift in when the fields are flooding for the rice growing season, dry seeding requires irrigation events following seeding to establish a good crop canopy prior to flooding. For this example we illustrate use of two irrigation events (May 23 and June 1) with 10 cm irrigation water for each event. Figure C.13 illustrates the DNDC irrigation tab with these two 10 cm irrigation events scheduled for May 23 and June 1.

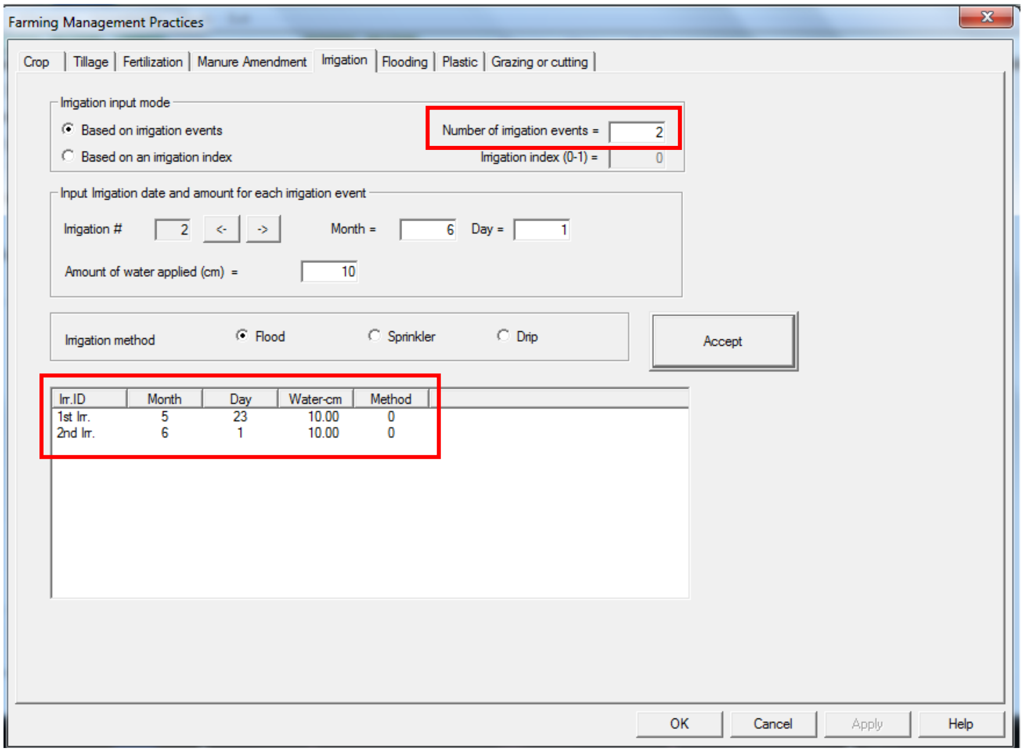

Figure C.13. Irrigation Events for Dry Seeding Scenario

Results for each site run can be examined using the DNDC results tab. Annual emissions for year 20 of a 20-year run for both baseline and dry seeded scenarios are presented in Figure C.14 and Figure C.15, respectively.

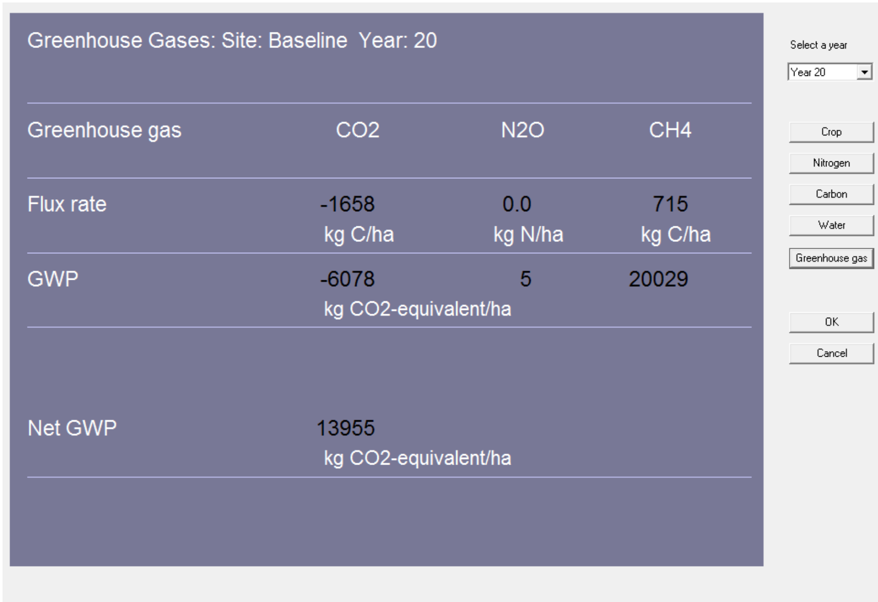

Figure C.14. DNDC Results Panel for Baseline Scenario

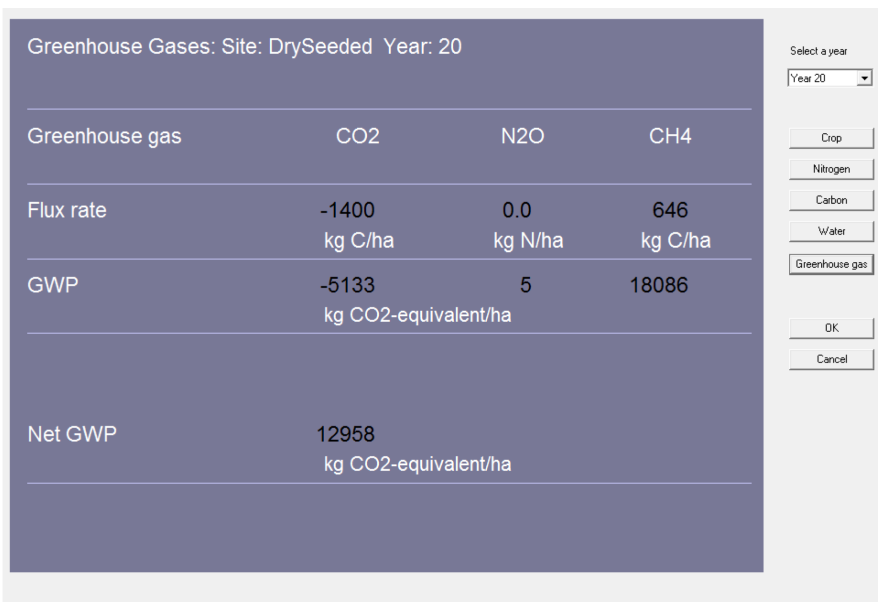

Figure C.15. DNDC Results Panel Dry Seeding Scenario

For this example shift from wet seeded rice to dry seeded, the modeled reduction in GHG emissions was 0.997 tCO_2e/ha.

Once the site level *.dnd files are created for both the baseline and project scenarios, the new software tool for creating all the batch file inputs following the Monte Carlo sampling procedures described in the RCPP can be run. Once the input files are complete, the user can then select batch mode from the tools menu in DNDC (see Figure C.16) and run DNDC in batch mode. A second software tool will then compile all the results from the batch run and provide the model estimates of GHG reductions.

Figure C.16. Batch Mode in DNDC

Appendix D Derivation of Structural Uncertainty Deduction Factors

D.1 Overview

As described in Section 5.4.2 of the protocol, the deduction factor to account for DNDC model structural uncertainty will be published on the Reserve's website (and periodically updated),. This section explains the methodology used by the Reserve to determine the deduction factor.

The structural uncertainty deduction factor will be a function of the total number of fields registering emission reductions with the Reserve in any given cultivation cycle. The procedure described in this appendix will be performed for each region for which the RCPP is applicable in order to determine the appropriate uncertainty deduction factor to be used for each region. For each region, the Reserve will determine the exact deduction factors to be used, and whether the deduction factors are additive or multiplicative (determined as described below). This version of the protocol is applicable to the California Sacramento Valley Region and uses DNDC Version 9.5, for which the structural uncertainty deduction is additive. The structural uncertainty factor is derived based on validation of a specific version of DNDC, and can only be applied to that version. As such, the Reserve will publish structural uncertainty deductions that are specific to a single version of the DNDC model.

The structural uncertainty deduction factor $\boldsymbol{\mu_{struct}}$ is defined such that, after application of the uncertainty deduction factor to the direct emission reductions[81] the following inequality holds in 95 percent of the cases, i.e. with 95 percent confidence.

$$\mathbf{DERs} < \boldsymbol{BE_{meas}} - \boldsymbol{PE_{meas}}$$

The uncertainty deduction can be either added or multiplied to the gross difference between project and baseline emissions, depending on whether the error structure of the residuals is additive or multiplicative.

In the additive case:

$$\mathbf{DERs} = \boldsymbol{\mu_{struct}} + (\boldsymbol{BE_{meas}} - \boldsymbol{PE_{meas}})$$

In the multiplicative case:

$$\mathbf{DERs} = \boldsymbol{\mu_{struct}} \times (\boldsymbol{BE_{meas}} - \boldsymbol{PE_{meas}})$$

Where,

DERs	=	Direct emission reductions
μ_{struct}	=	Structural uncertainty factor
$PE_{meas}(i)$	=	Field results for project emissions
$BE_{meas}(i)$	=	Field results for baseline emissions

Before the derivation of $\boldsymbol{\mu_{struct}}$ is continued, the lack of bias is confirmed and it is determined whether the error structure of the residuals is additive or multiplicative.

[81] Note that although DNDC is used to model both direct emission reductions and some indirect emission reductions, for simplicity, this guide refers to all modeled emission reductions as direct.

D.2 Confirming the Lack of Bias

The derivation of the structural uncertainty term assumes that no bias exists between measured and modeled results, or that $\langle \boldsymbol{Y_{meas}} \rangle = \langle \boldsymbol{Y_{model}} \rangle$. The DNDC model has been shown to predict greenhouse fluxes without bias, when correctly calibrated. This methodology specifies how model inputs can be set so that the model is calibrated correctly. For each region, it is explicitly tested that the model calibration strategy does not lead to bias by comparing modeled and measured emissions using a paired t-test.

D.3 Verification of the Nature of the Structural Error

The structural error induced by a biogeochemical model such as DNDC is either multiplicative or additional.

In case the error is additive:

$$\boldsymbol{Y_{model,i}} = \boldsymbol{Y_{field,i}} + \boldsymbol{\varepsilon_i} \text{ with } \boldsymbol{\varepsilon} \sim \boldsymbol{\mathcal{N}}(\boldsymbol{0}, \boldsymbol{\sigma})$$

In case the error is multiplicative:

$$\boldsymbol{Y_{model,i}} = \boldsymbol{Y_{meas,i}} \times \boldsymbol{e^{\varepsilon_i}} \text{ with } \boldsymbol{\varepsilon} \sim \boldsymbol{\mathcal{N}}(\boldsymbol{0}, \boldsymbol{\sigma})$$

For each region, it is explicitly determined whether an additive or multiplicative error model must be assumed. The deviation between modeled and measured results will be multiplicative if residuals increase with increasing modeled values. However, if the deviation between modeled and measured results is additive, the residuals will be constant across modeled values. This is verified by investigating the heteroscedasticity of the residuals or by plotting the residuals versus the model values. In case of doubt, the additive case will lead to more conservative crediting than the multiplicative case and may be used as a default.

D.4 Derivation of the Structural Uncertainty Deduction in Case the Error Term is Additive

If the error is additive and the model is bias-free, the following error model can be assumed for the project and baseline emissions.

$$\boldsymbol{PE_{model}} = \boldsymbol{PE_{meas}} + \boldsymbol{\varepsilon_1} \text{ with } \boldsymbol{\varepsilon_1} \sim \boldsymbol{\mathcal{N}}(\boldsymbol{0}, \boldsymbol{\sigma^2})$$
$$\boldsymbol{BE_{model}} = \boldsymbol{BE_{meas}} + \boldsymbol{\varepsilon_2} \text{ with } \boldsymbol{\varepsilon_2} \sim \boldsymbol{\mathcal{N}}\left(\boldsymbol{0}, \boldsymbol{\sigma^2}\right)$$

A correlation between the project and baseline residuals may exist:

$$\boldsymbol{\rho} = \textbf{corr}(\boldsymbol{\varepsilon_1}, \boldsymbol{\varepsilon_2})$$

Where,

μ_{struct}	=	Structural uncertainty factor
$PE_{model}(i)$	=	Model results for project emissions
$BE_{model}(i)$	=	Model results for baseline emissions
$PE_{meas}(i)$	=	Field results for project emissions
$BE_{meas}(i)$	=	Field results for baseline emissions
ε_1	=	Error term for project emissions

ε_2	=	Error term for baseline emissions
σ	=	Standard deviation of the residuals between modeled and measured values
ρ	=	Correlation between project residuals and baseline residuals

If the direct emission reductions are the difference between project and baseline, one can write:

$$DER_{model} = BE_{model} - PE_{model}$$
$$DER_{meas} = BE_{meas} - PE_{meas}$$

Where:

DER_{model}	=	Direct emission reductions based on modeled emissions
DER_{meas}	=	Direct emission reductions based on measured emissions

Because there is no bias between the model and the measurements, the average of the difference between DER_{model} – DER_{meas} is 0. The variance of this difference is:

$$\begin{aligned}\mathrm{Var}(DER_{model} - DER_{meas}) &= \mathrm{Var}(\varepsilon_1) + \mathrm{Var}(\varepsilon_2) - 2\mathrm{Cov}(\varepsilon_1, \varepsilon_2)\\ &= \sigma^2 + \sigma^2 - 2\sigma^2\rho\\ &= 2\sigma^2(1-\rho)\end{aligned}$$

In case there are multiple fields **n**, the inequality introduced in the beginning of this section has to hold only for the sum of the direct emission reductions, and for the direct emission reductions of each individual field. In this case, the variance of the sum of the emission reductions is:

$$\begin{aligned}\mathrm{Var}\left(\sum_{i=1}^{n} DER_{model,i} - DER_{meas,i}\right) &= n\cdot\mathrm{Var}(\varepsilon_1) + n\cdot\mathrm{Var}(\varepsilon_2) - 2n\cdot\mathrm{Cov}(\varepsilon_1, \varepsilon_2)\\ &= n\sigma^2 + n\sigma^2 - 2n\sigma^2\rho\\ &= 2n\sigma^2(1-\rho)\end{aligned}$$

If s is the standard deviation of the model residuals based on a limited set of k calibration values, the one-sided 95 percent confidence interval around the sum of the differences DER_{model} – DER_{meas} is:

$$DER_{model} - DER_{meas} < s\sqrt{2(1-\rho)} \times t_{inv}(0.95, k)$$

In other words:

$$\mu_{struct} = \frac{s\sqrt{2(1-\rho)}}{\sqrt{n}} \times t_{inv}(0.95, k)$$

Where:

μ_{struct}	=	Structural uncertainty factor
s	=	Standard deviation
ρ	=	Correlation between project residuals and baseline residuals
t_{inv}	=	Inverse of the cumulative t-distribution with a specific confidence and degrees of freedom
k	=	Number of pairs of modeled and measured values used for model verification.
n	=	Number of fields within the project “aggregate”

D.5 Derivation of the Structural Uncertainty Deduction in Case the Error Term is Multiplicative

If the error is multiplicative and the model is bias-free, the following error model can be assumed for the project and baseline emissions:

$$\boldsymbol{PE_{model}} = \boldsymbol{PE_{meas}} \times \boldsymbol{e^{\varepsilon_1}} \text{ with } \boldsymbol{\varepsilon_1 \sim \mathcal{N}(0, \sigma^2)}$$
$$\boldsymbol{BE_{model}} = \boldsymbol{BE_{meas}} \times \boldsymbol{e^{\varepsilon_2}} \text{ with } \boldsymbol{\varepsilon_2 \sim \mathcal{N}\left(0, \sigma^2\right)}$$

A correlation between the project and baseline residuals may exist:

$$\boldsymbol{\rho} = \mathbf{corr}(\boldsymbol{\varepsilon_1}, \boldsymbol{\varepsilon_2})$$

Where:

$\mathrm{PE_{model}(i)}$	=	Model results for project emissions
$\mathrm{BE_{model}(i)}$	=	Model results for baseline emissions
$\mathrm{PE_{meas}(i)}$	=	Field results for project emissions
$\mathrm{BE_{meas}(i)}$	=	Field results for baseline emissions
ε_1	=	Error term for project emissions
ε_2	=	Error term for baseline emissions
σ	=	Standard deviation of the residuals between modeled and measured values
ρ	=	Correlation between project residuals and baseline residuals

We will use the same terminology DER_{model} and DER_{meas} as introduced in the additive case in the subsequent derivation. The derivation is similar to the additive case if the following log-transformation is applied:

$$\ln\left(\frac{\boldsymbol{DER_{meas}}}{\boldsymbol{DER_{model}}}\right) = \ln(\boldsymbol{PE_{meas}}) + \boldsymbol{\varepsilon_1} - \ln(\boldsymbol{BE_{meas}}) - \boldsymbol{\varepsilon_2} - \ln(\boldsymbol{PE_{meas}}) + \ln\,(\boldsymbol{BE_{meas}})$$

The variance of this ratio can be derived similarly as for the additive case:

$$\mathbf{Var}\left(\ln\left(\frac{\boldsymbol{DER_{meas}}}{\boldsymbol{DER_{model}}}\right)\right) = \boldsymbol{2\sigma^2(1-\rho)}$$

The quantity **σ** can be estimated by the standard deviation of the difference of the log-transformed project and baseline emissions based on a limited set of **k** calibration values on the condition that a student-t distribution is used in the subsequent one-sided confidence interval:

$$\sum_{i=1}^{n} \ln\left(\frac{\boldsymbol{DER_{meas}}}{\boldsymbol{DER_{model}}}\right) < s\frac{\sqrt{\boldsymbol{2(1-\rho)}}}{\sqrt{\boldsymbol{n}}} \times \boldsymbol{t_{inv}(0.95, k)}$$

Rearranging this equation yields:

$$\ln\left(\frac{\boldsymbol{DER_{meas}}}{\boldsymbol{DER_{model}}}\right) < s\frac{\sqrt{\boldsymbol{2(1-\rho)}}}{\sqrt{\boldsymbol{n}}} \times \boldsymbol{t_{inv}(0.95, k)}$$

$$DER_{meas} < DER_{model} \times e^{s\frac{\sqrt{2(1-\rho)}}{\sqrt{n}} \times t_{inv}(0.95,k)}$$

In other words:

$$\mu_{struct} = e^{-s\frac{\sqrt{2(1-\rho)}}{\sqrt{n}} \times t_{inv}(0.95,k)}$$

D.6 Quantifying the Standard Deviation s and the Correlation ρ

The calculation of μ_{struct} is critically dependent on the standard deviation of the residuals (i.e. the difference between modeled and measured values) **s** and the correlation between the residuals of the project emissions and the residuals of the baseline emissions **ρ**.

These quantities are calculated based on at least 8 pairs of measured and simulated annual emissions that have been measured over at least two growing seasons.

In case only annual fluxes are available, k pairs of $\left(Y_{meas}(i), Y_{model}(i)\right)$ will be available with $k \geq 8$.

In the additive error case, the quantity s can be calculated as the standard deviation of the difference between $Y_{meas}(i)$ and $Y_{model}(i)$. Note that the student-t distribution includes a deduction due to the standard deviation being estimated on a limited set of values. Lower deductions will be achieved if k is higher and more measurements are available.

The quantity ρ can be estimated by dividing the measurements in “baseline” cases, $BE_{meas}(i)$ and “project” cases, $PE_{meas}(i)$. In conventional language, the baseline would be the control or conventional treatment. Subsequently, pairs of measured and simulated emission reductions $DER_{meas}(i)$ and $DER_{model}(i)$ can be calculated as the difference between $PE_{meas}(i)$ and $BE_{meas}(i)$, and $PE_{model}(i)$ and $BE_{model}(i)$, respectively. **ρ** is calculated as the correlation coefficient between $DER_{meas}(i)$ and $DER_{model}(i)$. Smaller correlation coefficients will result in greater uncertainty deductions. Therefore, a set of correlation coefficients is calculated through leave-one-out jackknifing and the correlation coefficient set to the low range of this set of values.

In the multiplicative error case, the quantity s can be calculated as the standard deviation of the difference between $\ln Y_{meas}(i)$ and $\ln Y_{meas}(i)$. Similarly as for the additive case, smaller deductions will be achieved if k is higher and more measurements are available. **ρ** is calculated as the correlation coefficient between $\ln\left(\frac{PE_{meas}(i)}{BE_{meas}(i)}\right)$ and $\ln\left(\frac{PE_{model}(i)}{BE_{model}(i)}\right)$.

However, if a set of daily fluxes are available, the quantities s and **ρ** are calculated with more accuracy based on daily values of these quantities as:

$$s_{annual} = 365 \times s_{daily}$$
$$\rho_{annual} = \rho_{daily}$$

Note that any other time period (i.e. 3-daily or weekly) can be used.

Appendix E Summary of Performance Standard Research

This section summarizes research on industry trends in the use of water and residue management practice in rice cultivation that have the potential to reduce methane emissions. The research focused on three practices that had previously been identified in other methodologies as having GHG mitigation potential: dry seeding, reduced winter flooding, and residue management. The outcomes of the research were used to develop performance standards in this protocol.

E.1 Background on Water and Residue Management Practices

Rice is a unique agricultural system due to the use of flooding to meet the plant physiological demands and to control weeds. There are unique advantages of flooding and maintaining a flood throughout the growing season. These advantages include: (1) easier water management and less water use, (2) red rice and grass suppression, (3) less seedling stress from cool weather, (4) elimination of early-season blackbird problems, and (5) reduction in seedling loss due to salt.

Producers' decisions regarding which seeding method to use are targeted at selecting the method that will result in proper seedling emergence that will lead to a uniform canopy. Seeding methods depend on soil type, weather conditions, and producer preferences. Seeding methods for rice production include both water seeding and dry seeding. **Water seeding** describes sowing of dry or soaked seed into a flooded field. It is usually implemented for any or all of the following reasons: red rice control, wet planting season, planting efficiency, and earlier crop maturity. **Dry seeding** simply describes sowing seed into a dry seedbed by drilling or broadcasting. Dry seeding method usually offers more flexibility in planting but may require more time to do so. The flood for dry seeded rice starts approximately 25 to 30 days after seeding. During the dry period, fields are periodically irrigated to promote germination and stand establishment. This system is also weather dependent. A small fraction of the rice acreage is dry seeded in California.

In California, water seeding with continuous flood is predominant during the growing season. Continuous flood regime is used on over 96 percent of the acreage in California. Fields are flooded to a depth of 4 to 5 inches just prior to aerial seeding. While deeper flooding will further reduce weed pressures, it will also lead to poor stand establishment. Once the rice stand is established and the panicle initiation has occurred, many growers will increase the depth of the flood water to 8 inches. This helps with further weed control and protects the rice reproductive organs from cool nighttime temperatures that can lead to reduced yields via blanking. Occasionally, several weeks after seeding, fields are drained for one day to apply herbicide for weed control. This drain is short lived and does not lead to drying of the soil surface. Fields are also drained near the harvest date. The exact timing for draining the fields can vary and can influence total yields.

The University of California Cooperative Extension (UCCE) recommends that growers drain their fields when the panicles are "fully tipped and golden." This is done through visual inspection and is typically two to four weeks prior to anticipated harvest date. According to UCCE, there is a large variability in when growers choose to drain the fields. Some growers choose to drain when the rice is partially or 50 percent "tipped," some wait until 75 percent tipped, and others follow UCCE guidelines of 100 percent or fully tipped.

After the growing season, winter flooding can be used to enhance rice straw decomposition. With a winter flood system, the flood water is introduced to the field shortly after harvest is completed. Growers either maintain flooded conditions until spring by reapplying flood waters or they just use a single flood event. Growers' decisions to flood the field after harvest are influenced by timing of the harvest, habitat goals, and expectations regarding availability of water (Term 91).

E.2 Industry Trends in the Use of GHG Mitigation Practices

Winter Flooding

Two sources of data were used to characterize the use of winter flooding in California rice systems. Site-specific records on the use of winter flooding were collected from the following four irrigation districts: Glen-Colusa, RD 108, Richvale, and Western Canal. In addition, multi-temporal remote sensing data (MODIS and Landsat) were analyzed to map spatial patterns of winter flooding from 2005 to 2010 for the entire California Sacramento Valley.

The data from the Glenn-Colusa Irrigation District (representing over 20 percent of California rice acreage) were analyzed in a GIS to assess acreage of winter flooding from 2007 to 2010 and persistence of winter flooding from one year to the next for each rice field. Approximately 40 percent of the fields did not use winter flooding from 2007 to 2010 (Table D.1). Of the 60 percent of the fields that did use winter flooding at some point, less than one percent of the fields winter flooded for all four years. The data from the other irrigation districts (RD 108, Richvale, and Western Canal) showed similar variability in the fraction of fields with winter flooding.

Table E.1. Presence and Frequency of Winter Flooding in Glenn-Colusa Irrigation District (2007-2010)

Class	Acreage	%
No Floods	42161.9	40.0%
1 Yrs	20314.3	19.3%
2 Yrs	22346.9	21.2%
3 Yrs	17566.9	16.7%
4 Yrs	1912.6	1.8%
Other	977.4	0.9%

In addition, multi-temporal remote sensing data (MODIS and Landsat) was analyzed in order to map spatial patterns of winter flooding for rice growing areas for all of California from 2005 to 2010. These results also indicated that the use of winter flooding varies from one year to the next and there is no clear trend in the extent and frequency of use of winter flooding for all rice growing regions. Details of the spatial analysis of winter flooding are provided in a separate background research paper that will be published on the Reserve website.

The results of this research show that the use of winter flooding every year is virtually non-existent; it is more typical for winter flooding to be used one, two or three years out of every five years with no winter flooding during the other years; and 40 percent of acres appear to never be flooded during the five year interval investigated. Data reported in the background paper[82] affirm these same findings over a longer historical period. Therefore, reduced winter flooding (i.e. the

[82] Background paper will be made available on the Climate Action Reserve website.

absence of winter flooding) is already somewhat common in the California Sacramento Valley. In addition, the intermittent trend in use/non-use of winter flooding, make it difficult to reliably determine what expected levels of reduced winter flooding would be in any given year under "business as usual." These findings, combined with concerns about negative impacts on waterfowl habitat, led to a decision to exclude reduced winter flooding as an eligible project activity in the protocol.

Rice Straw Residue Management

Rice straw represents a significant challenge to rice farmers. Techniques for managing rice straw can be categorized into the following management alternatives: burning, baling, soil incorporation without winter flooding, and soil incorporation with winter flooding for enhanced straw decomposition.

Rice straw may or may not be prepared by chopping or soil-incorporating before flooding. After flooding, many fields are rolled with specially built "cage rollers" which help create soil/straw contact. Decomposition of straw in this system is not limited by moisture and has consistently given more complete decomposition compared to non-flooded systems.

Most potential uses of rice straw can be categorized into energy use, manufacturing and construction, environmental mitigation or livestock use. Environmental mitigation includes the use of rice straw for erosion control on construction areas or for rehabilitation on burned slopes. Small amounts of rice straw are used in composting, mushroom production, and livestock feed and bedding.

There are many potential uses of rice straw, yet few are currently being used. The reasons appear to be related to 1) technical constraints, 2) economic feasibility, particularly related to the cost of removing straw from the field, and 3) supply and storage problems.

Until 1991, burning rice straw was the most common practice. Following the 1991 Rice Straw Burning Reduction Act, burning of rice straw decreased dramatically on an annual basis. By 2001, growing season burning of rice straw was permitted for disease control only with a cap of 25 percent of total rice acreage in the state burned annually. Currently, burning occurs on only 10 to 12 percent of rice acreage in California.[83]

If the straw is not burned, then growers will either retain and incorporate all of the straw on the field or they will bail the rice straw for off-field uses. The current estimate from the California Rice Commission (CalRice) for baling in California is 6 to 8 percent of the acreage per year. This estimate was further corroborated by the Reserve through analysis of previous research,[84] and through the use of a survey of University of California Cooperative Extension (UCCE) rice farm advisors and straw balers in California. Results from the survey suggest that rice baling has declined in recent years due to a loss of demand from the building and construction industry. Estimates from UCCE Rice Farm Advisors ranged from 2 to 6 percent of the California acreage in a given year. This obviously fluctuates a bit with various straw markets. It is also important to note that baling does not remove all of the rice straw following harvest. Due to operational constraints and the market for straw, baling typically removes one to two tons of rice straw per acre out of approximately three tons per acre that is produced. Therefore, anywhere from 50 percent to 33 percent of the rice straw remains on the field. On an annual basis, 80 to 84 percent of all rice fields have 100 percent of the rice straw incorporated into the soil.

[83] Personal communication with Paul Buttner.
[84] Garnache et al., 2011.

Based on the evidence presented by California rice industry experts, the Reserve has concluded that baling of rice straw is not a common practice in California, with a likely adoption rate of between 2 to 7 percent of the acreage. Thus, the Reserve has concluded that switching from rice straw incorporation to baling constitutes an additional GHG reduction practice in California.

Dry Seeding

According to the USDA Economic Research Service ERS data analyzed by Livezey et al. in 2001, a dry seeding method is relatively common in most U.S. rice growing regions; however, it is not common practice in California. In 2001, the estimated acreage of rice that was dry seeded was 5 percent according to the ERS data.[85] To confirm that dry seeding is still not a common practice in California, the Reserve again relied on the estimates provided in survey responses from UCCE Rice Farm Advisors, as well as estimates from the California Rice Commission. According to experts from the UCCE and CalRice, dry seeding is occurring on less than 3 percent of the rice acreage in California.

Based on the evidence presented by California rice industry experts, the Reserve has concluded that dry seeding is not a common practice in California, with a likely adoption rate of less than 3 percent of the acreage. Thus, the Reserve has concluded that switching from water seeding to dry seeding constitutes an additional GHG reduction practice in California.

[85] Livezy et al., 2001, Table 5, pg.10.

Appendix F Wildlife Habitat Conservation and the Rice Industry

In California's Central Valley, approximately 95 percent of the original existing wetlands have been converted from their natural state.[86]

As native wetland habitats have been increasingly degraded, wetland-dependent species, such as waterfowl and shorebirds, have adapted to using flooded rice lands as a substitute for their native habitat. Rice fields may be flooded for up to eight months of the year, mimicking natural wetland conditions and providing surrogate habitat for foraging, breeding, and in the case of migratory birds, wintering.

Though a wide range of species can be observed in each of the U.S. rice growing regions, more species data are available for California's Central Valley than for other U.S. rice growing regions. In California, seven million waterfowl and several hundred thousand shorebirds are supported by rice lands annually,[87] and over 230 species have been identified in the state's rice lands, including waterfowl (e.g. ducks), shorebirds, wading birds, raptors, reptiles, amphibians, and small mammals.[88] Notably, 31 special-status species, such as the federally endangered Giant Garter Snake, have also been identified in California rice lands.

In the U.S., rice lands are considered a leading example of integrating agricultural and natural resource management, with USDA recently honoring the USA Rice Federation with the first national "Legacy of Conservation" award in 2011.

The Reserve's Program Manual explains that generally "projects must have no negative social, economic or environmental consequences and ideally should result in benefits beyond climate change mitigation."

The adoption of dry seeding is expected to result in a delay in winter flooding by a few days, meaning that though there is a slight delay in the provision of surrogate habitat (e.g. flooded rice fields) to wetland-dependent species, the quality of the surrogate habitat will not be affected. The effect of baling on the quality of flooded rice lands as surrogate habitat is somewhat less clear. In one study of species preferences for different rice straw management options, wetland-dependent bird species appeared to have a slight preference for fields where rice straw had been left on the field (whether spread or incorporated) than fields where the rice straw residue had been removed (by baling).[89]

The Reserve will continue to monitor the impacts on wildlife habitat that result from the above two RC management changes, as well as other potential management changes that may be allowed in subsequent versions of this protocol. Should it be determined that a certain activity is resulting in negative impacts, mitigation options and/or changes in approved project activities may be required under subsequent protocol versions.

[86] Petrie, M., & Petrik, K. (May 2010).
[87] Ibid.
[88] Sterling, J., & Buttner, P. (2009).
[89] Elphick, Chris and Lewis Oring, "Conservation implications of flooding rice fields on winter waterbird communities," *Agriculture, Ecosystems, and Environment* 94 (2003).

Rice Cultivation Project Protocol
Version 1.1
ERRATA AND CLARIFICATIONS

The Climate Action Reserve (Reserve) published its Rice Cultivation Project Protocol Version 1.1 (RCPP V1.1) in June 2013. While the Reserve intends for the RCPP V1.1 to be a complete, transparent document, it recognizes that correction of errors and clarifications will be necessary as the protocol is implemented and issues are identified. This document is an official record of all errata and clarifications applicable to the RCPP V1.1.[1]

Per the Reserve's Program Manual, both errata and clarifications are considered effective on the date they are first posted on the Reserve website. The effective date of each erratum or clarification is clearly designated below. All listed and registered rice cultivation projects must incorporate and adhere to these errata and clarifications when they undergo verification. The Reserve will incorporate both errata and clarifications into future versions of the protocol.

All project developers and verification bodies must refer to this document to ensure that the most current guidance is adhered to in project design and verification. Verification bodies shall refer to this document immediately prior to uploading any Verification Statement to assure all issues are properly addressed and incorporated into verification activities.

If you have any questions about the updates or clarifications in this document, please contact Policy at policy@climateactionreserve.org or (213) 891-1444 x3.

[1] See Section 4.3.4 of the Climate Action Reserve Program Manual for an explanation of the Reserve's policies on protocol errata and clarifications. "Errata" are issued to correct typographical errors. "Clarifications" are issued to ensure consistent interpretation and application of the protocol. For document management and program implementation purposes, both errata and clarifications are contained in this single document.

Errata and Clarifications (arranged by protocol section)

Appendix B Step 1.3

1. DNDC Climate Input Data File Formatting (ERRATUM – January 21, 2014)

Section: Appendix B, Step 1.3 DNDC Climate Input Parameters

Context: This step provides background information on the climate input parameters used to run the DNDC model and instructs project developers on how to enter data for these parameters into DNDC. Following an initial description of the climate input parameters and a bulleted list of requirements for determining climate parameter inputs, a paragraph outlines how to enter data into the model, beginning with the words "Data for N concentration in rainfall…" (page 77). The final sentence in that paragraph erroneously lists "Humidity" twice in the data file format. The same mistake is repeated in the example data layout provided in Table B.5. Humidity data should appear once in the series, as the final data input parameter.

Correction: The last sentence on page 77 should be amended to read: "In other words, data needs to be input in text files in the following order: Jday, MaxT, MinT, Precipitation, Wind Speed, Humidity."

Table B.5 on page 78 should be amended to read as follows:

Table B.5. Required Formatting for Climate Input Files

Jday	MaxT (^oC)	MinT (^oC)	Precipitation (cm)	Wind Speed (m/s)	Humidity (%)
1	12.1	5.2	1.41	2.3	77
2	11.1	6.2	3.01	7.5	80
3	10.1	7.2	0.34	4.3	82
4	11.1	8.2	0.01	2.9	81

*NOTE: Only the format and data itself and not the text of a header row should be entered into the Climate Input files.

Appendix B Step 2.1

2. Missing Climate Data (CLARIFICATION – January 21, 2014)

Section: Appendix B, Step 2.1 Missing Climate or Soil Data

Context: The DNDC model will crash if instructed to run without a full set of data for each input parameter. This step provides a methodology for how to overcome missing climate or soil data. The guidance with respect to missing climate data does not address such instances where climate data are missing for a period not exceeding 14 days, in which a complete and continuous set of data from the 14 day period immediately prior to and following the data gap (for a total of 28 days) are also not available from the same source. In such circumstances, data from another source or the nearest alternative weather station must be used.

Clarification: The following text shall be inserted following the first sentence of the last paragraph on page 82, which begins with the words “For gaps in climate data that do not exceed 14 days…”:

> “If a complete and continuous set of data for the 14 days preceding and following the data gap (for a total of 28 days) cannot be obtained from the same source, project developers must substitute data for the data gap from another source in that same region, and if such data are not available, project developers must then use data from the nearest alternative weather station.”

A.2.6 Landfill Project Protocol v5.0

CLIMATE
ACTION
RESERVE

Version 5.0 | April 24, 2019

Landfill

Project Protocol

Climate Action Reserve
www.climateactionreserve.org

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Abbreviations and Acronyms

ACF	Actual cubic feet
BAU	Business as usual
CAA	Clean Air Act
CARB	California Air Resources Board
CEQA	California Environmental Quality Act
CH_4	Methane
CNG	Compressed natural gas
CO_2	Carbon dioxide
EG	Emission Guidelines
EPA	U.S. Environmental Protection Agency
GHG	Greenhouse gas
GCCS	Gas Collection and Control System
IPCC	Intergovernmental Panel on Climate Change
LFG	Landfill gas
LFGE	Landfill gas-to-energy
LMOP	Landfill Methane Outreach Program
LNG	Liquefied natural gas
Mg	Mega gram (1,000,000 grams, or one tonne or “t”)
MMg	Million mega grams
MSW	Municipal solid waste
MWh	Megawatt hour
N_2O	Nitrous oxide
NEPA	National Environmental Policy Act
NESHAP	National Emission Standards for Hazardous Air Pollutants
NG	Natural gas
NMOC	Non-methane organic compounds
NPV	Net Present Value
NSPS	New Source Performance Standards
NSR	New Source Review
PSD	Prevention of Significant Deterioration
QA/QC	Quality Assurance/Quality Control
RCRA	Resources Conservation and Control Act
Reserve	Climate Action Reserve
SCF	Standard cubic feet (60°F and 1 atm)
tCO_2e	Metric ton of carbon dioxide equivalent
VOC	Volatile organic compound
WIP	Waste in place

1 Introduction

The Climate Action Reserve (Reserve) Landfill Project Protocol provides guidance to account for and report greenhouse gas (GHG) emission reductions associated with installing a landfill gas collection and destruction system at a landfill.

The Climate Action Reserve is an environmental nonprofit organization that promotes and fosters the reduction of greenhouse gas (GHG) emissions through credible market-based policies and solutions. A pioneer in carbon accounting, the Reserve serves as an approved Offset Project Registry (OPR) for the State of California's Cap-and-Trade Program and plays an integral role in supporting the issuance and administration of compliance offsets. The Reserve also establishes high quality standards for offset projects in the North American voluntary carbon market and operates a transparent, publicly-accessible registry for carbon credits generated under its standards.

Project developers that install landfill gas capture and destruction technologies use this document to register GHG reductions with the Reserve. This protocol provides eligibility rules, methods to calculate reductions, performance-monitoring instructions, and procedures for reporting project information to the Reserve. Additionally, all project reports receive annual, independent verification by ISO-accredited and Reserve-approved verification bodies. Guidance for verification bodies to verify reductions is provided in the Verification Program Manual[1] and Section 8 of this protocol.

This protocol is designed to ensure the complete, consistent, transparent, accurate, and conservative quantification of GHG emission reductions associated with a landfill project.[2]

[1] Available online at http://www.climateactionreserve.org/how/verification/verification-program-manual/
[2] See the WRI/WBCSD GHG Protocol for Project Accounting (Part I, Chapter 4) for a description of GHG accounting principles.

2 The GHG Reduction Project

2.1 Background

Most MSW in the United States is deposited in landfills, where bacteria decompose the organic material. A product of both the bacterial decomposition and oxidation of solid waste is landfill gas, which is composed of methane (CH_4) and carbon dioxide (CO_2) in approximately equal concentrations, as well as smaller amounts of non-methane organic compounds (NMOC), nitrogen (N_2), oxygen (O_2) and other trace gases. If not collected and destroyed, over time, this landfill gas is released to the atmosphere. In the United States, the Environmental Protection Agency (EPA) has concluded that landfills are the largest source of anthropogenic emissions of CH_4, accounting for 16 percent of total CH_4 emissions.[3] However, the solid waste industry has made significant efforts to reduce their GHG emissions, with an almost 40% reduction in CH_4 emissions since 1990.[4]

There is considerable uncertainty regarding the actual amount of fugitive methane emissions from landfills. Therefore, this protocol does not address fugitive landfill methane emissions. Instead, it addresses the methane that is captured and destroyed in excess of any regulatory requirements. Landfill operations that utilize bioreactor technologies are not eligible to use this protocol, as it is unclear what effects the bioreactor may have on the baseline fugitive methane emissions and the timing of their release from the landfill.

2.2 Project Definition

For the purpose of this protocol, the GHG reduction project is defined as the collection of methane gas from one or more specified cells at an eligible landfill, and the destruction of such methane gas in one or more eligible destruction devices. The expansion of an existing Gas Collection and Control System (GCCS) to a new cell or cells can optionally be included within an existing landfill project or submitted as a new project. If any cells are to be considered as a new project, those cells must be engineered in such a way that LFG cannot migrate between cells in the proposed new project and cells in the existing project. Where a single landfill contains multiple cells, across multiple landfill projects, those projects may share common destruction devices, provided the flow of methane from each project is metered separately.

Qualifying destruction devices may include utility flares, enclosed flares, engines, turbines, microturbines, boilers, pipelines, leachate evaporators, kilns, sludge dryers, burners, furnaces, or fuel cells. Devices not specifically listed here may still be eligible under this protocol, provided written approval is obtained from the Reserve. All destruction devices require an appropriate default or site-specific destruction efficiency value.[5]

An eligible landfill is one that:

1. Is not subject to regulations or other legal requirements requiring the destruction of methane gas; and
2. Is not a bioreactor, as defined by the U.S. EPA: "a MSW landfill or portion of a MSW landfill where any liquid other than leachate (leachate includes landfill gas condensate)

[3] U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2016, EPA-430-R-18-003 (April 2018).
[4] Ibid, *Table 7-3: CH_4 Emissions from Landfills (MMR CO_2 Eq.)*.
[5] See Table B.2 and the guidance in Section B.1 for biogas destruction efficiency defaults and site-specific values.

is added in a controlled fashion into the waste mass (often in combination with recirculating leachate) to reach a minimum average moisture content of at least 40 percent by weight to accelerate or enhance the anaerobic (without oxygen) biodegradation of the waste"[6]; and

3. Does not add any liquid other than leachate into the waste mass in a controlled manner.

Captured landfill gas may be destroyed onsite or transported for offsite use. Regardless of how project developers use the captured landfill gas, for the project to be eligible to register with the Reserve under this protocol, the ultimate fate of the methane must be destruction.[7]

Landfill gas collection and destruction systems typically consist of wells, pipes, blowers, caps and other technologies that enable or enhance the collection of landfill gas and convey it to a destruction technology. At some landfills, a flare will be the only device where landfill gas is destroyed. For projects that utilize energy or process heat technologies to destroy landfill gas, such as turbines, reciprocating engines, fuel cells, boilers, heaters, or kilns, these devices will be where landfill gas is destroyed. Most projects that produce energy or process heat also include a flare to destroy gas during periods when the gas utilization project is down for repair or maintenance. Direct use arrangements which entail the piping of landfill gas to be destroyed by an industrial end user at an offsite location are also an eligible approach to destruction of the landfill gas. For instances of direct use, agreements between the project developer and the end user of the landfill gas (e.g., an industrial client purchasing the landfill gas from the project developer), must include a legally binding agreement to assure that the GHG reductions will not be claimed by more than one party. Direct use project developers must also be able to identify the specific destruction technology at the receiving end of the pipeline.

Projects that utilize landfill methane for energy generation may avoid GHG emissions associated with fossil fuel combustion. However, under this protocol such projects do not receive credit for fossil fuel displacement. Although the Reserve does not issue CRTs for fossil fuel displacement, it strongly supports using landfill methane for energy production.

2.3 The Project Developer

The "project developer" is an entity that has an active account on the Reserve, submits a project for listing and registration with the Reserve, and is ultimately responsible for all project reporting and verification. Project developers may be landfill owners, landfill operators, GHG project financiers, utilities, or independent energy companies. The project developer must have clear ownership of the project's GHG reductions. Ownership of the GHG reductions must be established by clear and explicit title, and the project developer must attest to such ownership by signing the Reserve's Attestation of Title form.[8]

[6] 40 CFR 63.1990 and 40 CFR 258.28a.
[7] It is possible that at some point landfill gas may be used in the manufacture of chemical products. However, given that these types of projects are few, if any, these projects are not addressed in this protocol.
[8] Attestation of Title form available at http://www.climateactionreserve.org/how/program/documents/.

3 Eligibility Rules

Projects that meet the definition of a GHG reduction project in Section 2.2 must fully satisfy the following eligibility rules in order to register with the Reserve.

Eligibility Rule I:	Location	→	*U.S. and its tribal lands and territories*
Eligibility Rule II:	Project Start Date	→	*No more than 12 months prior to project submission*
Eligibility Rule III:	Project Crediting Period	→	*Emission reductions may only be reported during the crediting period; the crediting period may be renewed one time*
Eligibility Rule IV:	Additionality	→	*Meet performance standard*
		→	*Avoid exceeding limits on credit stacking*
		→	*Exceed legal requirements*
Eligibility Rule V:	Regulatory Compliance	→	*Compliance with all applicable laws*

3.1 Location

Under this protocol, only projects located at landfills in the United States and its tribal lands and territories are eligible to register with the Reserve.[9]

3.2 Project Start Date

The project start date shall be defined by the project developer, but must be no more than 90 days after landfill gas is first destroyed in a project destruction device, regardless of whether sufficient monitoring data are available to report reductions. The start date is defined in relation to the commencement of methane destruction, not other activities that may be associated with project initiation or development.

To be eligible, the project must be submitted to the Reserve no more than twelve months after the project start date.[10] Projects may always be submitted for listing by the Reserve prior to their start date. For projects that are transferring to the Reserve from other offset registries, start date guidance can be found in the Program Manual.

3.3 Project Crediting Period

The Reserve will issue CRTs for GHG reductions quantified and verified using this protocol for an initial crediting period of ten years following the project start date. However, the Reserve will cease to issue CRTs for GHG reductions if at any point landfill gas destruction becomes legally required at the landfill. If an eligible project has begun operation at a landfill that later becomes subject to a regulation, ordinance, or permitting condition that would call for the installation and operation of a landfill gas control system, the Reserve will issue CRTs for GHG reductions achieved up until the date that the landfill gas control system is legally required to be operational.

[9] Refer to Appendix A for information on the performance standard analysis supporting application of this protocol in the United States.

[10] Projects are considered submitted when the project developer has fully completed and filed the appropriate Project Submittal Form, available at: http://www.climateactionreserve.org/how/program/documents/.

The project crediting period begins at the project start date regardless of whether sufficient monitoring data are available to verify GHG reductions. Projects will be eligible to apply for a second crediting period, provided the project meets the eligibility requirements of the most current version of the protocol at the time of such application. If a project developer wishes to apply for eligibility under a second, 10-year crediting period, they must do so no sooner than six months before the end date of the initial crediting period.

A project may be eligible for a second crediting period even if the project has failed to maintain continuous reporting up to the time of applying for a second crediting period, provided the project developer elects to take a zero-credit reporting period for any period for which continuous reporting was not maintained.[11] The second crediting period shall begin on the day following the end date of the initial crediting period.

3.4 Additionality

The Reserve registers only projects that yield surplus GHG reductions that are additional to what would have occurred in the absence of a carbon offset market.

Projects must satisfy the following tests to be considered additional:

1. The performance standard test
2. The legal requirement test

3.4.1 The Performance Standard Test

Projects pass the performance standard test by meeting a performance threshold, i.e., a standard of performance applicable to all landfill projects, established on an *ex ante* basis by this protocol.[12]

If a project upgrades to a newer version of the protocol for a subsequent verification, it must meet the performance standard test requirements of that version of the protocol, applied as of the original project start date. If a project is submitted for a second crediting period, it is subject to the performance standard test in the most current version of the protocol at that time, applied as of the original project start date.

For this protocol, the Reserve uses a practice-change threshold that focuses on the baseline scenario and changes made in the project scenario. A project passes the performance standard test if it involves one of the following activities:

1. Installation of a landfill gas collection system and a new qualifying destruction device at an eligible landfill where landfill gas has never been collected and destroyed prior to the project start date.

2. Installation of a new qualifying destruction device at an eligible landfill where landfill gas is currently collected and vented, but has never been destroyed in any manner prior to the project start date.

[11] See zero-credit reporting period guidance and requirements in the Reserve Program Manual, http://www.climateactionreserve.org/how/program/program-manual/.

[12] The Reserve defined the performance standard based upon an evaluation of landfill practices in the United States. A summary of the performance standard analysis is provided in Appendix A.

3. Installation of a new qualifying destruction device at an eligible landfill where landfill gas was collected and destroyed at any time prior to the project start date using:
   a. A non-qualifying destruction device (e.g., passive flare); or
   b. A destruction device that is not otherwise eligible under the protocol (e.g., a destruction device installed prior to the earliest allowable project start date).

4. Installation of a new gas collection system on a physically-distinct[13] cell (or cells) where neither gas collection nor destruction has previously occurred, and connection of this new collection system to an existing landfill gas destruction system. The new collection system must have its own metering that satisfies the requirements of this protocol. In this scenario, more than one project may exist at a single landfill. The start date for this project shall be no more than 90 days following the first flow of landfill gas from the new collection system to the destruction system, regardless of the presence of adequate metering for crediting.

Destruction devices that were installed temporarily and utilized only for pilot or testing purposes specifically in anticipation of the GHG project shall not be considered in determining project eligibility or quantification. Devices may only be excluded under this provision if they were installed as a direct precursor to the project activity in order to gather information or determine project viability. Verifiable evidence of this intent must be presented. Changes in landfill ownership, or in the ownership of destruction devices, are not considered in determining prior landfill gas management practices. If landfill gas was previously collected and destroyed (in the given cells of the project) by a party other than the project developer, it still qualifies as “prior” collection and destruction.

Under scenarios (1), (2), and (3) above, expanding a well-field (either in conjunction with, or subsequent to, installing a new destruction device) may constitute a system expansion rather than a separate project. Expanding a well-field is eligible as a new, separate project only if it meets the conditions described in scenario (4). In these scenarios, expanding a well-field initiates a new crediting period.

The practice-change threshold is applied as of the project start date and is evaluated at the project’s initial verification.

The Reserve will periodically re-evaluate the appropriateness of the performance standard criteria by updating the analysis in Appendix A. As part of its periodic assessments of the performance threshold, the Reserve will use a stakeholder process to evaluate whether implementation of this protocol has resulted in negative environmental effects, such as increased emissions of criteria pollutants and/or methane. Projects under this protocol are expected to have positive environmental effects. If it is determined that negative environmental effects have occurred, the Reserve will identify and implement revisions to the protocol to prevent such effects from occurring in the future, or may suspend implementation of the protocol if necessary.

3.4.2 Limits on Credit Stacking

When multiple forms of incentive credits are sought for a single activity at a single facility or on a single piece of land, with some temporal overlap between the different credits or payments, it is referred to as “credit stacking”. Under this protocol, credit stacking is defined as receiving both

[13] The landfill cell must be engineered in such a way that landfill gas cannot migrate between that cell and other landfill cells.

offset credits and other types of mitigation credits for the same activity on spatially overlapping areas (i.e., in the same landfill). Mitigation credits are any instruments issued for the purpose of offsetting the environmental impacts of another entity, such as emissions of GHGs, or the displacement of fossil fuel emissions from transport applications, to name a few.

Any type of mitigation credit received for activities on the project area must be disclosed by the project developer to the verification body and the Reserve on an ongoing basis.

The Reserve has identified market opportunities for the upgrade of landfill gas into high-Btu fuels, that provide an incentive sufficient to raise additionality concerns. Such opportunities include the federal Renewable Fuel Standard (RFS) and the California Low Carbon Fuel Standard (LCFS), where the carbon incentive is often orders of magnitude greater than that provided by the sale of offset credits. Analysis reveals that the strength of these incentives is driving investment in landfill gas projects at present, and that such projects can be considered "business as usual", without the additional presence of carbon offset revenues.[14] Therefore, projects that receive mitigation credits for upgrading landfill gas into high-Btu fuels will not be eligible to receive offset credits for the same period of time under this protocol.

3.4.3 The Legal Requirement Test

All projects are subject to a legal requirement test to ensure that the GHG reductions achieved by a project would not otherwise have occurred due to federal, state, or local regulations, or other legally binding mandates. Projects pass the legal requirement test when there are no laws, statutes, regulations, court orders, environmental mitigation agreements, permitting conditions, or other legally binding mandates requiring the destruction of landfill gas methane at the project site.[15] To satisfy the legal requirement test, project developers must submit a signed Attestation of Voluntary Implementation form[16] prior to the commencement of verification activities each time the project is verified. In addition, the project's Monitoring Plan (Section 6) must include procedures that the project developer will follow to ascertain and demonstrate that the project at all times passes the legal requirement test.

As of the project start date, landfills collecting and destroying landfill gas to comply with regulations or other legal mandates – or that are required by regulation or legal mandate to install a landfill gas control system in the future – are not eligible to register new projects with the Reserve. Landfills collecting and destroying landfill gas to comply with regulations or other legal mandates are not eligible to register GHG reductions associated with the early installation of gas control systems during landfill expansion into new cells.

If an eligible project begins operation at a landfill that later becomes subject to a regulation, ordinance, or permitting condition that calls for the installation of a landfill gas control system, GHG reductions may be reported to the Reserve up until the date that the installation of a landfill gas control system is legally required to be operational. If the landfill's methane emissions are included under an emissions cap (e.g., under a state or federal cap-and-trade program), emission reductions may likewise be reported to the Reserve until the date that the emissions cap takes effect.

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[14] Further information about the Reserve's performance standard analysis is available in Section A.3.

[15] A project may pass the legal requirement test if a landfill gas control system is installed to treat landfill gas for NMOC in order to comply with a regulation, ordinance, or permitting condition, but destruction of the landfill gas is not the only compliance mechanism available to the landfill operator, and the total mass flow of NMOC for the landfill gas control system is less than the applicable NMOC threshold (see Section 3.4.3.1).

[16] Form available at http://www.climateactionreserve.org/how/program/documents/.

3.4.3.1 Federal Regulations

There are several EPA regulations for MSW landfills that have a bearing on the eligibility of methane collection and destruction projects as voluntary GHG reduction projects. These regulations include:

- New Source Performance Standards (NSPS) for MSW Landfills, codified in 40 CFR 60 subpart WWW – Targets landfills that commenced construction or made modifications after May 1991
- New Source Performance Standards (NSPS) for MSW Landfills, codified in 40 CFR 60 subpart XXX – Targets landfills that commenced construction, reconstruction, or modification after July 17, 2014
- Emission Guidelines (EG) for MSW Landfills, codified in 40 CFR 60 subpart Cc. – Targets existing landfills that commenced construction before May 30, 1991, but accepted waste after November 8, 1987
- The National Emission Standards for Hazardous Air Pollutants (NESHAP), codified in 40 CFR 63 subpart AAAA – Regulates new and existing landfills

These regulations require control of non-methane organic compounds (NMOC) from landfills according to certain size and emission thresholds. In most cases, activities to reduce NMOC will also lead to a reduction in CH_4 emissions, as gas collection and destruction is a common NMOC management technique employed at regulated landfills. If the project start date occurs prior to the date of an NMOC test that crosses the regulatory threshold, the project may continue to receive credits for landfill gas destruction up until the date that the system is required to be operational by the regulation. If the project start date occurs after the date of an NMOC test that crosses the regulatory threshold, the landfill is not eligible to register as a project.

Landfills smaller than 2.5 million megagrams or 2.5 million cubic meters of waste, and those landfills not defined as MSW landfills such as landfills that contain only construction and demolition material or industrial waste, are not usually subject to NSPS, EG or NESHAP.

The list of regulations above should not be considered exhaustive, and the onus will be on project developers and verification bodies to ensure all applicable laws have been considered, when demonstrating that the legal requirement test has been met.

3.4.3.2 State and Local Regulations, Ordinances, and Permitting Requirements

All states are required by the Clean Air Act (CAA) and Subtitle D of the Resource Conservation and Recovery Act (RCRA Subtitle D) to promulgate rules for landfills. Some landfills that exceed applicable emission thresholds will require site-specific permits requiring controls under the New Source Review (NSR) or Prevention of Significant Deterioration (PSD) permitting program authorized by the CAA and implemented by states. These state-level rules generally follow federal guidelines. However, the state rules can be more stringent, or require the installation of a gas collection and destruction system, or the destruction of volatile organic compounds (VOC), NMOC, or CH_4 earlier, or at smaller facilities, than the federal regulations would require.

For example, on June 17, 2010, California Air Resources Board (CARB) approved a discrete early action measure to reduce methane emissions from landfills. The control measure applies to landfills with greater than 450,000 Mg WIP. The regulation reduces methane emissions from landfills by requiring gas collection and control systems where these systems were not previously required and establishes statewide performance standards to maximize methane capture efficiencies.[17]

In recent years the inclusion of air quality, water quality and even GHG emission control measures in permitting requirements (CEQA, NEPA, etc.) has become more prevalent. State and local governments may regulate MSW landfills by putting in place nuisance laws or requiring solid waste facilities smaller than the facilities regulated by the CAA or RCRA Subtitle D to control landfill gas. Other regulations or ordinances may require minimal gas collection to prevent lateral migration of the landfill gas to neighboring properties. Collection and destruction activities required under NSPS, EG, NESHAP, CAA and other state and local regulations, ordinances or permitting requirements are not eligible as GHG reduction projects.[18]

The Reserve acknowledges that non-CAA programs such as RCRA Subtitle D, water quality regulations and other state and local regulations, ordinances or permitting requirements do not always dictate the installation of a landfill gas collection system as the only compliance mechanism to manage NMOC emissions or VOC water contamination, but that the installation of a landfill gas collection system is commonly the most effective and least demanding compliance mechanism available. Therefore, the installation of a landfill gas collection and destruction system for compliance with non-CAA regulations will not qualify as a GHG reduction project under this protocol unless these projects also meet the eligibility requirements discussed below.

Some water quality, explosive gas mitigation, and local nuisance regulations and ordinances allow for passive landfill gas control systems, which collect and vent landfill gas to the atmosphere, but are not required to treat or destroy the vented gases. Project activities that add a destruction device to a landfill that is only required to implement a passive landfill gas control system pass the legal requirement test.

3.5 Regulatory Compliance

As a final eligibility requirement, project developers must attest that the project is in material compliance with all applicable laws (e.g., air, water quality, safety, etc.) prior to verification activities commencing each time a project is verified. Project developers are required to disclose in writing to the verifier any and all instances of non-compliance of the project with any law. If a verifier finds that a project is in a state of recurrent non-compliance or non-compliance that is the result of negligence or intent, then CRTs will not be issued for GHG reductions that occurred during the period of non-compliance. Non-compliance solely due to administrative or reporting issues, or due to “acts of nature,” will not affect CRT crediting.

Where projects are co-located at a single landfill, and in particular where projects share common equipment or infrastructure, the onus will be on the project developer(s) to demonstrate that a regulatory violation at the site is not relevant to all projects.

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[17] California Air Resources Board, Landfill Methane Control Measure webpage: http://www.arb.ca.gov/cc/landfills/landfills.htm.

[18] The Reserve acknowledges that the third-party verifier will need to exercise some discretion when reviewing permits that require the installation of a landfill gas control system or any portion thereof. Permits tend to include strong language, such as “must” or “shall” install a landfill gas control system, even in the case that a landfill chooses to voluntarily install a landfill gas control system but is required to obtain a permit to do so.

4 The GHG Assessment Boundary

The GHG Assessment Boundary delineates the GHG sources, sinks, and reservoirs (SSRs) that shall be assessed by project developers in order to determine the total net change in GHG emissions caused by a landfill project.

This protocol does not account for carbon dioxide emission reductions associated with displacing grid-delivered electricity or fossil fuel use.

CO_2 emissions associated with the generation and destruction of landfill gas are considered biogenic emissions[19] (as opposed to anthropogenic) and are not be included in the GHG Assessment Boundary. This is consistent with the Intergovernmental Panel on Climate Change's (IPCC) guidelines for captured landfill gas.[20]

Figure 4.1 below provides a general illustration of the GHG Assessment Boundary, indicating which SSRs are included or excluded from the boundary. All SSRs within the dashed line are accounted for under this protocol.

Table 4.1 provides greater detail on each SSR and provides justification for the inclusion or exclusion of SSRs and gases from the GHG Assessment Boundary.

[19] The rationale is that carbon dioxide emitted during combustion represents the carbon dioxide that would have been emitted during natural decomposition of the solid waste. Emissions from the landfill gas control system do not yield a net increase in atmospheric carbon dioxide because they are theoretically equivalent to the carbon dioxide absorbed during plant growth.

[20] *IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories*; p.5.10, ftnt.

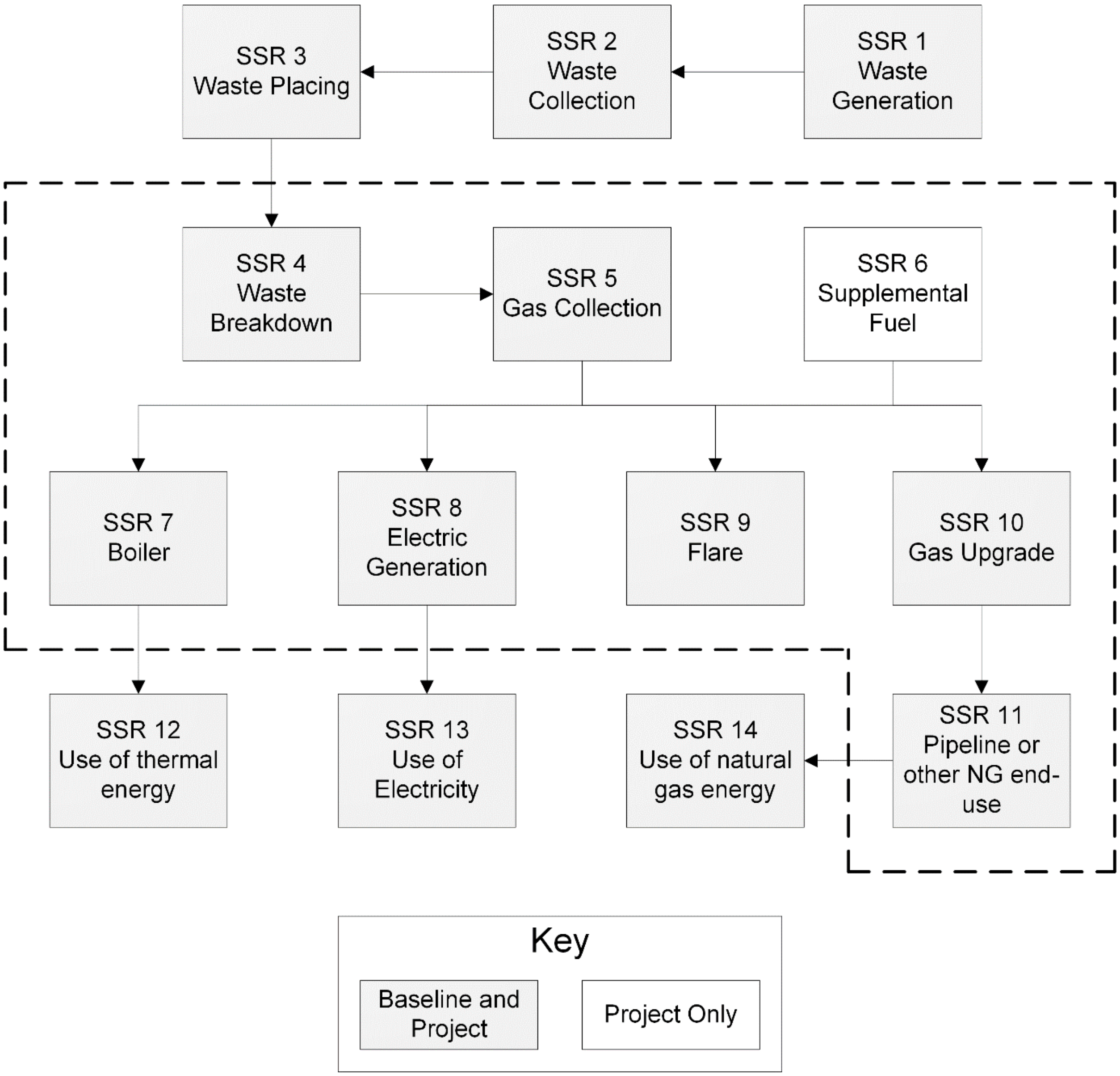


Figure 4.1. General Illustration of the GHG Assessment Boundary

Table 4.1. Summary of Identified Sources, Sinks, and Reservoirs

SSR	Source	Gas	Relevant to Baseline (B) or Project (P)	Included/ Excluded	Justification/Explanation
1	Emissions from Waste Generation	N/A	B,P	Excluded	GHG emissions from this source are assumed to be equal in the baseline and project scenarios
2	Emissions from Waste Collection prior to landfilling	CO_2	B,P	Excluded	GHG emissions from this source are assumed to be equal in the baseline and project scenarios
		CH_4		Excluded	GHG emissions from this source are assumed to be equal in the baseline and project scenarios
		N_2O		Excluded	GHG emissions from this source are assumed to be equal in the baseline and project scenarios s
3	Emissions from Waste Placing Activities	CO_2	B,P	Excluded	GHG emissions from this source are assumed to be equal in the baseline and project scenarios
		CH_4		Excluded	GHG emissions from this source are assumed to be equal in the baseline and project scenarios
		N_2O		Excluded	This emission source is assumed to be equal in the baseline and project scenarios
4	Emissions from Waste Breakdown in Landfill	CO_2	B,P	Excluded	Biogenic CO_2 emissions are excluded
		CH_4		Included	Primary source of GHG emissions in baseline. Calculated based on destruction in baseline and project destruction devices.
5	Emissions from Gas Collection System	CO_2	P	Included	Landfill projects result in CO_2 emissions associated with the energy used for collection and processing of landfill gas
		CH_4		Excluded	This emission source is assumed to be very small
		N_2O		Excluded	This emission source is assumed to be very small
	Emissions from Baseline Gas Collection System	CO_2	B	Excluded	This emission source is assumed to be very small
		CH_4		Excluded	This emission source is assumed to be very small
		N_2O		Excluded	This emission source is assumed to be very small
6	Emissions from Supplemental Fuel	CO_2	P	Included	Landfill projects may require use of supplemental fossil fuel, resulting in significant new GHG emissions
		CH_4		Included	Calculated based on destruction efficiency of destruction device
		N_2O		Excluded	This emission source is assumed to be very small
	Emissions from Baseline Supplemental Fuel Use	CO_2	B	Excluded	This emission source is assumed to be very small
		CH_4		Excluded	This emission source is assumed to be very small
		N_2O		Excluded	This emission source is assumed to be very small
7		CO_2	P	Excluded	Biogenic CO_2 emissions are excluded

SSR	Source	Gas	Relevant to Baseline (B) or Project (P)	Included/ Excluded	Justification/Explanation
	Emissions from Project LFG Boiler Destruction	CH_4		Included	Calculated in reference to destruction efficiency
		N_2O		Excluded	This emission source is assumed to be very small
	Emissions from Baseline LFG Boiler Destruction	CO_2	B	Excluded	Biogenic CO_2 emissions are excluded
		CH_4		Included	Calculated in reference to destruction efficiency
		N_2O		Excluded	This emission source is assumed to be very small
8	Emissions from Project LFG Electricity Generation	CO_2	P	Excluded	Biogenic CO_2 emissions are excluded
		CH_4		Included	Calculated in reference to destruction efficiency
		N_2O		Excluded	This emission source is assumed to be very small
	Emissions from Baseline LFG Electricity Generation	CO_2	B	Excluded	Biogenic CO_2 emissions are excluded
		CH_4		Included	Calculated in reference to destruction efficiency
		N_2O		Excluded	This emission source is assumed to be very small
9	Emissions from Project LFG Flare Destruction	CO_2	P	Excluded	Biogenic CO_2 emissions are excluded
		CH_4		Included	Calculated in reference to destruction efficiency
		N_2O		Excluded	This emission source is assumed to be very small
	Emissions from Baseline LFG Flare Destruction	CO_2	B	Excluded	Biogenic CO_2 emissions are excluded
		CH_4		Included	Calculated in reference to destruction efficiency
		N_2O		Excluded	This emission source is assumed to be very small
10	Emissions from Upgrade of LFG	CO_2	B,P	Included	Landfill projects may result in GHG emissions from additional energy used to upgrade landfill gas
		CH_4		Excluded	This emission source is assumed to be very small
		N_2O		Excluded	This emission source is assumed to be very small
11	Emissions from Project LFG Pipeline or other NG end-use	CO_2	P	Excluded	Biogenic emissions are excluded
		CH_4		Included	Calculated in reference to destruction efficiency
		N_2O		Excluded	Assumed to be very small
	Emissions from Baseline LFG Pipeline or other NG end-use	CO_2	B	Excluded	Biogenic emissions are excluded
		CH_4		Included	Calculated in reference to destruction efficiency
		N_2O		Excluded	This emission source is assumed to be very small
12	Use of Project Generated Thermal Energy	CO_2	P	Excluded	This protocol does not cover displacement of GHG emissions from use of LFG-generated thermal energy
	Use of Baseline Generated Thermal Energy	CO_2	B	Excluded	This protocol does not cover displacement of GHG emissions from use of LFG-generated thermal energy

SSR	Source	Gas	Relevant to Baseline (B) or Project (P)	Included/ Excluded	Justification/Explanation
13	Use of Project Generated Electricity	CO_2	P	Excluded	This protocol does not cover displacement of GHG emissions from use of LFG-generated electricity.
	Use of Baseline Generated Electricity	CO_2	B	Excluded	This protocol does not cover displacement of GHG emissions from use of LFG-generated electricity.
14	Use of Natural Gas Energy	CO_2	P	Excluded	This protocol does not cover displacement of GHG emissions from use of LFG delivered through pipeline or other end uses
	Use of Baseline Natural Gas Energy	CO_2	B	Excluded	This protocol does not cover displacement of GHG emissions from use of LFG delivered through pipeline or other end uses

5 Quantifying GHG Emission Reductions

GHG emission reductions from a landfill project are quantified by comparing actual project emissions to baseline emissions at the landfill. Baseline emissions are an estimate of the GHG emissions from sources within the GHG Assessment Boundary (see Section 4) that would have occurred in the absence of the landfill project. Project emissions are actual GHG emissions that occur at sources within the GHG Assessment Boundary. Project emissions must be subtracted from the baseline emissions to quantify the project's total net GHG emission reductions (Equation 5.1).

GHG emission reductions must be quantified and reported on at least an annual basis. Such reports must be verified on a schedule in accordance with the requirements of Section 7.3. Project developers may choose to quantify and verify GHG emission reductions on a more frequent basis if they desire. The length of time over which GHG emission reductions are quantified and reported is called the "reporting period".

The calculations provided in this protocol are derived from internationally accepted methodologies.[21] Project developers shall use the calculation methods provided in this protocol to determine baseline and project GHG emissions in order to quantify GHG emission reductions.

[21] The Reserve's GHG reduction calculation method is derived from the Kyoto Protocol's Clean Development Mechanism (ACM0001 V.6 and AM0053 V.1), the EPA's Climate Leaders Program (Draft Landfill Offset Protocol, October 2006), the GE AES Greenhouse Gas Services Landfill Gas Methodology V.1, and the RGGI Model Rule (January 5, 2007).

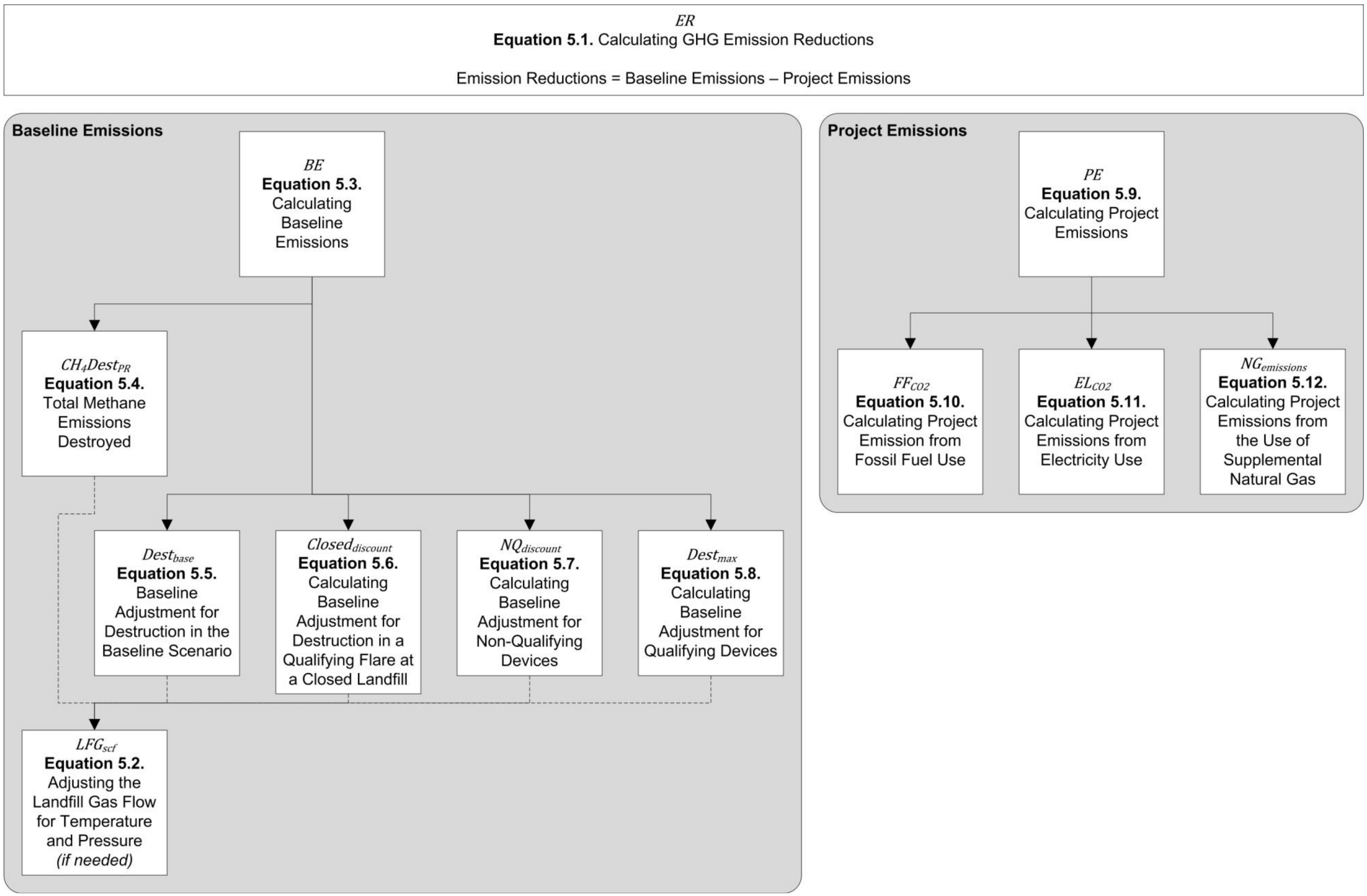


Figure 5.1. Organizational Chart for Equations in Section 5

Equation 5.1. Calculating GHG Emission Reductions

$$ER = BE - PE$$

Where,			Units
ER	=	GHG emission reductions of the project activity during the reporting period	tCO_2e
BE	=	Baseline emissions during the reporting period	tCO_2e
PE	=	Project emissions during the reporting period	tCO_2e

If any of the landfill gas flow metering equipment does not internally correct for the temperature and pressure of the landfill gas, separate pressure and temperature measurements must be used to correct the flow measurement. Corrected values must be used in all of the equations of this section. Apply Equation 5.2 only if the landfill gas flow metering equipment does not internally correct for temperature and pressure.

Equation 5.2. Adjusting the Landfill Gas Flow for Temperature and Pressure

$$LFG_{i,t} = LFG_{unadjusted} \times \frac{520}{T} \times \frac{P}{1}$$

Where,			Units
$LFG_{i,t}$	=	Adjusted volume of landfill gas fed to the destruction device *i*, in time interval *t*	scf
$LFG_{unadjusted}$	=	Unadjusted volume of landfill gas collected for the given time interval	acf
T	=	Measured temperature of the landfill gas for the given time period (°R = °F + 459.67)	°R
P	=	Measured pressure of the landfill gas in for the given time interval	atm

5.1 Quantifying Baseline Emissions

Traditional baseline emission calculations are not required for this protocol for the quantification of methane reductions. The baseline scenario assumes that all uncontrolled methane emissions are released to the atmosphere except for the portion of methane that would be oxidized by bacteria in the soil of uncovered landfills absent the project,[22] or destroyed by a baseline destruction device. Therefore, with the exception of the deductions outlined below, baseline emissions are equal to the sum of all methane destroyed by eligible destruction devices.

As noted in Section 3.4.1, projects may fall into five categories based on the baseline state of the landfill and level of landfill gas management. Each of these categories requires a slightly different methodology for calculating relevant baseline emissions.

1. Landfills where no previous collection or destruction took place prior to the project start date must deduct the following from baseline emissions:
    a. The amount of methane that would have been oxidized by soil bacteria in the absence of the project.

2. Landfills where previous collection and/or destruction took place in a non-qualifying destruction device must deduct the following from baseline emissions:
    a. The amount of methane destroyed by the non-qualifying destruction device.

[22] A small portion of the methane generated in landfills (around 10%) is naturally oxidized to carbon dioxide by methanotrophic bacteria in the cover soils of well managed landfills. The 10% factor is based on Intergovernmental Panel on Climate Change (IPCC) guidelines (2006).

   b. The amount of methane that would have been oxidized by soil bacteria in the absence of the project.

3. Landfills where previous collection and destruction took place in a qualifying destruction device must deduct the following from baseline emissions:
   a. The amount of methane that could have been destroyed if the baseline destruction device was operating at full capacity.
   b. The amount of methane that would have been oxidized by soil bacteria in the absence of the project.

4. Closed landfills where previous collection and destruction took place in a qualifying flare must deduct the following from baseline emissions:
   a. The amount of methane collected by baseline landfill gas wells and destroyed in the qualifying flare.
   b. The amount of methane that would have been oxidized by soil bacteria in the absence of the project.

5. Projects where an existing GCCS is connected to a new landfill cell that was previously not affected by the GCCS must deduct the following from baseline emissions:
   a. If previous collection and destruction of methane from this cell (other than in the project GCCS), then the appropriate amount of methane shall be deducted according to the guidance in items 2-4, above, depending on which is relevant.
   b. The amount of methane that would have been oxidized by soil bacteria in the absence of the project.

These conditions ensure that the reductions resulting from the GHG project can be accounted for separately from collection and destruction that would have occurred from the baseline equipment. Only the landfill gas destroyed beyond what would have been destroyed by the baseline collection and destruction system is considered eligible for crediting.

Baseline emissions shall be calculated using Equation 5.3. Both the OX discount factor and the DF discount factor shall only be applied to periods of time during the reporting period for which each factor is applicable. The OX discount factor shall only be applied for the number of days during the reporting period when the landfill did not incorporate a synthetic liner throughout the entire area of the final cover system. The DF discount factor shall only be applied for the number of days during the reporting period when methane concentration values were taken at a frequency that is less than continuous (every 15 minutes). Thus, Equation 5.3 may be calculated separately for different portions of the reporting period, with the results summed to provide a total BE value for the entire reporting period.

Equation 5.3. Calculating Baseline Emissions

$$BE = CH_4Dest_{PR} \times GWP \times (1 - OX) \times (1 - DF) - Dest_{base} \times (1 - OX)$$

Where,			Units
BE	=	Baseline emissions during the reporting period	tCO_2e
CH_4Dest_{PR}	=	Total methane destroyed by the project landfill gas collection and destruction system during the reporting period (see Equation 5.4)	tCH_4
GWP	=	Global warming potential factor of methane to carbon dioxide equivalent, equal to 25 at the time of publication[23]	tCO_2e/tCH_4
OX	=	Factor for the oxidation of methane by soil bacteria. Equal to 0.10 for all landfills except those that incorporate a synthetic liner throughout the entire area of the final cover system, where OX = 0	
DF	=	Discount factor to account for uncertainties associated with the monitoring equipment. (See Section 6.1.) Equal to zero if using continuous methane monitoring	
$Dest_{base}$	=	Adjustment to account for baseline LFG destruction device (see Equation 5.5). Equal to zero if no baseline LFG destruction system is in place prior to project implementation	tCO_2e

The term CH_4Dest_{PR} represents the amount of methane destroyed by the project. This term is calculated according to Equation 5.4.

[23] At time of publication, landfill projects are instructed to use GWP values from the IPCC 4th Assessment Report. This value may be updated in the future via guidance from the Reserve.

Equation 5.4. Total Methane Emissions Destroyed

$$CH_4Dest_{PR} = \sum_i (CH_4Dest_i) \times (0.0423 \times 0.000454)$$

Where,

			Units
CH_4Dest_{PR}	=	Total methane destroyed by the project landfill gas collection and destruction system during the reporting period	tCH_4
$CH_4\ Dest_i$	=	The net quantity of methane destroyed by destruction device *i* during the reporting period	scf CH_4
0.0423	=	Density of methane	lb CH_4/scf CH_4
0.000454	=	Conversion factor from pounds to metric tonnes	tCH_4/lb CH_4

And,

$$CH_4Dest_i = Q_i \times DE_i$$

Where,

			Units
$CH_4\ Dest_i$	=	The net quantity of methane destroyed by device *i* during the reporting period	scf
Q_i	=	Total quantity of landfill methane sent to destruction device *i* during the reporting period	scf
DE_i	=	Methane destruction efficiency for device *i*. See Appendix B for guidance	

And,

$$Q_i = \sum_t \left(LFG_{i,t} \times PR_{CH_4,t}\right)$$

Where,

			Units
Q_i	=	Total quantity of landfill methane sent to destruction device *i* during the reporting period	scf
$LFG_{i,t}$	=	Adjusted volume of landfill gas fed to the destruction device *i*, in time interval *t*	scf
t	=	Time interval for which LFG flow and concentration measurements are aggregated. See Table 6.1 for guidance	
$PR_{CH4,t}$	=	The average methane fraction of the landfill gas in time interval *t*	scf CH_4/ scf LFG

For projects where methane was destroyed in the baseline, Equation 5.5 must be applied. This equation accounts for the methane emissions calculated in Equation 5.4 that would have been destroyed in the absence of the project activity.

Any project at a landfill where methane was collected and destroyed at any time prior to the project start date – even if the prior collection and/or destruction system was removed or has been dormant for an extended period of time – must apply the baseline deduction. The time period over which the value of $Dest_{base}$ is to be aggregated, using Equation 5.5, may be chosen by the project developer, but cannot be less than weekly, and must be consistent throughout the reporting period.

Equation 5.5. Baseline Adjustment for Destruction in the Baseline Scenario

$$\boldsymbol{Dest_{base} = (Closed_{discount} + NQ_{discount} + Dest_{max}) \times 0.0423 \times 0.000454 \times GWP}$$

Where,			Units
$Dest_{base}$	=	Adjustment to account for the baseline methane destruction associated with a baseline destruction device. Equal to zero if there is no baseline installation	tCO_2e
$Closed_{discount}$	=	Adjustment to account for the methane that would have been combusted in the baseline flare from baseline wells at a closed landfill. Equal to zero if the project is not a flare project at a closed landfill	scf CH_4
$NQ_{discount}$	=	Adjustment to account for the methane that would have been combusted in the baseline, non-qualifying combustion device. Equal to zero if there is no non-qualifying combustion device	scf CH_4
$Dest_{max}$	=	Deduction of the un-utilized capacity of the baseline destruction device. This deduction is to be applied only when a new destruction device is used during project activity. See Box 5.1 below for an example of the application of the $Dest_{max}$ adjustment	scf CH_4
0.0423	=	Density of methane	lb CH_4/ scf CH_4
0.000454	=	Conversion factor	tCH_4/ lb CH_4
GWP	=	Global warming potential factor of methane to carbon dioxide equivalent, equal to 25 at the time of publication[24]	tCO_2e/tCH_4

Equation 5.6. Calculating Baseline Adjustment for Destruction in a Qualifying Flare at a Closed Landfill

$$\boldsymbol{Closed_{discount} = LFG_{B1} \times B_{CH_4,closed}}$$

Where,			Units
$Closed_{discount}$	=	Adjustment to account for the methane that would have been combusted in the baseline flare from baseline wells at a closed landfill. Equal to zero if the project is not a flare project at a closed landfill	scf CH_4
LFG_{B1}	=	Landfill gas from the baseline landfill gas wells that would have been destroyed by the qualifying destruction system during the reporting period. See Appendix C for guidance on calculating LFG_{B1}	scf
$B_{CH4,closed}$	=	Methane fraction of landfill gas destroyed by the collection system during the reporting period. See Appendix C for guidance on calculating $B_{CH4,closed}$	scf CH_4/ scf LFG

$NQ_{discount}$, may be determined using either of the following options.

1. $NQ_{discount}$ shall be equal to the measured quantity of methane recovered through an active gas collection system installed into the corresponding cell or waste mass of the landfill in which the baseline devices operated. The landfill gas flow from these active wells shall be determined using Equation 5.4 above for a minimum of one month.[25]

[24] At time of publication, landfill projects are instructed to use GWP values from the IPCC 4th Assessment Report. This value may be updated in the future via guidance from the Reserve.
[25] For the purpose of using Equation 5.4 to determine $NQ_{discount}$, the quantity of landfill gas would be only that which is being metered from the corresponding cell or waste mass in which the baseline devices had operated, and not necessarily all of the landfill gas being destroyed by the destruction system.

2. $NQ_{discount}$ shall be monitored and calculated per Equation 5.7 and Appendix D.

Equation 5.7. Calculating Baseline Adjustment for Non-Qualifying Devices

$$NQ_{discount} = LFG_{B2} \times B_{CH_4,NQ}$$

Where,

			Units
$NQ_{discount}$	=	Adjustment to account for the methane that would have been combusted in the baseline, non-qualifying combustion device. Equal to zero if there is no non-qualifying combustion device	scf CH_4
LFG_{B2}	=	Landfill gas that would have been destroyed by the original, non-qualifying destruction system during the reporting period. See Appendix C for guidance on calculating LFG_{B2}	scf
$B_{CH4,NQ}$	=	Methane fraction of landfill gas destroyed by non-qualifying devices in the baseline. Equal to average methane concentration over the reporting period if maximum capacity is used for LFG_{B2}. See Appendix C for further guidance on calculating $B_{CH4,NQ}$	scf CH_4/ scf LFG

Equation 5.8. Calculating Baseline Adjustment for Qualifying Devices

$$Dest_{max} = \sum_t \left[\left(LFG_{Bmax,t} - LFG_{B3,t}\right) \times PR_{CH_4,t}\right]$$

Where,

			Units
$Dest_{max}$	=	Deduction of the un-utilized capacity of the baseline destruction device. This deduction is to be applied only when a new destruction device is used during project activity. See Box 5.1 below for an example of the application of the $Dest_{max}$ adjustment	scf CH_4
$LFG_{Bmax,t}$	=	The maximum landfill gas flow capacity of the baseline methane destruction device in time interval *t*	scf
$LFG_{B3,t}$	=	The actual landfill gas flow of the baseline methane destruction device in time interval *t*	scf
$PR_{CH4,t}$	=	The average methane fraction of the landfill gas in time interval *t* as measured	scf CH_4 /scf LFG
t	=	Time interval for which LFG flow and concentration measurements are aggregated. See Table 6.1 for guidance	

Box 5.1. Applying the $Dest_{max}$ Adjustment

This adjustment was designed to help differentiate system upgrades from additional projects, while encouraging project developers to use their landfill gas beneficially. In short, this methodology assumes that any gas that *could* have been destroyed in the baseline qualifying device is not additional; diversion of that gas to a new destruction device represents an upgrade. Therefore, this term deducts from calculated project reductions that portion of gas that, in the absence of the new destruction device, still could have been destroyed.

Example:
A flare with a capacity of 1000 cfm was installed at a landfill in 1998. Therefore, because this flare was operational before 2001, the landfill gas control system is ineligible as a project under this protocol. However, in 2005, an electric generator with a 2000 cfm capacity was installed, and all landfill gas was diverted to this device. The addition of the electric generator meets the eligibility requirements of this protocol, and therefore qualifies as a new project. Because the baseline flare is a qualifying destruction device under this protocol and is not eligible as a project due to other eligibility criteria (i.e., operational date), it must be accounted for using $Dest_{max}$.

In 2005, 900 cfm was sent to generator, and 0 cfm was sent to the flare. In the year 2006, due to landfill expansion and installation of additional wells, the generator destroyed 1400 cfm while the flare was non-operational. In 2007, further well expansion allowed the generator to operate at full capacity and the flare was used to destroy an additional 300 cfm of landfill gas.

Calculations:

Year	Generator Destruction (cfm)	Flare Capacity (cfm)	Flare Destruction (cfm)	Deduction (cfm)	Project Reductions (cfm)
2005	900	1000	0	1000	-100 (0)
2006	1400	1000	0	1000	400
2007	1800	1000	300	700	1100

Note: this example and the calculations are significantly simplified for illustrative purposes. The example values are calculated on a cubic feet per minute of landfill gas basis. Reporters are actually required to report the cumulative value of methane gas sent to the destruction device for each time interval *t*.

5.2 Quantifying Project Emissions

Project emissions must be quantified at a minimum on an annual, *ex post* basis. As shown in Equation 5.9, project emissions equal:

- Total indirect carbon dioxide emissions resulting from consumption of electricity from the grid related to project activities
- Total carbon dioxide emissions from the onsite destruction of fossil fuel related to project activities
- Total carbon dioxide emissions from the combustion of supplemental natural gas
- Total methane emissions from the incomplete combustion of supplemental natural gas

Project emissions shall be calculated using Equation 5.9.

Equation 5.9. Calculating Project Emissions

$$PE = FF_{CO_2} + EL_{CO_2} + NG_{emissions}$$

Where,			Units
PE	=	Project emissions during the reporting period	tCO_2e
FF_{CO2}	=	Total carbon dioxide emissions from the destruction of fossil fuel during the reporting period	tCO_2
EL_{CO2}	=	Total carbon dioxide emissions from the consumption of electricity from the grid during the reporting period	tCO_2
$NG_{emissions}$	=	Total quantity of emissions from supplemental natural gas, including both uncombusted methane and carbon dioxide emissions during the reporting period	tCO_2e

Equation 5.10. Calculating Project Emissions from Fossil Fuel Use

$$FF_{CO_2} = \frac{\sum_j \left(FF_{PR,j} \times EF_{FF,j}\right)}{1000}$$

Where,			Units
FF_{CO2}	=	Total carbon dioxide emissions from the destruction of fossil fuel during the reporting period	tCO_2
$FF_{PR,j}$	=	Total fossil fuel consumed by the project landfill gas collection and destruction system during the reporting period, by fuel type *j*	volume fossil fuel
$EF_{FF,j}$	=	Fuel specific emission factor. See Appendix B	kg CO_2/volume fossil fuel
1000	=	Conversion factor	kg CO_2/tCO_2

Equation 5.11. Calculating Project Emissions from Electricity Use

$$EL_{CO_2} = \frac{\left(EL_{PR} \times EF_{EL}\right)}{2204.62}$$

Where,			Units
EL_{CO2}	=	Total carbon dioxide emissions from the consumption of electricity from the grid during the reporting period	tCO_2
EL_{PR}	=	Total electricity consumed by the project landfill gas collection and destruction system during the reporting period	MWh
EF_{EL}	=	CO_2 emission factor for electricity used[26]	lb CO_2/ MWh
2204.62	=	Conversion factor	lb CO_2/ tCO_2

[26] Refer to the most version of the U.S. EPA eGRID most closely corresponding to the time period during which the electricity was used. Projects shall use the annual total output emission rates for the subregion where the project is located, not the annual non-baseload output emission rates. The eGRID tables are available from the U.S. EPA website: http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

Equation 5.12. Calculating Project Emissions from the Use of Supplemental Natural Gas

$$NG_{emissions} = \sum_{i}\left[NG_i \times NG_{CH_4} \times 0.0423 \times 0.000454 \times \left[\left((1 - DE_I) \times GWP\right) + \left(DE_i \times \frac{12}{16} \times \frac{44}{12}\right)\right]\right]$$

Where,			Units
$NG_{emissions}$	=	Total emissions from supplemental natural gas during the reporting period, including both uncombusted methane and carbon dioxide emissions	tCO_2e
NG_i	=	Total quantity of supplemental natural gas delivered to the destruction device *i* during the reporting period	scf
DE_i	=	Methane destruction efficiency of destruction device *i*. See Appendix B	
NG_{CH4}	=	Average methane fraction of the supplemental natural gas as provided for by fuel vendor	scf CH_4/scf NG
0.0423	=	Density of methane	lb CH_4/scf CH_4
0.000454	=	Conversion factor	tCH_4/lb CH_4
GWP	=	Global warming potential factor of methane to carbon dioxide equivalent, equal to 25 at the time of publication[27]	tCO_2e/tCH_4
12/16	=	Carbon ratio of methane	C/CH_4
44/12	=	Carbon ratio of carbon dioxide	CO_2/C

[27] At time of publication, landfill projects are instructed to use GWP values from the IPCC 4th Assessment Report. This value may be updated in the future via guidance from the Reserve.

6 Project Monitoring

The Reserve requires a Monitoring Plan to be established for all monitoring and reporting activities associated with the project. The Monitoring Plan will serve as the basis for verifiers to confirm that the stipulations of this section and Section 7 have been and will continue to be met, and that consistent, rigorous monitoring and record-keeping is ongoing at the project site. The Monitoring Plan must cover all aspects of monitoring and reporting contained in this protocol and must specify how data for all relevant parameters in Table 6.1 (below) will be collected and recorded.

At a minimum the Monitoring Plan shall stipulate the frequency of data acquisition; a record keeping plan (see Section 7.2 for minimum record keeping requirements); the frequency of instrument cleaning, inspection, field check and calibration activities; and the role of the individual performing each specific monitoring activity, as well as QA/QC provisions to ensure that data acquisition and meter calibration are carried out consistently and with precision. The Monitoring Plan shall also contain a detailed diagram of the landfill gas collection and destruction system, including the placement of all meters and equipment that affect SSRs within the GHG Assessment Boundary (see Figure 4.1).

Finally, the Monitoring Plan must include procedures that the project developer will follow to ascertain and demonstrate that the project at all times passes the legal requirement test (Section 3.4.3).

Project developers are responsible for monitoring the performance of the project and operating the landfill gas collection and destruction system in a manner consistent with the manufacturer's recommendations for each component of the system.

6.1 Monitoring Requirements

Methane emission reductions from landfill gas capture and control systems must be monitored with measurement equipment that directly meters:

- The flow of landfill gas delivered to each destruction device, measured continuously and recorded every 15 minutes or totalized and recorded at least daily, adjusted for temperature and pressure

- The fraction of methane in the landfill gas delivered to the destruction device, measured continuously and recorded every 15 minutes and averaged at least daily (measurements taken at a frequency that is less than continuous and more than weekly may be used with the application of a 10% discount in Equation 5.3). Projects may not be eligible for crediting if methane concentration is not measured and recorded at least weekly

- The operational activity of the destruction device(s), monitored and documented at least hourly to ensure landfill gas destruction

If discontinuous CH_4 concentration monitoring is to be employed, then the project developer shall develop a prescriptive methodology for how such monitoring is to be carried out. The method should be reasonable in the circumstances of the project and shall be consistently applied throughout the reporting period. Any such methodology, and adherence to the methodology (or otherwise), should be clearly set out in the project monitoring report.

Methane fraction of the landfill gas is to be measured on a wet/dry basis, depending on the basis of measurement for flow, temperature, and pressure (must be measured on same basis as flow, temperature, and pressure). The methane analyzer and flow meter should be installed in the same relative placement to any moisture-removing components of the landfill gas system (there should not be a moisture-removing component separating the measurement of flow and methane fraction). The meters themselves should also operate on the same basis (i.e., if one meter internally dries the sample prior to measurement, the same should occur at other meters). An acceptable variation to this arrangement would be in the case where flow is measured on a dry basis, while the methane concentration is measured on a wet basis. The opposite arrangement is not permissible. No separate monitoring of temperature and pressure is necessary when using flow meters that automatically correct for temperature and pressure, expressing LFG volumes in normalized cubic meters.

A single flow meter may be used for multiple destruction devices under certain conditions. If all destruction devices are of identical efficiency and verified to be operational, no additional steps are necessary for project registration. Otherwise, the destruction efficiency of the least efficient destruction device shall be used as the destruction efficiency for all destruction devices monitored by this meter.

If there are any periods when not all destruction devices measured under a single flow meter are operational, methane destruction during these periods will be eligible provided that the verifier can confirm all of the following conditions are met:

1. The destruction efficiency of the least efficient destruction device in operation shall be used as the destruction efficiency for all destruction devices monitored by this meter; and

2. All devices are either equipped with valves on the input gas line that close automatically if the device becomes non-operational (requiring no manual intervention), or designed in such a manner that it is physically impossible for gas to pass through while the device is non-operational; and

3. For any period where one or more destruction devices within this arrangement is not operational, it must be documented that the remaining operational devices have the capacity to destroy the maximum gas flow recorded during the period. For devices other than flares, it must be shown that the output corresponds to the flow of gas.

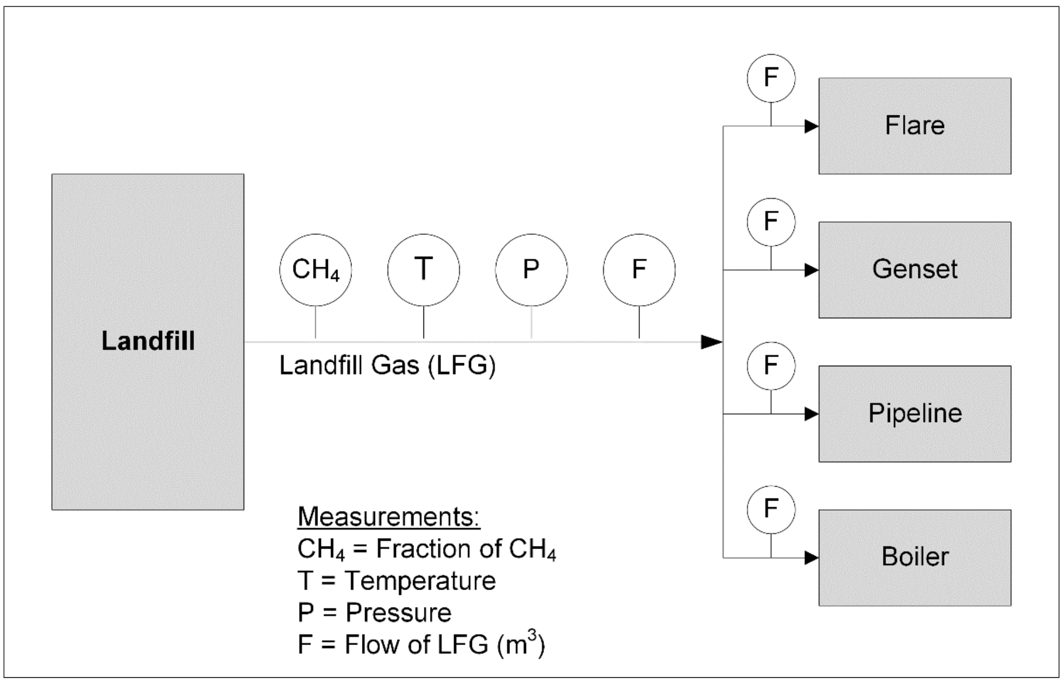
These means for allowing a single device to monitor operational activity at multiple destruction devices shall not be construed to relax the requirement for hourly operational data for all destruction devices. Rather, this arrangement permits a specific metering arrangement during periods when one or more devices are *known* to not be operating. In order to know the operational status of a device, it must be monitored. All destruction devices must have their operational status monitored and recorded at least hourly. In other words, the project dataset will include an indication of operational status corresponding to each hour of landfill gas data. If these data are missing or never recorded for a particular device, that device will be assumed to be not operating and no emission reductions may be claimed for landfill gas destroyed by that device during the period when data are missing.

All flow data collected must be corrected for temperature and pressure at 60^{o} F and 1 atm. If any of the landfill gas flow metering equipment does not internally correct for the temperature and pressure of the landfill gas, separate pressure and temperature measurements must be used to correct the flow measurement. The temperature and pressure of the landfill gas must be measured continuously. Corrected values must be used in all of the equations of this section.

Apply Equation 5.2 only if the landfill gas flow metering equipment does not internally correct for temperature and pressure.

The continuous methane analyzer should be the preferred option for monitoring methane concentrations, as the methane content of landfill gas captured can vary by more than 20% during a single day due to gas capture network conditions (dilution with air at wellheads, leakage on pipes, etc.).[28] When using the alternative approach of discontinuous methane concentration measurement using a calibrated portable gas analyzer, project developers must account for the uncertainty associated with these measurements by applying a 10% discount factor to the total quantity of methane collected and destroyed in Equation 5.3.

Figure 6.1 represents the suggested arrangement of the landfill gas flow meters and methane concentration metering equipment.



Note: The number of flow meters must be sufficient to track the total flow as well as the flow to each combustion device. The above scenario includes one more flow meter than would be necessary to achieve this objective.
Source: Consolidated baseline methodology for landfill gas project activities, Clean Development Mechanism, Version 07, Sectoral Scope 13 (2007).

Figure 6.1. Suggested Arrangement of LFG Metering Equipment

The operational activity of the landfill gas collection system and the destruction devices shall be monitored and documented at least hourly to ensure actual landfill gas destruction. GHG reductions will not be accounted for during periods that the destruction device was not operational. For flares, operation is defined as thermocouple readings above 500° F. For all other destruction devices, the means of demonstration shall be determined by the project developer and subject to verifier review. If relying on the difference between ambient

[28] Consolidated baseline methodology for landfill gas project activities, Clean Development Mechanism, Version 07, Sectoral Scope 13 (2007).

temperatures and temperatures recorded by a thermocouple to demonstrate operational activity (instead of using a fixed temperature threshold), then a temperature difference of at least 200° F shall be used. If any destruction device is equipped with a safety shut off valve, that prevents biogas flow to the destruction device when not operational, then demonstrating the presence and operability of the shut off valve will be sufficient to demonstrate operational activity of that device.

In “direct use” scenarios where landfill gas is delivered offsite to a third-party end user (not to a commercial natural gas transmission and distribution system or to a facility under management control of the project operator), reasonable efforts must be made to obtain data demonstrating the operational status of the destruction device(s). If it is not possible to obtain such data, the verifier must use their professional judgment to confirm that there has been no significant release of project landfill gas and that the project developer is using the destruction efficiency value appropriate for the end use. Evidence that may assist a verifier in making a determination to that effect may include, but is not limited to, one or more of the following:

- A signed attestation from the third-party operator of the destruction device that no catastrophic failure of destruction or significant release of landfill gas occurred during the reporting period, and that the safety features and/or design of the destruction equipment are such that the destruction device does not allow landfill gas to pass through it when non-operational and/or that the project developer is able to switch off the flow of landfill gas offsite in the event of emergencies (and has rigorous procedures in place to ensure such shutoff occurs immediately)
- The verifier confirming the same via a first-person interview with the third-party operator
- Examination of the safety features and/or design of the destruction equipment, such that the destruction device does not allow landfill gas to pass through it when non-operational and/or that the project developer is able to switch off the flow of landfill gas offsite in the event of emergencies (and has rigorous procedures in place to ensure such shutoff occurs immediately)
- Records that can corroborate the type and level of operation of the destruction device during the reporting period, such as engine output data, etc.

If the verifier is reasonably assured that no significant release of landfill gas has occurred offsite during the reporting period, the project can use the destruction efficiency appropriate to that offsite destruction device, despite the lack of hourly data from a monitoring device confirming operational status.

6.1.1 Indirect Monitoring Alternative

As an alternative to the direct measurement of LFG, projects may instead choose to demonstrate volumes of CH_4 destroyed using output data for their destruction device. Where the output of destruction devices (such as gensets) is measured via the use of a commercial transfer meter (i.e., a meter whose output is used as the basis for the quantification under an energy delivery contract), which is subject to regular, professional maintenance, the project may use such data as the basis for determining the volume of CH_4 destroyed. The meter output shall be subjected to an appropriate conversion methodology to calculate the volume of CH_4 destroyed during the reporting period. One example of a methodology that may be suitable is brake-specific fuel consumption calculations. Projects may also be able to use results of performance testing mandated under 40 CFR Part 60 Subpart IIII, Subpart JJJJ, and Subpart KKKK, to develop an appropriate conversion methodology. If using the indirect monitoring alternative, the commercial meter must be maintained by appropriately-trained professionals, in accordance with manufacturer requirements. In scenarios where projects are able to control the maintenance of such meters, the QA/QC requirements in Section 6.2 apply. In scenarios where projects are not able to control the maintenance of such meters, reasonable efforts must be made to obtain documentation demonstrating manufacturer maintenance requirements have been met during the reporting period.

The monitoring methodology to be employed must be clearly set out in the project monitoring report, it must be applied consistently throughout the reporting period, and it must be demonstrated to the satisfaction of the project's verifier and the Reserve that the use of such data and methodology is reasonable under the circumstances, and results in a conservative estimation of the volume of CH_4 destroyed.

6.2 Instrument QA/QC

Monitoring instruments shall be inspected and calibrated according to the following schedule.

All gas flow meters[29] and continuous methane analyzers must be:

- Cleaned and inspected on a regular basis, as specified in the project's Monitoring Plan, with activities and results documented by site personnel. Cleaning and inspection procedures and frequency must, at a minimum, follow the manufacturer's recommendations
- Field checked for calibration accuracy by a third-party technician with the percent drift documented, using either a portable instrument (such as a pitot tube) or manufacturer specified guidance, at the end of – but no more than two months prior to or after – the end date of the reporting period[30]
- Calibrated by the manufacturer or a certified third-party calibration service per manufacturer's guidance or every 5 years when calibration frequency is not specified by the manufacturer

Conformance with the factory calibration requirement is only required during periods of time where data gathered by the meter are used for emission reduction quantification. Periods where the meter did not meet this requirement will not cause the project to fail this requirement, provided the meter was not being used for project emission reduction quantification during such periods, and provided the meter was brought back into conformance before being employed to gather project data.

If a stationary meter that was in use for 60 days or more is removed and not reinstalled during a reporting period, that meter shall either be field-checked for calibration accuracy prior to removal or calibrated (with percent drift documented) by the manufacturer or a certified calibration service (with as-found results recorded) prior to quantification of emission reductions for that reporting period.

If the required calibration or calibration check is not performed and properly documented, no GHG credits may be generated for that reporting period. Flow meter calibrations shall be documented to show that the meter was calibrated to a range of flow rates corresponding to the

[29] Field checks and calibrations of flow meters shall ensure that the meter accurately reads volumetric flow, and has not drifted outside of the prescribed +/-5% accuracy threshold.
[30] Instead of performing field checks, the project developer may instead have equipment calibrated by the manufacturer or a certified calibration service per manufacturer's guidance, at the end of but no more than two months prior to or after the end date of the reporting period to meet this requirement.

flow rates expected at the landfill. Methane analyzer calibrations shall be documented to show that the calibration was carried out to the range of conditions (temperature and pressure) corresponding to the range of conditions as measured at the landfill.

The as-found condition (percent drift) of a field check must always be recorded. If the meter is found to be measuring outside of the +/- 5% threshold for accuracy, the data must be adjusted for the period beginning with the last successful field check or calibration event up until the meter is confirmed to be in calibration (unless the last event occurred during the prior reporting period, in which case adjustment is made back to the beginning of the current reporting period). If, at the time of the failed field check, the meter is cleaned and checked again, with the as-left condition found to be within the accuracy threshold, a full calibration is not required for that piece of equipment. This shall be considered a failed field check, followed by a successful field check. The data adjustment shall be based on the percent drift recorded at the time of the failed field check. However, if the as-left condition remains outside of the +/- 5% accuracy threshold (whether or not additional cleaning and accuracy testing occurs), calibration is required by the manufacturer or a certified service provider for that piece of equipment.

For the interval between the last successful field check and any calibration event confirming accuracy outside of the +/- 5% threshold, all data from that meter or analyzer must be scaled according to the following procedure. These adjustments must be made for the entire period from the last successful field check until such time as the meter is properly calibrated.

1. For calibrations that indicate under-reporting (lower flow rates, or lower methane concentration), the metered values must be used without correction.

2. For calibrations that indicate over-reporting (higher flow rates, or higher methane concentration), the metered values must be adjusted based on the greatest calibration drift recorded at the time of calibration.

For example, if a project conducts field checks quarterly during a year-long reporting period, then only three months of data will be subject at any one time to the adjustments above. However, if the project developer feels confident that the meter does not require field checks or calibration on a greater than annual frequency, then failed events will accordingly require the penalty to be applied to the entire year’s data. Frequent calibration may minimize the total accrued drift (by zeroing out any error identified) and result in smaller overall deductions. Additionally, strong equipment inspection practices that include checking all probes and internal components will minimize the risk of meter and analyzer inaccuracies and the corresponding deductions. If it is not possible to determine the accrued drift and/or an appropriate method for scaling the data (e.g., drift is recorded in milliwatts, which cannot be directly translated into a drift percentage), the project developer should seek guidance from the instrument manufacturer to confirm when the 5% drift threshold has been reached and how to appropriately scale the relevant data.

Additional field checks carried out during the reporting period at the project developer’s discretion may be performed by an individual that is not a third-party technician. In this case, the competency of the individual and the accuracy of the field check procedure must be assessed and approved by the verification body. Furthermore, if the field check reveals accuracy outside of the +/- 5% threshold, calibration is required and the data must be scaled as detailed above. In order to provide flexibility in verification, data monitored up to two months after a field check may be verified. As such, the end date of the reporting period must be no more than two months after the latest successful field check.

If a portable instrument either:

1. acquires project data (e.g., a handheld methane analyzer is used to take weekly methane concentration measurements), or

2. is used to field check the calibration accuracy of equipment that acquires project data and the portable instrument produces a data output that is or could be used in emission reduction calculations (i.e., flow or concentration); then,

the portable instrument shall be maintained and calibrated per the manufacturer's specifications, and calibrated at least annually by the manufacturer, by a laboratory approved by the manufacturer, or at an ISO 17025 accredited laboratory. Other pieces of equipment used for QA/QC of monitoring instruments shall be maintained according to the manufacturer's specifications, including calibration where specified. Portable methane analyzers must also be field calibrated to a known sample gas prior to each use.

6.3 Missing Data

In situations where the flow rate or methane concentration monitoring equipment is missing data, the project developer shall apply the data substitution methodology provided in Appendix D. If for any reason the destruction device monitoring equipment is inoperable (for example, the thermocouple on the flare), then no emission reductions can be registered for the period of inoperability.

6.4 Monitoring Parameters

Prescribed monitoring parameters necessary to calculate baseline and project emissions are provided in Table 6.1.

Table 6.1. Monitoring Data to be Collected and Used to Estimate Emission Reductions

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
		Regulatory compliance	Project developer attestation to compliance with regulatory requirements relating to landfill gas project	Each reporting period		Must be monitored and determined for each reporting period. The project developer shall document all federal, state, and local regulations, ordinances, and permit requirements (and compliance status for each) that apply to the GHG reduction project. The project developer shall provide a signed attestation to their compliance status for the above mentioned federal, state, and local regulations, ordinances, and permit requirements
		Legal requirement test	Project developer attestation of voluntary implementation	Each reporting period		Must be monitored and determined for each reporting period. The project developer shall document
		Operation of destruction device		Hourly	o	Required for each destruction device. For flares, operation is defined as thermocouple readings above 500° F. The presence and operability of a safety shut off valve will be sufficient to demonstrate operational activity of the given device.
Equation 5.1	ER	GHG emission reductions during the reporting period	tCO_2e	Per reporting period	c	
Equation 5.1 Equation 5.3	BE	Baseline emissions during the reporting period	tCO_2e	Per reporting period	c	

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
Equation 5.1 Equation 5.9	PE	Project emissions during the reporting period	tCO_2e	Per reporting period	c	
Equation 5.2 Equation 5.4	$LFG_{i,t}$	Adjusted volume of landfill gas fed to the destruction device *i*, in time interval *t*	scf	Continuous	m/c	Measured continuously by a flow meter and recorded at least once every 15 minutes. Data to be aggregated by time interval t (this parameter is calculated in cases where the metered flow must be corrected for temperature and pressure)
Equation 5.2	$LFG_{unadjusted}$	Unadjusted volume of landfill gas collected for the given time interval	acf	Continuous	m	Used only in cases where the flow meter does not automatically correct to 60° F and 1 atm
Equation 5.3 Equation 5.4	CH_4Dest_{PR}	Total methane destroyed by the project landfill gas collection and destruction system during the reporting period	tCH_4		c	
Equation 5.3	DF	Discount factor to account for uncertainties associated with the monitoring equipment	0-1.0	Continuous	r	Equal to zero if using continuous methane monitor (see Section 6.1)
Equation 5.3	OX	Factor for the oxidation of methane by soil bacteria	0, 0.1		r	Equal to 0.10 for all landfills except those that incorporate a synthetic liner throughout the entire area of the final cover system where OX = 0

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
Equation 5.3	GWP	100-year global warming potential for CH_4	tCO_2e/tCH_4	Per reporting period	r	As of publication, the value is 25.[31] This may be updated in the future via guidance from the Reserve
Equation 5.3 Equation 5.5	$Dest_{base}$	Adjustment to account for the baseline methane destruction associated with a baseline destruction device	tCO_2e		c	Equal to zero if no baseline LFG destruction system is in place prior to project implementation
Equation 5.4	CH_4Dest_i	The net quantity of methane destroyed by destruction device *i* during the reporting period	scf CH_4		c	
Equation 5.4	Q_i	Total quantity of landfill methane sent to destruction device *i* during the reporting period	scf CH_4	Daily/Weekly	c	Calculated daily if methane is continuously metered or weekly if methane is measured weekly
Equation 5.4 Equation 5.12	DE_i	Methane destruction efficiency for device *i*	%	Once	r/m	See Appendix B for guidance and default values
Equation 5.4	*t*	Time interval for which LFG flow and concentration measurements are aggregated	week, day, or smaller interval	Continuous/ Daily/Other	r	The interval employed is contingent upon the interval of data acquisition.

[31] Intergovernmental Panel on Climate Change (IPCC) 4th Assessment Report (2007).

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
Equation 5.4 Equation 5.8	$PR_{CH4,t}$	The average methane fraction of the landfill gas in time interval *t*	scf CH_4 / scf LFG	Continuous/ Other	m	Measured by continuous gas analyzer or a calibrated portable gas analyzer. Data to be averaged by time interval *t*.
Equation 5.5 Equation 5.6	$Closed_{discount}$	Adjustment to account for the methane which would have been combusted in the baseline flare from baseline wells at a closed landfill	scf CH_4	Yearly	c	Calculated per year, but may be scaled for project reporting periods less than one year
Equation 5.5 Equation 5.7	$NQ_{discount}$	Adjustment to account for the methane which would have been combusted in the baseline, non-qualifying combustion device	scf CH_4	Yearly	c	Calculated per year, but may be scaled for project reporting periods less than one year
Equation 5.5 Equation 5.8	$Dest_{max}$	Deduction of the un-utilized capacity of the baseline destruction device	scf CH_4	Weekly, Monthly, or Per reporting period (no more than weekly)	c	This deduction is to be applied only when a new destruction device is used during project activity
Equation 5.6	LFG_{B1}	Landfill gas from the baseline landfill gas wells that would have been destroyed by the qualifying destruction system during the reporting period	scf LFG	Yearly	c	Calculated using Appendix D. Calculated per year, but may be scaled for project reporting periods less than one year

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
Equation 5.6	$B_{CH4,closed}$	Methane fraction of landfill gas destroyed by baseline flares at a closed landfill	scf CH_4 / scf LFG	Continuously/ Other	m	Measured by continuous gas analyzer or a calibrated portable gas analyzer.
Equation 5.7	LFG_{B2}	Landfill gas that would have been destroyed by the original, non-qualifying destruction system during the reporting period	scf LFG / yr	Yearly	c	Calculated per Section 5, or according to guidance provided in Appendix D. Calculated per year, but may be scaled for project reporting periods less than one year
Equation 5.7	$B_{CH4,NQ}$	Methane fraction of landfill gas destroyed by non-qualifying devices in the baseline	scf CH_4 / scf LFG	Continuously/ Other	m	Measured by continuous gas analyzer or a calibrated portable gas analyzer
Equation 5.8	$LFG_{Bmax,t}$	The maximum landfill gas flow capacity of the baseline methane destruction device in time interval *t*	scf	At beginning of first reporting period	c	Calculated based on manufacturer's and/or engineer specifications for the destruction device and blower system. The maximum capacity of the limiting component, either the destruction device or blower, shall be used
Equation 5.8	$LFG_{B3,t}$	The actual landfill gas flow of the baseline methane destruction device in time interval *t*	scf	Continuous	m	Measured continuously by a flow meter and recorded at least once every 15 minutes
Equation 5.9 Equation 5.10	FF_{CO2}	Total carbon dioxide emissions from the destruction of fossil fuel during the reporting period	tCO_2	Per reporting period	c	

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
Equation 5.9 Equation 5.11	EL_{CO2}	Total carbon dioxide emissions from the consumption of electricity from the grid during the reporting period	tCO_2		c	
Equation 5.9 Equation 5.12	$NG_{emissions}$	Total quantity of emissions from supplemental natural gas, including both uncombusted methane and carbon dioxide emissions during the reporting period	tCO_2	Per reporting period	c	Includes both uncombusted methane and carbon dioxide emissions
Equation 5.10	$FF_{PR,j}$	Total fossil fuel consumed by the project landfill gas collection and destruction system during the reporting period, by fuel type *j*	volume fossil fuel	Monthly	o	Calculated from monthly record of fossil fuel purchased and consumed
Equation 5.10	$EF_{FF,j}$	Fuel specific emission factor	kg CO_2 / volume fossil fuel	Per reporting period	r	See Appendix C

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
Equation 5.11	EL_{PR}	Total electricity consumed by the project landfill gas collection and destruction system during the reporting period	MWh		m/o	Obtained from either onsite metering or utility purchase records. Required to determine CO_2 emissions from use of electricity to operate the project activity
Equation 5.11	EF_{EL}	Carbon emission factor for electricity used	$lbCO_2$ / MWh	Per reporting period	r	See the most up to date version available of the U.S. EPA eGRID[32]
Equation 5.12	NG_i	Total quantity of supplemental natural gas delivered to the destruction device *i* during the reporting period	scf	Continuous	m	Metered prior to delivery to destruction device
Equation 5.12	NG_{CH4}	Average methane fraction of the supplemental natural gas as provided for by fuel vendor	scf CH_4 / scf NG		r	Refer to purchase records
	T	Temperature of the landfill gas	°C	Continuous	m	No separate monitoring of temperature is necessary when using flow meters that automatically adjust flow volumes for temperature and pressure, expressing LFG volumes in normalized cubic feet

[32] Available at: http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
	P	Pressure of the landfill gas	atm	Continuous	m	No separate monitoring of pressure is necessary when using flow meters that automatically measure adjust flow volumes for temperature and pressure, expressing LFG volumes in normalized cubic feet

7 Reporting Parameters

This section provides guidance on reporting rules and procedures. A priority of the Reserve is to facilitate consistent and transparent information disclosure among project developers. Project developers must submit verified emission reduction reports to the Reserve annually at a minimum.

7.1 Project Documentation

Project developers must provide the following documentation to the Reserve in order to register a landfill gas destruction project:

- Project Submittal form
- Signed Attestation of Title form
- Signed Attestation of Voluntary Implementation form
- Signed Attestation of Regulatory Compliance form
- Detailed system diagram from Monitoring Plan
- Verification Report
- Verification Statement

Project developers must provide the following documentation each reporting period in order for the Reserve to issue CRTs for quantified GHG reductions:

- Verification Report
- Verification Statement
- Signed Attestation of Title form
- Signed Attestation of Voluntary Implementation form
- Signed Attestation of Regulatory Compliance form

At a minimum, the above project documentation will be available to the public via the Reserve's online reporting tool of the same name, the Climate Action Reserve. Further disclosure and other documentation may be made available on a voluntary basis. Project submittal forms and project registration information can be found at: http://www.climateactionreserve.org/how/program/documents/.

7.2 Record Keeping

For purposes of independent verification and historical documentation, project developers are required to keep all information outlined in this protocol for a period of 10 years after the information is generated or 7 years after the last verification. This information will not be publicly available, but may be requested by the verifier or the Reserve.

System information the project developer should retain includes:

- All data inputs for the calculation of GHG reductions
- Copies of all solid waste, air, water, and land use permits; Notices of Violations (NOVs); and any administrative or legal consent orders dating back at least 3 years prior to the project start date, and for each subsequent year of project operation
- Project developer attestation of compliance with regulatory requirements relating to the landfill gas project
- Collection and control device information (installation dates, equipment list, etc.)

- LFG flow meter information (model number, serial number, manufacturer's calibration procedures)
- Methane monitor information (model number, serial number, calibration procedures)
- Destruction device monitor information (model number, serial number, calibration procedures)
- LFG flow data (for each flow meter)
- LFG flow meter calibration data (for each flow meter)
- Methane monitoring data
- Methane monitor calibration data
- Destruction device monitoring data (for each destruction device)
- Destruction device monitor calibration data (for each destruction device)
- CO_2e monthly and annual tonnage calculations
- Copies of the results of the NSPS/EG Tier 1 and/or Tier 2 NMOC emission rate estimates and the projected date when system start-up will be required by NSPS
- Initial and annual verification records and results
- All maintenance records relevant to the LFG control system, monitoring equipment, and destruction devices
- Operational records of the landfill relating to the amount of waste placed onsite (scalehouse records, etc.), or most recent documented WIP report accepted by a regulatory agency

Calibrated portable gas analyzer information that the project developer should retain includes:

- Date, time, and location of methane measurement
- Methane content of LFG (% by volume) for each measurement
- Methane measurement instrument type and serial number
- Date, time, and results of instrument calibration
- Corrective measures taken if instrument does not meet performance specifications

7.3 Reporting Period and Verification Cycle

7.3.1 Reporting Periods

The reporting period is the length of time over which GHG emission reductions from project activities are quantified. Project developers must report GHG reductions resulting from project activities during each reporting period. A reporting period may not exceed 12 months in length, except for the initial reporting period, which may cover up to 24 months. The Reserve accepts verified emission reduction reports on a sub-annual basis, should the project developer choose to have a sub-annual reporting period and verification schedule (e.g., monthly, quarterly, or semi-annually). Reporting periods must be contiguous; there must be no gaps in reporting during the crediting period of a project once the first reporting period has commenced.

7.3.2 Verification Periods

The verification period is the length of time over which GHG emission reductions from project activities are verified. The initial verification period for a landfill project is limited to one reporting period (i.e., up to 24 months). Subsequent verification periods may cover up to two reporting periods. CRTs will not be issued for reporting periods that have not been verified. For any reporting period that ends prior to the end of the verification period (i.e., year 1 of a 2-year verification period), an interim monitoring report must be submitted to the Reserve no later than six months following the end of the relevant reporting period. The interim monitoring report shall contain a summary of emission reductions, description of QA/QC activities, and description of any potential nonconformances, data errors, metering issues, or material changes to the project.[33] All mandatory sections of interim monitoring reports must be verified in the subsequent verification.

To meet the verification deadline, the project developer must have the required verification documentation (see Section 7.1) submitted within 12 months of the end of the verification period. The end date of any verification period must correspond to the end date of a reporting period.

7.3.3 Verification Site Visit Schedule

A site visit must occur during the initial verification, and at least once every two reporting periods thereafter. A reporting period may be verified without a new site visit if the following requirements are met:

1. A new site visit occurred in conjunction with the verification of the previous reporting period;
2. The current verification is being conducted by the same verification body that conducted the site visit for the previous verification; and
3. There have been no significant changes in data management systems, equipment, or personnel since the previous site visit.

The above requirements apply regardless of whether the verification period contains one or two reporting periods. The Reserve maintains the discretion to require a new site visit for a reporting period despite satisfaction of the above requirements. For example, the approval of a significant variance during the reporting period could be considered grounds for denial of the option to forego a site visit for the verification.

[33] A template monitoring report is available at: http://www.climateactionreserve.org/how/program/documents/.

8 Verification Guidance

This section provides verification bodies with guidance on verifying GHG emission reductions from landfill gas projects developed to the standards of this protocol. This verification guidance supplements the Reserve's Verification Program Manual and describes verification activities in the context of landfill gas destruction projects.

Verification bodies trained to verify landfill gas projects must conduct verifications to the standards of the following documents:

- Climate Action Reserve Program Manual
- Climate Action Reserve Verification Program Manual
- Climate Action Reserve Landfill Project Protocol

The Reserve's Program Manual, Verification Program Manual, and project protocols are designed to be compatible with each other and are available on the Reserve's website at http://www.climateactionreserve.org.

In cases where the Program Manual and/or Verification Program Manual differ from the guidance in this protocol, this protocol takes precedent.

Only ISO-accredited verification bodies trained by the Reserve for this project type are eligible to verify landfill projects. Verification bodies approved under other project protocol types are not permitted to verify landfill projects. Information about verification body accreditation and Reserve project verification training can be found in the Verification Program Manual.

8.1 Standard of Verification

The Reserve's standard of verification for landfill projects is the Landfill Project Protocol (this document), the Reserve Program Manual, and the Verification Program Manual. To verify a landfill project developer's project report, verification bodies apply the guidance in the Verification Program Manual and this section of the protocol to the standards described in Section 2 through 7 of this protocol. Sections 2 through 7 provide eligibility rules, methods to calculate emission reductions, performance monitoring instructions and requirements, and procedures for reporting project information to the Reserve.

8.2 Monitoring Plan

The Monitoring Plan serves as the basis for verification bodies to confirm that the monitoring and reporting requirements in Section 6 and Section 7 have been met, and that consistent, rigorous monitoring and record-keeping is ongoing at the project site. Verification bodies shall confirm that the Monitoring Plan covers all aspects of monitoring and reporting contained in this protocol and specifies how data for all relevant parameters in Table 6.1 are collected and recorded.

8.3 Verifying Project Eligibility

Verification bodies must affirm a landfill project's eligibility according to the rules described in this protocol. The table below outlines the eligibility criteria for a landfill project. This table does not represent all criteria for determining eligibility comprehensively; verification bodies must also look to Section 3 and the verification items list in Table 8.2.

Table 8.1. Summary of Eligibility Criteria

Eligibility Rule	Eligibility Criteria	Frequency of Rule Application
Location	United States and its territories	Once during first verification
Start Date	Projects must be submitted for listing within six months of the project start date	Once during first verification
Project Crediting Period	Ensure the project is within its first or second crediting period	Once during each crediting period
Performance Standard Test	Installation of a qualifying destruction device where not required by law (see Section 3.4.1 for other requirements)	Once during first verification
Limits on Credit Stacking	Ensure no credits are issued to the project for transport fuel incentive programs, or other programs with overlapping GHG boundaries	Every verification
Legal Requirement Test	Signed Attestation of Voluntary Implementation form and monitoring procedures that lay out procedures for ascertaining and demonstrating that the project passes the legal requirement test	Every verification
Regulatory Compliance	Signed Attestation of Regulatory Compliance form and disclosure of all non-compliance events to verifier; project must be in material compliance with all applicable laws	Every verification
Exclusions	▪ Bioreactors ▪ Landfills that re-circulate a liquid other than leachate in a controlled manner ▪ Indirect emissions from the displacement of grid electricity or natural gas	Every verification

8.4 Core Verification Activities

The Landfill Project Protocol provides explicit requirements and guidance for quantifying GHG reductions associated with the destruction of landfill methane. The Verification Program Manual describes the core verification activities that shall be performed by verification bodies for all project verifications. They are summarized below in the context of a landfill project, but verification bodies shall also follow the general guidance in the Verification Program Manual.

Verification is a risk assessment and data sampling effort designed to ensure that the risk of reporting error is assessed and addressed through appropriate sampling, testing, and review. The three core verification activities are:

1. Identifying emissions sources, sinks and reservoirs
2. Reviewing GHG management systems and estimation methodologies
3. Verifying emission reduction estimates

Identifying emission sources, sinks, and reservoirs

The verification body reviews for completeness the sources, sinks, and reservoirs identified for a project, such as system energy use, fuel consumption, combustion and destruction from various qualifying and non-qualifying destruction devices, and soil oxidation.

Reviewing GHG management systems and estimation methodologies
The verification body reviews and assesses the appropriateness of the methodologies and management systems that the landfill project uses to gather data on methane collected and destroyed and to calculate baseline and project emissions.

Verifying emission reduction estimates
The verification body further investigates areas that have the greatest potential for material misstatements and then confirms whether or not material misstatements have occurred. This involves site visits to the project to ensure the systems on the ground correspond to and are consistent with data provided to the verification body. In addition, the verification body recalculates a representative sample of the performance or emissions data for comparison with data reported by the project developer in order to double-check the calculations of GHG emission reductions.

8.5 Landfill Project Verification Items

The following tables provide lists of items that a verification body needs to address while verifying a landfill project. The tables include references to the section in the protocol where requirements are further described. The table also identifies items for which a verification body is expected to apply professional judgment during the verification process. Verification bodies are expected to use their professional judgment to confirm that protocol requirements have been met in instances where the protocol does not provide (sufficiently) prescriptive guidance. For more information on the Reserve's verification process and professional judgment, please see the Verification Program Manual.

Note: These tables shall not be viewed as a comprehensive list or plan for verification activities, but rather guidance on areas specific to landfill projects that must be addressed during verification.

8.5.1 Project Eligibility and CRT Issuance

Table 8.2 lists the criteria for reasonable assurance with respect to eligibility and CRT issuance for landfill projects. These requirements determine if a project is eligible to register with the Reserve and/or have CRTs issued for the reporting period. If any one requirement is not met, either the project may be determined ineligible or the GHG reductions from the reporting period (or sub-set of the reporting period) may be ineligible for issuance of CRTs, as specified in Sections 2, 3, and 6.

Table 8.2. Eligibility Verification Items

Protocol Section	Eligibility Qualification Item	Apply Professional Judgment?
2.2	Verify that the project meets the definition of a landfill project and is properly defined per Section 2.2	No
2.3	Verify ownership of the reductions by reviewing Attestation of Title	No
2.3	For direct use agreements between the project developer and the end user of the landfill gas (i.e., an industrial client purchasing the landfill gas from the project developer), verify that a legally binding mechanism is built into the agreement language to assure that the GHG offset credits will not be double counted	No
3.2	Verify eligibility of project start date	No
3.2	Verify accuracy of project start date based on operational records	Yes
3.3	Verify that project is within its first or second 10-year crediting period	No

Protocol Section	Eligibility Qualification Item	Apply Professional Judgment?
3.4.1	Verify that the project meets the appropriate performance standard test for the project type per Section 3.4.1	No
3.4.2	Verify no credits are issued to the project for transport fuel incentive programs, or other programs with overlapping GHG boundaries	No
3.4.3	Confirm execution of the Attestation of Voluntary Implementation form to demonstrate eligibility under the legal requirement test	No
3.4.3	Verify that the project activities comply with applicable laws by reviewing any instances of non-compliance provided by the project developer and performing a risk-based assessment to confirm the statements made by the project developer in the Attestation of Regulatory Compliance form	Yes
4	Confirm all baseline non-qualifying devices have been properly accounted for within project's GHG Assessment Boundary	No
4	Confirm all baseline qualifying devices have been properly accounted for within project's GHG Assessment Boundary	No
6	Verify that monitoring meets the requirements of the protocol. If it does not, verify that a variance has been approved for monitoring variations	No
6	Verify that the project monitoring plan contains procedures for ascertaining and demonstrating that the project passes the legal requirement test at all times	Yes
6	Verify that the landfill gas control system operated in a manner consistent with the design specifications	Yes
6	Verify that there is an individual responsible for managing and reporting GHG emissions, and that individual properly trained and qualified to perform this function	Yes
6.2	Verify that all gas flow meters and methane analyzers adhered to the inspection, cleaning, and calibration schedule specified in the protocol. If they do not, verify that a variance has been approved for monitoring variations or that adjustments have been made to data per the protocol requirements	No
6.2	If any piece of equipment failed a calibration check, verify that data from that equipment was scaled according to the failed calibration procedure for the appropriate time period	No
6.3	If used, verify that data substitution methodology was properly applied	No
7.1	Verify that appropriate documents are created to support and/or substantiate activities related to GHG emission reporting activities, and that such documentation is retained appropriately	Yes
	If any variances were granted, verify that variance requirements were met and properly applied	Yes
	If any zero-credit reporting periods were taken, verify that zero-credit reporting period requirements were met	Yes

8.5.2 Quantification of GHG Emission Reductions

Table 8.3 lists the items that verification bodies shall include in their risk assessment and re-calculation of the project's GHG emission reductions. These quantification items inform any determination as to whether there are material and/or immaterial misstatements in the project's GHG emission reduction calculations. If there are material misstatements, the calculations must be revised before CRTs are issued.

Table 8.3. Quantification Verification Items

Protocol Section	Quantification Item	Apply Professional Judgment?
4	Verify that SSRs included in the GHG Assessment Boundary correspond to those required by the protocol and those represented in the project	No
5	Verify that the project developer correctly accounted for baseline methane destruction in the baseline scenario	No
5	Verify that the project developer correctly monitored, quantified and aggregated the amount of methane collected from the landfill and destroyed by the project landfill gas control system?	No
5	Verify that the project developer correctly quantified and aggregated electricity use	Yes
5	Verify that the project developer correctly quantified and aggregated fossil fuel use	Yes
5	Verify that the project developer applied the correct emission factors for fossil fuel combustion and grid-delivered electricity	No
5	Verify that the project developer applied the correct methane destruction efficiencies	No
Appendix B	If the project developer used source test data in place of the default destruction efficiencies (Appendix B), verify accuracy and appropriateness of data and calculations	Yes

8.5.3 Risk Assessment

Verification bodies will review the following items in Table 8.4 to guide and prioritize their assessment of data used in determining eligibility and quantifying GHG emission reductions.

Table 8.4. Risk Assessment Verification Items

Protocol Section	Item that Informs Risk Assessment	Apply Professional Judgment?
6	Verify that the project monitoring plan is sufficiently rigorous to support the requirements of the protocol and proper operation of the project	Yes
6	Verify that appropriate monitoring equipment is in place to meet the requirements of the protocol	No
6	Verify that equipment calibrations have been carried out to satisfy the requirements of the protocol	No
6	Verify that the individual or team responsible for managing and reporting project activities are qualified to perform this function	Yes
6	Verify that appropriate training was provided to personnel assigned to greenhouse gas reporting duties	Yes
6	Verify that all contractors are qualified for managing and reporting greenhouse gas emissions if relied upon by the project developer. Verify that there is internal oversight to assure the quality of the contractor’s work	Yes
6.2	Verify that the methane destruction equipment was operated and maintained according to manufacturer specifications	Yes
7.2	Verify that all required records have been retained by the project developer	No

8.6 Completing Verification

The Verification Program Manual provides detailed information and instructions for verification bodies to finalize the verification process. It describes completing a Verification Report, preparing a Verification Statement, submitting the necessary documents to the Reserve, and notifying the Reserve of the project's verified status.

9 Glossary of Terms

Accredited verification body	A verification firm approved by the Climate Action Reserve to provide verification services for project developers.
Additionality	Landfill management practices that are above and beyond business-as-usual operation, exceed the baseline characterization, and are not mandated by regulation.
Anaerobic	Pertaining to or caused by the absence of oxygen.
Anthropogenic emissions	GHG emissions resultant from human activity that are considered to be an unnatural component of the Carbon Cycle (i.e., fossil fuel destruction, de-forestation, etc.).
Biogenic CO_2 emissions	CO_2 emissions resulting from the destruction and/or aerobic decomposition of organic matter. Biogenic emissions are considered to be a natural part of the Carbon Cycle, as opposed to anthropogenic emissions.
Bioreactor	Any landfill which: a. Meets the EPA definition of a bioreactor: “a MSW landfill or portion of a MSW landfill where any liquid other than leachate (leachate includes landfill gas condensate) is added in a controlled fashion into the waste mass (often in combination with recirculating leachate) to reach a minimum average moisture content of at least 40 percent by weight to accelerate or enhance the anaerobic (without oxygen) biodegradation of the waste.”[34] b. Has been designated by local, state, or federal regulators as a bioreactor. c. Has received grants or funding to operate as a bioreactor.
Carbon dioxide (CO_2)	The most common of the six primary greenhouse gases, consisting of a single carbon atom and two oxygen atoms.
Closed landfill	A landfill that has ceased waste acceptance, and has submitted a closure report to EPA or the state indicating that it will no longer accept waste.
CO_2-equivalent (CO_2e)	The quantity of a given GHG multiplied by its total global warming potential. This is the standard unit for comparing the degree of warming which can be caused by different GHGs.
Direct emissions	Greenhouse gas emissions from sources that are owned or controlled by the reporting entity.
Direct Use Project	A Landfill Gas to Energy Project where the landfill gas is used for its thermal capacity. Direct use projects offer a cost-effective alternative for fueling combustion or heating equipment at facilities located near a

[34] 40 CFR 63.1990 and 40 CFR 258.28a.

	landfill. Qualifying destruction devices include boilers, leachate evaporators, kilns, sludge dryers, burners, furnaces.
Eligible landfill	An "eligible landfill" is a landfill that: 1. Is not subject to regulations or other legal requirements requiring the destruction of methane gas 2. Is not a bioreactor 3. Does not add any liquid other than leachate into the waste mass in a controlled manner
Electricity Project	A Landfill Gas to Energy Project for the generation of electricity. Technologies include engines, turbines, microturbines and fuel cells.
Emission factor (EF)	A unique value for determining an amount of a greenhouse gas emitted for a given quantity of activity data (e.g., metric tons of carbon dioxide emitted per barrel of fossil fuel burned).
Emission guidelines (EG)	Guidelines for State regulatory plans that have been developed by the U.S. EPA. For landfills, emission guidelines are codified in 40 CFR 60 Subpart CC.
Flare	A destruction device that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame.
Fossil fuel	A fuel, such as coal, oil, and natural gas, produced by the decomposition of ancient (fossilized) plants and animals.
Greenhouse gas (GHG)	Carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), or perfluorocarbons (PFCs).
Global warming potential (GWP)	The ratio of radiative forcing (degree of warming to the atmosphere) that would result from the emission of one unit of a given GHG compared to one unit of CO_2.
Indirect emissions	Emissions that are a consequence of the actions of a reporting entity, but are produced by sources owned or controlled by another entity.
Landfill	A defined area of land or excavation that receives or has previously received waste that may include household waste, commercial solid waste, non-hazardous sludge and industrial solid waste.
Landfill gas (LFG)	Gas resulting from the decomposition of wastes placed in a landfill. Typically, landfill gas contains methane, carbon dioxide and other trace organic and inert gases.
Landfill gas project	Installation of infrastructure that in operating causes a decrease in GHG emissions through destruction of the methane component of landfill gas.

Landfill gas-to-energy (LFGE)	A LFGE project is one where the LFG destruction involves a destruction device that generates energy (engine, turbine, microturbine, fuel cell, boiler, upgrade to pipeline, upgrade to CNG/LNG, etc.). This does not include small-scale, non-commercial applications, such as leachate drying.
Medium-Btu project	See Direct Use project definition.
Metric ton or “tonne” (t, Mg)	A common international measurement for the quantity of GHG emissions, equivalent to about 2204.6 pounds or 1.1 short tons.
Methane (CH_4)	A potent GHG with a GWP of 21, consisting of a single carbon atom and four hydrogen atoms.
MMBtu	One million British thermal units.
Mobile combustion	Emissions from the transportation of materials, products, waste, and employees resulting from the combustion of fuels in company owned or controlled mobile combustion sources (e.g., cars, trucks, tractors, dozers, etc.).
National Emission Standards for Hazardous Air Pollutants (NESHAP)	Federal emission control standards codified in 40 CFR 63. Subpart AAAA of Part 63 prescribes emission limitations for MSW landfills.
New Source Performance Standards (NSPS)	Federal emission control standards codified in 40 CFR 60. Subpart WWW of Part 60 prescribes emission limitations for MSW landfills.
Non-methane organic compounds (NMOC)	Non-methane organic compounds as measured according to the provisions of 40 CFR 60.754.
Non-qualifying destruction device	A passive flare or other combustion system that results in the destruction of methane, but which cannot serve as the primary destruction device for a methane destruction project under this protocol.
Nitrous oxide (N_2O)	A GHG consisting of two nitrogen atoms and a single oxygen atom.
Project baseline	A business-as-usual GHG emission assessment against which GHG emission reductions from a specific GHG reduction activity are measured.
Project developer	An entity that undertakes a project activity, as identified in the Landfill Project Protocol. A project developer may be an independent third party or the landfill operating entity.
Qualifying destruction device	Includes but is not limited to a utility flare, enclosed flare, engine, turbine, microturbine, boiler, pipeline, vehicle, fuel cells, leachate evaporators,

	kilns, sludge dryers, burners, furnaces which can serve as the primary destruction device for a methane destruction project under this protocol.
Renewable Energy Certificates (RECs)	As defined by the U.S. EPA Green Power Partnership, a REC represents the property rights to the environmental, social, and other non-power qualities of renewable electricity generation. For a landfill project this is represented by the existence of a REC contract or participation of the landfill in a REC tracking system. The RECs may be sold as bundled (green power) or unbundled from the associated energy that is generated.
Reporting period	Specific time period of project operation for which the project developer has calculated and reported emission reductions and is seeking verification and issuance of credits. The reporting period must be no longer than 12 months.
Resource Conservation and Recovery Act (RCRA)	Federal legislation under which solid and hazardous waste disposal facilities are regulated.
Stationary combustion source	A stationary source of emissions from the production of electricity, heat, or steam, resulting from combustion of fuels in boilers, furnaces, turbines, kilns, and other facility equipment.
Upgraded Landfill Gas Project	A Landfill Gas to Energy Project where the landfill gas is cleaned to a level similar to natural gas. Three common types of projects are RNG (Renewable Natural Gas), CNG (Compressed Natural Gas) or LNG (Liquefied Natural Gas).
Verification	The process used to ensure that a given participant's GHG emissions or emission reductions have met the minimum quality standard and complied with the Reserve's procedures and protocols for calculating and reporting GHG emissions and emission reductions.
Verification body	An ISO-accredited and Reserve-approved firm that is able to render a verification opinion and provide verification services for operators subject to reporting under this protocol.
Verification period	The period of time over which GHG emission reductions are verified. Landfill projects may verify up to two reporting periods at a time.
Waste in place	The cumulative amount of solid waste, measured in metric tons, that has been permanently placed into the landfill.

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Appendix A Development of the Performance Standard Threshold

The initial performance standard for the Landfill Project Protocol Version 1.0 was adopted in 2007. This analysis used as its primary data source the database of nearly 2,400 landfills in the United States developed and maintained by the U.S. EPA's Landfill Methane Outreach Program (LMOP).[35] This database does not represent all U.S. landfills, but rather a subset of all landfills that have been identified as having current landfill gas to energy (LFGE) projects or where potential opportunities exist for such projects. This database is updated on an ongoing basis by LMOP staff. Landfill gas projects take time to move from conception to operation (often two years or more) so the database does not see rapid, significant changes. The original analysis conducted in 2007 concluded that any new installation of a landfill gas collection system and/or qualifying destruction device where gas had not previously been collected and destroyed (or was destroyed using a non-qualifying destruction device) could be considered additional.

In the years following the 2007 analysis, there was a significant increase in the market penetration of landfill gas to energy systems. Hence in 2011 the performance standard underwent a significant update, with the release of Version 4.0 of the Landfill Project Protocol. The focus on the original performance standard test and the 2011 update were landfills not required to collect and control gas emissions by NSPS/EG, either because they are under the landfill design size that would make them subject to the regulation or because they were still below the NMOC emissions per year threshold to trigger gas destruction obligations. The purpose of the 2011 analysis was to identify whether new criteria were necessary to continue to ensure that only additional landfill gas destruction projects are eligible to register with the Reserve, and if so, what those criteria should be.

A.1 2007 Performance Standard Analysis

Table A.1 and Table A.2 provide the summary conclusions of the Reserve's 2007 performance standard analysis, using the LMOP database available at that time. The original analysis excluded all landfills that were closed prior to 2001, since their methane production was assumed to have already dropped off significantly and they would therefore be poor candidates for landfill gas projects.

Table A.1. Summary of Information on U.S. Landfills (NSPS/EG and Non-NSPS/EG) (2007)

	Number of Landfills	Percent of Landfills	Number w/ LFG Collection	Percent w/ LFG Collection
Landfills in Analysis				
NSPS/EG	697	37.35	697	100
Non-NSPS/EG	1169	62.65	261	22.33
Subtotal	1866	100	958	51.34
Landfills Excluded from Analysis	518			
Total U.S. Landfills	2384			

[35] LMOP is a voluntary partnership program that was created to reduce methane emissions from landfills by encouraging the use of landfill gas for energy. LMOP tracks whether or not specific landfills are required to reduce landfill gas emissions under the New Source Performance Standards and Emission Guidelines for Municipal Solid Waste Landfills (NSPS/EG), promulgated March 1996. Because LMOP is not a regulatory program, it cannot make an official EPA designation regarding any landfill's NSPS/EG status. Information relating to NSPS/EG was obtained by voluntary submittal and is subject to change over time. Therefore, LMOP cannot guarantee the validity of this information.

Table A.2. Summary of Non-NSPS/EG Landfills Under Assumption that Flare-Only Landfills Are Already Regulated (2007)

	Flares Included		Flares Excluded	
Non-NSPS/EG Landfills	**Number of Landfills**	**Percentage**	**Number of Landfills**	**Percentage**
Flare-Only	166	14.2	Excluded	Excluded
Electricity	67	5.7	67	6.7
Gas Projects	28	2.4	28	2.8
Subtotal	261	22.3	95	9.5
No LFG collection	908	77.7	908	90.5
Total	1169	100.0	1003	100.0
Estimated Market Penetration of LFG Collection Projects at Unregulated Landfills		**22.3%**		**9.5%**

A.2 2011 Performance Standard Test: Size Threshold for LFGE Projects

In the 2011 performance standard analysis, the Reserve sought to identify characteristics or conditions that could distinguish between additional and non-additional projects. The analysis was based on the premise that in the absence of any incentives provided by GHG offsets or RECs, the feasibility of installing a LFGE project at an unregulated landfill depended largely on the amount of methane produced at the landfill. Landfills that produce more methane are more likely to be better candidates for such projects. The Reserve identified two key factors in methane production potential, first the amount of waste in place (WIP) and second, annual precipitation at the landfill.

Having identified two key factors in methane production potential, the next step in the Reserve's analysis was to examine the market penetration of voluntary LFGE projects at unregulated landfills as a function of the size of the landfill (measured as WIP at the time the project was installed) and annual precipitation.

The Reserve identified a WIP threshold for each precipitation zone that effectively screened out a majority of non-additional LFGE projects. The objective of excluding non-additional projects, however, had to be balanced against concerns about unfairly excluding landfills from eligibility where no projects currently exist. The result was to target a WIP threshold for each zone such that the percentage of unregulated landfills with LFGE projects was 5% or less (i.e., the "natural" market penetration of LFGE projects at landfills below the threshold was no more than 5%). For landfills in the arid precipitation zone, this threshold was determined to be 2.17 million metric tons (MMg). For landfills in the non-arid precipitation zone, this threshold was determined to be 0.72 MMg (Table A.3).

The percentage of incorrectly excluded landfills at these thresholds differs markedly for the arid and non-arid zones. For the arid zone, only 10% of unregulated landfills without LFGE projects are incorrectly excluded. For the non-arid zone, however, nearly 60% of unregulated landfills without LFGE projects are incorrectly excluded. Although that was a high rate of incorrect exclusions, the Reserve believed it was important to strike a balance strongly in favor of ensuring that projects that *did* pass an additionality screen were likely to be additional. In the absence of alternative characteristics or conditions that could be used to screen for additional projects, the Reserve believed it was necessary to adopt a stringent WIP threshold.

Table A.3. WIP Values for 5% Market Penetration of LFGE Projects[36]

	Arid Counties (<25” Annual Precipitation)	Non-Arid Counties (>25” Annual Precipitation)
WIP Threshold for 5% Market Penetration of LFGE Projects at Unregulated Landfills (metric tons)	2,165,000	715,000
Percentage of Landfills with No LFG Collection Excluded by this WIP Threshold	10%	58%

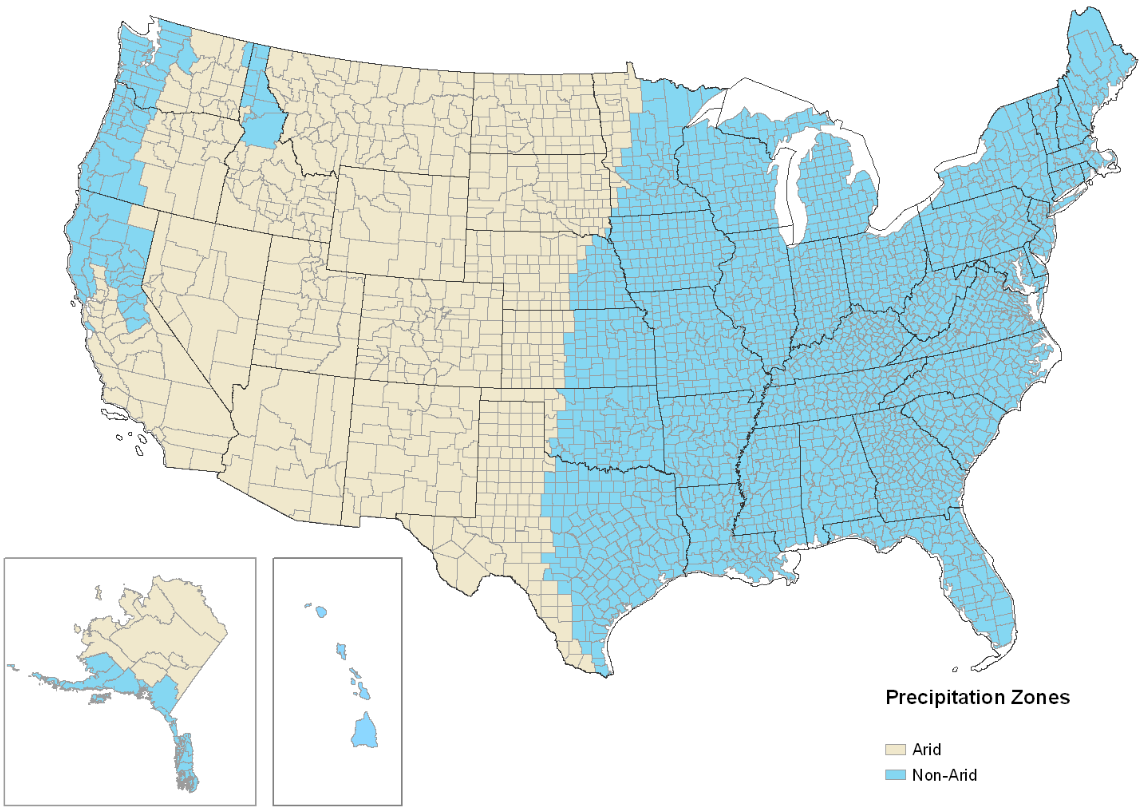

Figure A.1. Precipitation Zones of the United States, by County

Based on the USGS Hydrologic Zones of the United States (2003). Arid counties average less than 25 inches of precipitation annually, and non-arid counties average 25 inches or greater precipitation annually.

[36] It is likely that some of the LFGE projects at landfills not subject to NSPS/EG and below the size thresholds presented here are in fact required by local regulations. Thus, the actual “natural” market penetration below these thresholds is likely to be below 5%, and may be significantly below 5%. The analysis conservatively assumes that none are legally required.

A.3 Protocol Version 5.0 Performance Standard Analysis

Since the 2011 performance standard analysis, there have been significant changes in the U.S. domestic energy landscape and thus landfill gas market conditions. A review of updated LMOP data reveals that the market penetration of LFGE projects has remained steady (with relatively few LFGE project closures), but that the uptake of new LFGE projects has fallen off significantly in recent years. LMOP data are used in Figure A.2 below to depict the number of new LFGE projects installed per year from 2000 through 2017. These data indicate a significant decline in new LFGE project installations per year over the past few years; this is projected to continue beyond 2018.

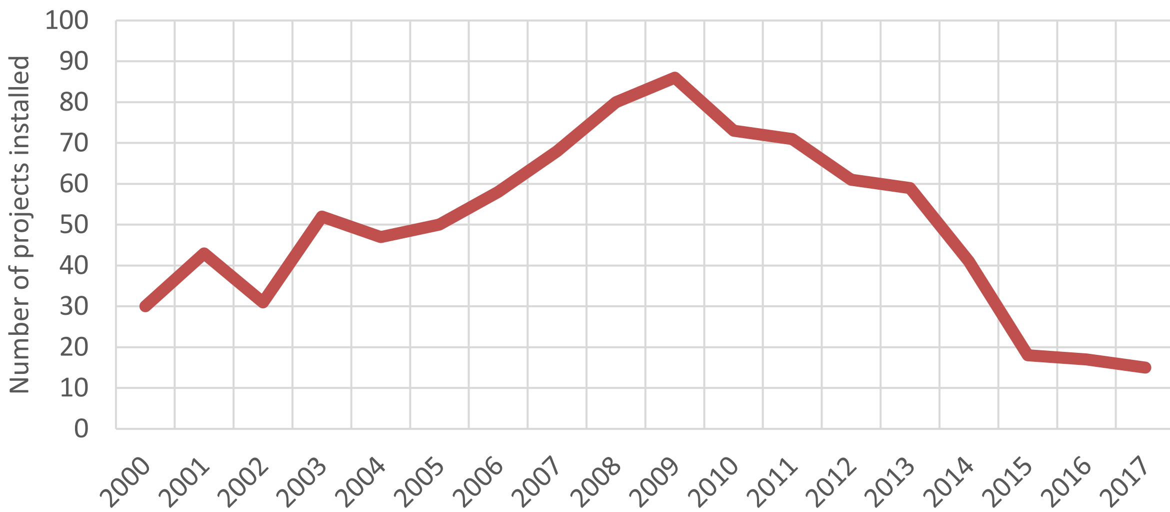

Figure A.2. New LFGE Installations

The number of new LFGE projects installed per year from the year 2000 to 2017.

Given that this declining trend of new LFGE project uptake occurred while the U.S. was experiencing a boom in domestic energy production, in particular natural gas (NG), Reserve staff sought to explore the nexus between NG pricing and LFGE project uptake. Reserve staff examined Energy Information Administration data on U.S. energy costs, including coal, petroleum, and natural gas. As landfill gas and natural gas can be effectively substituted in the production of marginal electrical demand, Reserve staff wanted to determine if the price of natural gas could be a useful means to predict LFGE project uptake.

Figure A.3 below indicates that a correlation can be drawn between declining costs of inputs for marginal electricity generation and the decline in the development of new LFGE projects. This data suggests a strong correlation between declining costs of energy inputs competing with LFG, in particular NG, and the installation of new LFGE projects.

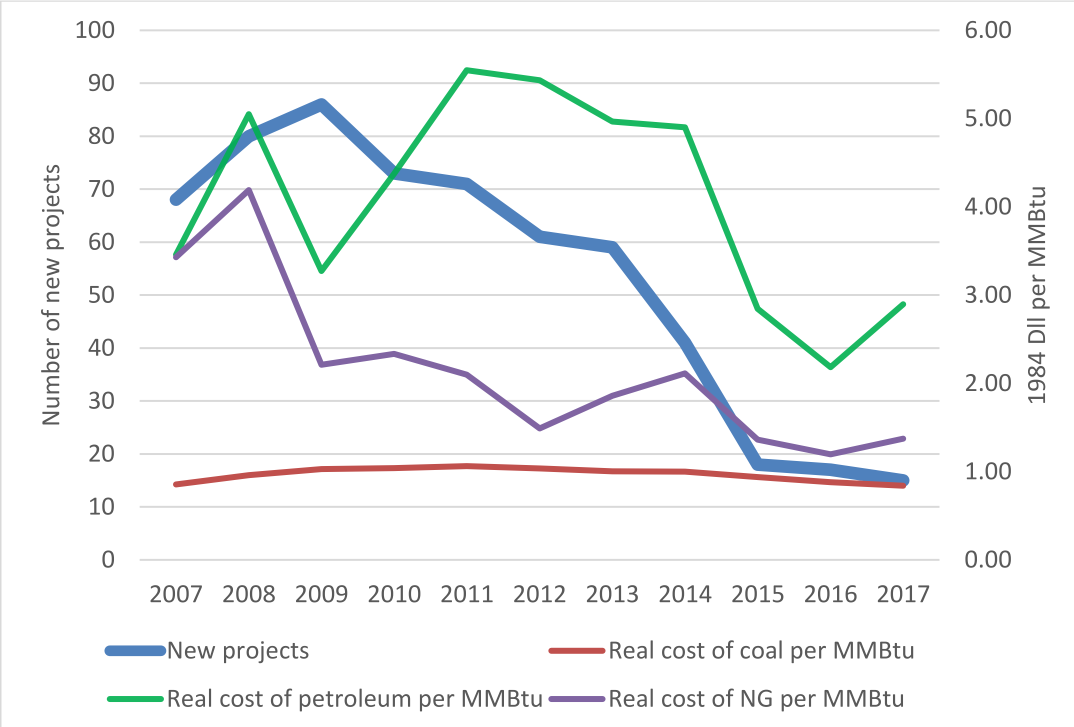

Figure A.3. New LFGE Installations and Marginal Power Input Costs

The number of new LFGE projects installed per year from the year 2007 to 2017 (both regulated and unregulated landfills), and marginal power generation fuel input costs (coal, petroleum, and NG).

Despite the strong observed correlation between NG pricing and new LFGE project development, Reserve staff and workgroup members were cautious not to assume causality. Expert guidance from the workgroup, literature, and Reserve staff suggested that NG pricing alone is insufficient to capture the complexities of LFGE market conditions. Instead, Reserve staff sought to look more broadly at the financial feasibility of LFGE projects, and examine other potentially key contributing factors, including regulatory conditions, LFGE incentives, availability of infrastructure such as NG pipelines, availability of end-use buyers, tax rates, as well as the underlying size and gassiness of landfills.

To more accurately distinguish the projects that would be financially feasible given current market conditions, the Reserve focused on three market factors: 1) landfill gas energy end-use categories; 2) market penetration per end-use category; and 3) LFGE project's financial feasibility (including the impacts of incentives other than offsets). Following expert guidance, the Reserve split LFGE projects into three categories for this assessment: high-Btu projects (RNG, CNG, or LNG projects injecting compressed gas into pipelines), medium-Btu projects (projects where gas is piped directly to a nearby customer or used onsite for its thermal capacity), and electricity generation projects.

The analysis of high-Btu projects reveals that they are not common practice (less than 1% of LMOP landfills have a high-Btu project in place[37]), however, some 39 new high-Btu projects are

[37] Penetration rate is defined as the number of landfills with at least one operational project divided by the total number of landfills in the LMOP database.

either currently in their planning stages or under construction (almost 60% of all LMOP planned or under construction projects for 2019 onwards[38]). Discussions with industry experts indicate that as of the end of 2018, some 50 existing high-Btu projects currently receive incentives under the federal Renewable Fuel Standard (RFS) program, and that RFS incentives are currently providing revenues equivalent to approximately $58/tCO$_2$e. Analysis also reveals that as of March 2019, some 110 landfills receive incentives under the California Low Carbon Fuel Standard (LCFS) for provision of renewable landfill gas as a transport fuel in California. This analysis suggests that if a landfill is able to support an RNG/CNG/LNG project, it will potentially be eligible for RFS RIN or LCFS revenues and if it is able to secure such transport fuel incentives, it will thus be feasible without offset revenues. Such projects are also very likely to trigger NSPS/EG size thresholds and be excluded pursuant to the legal requirement test. The analysis therefore suggests that projects receiving such incentives could reasonably be deemed non-additional.

As with any incentives created purely by regulation, these incentives are subject to significant risk that regulations may change or some other regulatory barrier may prevent the project from receiving such incentives. These risks are often referred to as ‘stroke of the pen’ risks. Given that investment in high-Btu projects is largely being driven by renewable transport fuel incentives, that such projects are subject to significant ‘stroke of the pen’ regulatory risks, and that such projects are likely to be excluded by the legal requirement test, the Reserve deems that landfill projects producing high-Btu fuels that do not receive transport fuel incentives do not need to be excluded via the limits on credit stacking to ensure additionality. Therefore, any high-Btu projects that do not receive transport fuel incentives, such as federal RFS or California LCFS incentives, will be considered to have met the requirements related to credit stacking. Any high-Btu projects that receive transport fuel incentives, such as the federal RFS or California LCFS, will not be eligible under this protocol, pursuant to the credit stacking provisions in Section 3.4.2. Project developers are required under Section 3.4.2 to disclose the issuance of any type of mitigation credit to the Reserve, and the Reserve will assess additionality with respect to each program.

In contrast to high-Btu projects, medium-Btu projects remain uncommon (landfills with at least one operational medium-Btu project represent less than 3% of all landfills in the LMOP database). Similarly, medium-Btu projects face stiff competition from natural gas as they are both typically used for thermal heating applications. Natural gas prices are currently very competitive relative to medium-Btu LFGE projects. In addition, the most limiting factor for the feasibility of a medium-Btu project is the availability of an end-use buyer of the landfill gas that is within close enough proximity to make the development of local transmission pipelines feasible (typically, such facilities must be within a 10-mile radius for the project to be feasible).[39] Given that these projects remain uncommon, and continue to face significant barriers, these projects can reasonably be deemed additional.

With a total number of 459 operational projects by September 2018, electricity projects represented close to 75% percent of all operational LFGE projects in the LMOP database. In other words, 14% of all landfills in the LMOP database have at least one active electricity project making this technology type fairly common. While electricity projects currently represent the vast

[38] Landfill Methane Outreach Program. “Webinar: Renewable Natural Gas from LFG and Sustainability at L’Oreal (PDF)”. United States Environmental Protection Agency. December 12, 2018. Available at https://www.epa.gov/lmop/webinar-renewable-natural-gas-landfill-gas-and-sustainability-loreal

[39] Landfill Methane Outreach Program. “LFG Energy Project Development Handbook.” United States Environmental Protection Agency. 2017. Available at: https://www.epa.gov/lmop/landfill-gas-energy-project-development-handbook

majority of LFGE projects, LMOP data reveals that the majority of new planned and in-construction LFGE projects are now set to utilize RNG/CNG. Furthermore, expert guidance indicated that despite electricity LFGE projects being common practice, new electricity LFGE projects currently face unfavorable market conditions, as reflected by the low numbers of projected and planned electricity LFGE projects.[40] Some unfavorable market conditions are low wholesale electricity purchase prices, lack of attractive incentives, and the upcoming expiration of state's Renewable Portfolio Standard goals.

To expand on the understanding of the downward trend for electricity projects, the Reserve sought to identify under which conditions projects would be additional. To do this, the Reserve evaluated the electricity generation capacity at which projects were likely to reach financial feasibility in the absence of GHG offset revenue. It was assumed that a project reaches the point of financial feasibility when it achieves a positive Net Present Value (NPV). The financial feasibility of 32 landfill scenarios was assessed using the LMOP Landfill Gas to Energy Cost Model (LFGcost-Web). The LFGcost-Web is an Excel-based tool that allows users to estimate the financial feasibility of a wide range of LFGE projects, based on specific landfill and project characteristics.[41] Once the Reserve input the set of assumptions for a given scenario in the model, the project design flow rate was gradually increased to evaluate the NPV that the model returned. If the NPV became positive, then landfills under the mix of assumptions for that specific scenario were considered non-additional at or above the given flow rate.

The Reserve retained a number of LFGcost model default assumptions and edited several, following expert consultation. The LFGcost input factors that most affected modeled results were the projects' regulatory status under NSPS, landfill ownership types (private or public), and revenue streams. Below is a summary of assumptions underlying how these specific factors were modeled:

1. Regulatory status: Smaller unregulated projects were assumed to not have an LGCC in place prior to installing an electricity project; thus, the costs of installing the piping, collection, and flaring systems are included in the modeling of these scenarios. Regulated (larger) projects, on the other hand, were assumed to have an LGCC system in place prior to assessing the feasibility of an electricity project, and therefore the costs of installing an LGCC system was not included in the modeling of those scenarios.

2. Landfill ownership status: The assumption as to whether a landfill was owned by a public or private entity was critical, in that it determined the tax rates imposed on the project. Projects funded and developed by local governments were given a 0% tax rate, while private projects were given a 25% tax rate. The Reserve developed the 25% private tax rate as a combination of the 21% federal tax rate plus an assumed average 4% state tax rate. A review of state tax rates revealed a simple average rate of 6% nationally, but the Reserve chose to use a 4% tax rate,[42] as this would more readily return positive NPV rates and conservatively exclude more projects.

3. Revenue streams: Project revenue streams modeled in the various scenarios were a mix of energy tax credits, RECs, and, most critically, electricity sales price. These assumptions were differentiated based on the availability of incentives and revenues

[40] LMOP, 2018.
[41] A copy of the LFGcost-Web tool and background information can be accessed here: https://www.epa.gov/lmop/lfgcost-web-landfill-gas-energy-cost-model.
[42] A table of state tax rates produced by the Tax Foundation was used for this analysis, which was accessed here: https://taxfoundation.org/state-corporate-rates-brackets-2019/.

across different regions in the United States. The assumption with respect to the electricity sales price warrants specific discussion, as it had the single largest effect on project NPV. The LFGcost tool used a default electricity sales price of $0.06/kWh. Expert guidance indicated that this price was not representative of wholesale prices paid to LFGE project operators and was too high. Therefore, the Reserve's analysis replaced this value with a price representing the national average historical wholesale 'high' price for 2018.[43] The Reserve then identified any pricing regions for which the average historical 2018 price was higher than the national average, and for those areas, the Reserve used the regional average, as this ensures the resulting NPV is more representative and conservative. In two regions, the Reserve used an electricity sales price which was above the national average historical 2018 wholesale price. In Vermont, an electricity price of $0.09/kWh[44] was used, representing the feed-in tariff available under their Standard Offer program. The average price in New England was set at $0.058/kWh, reflecting the average 2018 wholesale electricity price there (specifically at the Nepool MH DA LMP Peak).[45]

Four of the modeled scenarios returned a positive NPV, indicating that financial feasibility is strong without offsets, and they should therefore be excluded for not being additional. All four of these scenarios shared the following characteristics:

- They were large enough to be considered 'regulated' (so the cost of a mandatory GCCS was not included in the analysis);
- REC incentives were available; and
- Electricity sales prices were higher than the national average wholesale price.

The assumption regarding the costs of installing a collection and flaring system was most critical to all scenarios. The added cost of installing a GCCS as part of an electricity project was high enough to make any unregulated project infeasible even with the availability of incentives. Given that no unregulated project scenarios returned a positive NPV, the Reserve believes that the legal requirement test is enough to address the additionality of electricity projects. In the case of the four scenarios that returned positive NPV values, the landfill itself was large enough to trigger the legal requirement test to make it ineligible. For this reason, the Reserve has not included these four scenarios in the performance standard test itself, as such projects will effectively be excluded from eligibility via the legal requirement test.

[43] Energy Information Administration and Intercontinental Exchange (ICE). Wholesale Electricity and Natural Gas Market Data. Accessed in Jan 30, 2019. Available at https://www.eia.gov/electricity/wholesale/.
[44] VEPP Inc. Standard Offer Program Request for Proposals. 2019 RFP Coming January 2019. Available at: http://www.vermontstandardoffer.com/2019-rfp-informationa/.
45 EIA and ICE, 2019.

Appendix B Emission Factor Tables

Table B.1. CO_2 Emission Factors for Fossil Fuel Use[46]

Fuel Type	Default High Heat Value	Default CO_2 Emission Factor	
Coal and coke	mmBtu/ short ton	kg CO_2/ mmBtu	kg CO_2/ short ton
Anthracite	25.09	103.69	2601.582
Bituminous	24.93	93.28	2325.470
Subbituminous	17.25	97.17	1676.183
Lignite	14.21	97.72	1388.601
Coal Coke	24.8	113.67	2819.016
Mixed (Commercial sector)	21.39	94.27	2016.435
Mixed (Industrial coking)	26.28	93.9	2467.692
Mixed (Industrial sector)	22.35	94.67	2115.875
Mixed (Electric Power sector)	19.73	95.52	1884.610
Natural gas	mmBtu/ scf	kg CO_2/ mmBtu	kg CO_2/ scf
(Weighted U.S. Average)	0.001026	53.06	0.054
Petroleum products	mmBtu/ gallon	kg CO_2/ mmBtu	kg CO_2/ gallon
Distillate Fuel Oil No. 1	0.139	73.25	10.182
Distillate Fuel Oil No. 2	0.138	73.96	10.206
Distillate Fuel Oil No. 4	0.146	75.04	10.956
Residual Fuel Oil No. 5	0.14	72.93	10.210
Residual Fuel Oil No. 6	0.15	75.1	11.265
Used Oil	0.138	74	10.212
Kerosene	0.135	75.2	10.152
Liquefied petroleum gases (LPG)[1]	0.092	61.71	5.677
Propane[1]	0.091	62.87	5.721
Propylene[2]	0.091	67.77	6.167
Ethane[1]	0.068	59.6	4.053
Ethanol	0.084	68.44	5.749
Ethylene[2]	0.058	65.96	3.826
Isobutane[1]	0.099	64.94	6.429
Isobutylene[1]	0.103	68.86	7.093
Butane[1]	0.103	64.77	6.671
Butylene[1]	0.105	68.72	7.216
Naphtha (<401 deg F)	0.125	68.02	8.503
Natural Gasoline	0.11	66.88	7.357
Other Oil (>401 deg F)	0.139	76.22	10.595
Pentanes Plus	0.11	70.02	7.702
Petrochemical Feedstocks	0.125	71.02	8.878
Petroleum Coke	0.143	102.41	14.645
Special Naphtha	0.125	72.34	9.043
Unfinished Oils	0.139	74.54	10.361

[46] 40 CFR Part 98 Subpart C Table C-1: Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel.

Fuel Type	Default High Heat Value	Default CO_2 Emission Factor	
Heavy Gas Oils	0.148	74.92	11.088
Lubricants	0.144	74.27	10.695
Motor Gasoline	0.125	70.22	8.778
Aviation Gasoline	0.12	69.25	8.310
Kerosene-Type Jet Fuel	0.135	72.22	9.750
Asphalt and Road Oil	0.158	75.36	11.907
Crude Oil	0.138	74.54	10.287
Other fuels—solid	mmBtu/ short ton	kg CO_2/ mmBtu	kg CO_2/ short ton
Municipal Solid Waste	9.953	90.7	902.737
Tires	28	85.97	2407.160
Plastics	38	75	2850.000
Petroleum Coke	30	102.41	3072.300
Other fuels—gaseous	mmBtu/ scf	kg CO_2/ mmBtu	kg CO_2/ scf
Blast Furnace Gas	0.000092	274.32	0.025
Coke Oven Gas	0.000599	46.85	0.028
Propane Gas	0.002516	61.46	0.155
Fuel Gas[4]	0.001388	59	0.082
Biomass fuels—solid	mmBtu/ short ton	kg CO_2/ mmBtu	kg CO_2/ short ton
Wood and Wood Residuals (dry basis)[5]	17.48	93.8	1639.624
Agricultural Byproducts	8.25	118.17	974.903
Peat	8	111.84	894.720
Solid Byproducts	10.39	105.51	1096.249
Biomass fuels—gaseous	mmBtu/ scf	kg CO_2/ mmBtu	kg CO_2/ scf
Landfill Gas	0.000485	52.07	0.025
Other Biomass Gases	0.000655	52.07	0.034
Biomass Fuels—Liquid	mmBtu/ gallon	kg CO_2/ mmBtu	kg CO_2/ gallon
Ethanol	0.084	68.44	5.749
Biodiesel (100%)	0.128	73.84	9.452
Rendered Animal Fat	0.125	71.06	8.883
Vegetable Oil	0.12	81.55	9.786

[1] The HHV for components of LPG determined at 60°F and saturation pressure with the exception of ethylene.
[2] Ethylene HHV determined at 41°F (5°C) and saturation pressure.
[3] Use of this default HHV is allowed only for: (a) Units that combust MSW, do not generate steam, and are allowed to use Tier 1; (b) units that derive no more than 10 percent of their annual heat input from MSW and/or tires; and (c) small batch incinerators that combust no more than 1,000 tons of MSW per year.
[4] Reporters subject to subpart X of this part that are complying with §98.243(d) or subpart Y of this part may only use the default HHV and the default CO_2 emission factor for fuel gas combustion under the conditions prescribed in §98.243(d)(2)(i) and (d)(2)(ii) and §98.252(a)(1) and (a)(2), respectively. Otherwise, reporters subject to subpart X or subpart Y shall use either Tier 3 (Equation C-5) or Tier 4.
[5] Use the following formula to calculate a wet basis HHV for use in Equation C-1: $HHV^w = ((100 - M)/100)*HHV^d$ where HHV^w = wet basis HHV, M = moisture content (percent) and HHV^d = dry basis HHV from Table C-1.

B.1 Destruction Efficiencies for Destruction Devices

If available, the official source tested methane destruction efficiency shall be used in Equation 5.4 in place of the default methane destruction efficiency. Device-specific source testing shall be conducted annually, by a state or local agency accredited service provider, and include at least three test runs, with the accepted final value being one standard deviation below the mean of the measured efficiencies. If neither the state nor locality relevant to the project site offer accreditation for source testing service providers, projects may use an accredited service provider from another U.S. state or domestic locality. Alternatively, projects may choose a non-accredited service provider, under the following conditions: 1) the service provider must provide verifiable evidence of prior testing that was accepted for compliance by a domestic regulatory agency, and 2) the prior testing procedures must be substantially similar to the procedures used for determining methane destruction efficiency for the project destruction device(s).

If site-specific source test results conforming with the above paragraph are not available, project developers shall use the default methane destruction efficiencies provided below.

Table B.2. Default Destruction Efficiencies for Destruction Devices

Destruction Device	Destruction Efficiency (DE)
Open Flare	0.96
Enclosed Flare	0.995
Lean-burn Internal Combustion Engine	0.936
Rich-burn Internal Combustion Engine	0.995
Boiler	0.98
Microturbine or large gas turbine	0.995
Upgrade and use of gas as CNG/LNG fuel	0.95
Upgrade and injection into natural gas transmission and distribution pipeline	0.98*
Offsite use of gas under direct-use agreement	Per corresponding destruction device factor (not pipeline)

Source: The default destruction efficiencies for enclosed flares and electricity generation devices are based on a preliminary set of actual source test data provided by the Bay Area Air Quality Management District. The default destruction efficiency values are the lesser of the twenty fifth percentile of the data provided or 0.995. These default destruction efficiencies may be updated as more source test data is made available to the Reserve.

***** The Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories gives a standard value for the fraction of carbon oxidized for gas destroyed of 99.5% (Reference Manual, Table 1.6, page 1.29). It also gives a value for emissions from processing, transmission and distribution of gas which would be a very conservative estimate for losses in the pipeline and for leakage at the end user (Reference Manual, Table 1.58, page 1.121). These emissions are given as 118,000kgCH_4/PJ on the basis of gas consumption, which is 0.6%. Leakage in the residential and commercial sectors is stated to be 0 to 87,000kgCH_4/PJ, which equates to 0.4%, and in industrial plants and power station the losses are 0 to 175,000kg/CH_4/PJ, which is 0.8%. These leakage estimates are compounded and multiplied. The methane destruction efficiency for landfill gas injected into the natural gas transmission and distribution system can now be calculated as the product of these three efficiency factors, giving a total efficiency of (99.5% * 99.4% * 99.6%) 98.5% for residential and commercial sector users, and (99.5% * 99.4% * 99.2%) 98.1% for industrial plants and power stations. [47]

[47] GE AES Greenhouse Gas Services, Landfill Gas Methodology, Version 1.0 (July 2007).

Appendix C Baseline Monitoring and Calculation of LFG_{B1}, LFG_{B2}, and B_{CH4}

This appendix shall be used to calculate LFG_{B2} and $B_{CH4,NQ}$ for use in Equation 5.7. Much of the discussion here is concerned with accommodating the added complexity of monitoring passive flares and other non-qualifying devices. However, the methodology described is also applicable for measuring and documenting LFG_{B1} and $B_{CH4,closed}$ for calculating $Closed_{discount}$ in Equation 5.6.

C.1 Baseline Monitoring

Passive flares and other non-qualifying destruction devices are often installed at landfills for purposes other than methane destruction, and therefore are not amenable to simple monitoring. For example, flares installed for odor control may be used intermittently and without any instrumentation tracking gas flow and methane concentration. This makes assessing baseline methane destruction from passive flares extremely difficult to quantify. Quantification is further exacerbated by the fact that passive flares are not necessarily designed to accommodate metering equipment; for example, in many cases passive flares do not have sufficient straight pipe length to control for turbulence. These limitations, combined with the low flow rates generally seen at passive flares, greatly limit the number and type of metering equipment that can be used. Monitoring destruction of landfill gas from baseline landfill gas wells at closed landfill flares will face fewer obstacles.

Constraints on monitoring landfill gas from passive flares are unique to each landfill. The Reserve has attempted to make this methodology as flexible as possible to make it widely applicable. Any deviations from this methodology will require a formal request for variance.

C.2 Monitoring

Non-qualifying destruction devices (e.g., passive flares) and qualifying flares at closed landfills must be monitored for a period of at least three months. This period must occur prior to the project start date to ensure that the measured gas flow is not decreased by the addition of project wells or pressure changes that result from the project activity. Methane destruction from the chosen period must be extrapolated to one year based on the 90% upper confidence limit of the methane destruction identified in this period. Therefore, monitoring for more than three months, or with greater than weekly frequency, may lessen statistical uncertainty and reduce the required $NQ_{discount}$ or $Closed_{discount}$.

Gas flow must be measured weekly at a minimum and must be normalized to maximum flow capacity (scfm, 60°F and 1 atm). If gas flow falls below the measurable range for the chosen metering device, the minimum flow value of the chosen metering device must be applied to that time interval. Methane concentration must also be measured at least weekly.

One measurement should be entered on each day for which readings were taken. If continuous measurements were taken, these should be averaged. If a single measurement was taken, then this value should be used. Therefore, if a daily monitoring plan is chosen for the three-month period, a total of 90 data points will be available (one per day). However, if weekly measurements are taken, then only 13 data points will be available for the analysis (one per week). Alternatively, irregular measurement intervals (for example, if someone is onsite three consecutive days) or bi-weekly measurements can be used as well, allowing for anywhere between 13 and 90 data points for any 90-day period. However, no more than one data point per calendar day may be applied and all collected data must be used.

All metering equipment used in baseline monitoring is subject to the same maintenance, calibration, and QA/QC requirements outlined previously for project metering equipment. In the case where a project does not meet the baseline monitoring maintenance, calibration, and QA/QC requirements of this protocol version, it shall be acceptable for that project to have its baseline monitoring, maintenance, calibration, and QA/QC verified against the requirements of a previous version of this protocol, so long as it is the version that was in force at the beginning date of the project's baseline monitoring period.

C.3 Passive Flare Configuration

As the configuration of passive flares will be unique to each landfill, it is not possible to dictate a single monitoring methodology. Rather, the following options have been devised as acceptable configurations.

1. Each passive flare will be monitored individually for both flow and methane concentration according to the schedule outlined in Section C.2.
2. Wells from two or more passive flares may be connected to a single flare with a single set of meters for both flow and methane concentration. Additional engineering may be required to ensure that the altered pressure characteristics of the system do not decrease total gas flow. The flow characteristics of this system will require substantiation from engineering documents and calculations and will be assessed by the verification body.
3. Wells from two or more passive flares may be connected with the active collection system and monitored separately from the new project wells while under vacuum from the blower.

C.4 Calculation

Please use Equation C.1 to calculate the $Closed_{discount}$ and Equation C.2 to calculate the $NQ_{discount}$.

Equation C.1. Calculation of Baseline Discount for Flares at a Closed Landfill

$$Closed_{discount} = 525,600 \times CH_{4_{min}}$$

$$LFG_{B1} = 525,600 \times 90\%UCL\left(LFG_{scfm}\right)$$

Where,			Units
LFG_{B1}	=	Landfill gas from the baseline landfill gas wells that would have been destroyed by the qualifying destruction system during the reporting period	scf LFG
$90\%UCL(LFG_{scfm})$	=	90% upper confidence limit of the average flow rate in the metered period (must be >3 months)	scfm LFG
525,600	=	Minutes in one year	min/yr

$$B_{CH_4,closed} = 90\%UCL\left(B_{CH_4,closed,t}\right)$$

Where,			Units
$B_{CH4,closed,t}$	=	Methane concentration for baseline calculations	scf CH_4/ scf LFG
$90\%UCL(B_{CH4,closed,t})$	=	90% upper confidence limit of the average methane concentration in the metered period (must be >3 months)	scf CH_4/ scf LFG

$$90\%UCL = mean + t_{value} \times \left(\frac{SD}{\sqrt{n}}\right)$$

Where,			Units
mean	=	Sample mean (of $B_{CH4,closed,t}$ or LFG_{scfm})	scf or %
t_{value}	=	90% t-value coefficient for data set with degrees of freedom *df* (use Excel feature: =TINV(0.1,df)	
SD	=	Standard deviation of the sample (of $B_{CH4,closed,t}$ or LFG_{scfm})	scf or %
n	=	Sample size	
df	=	Degrees of freedom (= n-1)	

Equation C.2. Calculation of Baseline Discount for a Non-Qualifying Device

$$NQ_{discount} = 525,600 \times CH_{4_{min}}$$

$$LFG_{B2} = 525,600 \times 90\%UCL(LFG_{scfm})$$

Where,			Units
LFG_{B2}	=	Landfill gas that would have been destroyed by the original, non-qualifying destruction system during the reporting period	scf LFG
$90\%UCL(LFG_{scfm})$	=	90% upper confidence limit of the average flow rate in the metered period (must be >3 months)	scfm LFG
525,600	=	Minutes in one year	min/yr

$$B_{CH_4,NQ} = 90\%UCL(B_{CH_4,NQ,t})$$

Where,			Units
$B_{CH4,NQ,t}$	=	Methane concentration for baseline calculations	scf CH_4/ scf LFG
$90\%UCL(B_{CH4,NQ,t})$	=	90% upper confidence limit of the average methane concentration in the metered period (must be >3 months)	scf CH_4/ scf LFG

$$90\%UCL = mean + t_{value} \times \left(\frac{SD}{\sqrt{n}}\right)$$

Where,			Units
mean	=	Sample mean (of $B_{CH4,NQ,t}$ or LFG_{scfm})	scf or %
t_{value}	=	90% t-value coefficient for data set with degrees of freedom *df* (use Excel feature: =TINV(0.1,df)	
SD	=	Standard deviation of the sample (of $B_{CH4,NQ,t}$ or LFG_{scfm})	scf or %
n	=	Sample size	
df	=	Degrees of freedom (= n-1)	

C.5 Example

The following example (Table C.1) demonstrates the necessary calculation for determining $Closed_{discount}$ or $NQ_{discount}$. The calculations outlined above in Section C.4 are represented by the first three columns of data. The final conversions to tCO_2e/yr are done using Equation 5.5.

Note that although the measurements had average values yielding a deduction of 5,961 tCO_2e/yr, due to the limited data and variability of the measurements, the appropriate deduction is 7,830 tCO_2e/yr. If, instead of weekly data there was daily data over this three month period that yielded the exact same mean and standard deviation, the additional data alone would have lowered the deduction to only 6,807 tCO_2/yr. Alternately, if the data had been more consistent and showed a standard deviation for the flow data of only 6 with the same mean, then the deduction with 14 samples would have been only 6,689 tCO_2/yr. Therefore, the added uncertainty deduction of this method is directly related to the level of variability in the data and the number of samples.

Table C.1. Example Dataset and Calculation of $Closed_{discount}$ or $NQ_{discount}$

	Calculated According to Equations C.1 and C.2				Calculated According to Equation 5.5	
	CH_4 (%)	Flow (scfm)	Flow CH_4 (scfm)	CH_4/year (scf/yr)	CH_4/year (t/yr)	tCO_2e/year
6/1/2008	56.7	48	27	14,304,703	274	5,760
6/8/2008	55.3	75	41	21,799,260	418	8,778
6/15/2008	58.1	21	12	6,412,846	123	2,582
6/22/2008	54.0	90	49	25,544,160	490	10,286
6/29/2008	55.6	47	26	13,734,979	263	5,531
7/6/2008	56.3	23	13	6,805,994	131	2,741
7/13/2008	57.2	70	40	21,045,024	404	8,475
7/20/2008	58.0	15	9	4,572,720	88	1,841
7/27/2008	52.3	89	47	24,465,103	469	9,852
8/3/2008	55.7	42	23	12,295,886	236	4,951
8/10/2008	54.8	51	28	14,689,469	282	5,915
8/17/2008	62.1	19	12	6,201,554	119	2,497
8/24/2008	59.3	66	39	20,570,933	394	8,284
8/31/2008	57.6	70	40	21,192,192	406	8,534
Mean	**56.6**	**51.86**	**28**	**14,803,281**	**284**	**5,961**
SD	0.02	25.70				
n	14	14				
df	13	13				
90% t-value	1.77	1.77				
UCL at 90%	**57.8**	**64.02**	**37**	**19,443,275**	**373**	**7,830**

Appendix D Data Substitution Guidelines

This appendix provides guidance on calculating emission reductions when data integrity has been compromised due to missing data points. No data substitution is permissible for equipment such as thermocouples, which monitor the proper functioning of destruction devices. Rather, the methodologies presented below are to be used only for the methane concentration and flow metering parameters.

The Reserve expects that projects will have continuous, uninterrupted data for the entire verification period. However, the Reserve recognizes that unexpected events or occurrences may result in brief data gaps.

The following data substitution methodology may be used only for flow and methane concentration data gaps that are discrete, limited, non-chronic, and due to unforeseen circumstances. Data substitution can only be applied to methane concentration *or* flow readings, but not both simultaneously. If data is missing for both parameters, no reductions can be credited.

Further, substitution may only occur when two other monitored parameters corroborate proper functioning of the destruction device and system operation within normal ranges. These two parameters must be demonstrated as follows:

1. Proper functioning can be evidenced by thermocouple readings for flares, energy output engines, etc.
2. For methane concentration substitution, flow rates during the data gap must be consistent with normal operation.
3. For flow substitution, methane concentration rates during the data gap must be consistent with normal operations.

If corroborating parameters fail to demonstrate any of these requirements, no substitution may be employed. If the requirements above can be met, the following substitution methodology maybe applied:

Duration of Missing Data	Substitution Methodology
Less than six hours	Use the average of the four hours immediately before and following the outage
Six to 24 hours	Use the 90% lower or upper confidence limit of the 24 hours prior to and after the outage, whichever results in greater conservativeness
One to seven days	Use the 95% lower or upper confidence limit of the 72 hours prior to and after the outage, whichever results in greater conservativeness
Greater than one week	No data may be substituted, and no credits may be generated

The lower confidence limit should be used for both methane concentration and flow readings for landfill projects, as this will provide the greatest conservativeness.

For weekly measured methane concentration, the lower of the measurement before and the measurement after must be used. This substitution may only be used to substitute data for one consecutive missing weekly measurement.

A.2.7 Livestock Project Protocol v4.0

CLIMATE
ACTION
RESERVE

Version 4.0 | January 23, 2013

U.S. Livestock
Project Protocol

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Abbreviations and Acronyms

BCS	Biogas control system
CARB	California Air Resources Board
CH_4	Methane
CNG	Condensed natural gas
CO_2	Carbon dioxide
CRT	Climate Reserve Tonne
EPA	U.S. Environmental Protection Agency
GHG	Greenhouse gas
GWP	Global warming potential
IPCC	Intergovernmental Panel on Climate Change
lb	Pound
LNG	Liquefied natural gas
MCF	Methane conversion factor
MT	Metric ton or tonne
N_2O	Nitrous oxide
NG	Natural gas
QA/QC	Quality Assurance/Quality Control
Reserve	Climate Action Reserve
scf	Standard cubic foot at 1 atm pressure and 60°F temperature
SSR	Sources, sinks, and reservoirs
t	Metric ton or tonne
TAM	Typical animal mass
VS	Volatile solids

1 Introduction

The Climate Action Reserve's (Reserve) Livestock Project Protocol provides guidance to account for and report greenhouse gas (GHG) emission reductions associated with the installation of a biogas control system (BCS) for manure management on dairy cattle and swine farms. The protocol focuses on quantifying the change in methane emissions, but also accounts for potential increases in carbon dioxide emissions.

The Climate Action Reserve is the most experienced, trusted and efficient offset registry to serve the California cap-and-trade program and the voluntary carbon market. With deep roots in California and a reach across North America, the Reserve encourages actions to reduce greenhouse gas emissions and works to ensure environmental benefit, integrity and transparency in market-based solutions to address global climate change. It operates the largest accredited registry for the California compliance market and has played an integral role in the development and administration of the state's cap-and-trade program. For the voluntary market, the Reserve establishes high quality standards for carbon offset projects, oversees independent third-party verification bodies and issues and tracks the transaction of carbon credits (Climate Reserve Tonnes) generated from such projects in a transparent, publicly-accessible system. The Reserve program promotes immediate environmental and health benefits to local communities and brings credibility and value to the carbon market. The Climate Action Reserve is a private 501(c)(3) nonprofit organization based in Los Angeles, California.

Project developers that install manure biogas capture and destruction technologies use this document to register GHG reductions with the Reserve. The protocol provides eligibility rules, methods to calculate reductions, performance-monitoring instructions, and procedures for reporting project information to the Reserve. Additionally, all project reports receive independent verification by Reserve-approved verification bodies. Guidance for verification bodies to verify reductions is provided in the Verification Program Manual and Section 8 of this protocol.

This project protocol facilitates the creation of GHG emission reductions determined in a complete, consistent, transparent, accurate, and conservative manner, while incorporating relevant sources.[1]

[1] See the WRI/WBCSD GHG Protocol for Project Accounting (Part I, Chapter 4) for a description of GHG accounting principles.

2 The GHG Reduction Project

Manure treated and stored under anaerobic conditions decomposes to produce methane, which, if uncontrolled, is emitted to the atmosphere. This predominantly occurs when livestock operations manage waste with anaerobic, liquid-based systems (e.g. in lagoons, ponds, tanks, or pits). Within the livestock sector, the primary drivers of methane generation include the amount of manure produced and the fraction of volatile solids (VS) that decompose anaerobically. Temperature and the retention time of manure during treatment and storage also affect methane production.

2.1 Project Definition

For the purpose of this protocol, the GHG reduction project is defined as the installation and operation of a biogas control system[2] that captures and destroys methane gas from anaerobic manure treatment and/or storage facilities on livestock operations. The biogas control system must destroy methane gas that would otherwise have been emitted to the atmosphere in the absence of the project from uncontrolled anaerobic treatment and/or storage of manure.

Captured biogas can be destroyed on-site, or transported for off-site use (e.g. through gas distribution or transmission pipeline), or used to power vehicles. Regardless of how project developers take advantage of the captured biogas, the ultimate fate of the methane must be destruction.

"Centralized digesters" that integrate waste from more than one livestock operation also meet the definition of a GHG reduction project.

Note that the protocol does not preclude project developers from co-digesting organic matter in the biogas control system. However, the additional organics could impact the nutrient properties of digester effluent; project developers should consider this when assessing the project's associated water quality impacts. The Reserve has also developed the Organic Waste Digestion Project Protocol that provides a quantification methodology for crediting the co-digestion of eligible waste streams with livestock manure. The protocol is available at http://www.climateactionreserve.org/how/protocols/adopted/organic-waste-digestion/current/.

2.2 The Project Developer

The "project developer" is an entity that has an active account on the Reserve, submits a project for listing and registration with the Reserve, and is ultimately responsible for all project reporting and verification. Project developers could be livestock facility owners and operators, GHG project financiers, or other entities. The project developer must have clear ownership of the project's GHG reductions. Ownership of the GHG reductions must be established by clear and explicit title, and the project developer must attest to such ownership each time the project is verified by signing the Reserve's Attestation of Title form.[3]

Under this protocol, the project developer is the only party required to be involved with project implementation.

[2] Biogas control systems encompass anaerobic digester systems – which may be designed and operated in a variety of ways, from ambient temperature covered lagoons to heated lagoons to mesophilic plug flow or complete mix concrete tank digesters—as well as methane destruction systems, such as flares or engines.

[3] Attestation of Title form available at http://www.climateactionreserve.org/how/projects/register/project-submittal-forms/.

3 Eligibility Rules

Project developers using this protocol must satisfy the following eligibility rules to register reductions with the Reserve. The criteria only apply to projects that meet the definition of a GHG reduction project.

Eligibility Rule I:	Location	⟶	*U.S., its territories, and tribal lands*
Eligibility Rule II:	Project Start Date	⟶	*No more than 6 months prior to project submission*
Eligibility Rule III:	Anaerobic Baseline	⟶	*Demonstrate anaerobic baseline conditions*
Eligibility Rule IV:	Additionality	⟶	*Meet performance standard*
		⟶	*Exceed regulatory requirements*
Eligibility Rule V:	Regulatory Compliance	⟶	*Compliance with all applicable laws*

3.1 Location

Only projects located in the United States and its territories, or on U.S. tribal lands, are eligible to register reductions with the Reserve under this protocol. Livestock projects located in Mexico must use the Mexico Livestock Project Protocol if seeking to register GHG reductions with the Reserve.

3.2 Project Start Date

The start date for a livestock project is defined as the date on which the project's biogas control system becomes operational. For the purposes of this protocol, a BCS is considered *operational* on the date that the system begins producing and destroying methane gas following an initial start-up period. This date can be selected by the project developer within the 6 month period following the date on which manure is first loaded into the digester or on the date that the cover installation was completed (for a covered lagoon digester where the lagoon already contained manure).

Projects must be submitted to the Reserve no more than six months after the project start date.

3.3 Project Crediting Period

Project developers are eligible to register GHG reductions with the Reserve according to this protocol for a period of ten years following the project's start date. All projects that initially pass the eligibility requirements set forth in this protocol are eligible to register GHG reductions with the Reserve for the duration of the project's first crediting period (ten years), even if a regulatory agency with authority over a livestock operation passes a rule obligating the installation of a BCS during this initial crediting period.

If a project developer wishes to apply for eligibility under a second crediting period, they must do so within the final six months of the initial crediting period. Thus, the Reserve may issue CRTs for GHG reductions quantified and verified according to the U.S. Livestock Project Protocol for a maximum of two ten year crediting periods after the project start date. Section 3.5.1 and 3.5.2 describe the requirements to qualify for a second crediting period. Deadlines and requirements for reporting and verification, as laid out in this protocol, the Program Manual, and the Verification Program Manual, will continue to apply without interruption.

3.4 Uncontrolled Anaerobic Baseline

The installation of a BCS at a livestock operation where the primary manure management system is aerobic (produces little to no methane) may result in an increase of the amount of methane emitted to the atmosphere. Thus, the BCS must digest manure that would primarily be treated in an anaerobic system in the absence of the project in order for the project to meet the definition of a GHG reduction project. Sections 3.4.1, 3.4.2, and 3.4.3 explain the specific baseline scenario options. Under any one of these scenarios, the uncontrolled anaerobic baseline requirement may be temporarily disrupted for the purposes of construction of the project digester. In these cases, the verifier may use professional judgment to confirm that the requirements of this section have been met.

3.4.1 Existing Livestock Facilities

For livestock facilities that have been in operation for more than five years, developers of livestock projects must demonstrate that an uncontrolled anaerobic manure management system was in place for the five years immediately prior to the date that manure was first loaded into the project digester. That anaerobic system may include a lagoon or a pond as long as the depth of the system was sufficient to prevent algal oxygen production and create an oxygen-free bottom layer (i.e. greater than 1 meter in liquid depth).[4]

For livestock facilities that have been in operation for more than two years, but less than five years, developers of livestock projects must demonstrate that an uncontrolled anaerobic manure management system was in place at all times up until the project's start date.

3.4.2 New Livestock Facilities (Greenfields)

Greenfield livestock projects (i.e. projects that are implemented at livestock facilities that have been in operation for less than two years at a site that had no prior manure management infrastructure) are eligible only if the project developer can demonstrate that there are no restrictions to the construction and operation of an open, uncontrolled, anaerobic manure storage system. Since a greenfield project will not have an existing manure management system that can be used to model the baseline methane emissions, all greenfield projects shall utilize a set of standardized baseline management assumptions (see Table B.10).

3.4.3 Centralized Digesters

For projects that employ a centralized digester that will be accepting manure from more than one livestock operation, each individual source of manure (identified by livestock facility) must meet the anaerobic baseline requirements above as of the project start date. In other words, if a new facility begins sending manure to the project digester after the project start date, the anaerobic baseline of that manure must still be assessed as of the project start date.

[4] This is consistent with the United Nations Framework Convention on Climate Change (UNFCCC) Clean Development Mechanism (CDM) methodology ACM00010 (available at: http://cdm.unfccc.int/methodologies/PAmethodologies/approved.html). For additional information on the design and maintenance of anaerobic wastewater treatment systems, see U.S. Department of Agriculture Natural Resources Conservation Service, Conservation Practice Standard, Waste Storage Facility, No. 313; and U.S. Department of Agriculture Natural Resources Conservation Service, Conservation Practice Standard, Waste Treatment Lagoon, No. 359.

3.5 Additionality

The Reserve will only accept projects that yield surplus GHG reductions that are additional to what would have otherwise occurred. That is, the reductions are above and beyond business-as-usual operation.

Project developers satisfy the “additionality” eligibility rule by passing two tests:

1. The Performance Standard Test
2. The Legal Requirement Test

3.5.1 The Performance Standard Test

Projects pass the Performance Standard Test by meeting a program-wide performance threshold – i.e. a standard of performance applicable to all manure management projects, established on an *ex-ante* basis. The performance threshold represents “better than business-as-usual” manure management. If the project meets the threshold, then it exceeds what would happen under the business-as-usual scenario and generates surplus/additional GHG reductions.

For this protocol, the Reserve uses a technology-specific threshold; sometimes also referred to as a practice-based threshold, where it serves as “best-practice standard” for managing livestock manure. By installing a BCS, a project developer passes the Performance Standard Test.

The Reserve defined this performance standard by evaluating manure management practices in California and the United States. A summary of the study to establish the threshold is provided in Appendix C.

The Performance Standard Test is applied at the time of the project’s start date. All projects that pass this test at the project’s start date are eligible to register reductions with the Reserve for the duration of the first project crediting period, even if the Reserve revises the Performance Standard Test in subsequent versions of this protocol during that period. As stated in Section 3.3, the project crediting period is ten years.

If a project developer wishes to apply for a second crediting period, the project must meet the eligibility requirements of the most current version of this protocol at the time of the submittal for the second crediting period, including any updates to the Performance Standard Test.

3.5.2 The Legal Requirement Test

All projects are subject to a Legal Requirement Test to ensure that the GHG reductions achieved by a project would not otherwise have occurred due to federal, state, or local regulations, or other legally binding mandates. A project passes the Legal Requirement Test when there are no laws, statutes, regulations, court orders, environmental mitigation agreements, permitting conditions, or other legally binding mandates requiring the installation of a BCS at the livestock operation.

The Legal Requirement Test is applied at the time of a project’s start date. To satisfy the Legal Requirement Test, project developers must submit a signed Attestation of Voluntary Implementation form[5] prior to the commencement of verification activities for the first verification

[5] Attestation forms are available at http://www.climateactionreserve.org/how/projects/register/project-submittal-forms/.

period. All projects that pass this test at the project's start date are eligible to register reductions with the Reserve for the duration of their first crediting period, even if legal requirements change or new legal requirements are enacted during that period.

If a project developer wishes to apply for a second crediting period, the project must meet the eligibility requirements of the most current version of this protocol, including any updates to the Legal Requirement Test. Furthermore, during a project's second crediting period, it must demonstrate that it passes the Legal Requirement Test during each reporting period. To satisfy the Legal Requirement Test, project developers must submit a signed Attestation of Voluntary Implementation form prior to the commencement of verification activities for each verification period. If project activities become legally required during a project's second crediting period, the project will only be eligible to receive CRTs up to the date that the system is required to be operational.

The Reserve's analysis of manure management practices in the U.S. identified no regulations that obligate livestock owners to invest in a manure BCS. The analysis looked most closely at recent, stringent California air quality regulations (e.g. SJVAPCD Rule 4570 and Sacramento AQMD Rule 496), and found that installing an anaerobic digester is one of several compliance options, although high capital costs appear to prohibit the use of anaerobic digesters as a practical compliance mechanism for these air quality regulations.

3.6 Regulatory Compliance

As a final eligibility requirement, project developers must attest that project activities do not cause material violations of applicable laws (e.g. air, water quality, safety, etc.). To satisfy this requirement, project developers must submit a signed Attestation of Regulatory Compliance form[6] prior to the commencement of verification activities each time the project is verified. Project developers are also required to disclose in writing to the verifier any and all instances of legal violations – material or otherwise – caused by the project or project activities.

A violation should be considered to be "caused" by project activities if it can be reasonably argued that the violation would not have occurred in the absence of the project activities. If there is any question of causality, the project developer shall disclose the violation to the verifier.

If a verifier finds that project activities have caused a material violation, then CRTs will not be issued for GHG reductions that occurred during the period(s) when the violation occurred. Individual violations due to administrative or reporting issues, or due to "acts of nature," are not considered material and will not affect CRT crediting. However, recurrent administrative violations directly related to project activities may affect crediting. Verifiers must determine if recurrent violations rise to the level of materiality. If the verifier is unable to assess the materiality of the violation, then the verifier shall consult with the Reserve.

[6] Attestation forms are available at http://www.climateactionreserve.org/how/projects/register/project-submittal-forms/.

4 The GHG Assessment Boundary

The GHG Assessment Boundary delineates the GHG sources, sinks, and reservoirs (SSRs) that shall be assessed by project developers to determine the net change in emissions associated with installing a BCS. This protocol's assessment boundary captures sources from waste production to disposal, including off-site manure disposal.

CH_4 emissions from the land application of manure and digester effluent are excluded from the GHG Assessment Boundary. As these emission sources will either remain the same or decrease from the baseline to the project scenario, this exclusion is considered to be conservative.

N_2O emissions associated with manure management and disposal are also excluded from the GHG Assessment Boundary. Again, as these emission sources will either remain the same or decrease from the baseline to the project scenario, this exclusion is also considered to be conservative. Significant uncertainty remains regarding the quantification of potential N_2O changes. While some projects may result in a significant decrease in N_2O emissions, at this time there is no project-level methodology available to appropriately account for this uncertainty.

CO_2 emissions associated with the capture and destruction of biogas are considered biogenic emissions[7] (as opposed to anthropogenic) and are not included in the GHG Assessment Boundary.

This protocol does not account for CO_2 emission reductions associated with displacing grid-delivered electricity or fossil fuel use. However, project developers may reduce the project emissions associated with increased use of grid-connected electricity by utilizing project-generated electricity for project equipment.

Figure 4.1 provides a general illustration of the GHG Assessment Boundary, indicating which SSRs are included or excluded from the boundary. All SSRs within the dashed line are accounted for under this protocol.

Table 4.1 provides greater detail on each SSR and provides justification for the inclusion or exclusion of SSRs and gases from the GHG Assessment Boundary.

[7] The rationale is that carbon dioxide emitted during combustion represents the carbon dioxide that would have been emitted during natural decomposition of the manure. Emissions from the biogas control system do not yield a net increase in atmospheric carbon dioxide because they are theoretically equivalent to the carbon dioxide absorbed during plant/feed growth.

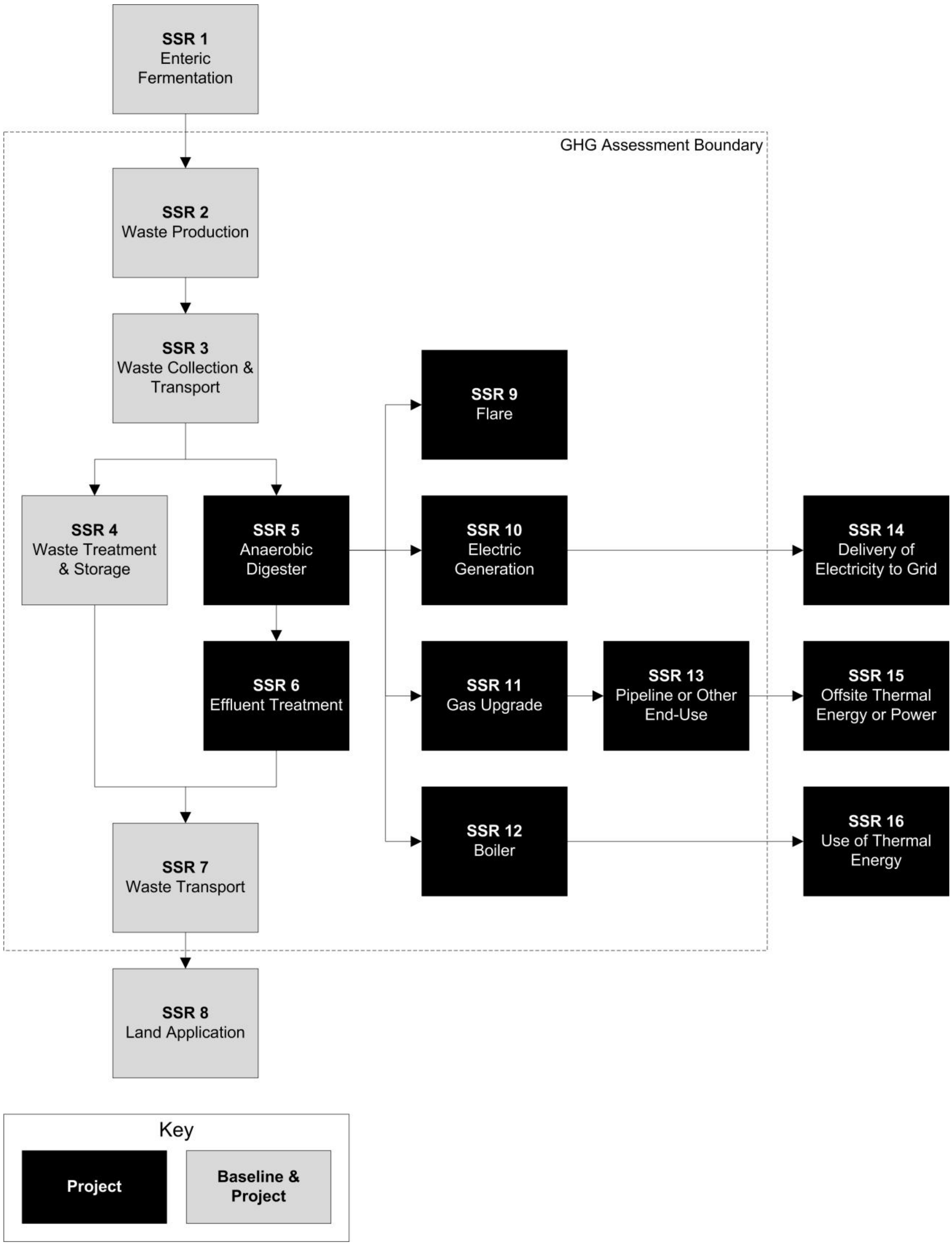


Figure 4.1. General Illustration of the GHG Assessment Boundary

Table 4.1 relates GHG source categories to sources and gases, and indicates inclusion in the calculation methodology. It is intended to be illustrative – GHG sources are indicative for the source category, GHGs in addition to the main GHG are also mentioned, where appropriate.

Table 4.1. Description of all Sources, Sinks, and Reservoirs

SSR	GHG Source	Gas	Relevant to Baseline (B) or Project (P)	Included/ Excluded	Justification/Explanation
1	Emissions from enteric fermentation	CH_4	B, P	*Excluded*	It is very unlikely that a livestock operation would change its feeding strategy to maximize biogas production from a digester; thus impacting enteric fermentation emissions from ruminant animals.
2	Emissions from waste deposits in barn, milking parlor or pasture/corral	N_2O	B, P	*Excluded*	This exclusion is conservative as emissions will either remain the same or decrease from the baseline to the project scenario, see page 8 for further explanation.
	Emissions from mobile and stationary support equipment	CO_2	B, P	*Included*	If any additional vehicles or equipment are required by the project beyond what is required in the baseline, emissions from such sources shall be accounted for.
		CH_4		*Excluded*	Emission source is assumed to be very small.
		N_2O		*Excluded*	Emission source is assumed to be very small.
3	Emissions from mechanical systems used to collect and transport waste (e.g. engines and pumps for flush systems; vacuums and tractors for scrape systems)	CO_2	B, P	*Included*	If any additional vehicle or equipment use is required by the project beyond what is required in the baseline, emissions from such sources shall be accounted for.
		CH_4		*Excluded*	Emission source is assumed to be very small.
		N_2O		*Excluded*	Emission source is assumed to be very small.
	Vehicle emissions (e.g. for centralized digesters)	CO_2		*Included*	If any additional vehicles or fuel use is required by the project beyond what is required in the baseline, emissions from such equipment shall be accounted for.
		CH_4		*Excluded*	Emission source is assumed to be very small.
		N_2O		*Excluded*	Emission source is assumed to be very small.

SSR	GHG Source	Gas	Relevant to Baseline (B) or Project (P)	Included/ Excluded	Justification/Explanation
4	Emissions from waste treatment and storage including: anaerobic lagoons, dry lot deposits, compost piles, solid storage piles, manure settling basins, aerobic treatment, storage ponds, etc.	CO_2	B, P	*Excluded*	Biogenic emissions are excluded.
		CH_4		*Included*	Primary source of emissions in the baseline.
		N_2O		*Excluded*	This exclusion is conservative as emissions will either remain the same or decrease from the baseline to the project scenario, see page 8 for further explanation.
	Emissions from support equipment	CO_2		*Included*	If any additional equipment is required by the project beyond what is required in the baseline, emissions from such equipment shall be accounted for.
		CH_4		*Excluded*	Emission source is assumed to be very small.
		N_2O		*Excluded*	Emission source is assumed to be very small.
5	Emissions from the anaerobic digester due to biogas collection inefficiencies and venting events	CH_4	P	*Included*	Project may result in leaked emissions from anaerobic digester.
6	Emissions from effluent treatment system	CH_4	P	*Included*	Primary source of emissions from project activities.
		N_2O		*Excluded*	See page 8.
7	Vehicle emissions for land application and/or off-site transport	CO_2	B, P	*Included*	If any additional vehicle use is required by the project beyond what is required in the baseline, associated additional emissions shall be accounted for.
		CH_4		*Excluded*	Emission source is assumed to be very small.
		N_2O		*Excluded*	Emission source is assumed to be very small.
8	Emissions from land application	CH_4	B, P	*Excluded*	Project activity is unlikely to increase emissions relative to baseline activity.
		N_2O	B, P	*Excluded*	This exclusion is conservative as emissions will either remain the same or decrease from the baseline to the project scenario, see page 8 for further explanation

SSR	GHG Source	Gas	Relevant to Baseline (B) or Project (P)	Included/ Excluded	Justification/Explanation
9	Emissions from combustion during flaring, including emissions from incomplete combustion of biogas	CO_2	P	*Excluded*	Biogenic emissions are excluded.
		CH_4		*Included*	Primary source of emissions from project activities.
		N_2O		*Excluded*	Emission source is assumed to be very small.
10	Emissions from combustion during electric generation, including incomplete combustion of biogas	CO_2	P	*Excluded*	Biogenic emissions are excluded.
		CH_4		*Included*	Primary source of emissions from project activities.
		N_2O		*Excluded*	Emission source is assumed to be very small.
11	Emissions from upgrading biogas for pipeline injection or use as CNG/LNG fuel	CO_2	P	*Included*	Emissions resulting from on-site fossil fuel use and/or grid electricity may be significant.
		CH_4		*Excluded*	Emission source is assumed to be very small.
		N_2O		*Excluded*	Emission source is assumed to be very small.
12	Emissions from combustion at boiler, including emissions from incomplete combustion of biogas	CO_2	P	*Excluded*	Biogenic emissions are excluded.
		CH_4		*Included*	Primary source of emissions from project activities.
		N_2O		*Excluded*	Emission source is assumed to be very small.
13	Emissions from combustion of biogas by end user of pipeline or CNG/LNG, including incomplete combustion	CO_2	P	*Excluded*	Biogenic emissions are excluded.
		CH_4		*Included*	Primary source of emissions from project activities.
		N_2O		*Excluded*	Emission source is assumed to be very small.
14	Use of project-generated electricity	CO_2 CH_4 N_2O	P	*Excluded*	This protocol does not cover displacement of GHG emissions from the use of biogas-generated electricity.
15	Off-site use of project-generated thermal energy or power	CO_2 CH_4 N_2O	P	*Excluded*	This protocol does not cover displacement of GHG emissions from the use of biogas delivered through pipeline or other end uses.
16	Use of project-generated thermal energy	CO_2 CH_4 N_2O	P	*Excluded*	This protocol does not cover displacement of GHG emissions from the use of biogas-generated thermal energy.
	Project construction and decommissioning emissions	CO_2 CH_4 N_2O	P	*Excluded*	Emission source is assumed to be very small.

5 Quantifying GHG Emission Reductions

GHG emission reductions from a livestock project are quantified by comparing actual project emissions to baseline emissions at the project site. Baseline emissions are an estimate of the GHG emissions from sources within the GHG Assessment Boundary (see Section 4) that would have occurred in the absence of the livestock project. Project emissions are actual GHG emissions that occur at sources within the GHG Assessment Boundary during the reporting period. Project emissions must be subtracted from the baseline emissions to quantify the project's total net GHG emission reductions (Equation 5.1).

GHG emission reductions are generally quantified and verified on an annual basis. Project developers may choose to verify GHG emission reductions on a more frequent or less frequent basis if they desire (see Section 7.3). The length of time over which GHG emission reductions are quantified and reported to the Reserve is called the "reporting period." The length of time over which GHG reductions are verified is called a "verification period." Under this protocol, a verification period may cover multiple reporting periods (see Section 7.3.4). Project developers should take note that some equations to calculate baseline and project emissions are run on a month-by-month basis and activity data monitoring takes place at varying levels of frequency. As applicable, monthly emissions data (for baseline and project) are summed together to calculate emission reductions over a given reporting period. Projects whose reporting periods begin or end with incomplete calendar months shall only quantify the baseline and project emissions for the portion of the month that is included within the reporting period.
The calculations provided in this protocol are derived from internationally accepted methodologies.[8] Project developers shall use the calculation methods provided in this protocol to determine baseline and project GHG emissions in order to quantify GHG emission reductions.

To support project developers and facilitate consistent and complete emissions reporting, the Reserve has developed an Excel-based calculation tool. This tool is available to all Reserve account holders and their designated representatives. Instructions for obtaining the most recent version of this tool are available on the U.S. Livestock Project Protocol webpage. The Reserve *recommends* the use of the Livestock Calculation Tool for all project calculations and emission reduction reports. Only the most recent version of this tool should be used, unless otherwise recommended by Reserve staff. In any case where there is potential disagreement between guidance provided in the protocol and guidance provided in the calculation tool, the protocol shall take precedence.

The current methodology for quantifying the GHG impact associated with installing a BCS requires the use of both modeled reductions (following Equation 5.2 to Equation 5.4 and Equation 5.6 to Equation 5.9) as well as the utilization of *ex-post* metered data from the BCS to be used as a check on the modeled reductions.

The Reserve recognizes that there can be material differences between modeled methane emission reductions and the actual metered quantity of methane that is captured and destroyed by the BCS due to digester start-up periods, venting events, and other BCS operational issues.

[8] The Reserve's GHG reduction calculation method is derived from the Kyoto Protocol's Clean Development Mechanism (ACM0010 V.5), the EPA's Climate Leaders Program (Manure Offset Protocol, August 2008), and the RGGI Model Rule (January 5, 2007).

These operational issues have the potential to result in substantially less methane destruction than is modeled, leading to an overestimation of GHG reductions in the modeled case.

To address this issue and maintain consistency with international best practice, the Reserve requires the modeled methane emission reduction results to be compared to the *ex-post* metered quantity of methane that is captured and destroyed by the BCS. The lesser of the two values will represent the total methane emission reductions for the reporting period. Equation 5.1 below outlines the quantification approach for calculating the emission reductions from the installation of a BCS.

5.1 Required Parameters for Modeling Baseline and Project Emissions

The following parameters must be determined for the modeling of baseline and project emissions:

Population – P_L

The procedure requires project developers to differentiate between livestock categories (*L*) (e.g. lactating dairy cows, non-milking dairy cows, heifers, etc.). This accounts for differences in methane generation across livestock categories. See Appendix B, Table B.2 for methane generation values. The population of each livestock category shall be monitored on a monthly basis, and for Equation 5.4 is averaged for an annual total population.

Volatile solids – VS_L

This value represents the daily organic material in the manure for each livestock category and consists of both biodegradable and non-biodegradable fractions. The VS content of manure is a combination of excreted fecal material (the fraction of a livestock category's diet consumed and not digested) and urinary excretions, expressed in a dry matter weight basis (kg/animal).[9] This protocol requires that the VS value for all livestock categories be determined as outlined in Box 5.1.

$Mass_L$

This value is the annual average live weight of the animals, per livestock category. These data are necessary because default VS values are supplied in units of kg/day/1000kg mass, therefore the average mass of the corresponding livestock category is required in order to convert the units of VS into kg/day/animal. Site specific livestock mass is preferred for all livestock categories. If site-specific data are unavailable, Typical Animal Mass (TAM) values may be used (see Appendix B, Table B.2).

Maximum methane production – $B_{0,L}$

This value represents the maximum methane-producing capacity of the manure, differentiated by livestock category (*L*) and diet. Project developers shall use the default B_0 factors from Appendix B, Table B.3. Alternatively, project developers may follow the sampling and testing procedure contained in Section 6.1 in order to determine a site-specific B_0 value for a particular animal category.

[9] IPCC 2006 Guidelines volume 4, chapter 10, p. 10.42.

MS_S

The MS value apportions manure from each livestock category to appropriate manure management system component (*S*), and is a critical factor in determining a project baseline, as well as project emissions from effluent treatment. It reflects the reality that waste from the operation's livestock categories are not managed uniformly. The MS value accounts for the operation's multiple types of manure management systems. It is expressed as a percent (%), relative to the total amount of VS produced by the livestock category. As waste production is normalized for each livestock category, the percentage shall be calculated as percent of population for each livestock category. For example, a dairy operation might send 85% of its milking cows' waste to an anaerobic lagoon and 15% could be deposited in a corral. In this situation, an MS value of 85% would be assigned to Equation 5.3 and 15% to Equation 5.4.

Importantly, the MS value indicates where the waste would have been managed in the baseline scenario. If a portion of the VS was removed from the waste stream through some sort of separation procedure, the MS value shall be adjusted to accurately reflect the baseline treatment of the VS. To account for VS removal from solids separation equipment, project developers may use a default value for the particular type of separation mechanisms employed (Table B.9), or a site-specific value based on the removal efficiency of the baseline system.

MS_{BCS}, which represents the fraction of manure that is sent to the BCS in the project scenario, follows the same logic as above, but is used to accurately quantify the project methane emissions from effluent treatment (see Equation 5.8).

MGS_{BCS}

The MGS_{BCS} value represents the maximum biogas storage capacity of the BCS system. This value is needed only in the case of a venting event during the reporting period, which is quantified using Equation 5.7. If the BCS consists of multiple digester tanks or covered lagoons, the project only need quantify the maximum storage (MGS_{BCS}) and biogas flow (F_{pw}) of the component(s) of the BCS that experienced the venting event.

Methane conversion factor – MCF

This method to calculate methane emissions reflects the site-specific monthly biological performance of the operation's baseline anaerobic manure management systems, as predicted using the van't Hoff-Arrhenius equation and farm-level data on temperature, as well as VS loading and system VS retention time.[10]

Each manure management system component has a volatile solids-to-methane conversion efficiency that represents the degree to which maximum methane production (B_0) is achieved. Methane production is a function of the extent of anaerobic conditions present in the system, the temperature of the system, and the retention time of organic material in the system.[11]

Default MCF values for non-anaerobic baseline manure management system components (as well as certain project BCS effluent treatment and Non-BCS sources) are available in Appendix B. These are used in Equation 5.4 and Equation 5.9.

Contrastingly, site-specific calculations of volatile solids-to-methane conversion efficiency are required for anaerobic baseline manure management system components and for the anaerobic

[10] The method is derived from Mangino et al., "Development of a Methane Conversion Factor to Estimate Emissions from Animal Waste Lagoons" (2001).
[11] IPCC 2006 Guidelines volume 4, chapter 10, p. 10.43.

treatment of project BCS effluent. For anaerobic lagoons, storage ponds, liquid slurry tanks etc., project developers perform a site-specific calculation of the mass of volatile solids degraded by the anaerobic storage/treatment system. This is expressed as “degraded volatile solids” or VS_{deg} in Equation 5.3, which equals the system’s monthly available volatile solids multiplied by ‘*f*’, the van’t Hoff-Arrhenius factor. The ‘*f*’ factor effectively converts total available volatile solids in the anaerobic manure storage/treatment system to methane-convertible volatile solids, based on the monthly temperature of the system. The multiplication of VS_{deg} by B_0 quantifies the maximum potential methane emissions that would have been produced for each livestock category’s contribution of manure to that system.

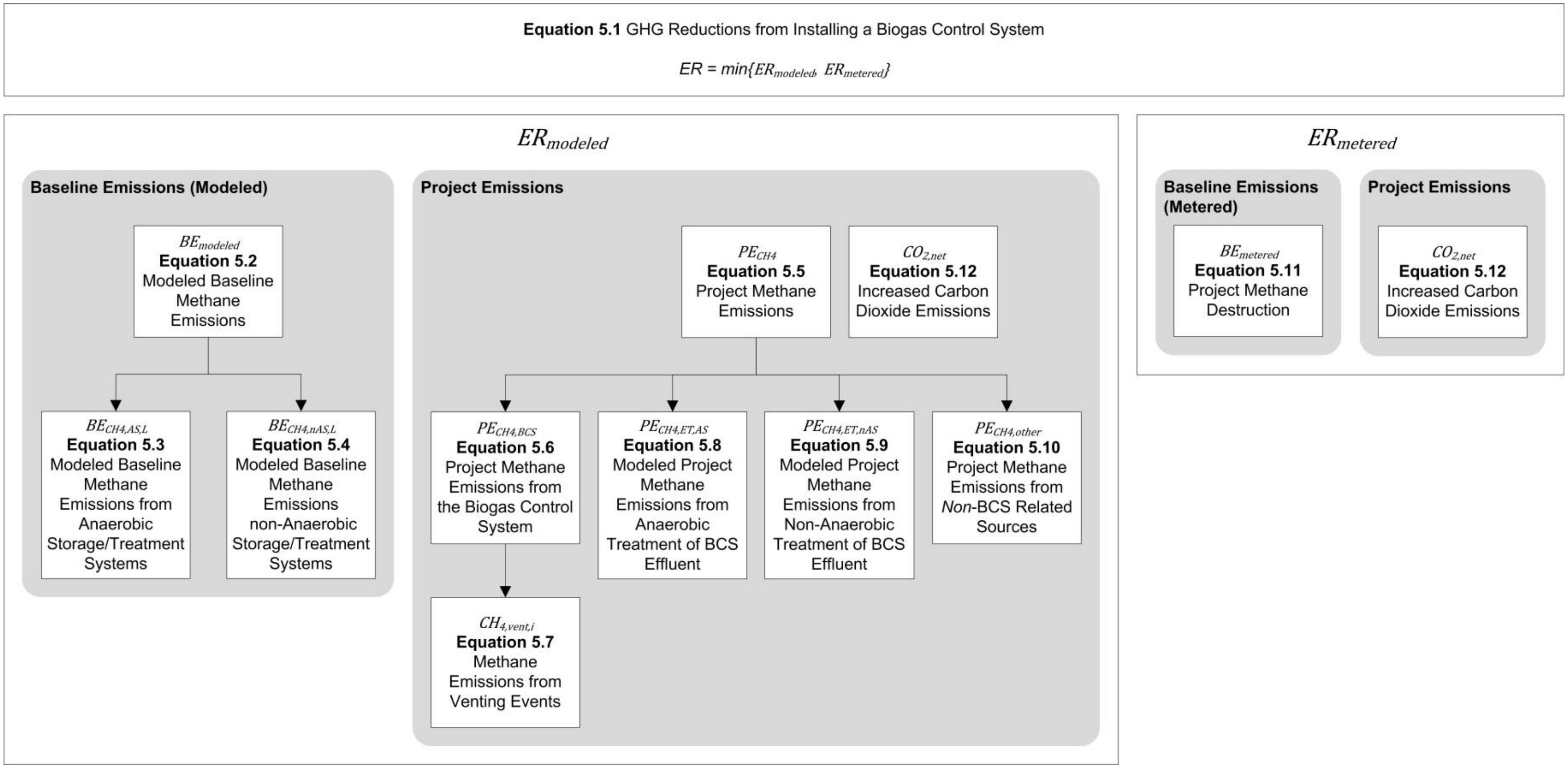


Figure 5.1. Organization of Equations in Section 5

Equation 5.1. GHG Reductions from Installing a Biogas Control System

$$ER = \min\{ER_{modeled}, ER_{metered}\}$$

$$ER_{modeled} = BE_{modeled} - PE_{CH_4} - CO_{2,net}$$

Where, Units

$ER_{modeled}$	=	Avoided methane emissions associated with the project during the reporting period, quantified using a modeled baseline scenario	tCO_2e
$BE_{modeled}$	=	Modeled baseline emissions from the baseline scenario (Equation 5.2)	tCO_2e
PE_{CH4}	=	Total project methane emissions during the reporting period (Equation 5.5)	tCO_2e
$CO_{2,net}$	=	Net increase in anthropogenic CO_2 emissions from electricity consumption and mobile and stationary combustion sources resulting from project activity (Equation 5.12)	tCO_2e

$$ER_{metered} = BE_{metered} - CO_{2,net}$$

Where, Units

$ER_{metered}$	=	Avoided methane emissions associated with the project during the reporting period, quantified using metered methane destruction data	tCO_2e
$BE_{metered}$	=	Aggregated quantity of methane collected and destroyed during the reporting period (Equation 5.11)	tCO_2e
$CO_{2,net}$	=	Net increase in anthropogenic CO_2 emissions from electricity consumption and mobile and stationary combustion sources resulting from project activity (Equation 5.12)	tCO_2e

5.2 Modeling Baseline Methane Emissions

Baseline emissions represent the GHG emissions within the GHG Assessment Boundary that would have occurred if not for the installation of the BCS. For the purposes of this protocol, project developers calculate their baseline emissions according to the manure management system in place prior to installing the BCS. Baseline emissions are then recalculated for each reporting period to reflect what the emissions would have been had the previous management system continued to function under current conditions. For Greenfield projects, as defined in Section 3.4.2, the baseline manure management practices shall be modeled according to the default values provided in Table B.10.

The procedure to determine the modeled baseline methane emissions follows Equation 5.2, which combines Equation 5.3 and Equation 5.4. The calculation procedures use a combination of site-specific values and default factors.

Box 5.1. Daily Volatile Solids for All Livestock Categories

Consistent with international best-practice, it is recommended that appropriate VS_L values for dairy livestock categories be obtained from the state-specific lookup tables (Tables B.5.a – B.5.f) provided in Appendix B. When possible, use the year corresponding to the appropriate emission year. If the current year's table is not included in the protocol, use the most current year that is available from the Reserve. Updated tables will be provided in the Livestock Calculation Tool, as well as the Reserve website.[12]

VS_L values for all other livestock can be found in Appendix B, Table B.3.

Important – Units provided for all VS values in Appendix B are in (kg/day/1000kg), In order to get VS_L in the appropriate units (kg/animal/day), the following equation must be used:

$$\boldsymbol{VS_L = VS_{Table} \times \frac{Mass_L}{1000}}$$

Where, Units

VS_L	=	Volatile solid excretion on a dry matter weight basis	kg/animal/day
VS_{Table}	=	Volatile solid excretion from lookup table (Table B.3 and Table B.5a - B.5d)	kg/day/1000kg
$Mass_L$	=	Average live weight for livestock category *L*. If site specific data are unavailable, use values from Appendix B, Table B.2 corresponding to the appropriate emission year (or the most current year that is available from the Reserve)	kg

Equation 5.2. Modeled Baseline Methane Emissions

$$\boldsymbol{BE_{modeled} = \sum_{S,L} \left(BE_{CH_4,AS,L} + BE_{CH_4,nAS,L} \right)}$$

Where, Units

$BE_{modeled}$	=	Total baseline methane emissions during the reporting period, summed for each baseline treatment system *S* and livestock category *L*	tCO_2e
$BE_{CH4,AS,L}$	=	Total monthly baseline methane emissions from anaerobic storage/treatment system *AS* by livestock category *L*, aggregated for the reporting period. See Equation 5.3	tCO_2e
$BE_{CH4,nAS,L}$	=	Total baseline methane emissions for the reporting period from non-anaerobic storage/treatment systems by livestock category *L.* See Equation 5.4	tCO_2e

[12] http://www.climateactionreserve.org/how/protocols/us-livestock/

Equation 5.3. Modeled Baseline Methane Emissions from Anaerobic Storage/Treatment Systems

$$BE_{CH_4,AS,L} = \left(VS_{deg,AS,L} \times B_{0,L} \times days_{mo} \times 0.68 \times 0.001 \times 21\right) \times \left(\frac{rd_{mo}}{days_{mo}}\right)$$

Where, Units

$BE_{CH4,AS,L}$	=	Total monthly baseline methane emissions from anaerobic manure storage/treatment system *AS* from livestock category *L*	tCO_2e/yr
$VS_{deg,AS,L}$	=	Monthly volatile solids degraded in anaerobic manure storage/treatment system *AS* from livestock category *L*	kg dry matter
$B_{0,L}$	=	Maximum methane producing capacity of manure for livestock category *L* – see Appendix B, Table B.3 for default values or Section 6.1 for guidance on determining a site-specific value	m^3 CH_4/kg of VS
0.68	=	Density of methane (1 atm, 60°F)	kg/m^3
0.001	=	Conversion factor from kg to metric tons	
21	=	Global Warming Potential of methane as carbon dioxide equivalent	tCO_2e/tCH_4
$days_{mo}$	=	Calendar days per month	days
rd_{mo}	=	Reporting days during the current month (see Box 5.2)	days

$$VS_{deg,AS,L} = \sum_{AS,L}\left(VS_{avail,AS,L} \times f\right)$$

Where, Units

$VS_{deg,AS,L}$	=	Monthly volatile solids degraded by anaerobic manure storage/ treatment system *AS* by livestock category *L*	kg dry matter
$VS_{avail,AS,L}$	=	Monthly volatile solids available for degradation from anaerobic manure storage/treatment system *AS* by livestock category *L*	kg dry matter
f	=	The van't Hoff-Arrhenius factor = "the proportion of volatile solids that are biologically available for conversion to methane based on the monthly temperature of the system" [13]	

Equation 5.3 continued on next page.

[13] Mangino, et al.

Equation 5.3. Continued

$$VS_{avail,AS,L} = \left(VS_L \times P_L \times MS_{AS,L} \times days_{mo} \times 0.8\right) + \left(VS_{avail-1,AS} - VS_{deg-1,AS}\right)$$

Where,			Units
$VS_{avail,AS,L}$	=	Monthly volatile solids available for degradation in anaerobic storage/treatment system *AS* by livestock category *L*	kg dry matter
VS_L	=	Volatile solids produced by livestock category *L* on a dry matter basis. Refer to Box 5.1 for guidance on using appropriate units for VS_L values from Appendix B	kg/animal/day
P_L	=	Average population of livestock category *L* (based on population data for the current month)	
$MS_{AS,L}$	=	Percent of manure sent to (managed in) anaerobic manure storage/treatment system *AS* from livestock category *L* [14]	%
$days_{mo}$	=	Calendar days per month	days
0.8	=	Management and design practices factor[15]	
$VS_{avail-1,AS}$	=	Previous month's volatile solids available for degradation in anaerobic system *AS*[16]	kg
$VS_{deg-1,AS}$	=	Previous month's volatile solids degraded by anaerobic system *AS*	kg

$$f = exp\left[\frac{E\left(T_{mo} - T_{ref}\right)}{(R)\left(T_{ref}\right)\left(T_{mo}\right)}\right]$$

Where,			Units
f	=	The van't Hoff-Arrhenius factor	
E	=	Activation energy constant (15,175)	cal/mol
T_{mo}	=	Monthly average ambient temperature (K = °C + 273). If T_{mo} < 5°C then *f* = 0.104. If T_{mo} > 29.5°C then *f* = 0.95	Kelvin
T_{ref}	=	303.16; Reference temperature for calculation	Kelvin
R	=	Ideal gas constant (1.987)	cal/Kmol

[14] The MS value represents the percent of manure that would be sent to (managed by) the anaerobic manure storage/treatment systems in the baseline case – as if the biogas control system was never installed.

[15] Mangino, et al. This factor was derived to "account for management and design practices that result in the loss of volatile solids from the management system." This reflects the difference between the theoretical modeled biological activity and empirical measurement of biological activity due to removal of liquid or other management practices that result in loss of VS from the treatment system. This does not account for removal of solids prior to the treatment system.

[16] IPCC 2006 Guidelines (Volume 4, Chapter 10, p. 42); ACM0010 (V2, p.8); and EPA Climate Leaders Manure Offset Protocol (August 2008).

Box 5.2. Calculating the Number of Reporting Days for a Reporting Period

For some projects, it may be necessary to exclude a number of days from the calculation of emission reductions. If the reporting period begins or ends mid-way through a month, the calculation shall be prorated to only include the number of days for each month that fall within the reporting period by setting *nrd* equal to the number of days that fall outside the reporting period. If the project is not eligible to report emission reductions for a certain period of time for other reasons (e.g. regulatory compliance issues, missing data), those days may also be included in the determination of *nrd*.

For example, if a reporting period begins on March 10, then nrd_{March} = 9. If the same reporting period ends on December 31st of the same year, then nrd_{rp} = 9, and *rd* = (306 – 9) = 297.

The following equation is used to determine the number of reporting days for the current period. This is to be applied for individual months for those equations that are run monthly, and for the entire reporting period for those equations that are run once per reporting period.

$$\boldsymbol{rd = days - nrd}$$

Where,

rd	=	Number of reporting days in the current period (month, reporting period, etc.)
days	=	Number of calendar days in the current period (e.g. equal to 30 for June)
nrd	=	Non-reporting days in the current period

Retention of Volatile Solids

Equation 5.3 calculates methane emissions from anaerobic manure storage/treatment systems based on site-specific information on the mass of volatile solids degraded by the anaerobic storage/treatment system and available for methane conversion.[17] It incorporates the effects of temperature through the van't Hoff-Arrhenius (*f*) factor and accounts for the retention of volatile solids through the use of monthly assumptions of baseline conditions. Each month, a certain quantity of VS is converted into methane (VS_{deg}). The VS that is available for conversion each month (VS_{avail}) is the sum of VS that enters the manure management system, as well as VS that remains in the system from the previous month ($VS_{avail-1} – VS_{deg-1}$).

Project developers shall not carry over volatile solids from one month to the next when modeling baseline anaerobic treatment systems where the retention time was 30 days or less. For these systems ($VS_{avail-1} – VS_{deg-1}$) = 0 in Equation 5.3 for every month.

Depending on the accumulation of sludge in the baseline manure storage system, it may have been necessary to drain and clean the system on a periodic basis. This cleaning removes the non-degraded VS that has accumulated in the system. For anaerobic lagoons with a retention time greater than 30 days, project developers shall zero out the VS retained in the system following the month when the system would have been completely drained and sludge removed under baseline operating conditions. For the month following the sludge removal, ($VS_{avail-1} – VS_{deg-1}$) = 0 in Equation 5.3. For projects where a BCS is being retrofit into existing operations, baseline anaerobic system management practices should reflect actual pre-project manure management practices on that farm.

[17] These system components must meet the Anaerobic Baseline requirement in Section 3.4.

If the farm utilized solids separation in the baseline (thus preventing or delaying sludge accumulation), this removal and alternative treatment of VS should be reflected in the MS values, as explained earlier in this section.

The removal of supernatant liquids for spraying on fields at agronomic rates does not affect the monthly carryover of VS, as long as the system maintains at least one meter of liquid depth. Projects therefore do not need to account for regular field spraying activities that meet this description.

Equation 5.4 applies to non-anaerobic storage/treatment systems. Both Equation 5.3 and Equation 5.4 reflect basic biological principles of methane production from available volatile solids, determine methane generation for each livestock category, and account for the extent to which the waste management system handles each category's manure.

Equation 5.4. Modeled Baseline Methane for Non-Anaerobic Storage/Treatment Systems

$$\boldsymbol{BE_{CH_4,nAS,L}} = \left(\boldsymbol{P_L} \times \boldsymbol{MS_{L,nAS}} \times \boldsymbol{VS_L} \times \boldsymbol{days_{rp}} \times \boldsymbol{MCF_{nAS}} \times \boldsymbol{B_{0,L}}\right) \times \mathbf{0.68} \times \mathbf{0.001} \times \mathbf{21} \times \left(\frac{\boldsymbol{rd_{rp}}}{\boldsymbol{days_{rp}}}\right)$$

Where,			Units
$BE_{CH4,nAS,L}$	=	Total baseline methane emissions during the reporting period from non-anaerobic storage/treatment systems	tCO_2e
P_L	=	Average population of livestock category *L* during the reporting period (based on monthly population data)	
$MS_{L,nAS}$	=	Percent of manure from livestock category *L* managed in non-anaerobic storage/treatment systems	%
VS_L	=	Volatile solids produced by livestock category *L* on a dry matter basis. Refer to Box 5.1 for guidance on using appropriate units for VS_L values from Appendix B	kg/animal/day
$days_{rp}$	=	Number of days in the reporting period	days
MCF_{nAS}	=	Methane conversion factor for non-anaerobic storage/treatment system. See Appendix B	%
$B_{0,L}$	=	Maximum methane producing capacity for manure for livestock category *L*. See Appendix B, Table B.3 for default values, or Section 6.1 for determining a site-specific value	m^3 CH_4/kg of VS dry matter
0.68	=	Density of methane (1 atm, 60°F)	kg/m^3
0.001	=	Conversion factor from kg to metric tons	
21	=	Global Warming Potential of methane as carbon dioxide equivalent	tCO_2e/tCH_4
rd_{rp}	=	Reporting days during the reporting period	days

5.3 Calculating Project Methane Emissions

Project emissions are actual GHG emissions that occur within the GHG Assessment Boundary after the installation of the BCS. Project emissions are calculated on an annual, *ex-post* basis. Like baseline emissions, some parameters are monitored on a monthly basis. Unlike baseline emission calculations, methane emissions from the BCS are calculated from metered data, rather than modeled projections. Methane emissions from manure storage and/or treatment systems other than the BCS are modeled much the same as in the baseline scenario.

As shown in Equation 5.5, project methane emissions equal:

- The amount of methane created by the BCS that is not captured and destroyed by the control system, plus
- Methane from the digester effluent treatment systems (where applicable), plus
- Methane from sources in the waste treatment and storage category other than the BCS and associated effluent treatment systems. This includes all other manure treatment systems such as compost piles, solids storage etc.

Consistent with this protocol's baseline methane calculation approach, the formula to account for project methane emissions incorporates all potential sources within the waste treatment and storage category. Non-BCS-related sources follow the same calculation approach as provided in the baseline methane equations. Several activity data for the variables in Equation 5.9 will be the same as those in Equation 5.2 to Equation 5.4.

If the project elects to install an impermeable cover on an effluent pond (potentially creating an additional anaerobic digester) and the biogas generated in this covered pond is collected and destroyed by the project BCS, then this covered pond shall be considered part of the project digester system. If the biogas generated by this covered pond is not destroyed, it must be quantified as project methane emissions using Equation 5.8.

Although not common under normal digester operation, it is possible that a venting event may occur due to catastrophic failure of digester cover materials, the digester vessel, or the gas collection system. In the event that a catastrophic system failure results in the venting of biogas, the quantity of methane released to the atmosphere shall be estimated according to Equation 5.7 below.

Equation 5.5. Project Methane Emissions

$$PE_{CH_4} = \left(PE_{CH_4,BCS} + PE_{CH_4,ET,AS} + PE_{CH_4,ET,nAS} + PE_{CH_4,other}\right) \times 21$$

Where,

			Units
PE_{CH4}	=	Total project methane emissions for the reporting period,	tCO_2e
$PE_{CH4,BCS}$	=	Methane emissions from the BCS during the reporting period (Equation 5.6)	tCH_4
$PE_{CH4,ET,AS}$	=	Monthly methane emissions from the BCS effluent anaerobic treatment systems, aggregated for the reporting period (Equation 5.8)	tCH_4
$PE_{CH4,ET,nAS}$	=	Methane emissions from the BCS effluent non-anaerobic treatment systems during the reporting period (Equation 5.9)	tCH_4
$PE_{CH4,other}$	=	Methane emissions from sources in the waste treatment and storage category other than the BCS and associated effluent treatment systems, during the reporting period (Equation 5.10)	tCH_4
21	=	Global warming potential of methane as carbon dioxide equivalent	tCO_2e/tCH_4

Equation 5.6. Project Methane Emissions from the Biogas Control System

$$PE_{CH_4,BCS} = \sum_i \left[\left[CH_{4,metered,i} \times \left(\left(\frac{1}{BCE} \right) - BDE_{i,weighted} \right) \right] + CH_{4,vent,i} \right]$$

Where, Units

$PE_{CH4,BCS}$	=	Methane emissions from the BCS, to be summed for each reporting period	tCH_4
$CH_{4,metered,i}$	=	Quantity of methane collected and metered in month *i*	tCH_4
BCE	=	Methane collection efficiency of the BCS. Project developers shall use the appropriate default value provided in Table B.4	fraction
$BDE_{i,weighted}$	=	Weighted average of all destruction devices used in month i	fraction
$CH_{4,vent,i}$	=	Quantity of methane that is vented to the atmosphere due to BCS venting events in month *i*, as quantified in Equation 5.7 below	tCH_4

$$CH_{4,metered,i} = F \times \frac{520}{T_b} \times \frac{P}{1} \times CH_{4,conc} \times 0.0423 \times 0.000454$$

Where, Units

$CH_{4,metered,i}$	=	Wuantity of methane collected and metered in month *i*[18]	tCH_4
F	=	Measured volumetric flow of biogas in month *i*	scf
T_b	=	Temperature of the biogas flow (°R = °F + 459.67)	°R
P	=	Pressure of the biogas flow	atm
$CH_{4,conc}$	=	Measured methane concentration of biogas for month *i*	fraction
0.0423	=	Density of methane gas (1 atm, 60°F)	lb CH_4/scf
0.000454	=	Conversion factor from lb to metric ton	

** The terms (520/T_b) and (P/1) should be omitted if the continuous flow meter internally corrects for temperature and pressure to 60°F and 1 atm.*

$$BDE_{i,weighted} = \frac{\sum_{DD}\left(BDE_{DD} \times F_{i,DD}\right)}{F_i}$$

Where, Units

$BDE_{i,weighted}$	=	Monthly weighted average of all destruction devices used in month *i*	fraction
BDE_{DD}	=	Default methane destruction efficiency of a particular destruction device 'DD'. See Appendix B for default destruction efficiencies[19]	fraction
$F_{i,DD}$	=	Monthly flow of biogas to a particular destruction device 'DD'	scf/month
F_i	=	Total monthly measured volumetric flow of biogas to all destruction devices	scf/month

[18] This value reflects directly measured biogas mass flow and methane concentration in the biogas to the combustion device.

[19] Project developers have the option to use either the default methane destruction efficiencies provided, or site specific methane destruction efficiencies, for each of the combustion devices used in the project. Site-specific values must be provided by an independent air emissions testing body that is accredited by a state or local agency, or the Stack Testing Accreditation Council (STAC). See Appendix B for more information. Where a state/region does not have an appropriate accreditation system or accredited service providers, the project developer may look to another state/region to find suitably qualified service providers.

Equation 5.7. Methane Emissions from Venting Events

$$CH_{4,vent,i} = \left(MGS_{BCS} + (F_{pw} \times t)\right) \times CH_{4,conc} \times 0.0423 \times 0.000454$$

Where, Units

$CH_{4,vent,i}$	=	Quantity of methane that is vented to the atmosphere due to BCS venting events in month *i*	tCH_4
MGS_{BCS}	=	Maximum biogas storage of the BCS system[20]	scf
F_{pw}	=	Average total daily flow of biogas from the digester for the entire week prior to the venting event[20]	scf/day
t	=	Number of days of the month that biogas is venting uncontrolled from the BCS system (can be a fraction)	days
$CH_{4,conc}$	=	Measured methane concentration of biogas prior to the venting event	fraction
0.0423	=	Density of methane gas (1 atm, 60°F)	lb CH_4/scf
0.000454	=	Conversion factor from lb to metric ton	

Equation 5.8, along with Equation 5.9, shall be used to account for all treatment systems associated with the BCS effluent. The factor ETF_i shall be estimated by the project developer to determine what fraction of the VS in the effluent is sent to each treatment system, and is represented as a fraction (e.g. if 85% of the BCS effluent is sent to an effluent pond, then ETF_i for that system is equal to 0.85). Anaerobic effluent treatment systems are those which store liquid effluent in a lagoon, pond, or tank. This includes liquid storage systems that employ non-airtight covers (i.e. biogas is freely vented to the atmosphere) as long as the entire system is managed as a passive storage system, rather than an actively-managed treatment system (i.e. no heating, mixing, etc.).

Equation 5.8. Modeled Project Methane Emissions from Anaerobic Treatment of BCS Effluent

$$PE_{CH_4,ET,AS} = \sum_i \left(VS_{ET,i} \times B_{0,ET} \times days_{mo} \times 0.8 \times f \times 0.68 \times 0.001\right) \times \frac{rd_{mo}}{days_{mo}}$$

Where, Units

$PE_{CH4,ET,AS}$	=	Monthly methane emissions from anaerobic effluent treatment systems	tCH_4
$VS_{ET,i}$	=	Volatile solids to anaerobic effluent treatment system *i* (see below)	kg/day
$B_{0,ET}$	=	Maximum methane producing capacity (of VS dry matter)[21]	m^3CH_4/kg VS
$days_{mo}$	=	Calendar days in the current month	days
0.8	=	Management and design practices factor[15]	fraction
f	=	The van't Hoff-Arrhenius factor, as calculated in Equation 5.3	
0.68	=	Density of methane (1 atm, 60°F)	kg/m^3
0.001	=	Conversion from kg to metric tons	t/kg
rd_{mo}	=	Reporting days in the current month	days

Equation 5.8 continued on next page

[20] If the BCS consists of multiple digester tanks or covered lagoons, the project only need quantify the maximum storage (MGS_{BCS}) and biogas flow (F_{pw}) of the component(s) of the BCS that experienced the venting event.

[21] The B_0 value for the project effluent pond is not differentiated by livestock category. Project developers shall use the B_0 value that corresponds with a weighted average of the operation's livestock categories that contribute manure to the BCS (weighted by the kg of VS contributed by each livestock category). Supporting laboratory data and documentation per Section 6.1 needs to be supplied to the verifier to justify an alternative value.

Equation 5.8. Continued

$$VS_{ET,i} = \left[\left(\sum_{L}(VS_L \times P_L \times MS_{L,BCS})\right) \times 0.3\right] \times ETF_i$$

Where,

			Units
$VS_{ET,i}$	=	Volatile solids to anaerobic effluent treatment system *i*	kg/day
VS_L	=	Volatile solids produced by livestock category 'L' on a dry matter basis. *Important* – refer to Box 5.1 for guidance on using appropriate units for VS_L values from Appendix B	kg/animal/ day
P_L	=	Average population of livestock category *L* during the reporting period (based on monthly population data)	
$MS_{L,BCS}$	=	Fraction of manure from livestock category *L* that is managed in the BCS	fraction
0.3	=	Default value representing the amount of VS that exits the digester as a fraction of the VS entering the digester[22]	fraction
ETF_i	=	Fraction of the effluent that exits the digester and is sent to effluent treatment system *i*	fraction

If the effluent from the project digester is directed to a covered liquid effluent storage system, and the biogas from this storage system is not collected and destroyed, then the following scenarios apply:

1. If the effluent from this system is applied directly to land and biogas flow and methane concentration are monitored in accordance with Section 6, then $PE_{CH4,ET,AS}$ for this system shall be determined using Equation 5.6, assuming a BCE value of 0.95 and a BDE value of 0.

   For any periods where biogas flow and/or methane concentration data from this system are missing (and not replaceable through data substitution) or not in conformance with Section 6, Equation 5.8 shall be used to determine the quantity of project methane emissions from this system component.

2. If the effluent from the covered liquid effluent storage system is directed to another treatment system (i.e. not land-applied), then an additional calculation is required. The methane released from the covered liquid effluent system shall be quantified using the guidance in Scenario 1 above, but the additional methane released by the further treatment system must also be quantified. Equation 5.9 shall be used to calculate the methane released from the additional treatment system using the default assumptions that 30% of the $VS_{ET,i}$ from the effluent storage system enters the additional treatment system.

[22] Per ACM0010 (V2 Annex I).

Equation 5.9. Modeled Project Methane Emissions from Non-Anaerobic Treatment of BCS Effluent[23]

$$PE_{CH_4,ET,nAS} = \sum_{i} (VS_{ET,i} \times B_{0,ET} \times rd_{rp} \times 0.68 \times MCF_{ET,i} \times 0.001)$$

Where,

			Units
$PE_{CH4,ET,nAS}$	=	Project methane emissions from non-anaerobic effluent treatment systems during the reporting period	tCH_4
$VS_{ET,i}$	=	Volatile solids to non-anaerobic effluent treatment system *i* (see Equation 5.8)	kg/day
$B_{0,ET}$	=	Maximum methane producing capacity (of VS dry matter)[24]	m^3CH_4/kg
rd_{rp}	=	Number of reporting days in the current reporting period	days
0.68	=	Density of methane (1 atm, 60°F)	kg/m^3
$MCF_{ET,i}$	=	Methane conversion factor for effluent treatment system *i* (Table B.6)	fraction
0.001	=	Conversion factor from kg to metric tons	

Equation 5.10. Project Methane Emissions from *Non*-BCS Related Sources[25]

$$PE_{CH_4,other} = \sum_{L} (P_L \times VS_L \times B_{0,L} \times MCF_{non-BCS} \times rd_{rp} \times 0.68 \times 0.001)$$

Where,

			Units
$PE_{CH4,other}$	=	Methane from sources in the waste treatment and storage category other than the BCS and associated effluent treatment systems during the reporting period	tCH_4
P_L	=	Average population of livestock category *L* during the reporting period	
VS_L	=	Volatile solids produced by livestock category 'L' on a dry matter basis. Refer to Box 5.1 for guidance on using appropriate units for VS_L values from Appendix B	kg/ animal/ day
$B_{0,L}$	=	Maximum methane producing capacity of VS dry matter for manure for livestock category *L*, (Appendix B, Table B.3)	m^3 CH_4/kg
$MCF_{non-BCS}$	=	Management-weighted methane conversion factor for waste treatment and storage systems other than the BCS and associated effluent treatment systems	fraction
rd_{rp}	=	Number of reporting days in the current reporting period	days
0.68	=	Density of methane (1 atm, 60°F)	kg/m^3
0.001	=	Conversion factor from kg to metric tons	

$$MCF_{non-BCS} = \sum_{S} (MCF_S \times MS_{L,S})$$

Where,

			Units
$MCF_{non-BCS}$	=	Management-weighted methane conversion factor for waste treatment and storage systems other than the BCS and associated effluent treatment systems	fraction
MCF_S	=	Methane conversion factor for system component *S* (Table B.9)	fraction
$MS_{L,S}$	=	Fraction of manure from livestock category *L* that is managed in non-BCS system component *S*	fraction

[23] Non-anaerobic effluent treatment systems are those which manage effluent in solid form, or those which manage liquid effluent in a way that would be considered aerobic (e.g. a pond with effective aeration equipment).

[24] The B_o value for the project effluent pond is not differentiated by livestock category. Project developers shall use the B_o value that corresponds with a weighted average of the operation's livestock categories that contribute manure to the BCS (weighted by the kg of VS contributed by each livestock category). Supporting laboratory data and documentation per Section 6.1, need to be supplied to the verifier to justify an alternative value.

[25] According to this protocol, non-BCS-related sources means manure management system components (system component 'S') other than the biogas control system and the BCS effluent treatment systems (if used).

5.4 Metered Methane Destruction Comparison

As described above, the Reserve requires all projects to compare the modeled methane emission reductions for the reporting period, as calculated in Equation 5.2 to Equation 5.4 and Equation 5.6 to Equation 5.9, with the actual metered amount of methane that is destroyed in the BCS over the same period. The lesser of the two values is to be used as the total methane emission reductions for the reporting period in question.

In order to calculate the metered methane reductions, the monthly quantity of biogas that is metered and destroyed by the BCS must be aggregated over the reporting period. In the event that a project developer is reporting reductions for a period of time that is less than a full year, the total modeled methane emission reductions would be aggregated over this time period and compared with the metered methane that is destroyed in the BCS over the same period of time. Similarly, projects whose reporting periods begin or end with incomplete calendar months shall only quantify the baseline and project emissions for the portion of the month that is included within the reporting period. For example, if a project is reporting and verifying only 6 months of data (e.g. July to December), then the modeled emission reductions over this 6 month period would be compared to the total metered biogas destroyed over the same six month period, and the lesser of the two values would be used as the total methane emission reduction quantity for this six month period. See Equation 5.1 for calculation guidance.

Equation 5.11 below details the metered methane destruction calculation.

Equation 5.11. Metered Methane Destruction

$$\boldsymbol{BE_{metered}} = \sum_{\boldsymbol{i}} \left(\boldsymbol{CH_{4,metered,i}} \times \boldsymbol{BDE_{i,weighted}} \right) \times \mathbf{21}$$

Where,

			Units
$BE_{metered}$	=	Aggregated quantity of methane collected and destroyed during the reporting period	tCO_2e
$CH_{4,metered,i}$	=	Quantity of methane collected and metered in month $_i$. See Equation 5.6 for calculation guidance	tCH_4/month
$BDE_{i,weighted}$	=	Weighted average of all destruction devices used in month *i*.[26] See Equation 5.6 for calculation guidance	fraction
21	=	Global warming potential of methane as carbon dioxide equivalent	tCO_2e/tCH_4

5.5 Calculating Baseline and Project Carbon Dioxide Emissions

Sources of carbon dioxide emissions associated with a project may include electricity use by pumps and equipment, fossil fuel generators used to power pumping systems or milking parlor equipment, tractors that operate in barns or free-stalls, on-site manure hauling trucks, or vehicles that transport manure off-site. Per Table 4.1, the carbon dioxide emissions from any additional equipment, vehicles, or fuel use that is required by the project beyond what is required in the baseline shall be accounted for. In practice, project developers shall account for the emissions from any new electric- or fuel-powered equipment or vehicles purchased and

[26] Project developers have the option to use either the default methane destruction efficiencies provided, or site specific methane destruction efficiencies, for each of the combustion devices used in the project. Site-specific values must be provided by an independent air emissions testing body that is accredited by a state or local agency, or the Stack Testing Accreditation Council (STAC). See Appendix B for more information.

installed/operated specifically for the purpose of implementing the project, as well as any additional fuel used by old or new vehicles to collect or transport waste.

Project developers may either use Equation 5.12 below to calculate the net increase in carbon dioxide emissions, or, if they can demonstrate during verification that project carbon dioxide emissions are estimated to be equal to or less than 5% of the total baseline emissions, then the project developer may estimate baseline and project carbon dioxide emissions. If an estimation method is used, verifiers shall confirm based on professional judgment that project carbon dioxide emissions are equal to or less than 5% of the total baseline emissions based on documentation and the estimation methodology provided by the project developer. If emissions cannot be confirmed to be below 5%, then Equation 5.12 shall be used. Regardless of the method used, all estimates or calculations of anthropogenic carbon dioxide emissions within the GHG Assessment Boundary must be verified and included in emission reduction calculations.[27]

If calculations or estimates indicate that the project results in a net decrease in carbon dioxide emissions from grid-delivered electricity, mobile and stationary sources, then for quantification purposes the net increase in these emissions must be specified as zero (i.e. $CO_{2,net} = 0$ in Equation 5.12).

Carbon dioxide emissions from the combustion of biogas are considered biogenic emissions and are excluded from the GHG Assessment Boundary.

Equation 5.12 below calculates the net increase in anthropogenic carbon dioxide emissions resulting from the project activity.

[27] This is consistent with guidance in WRI's GHG Project Protocol regarding the treatment of significant secondary effects.

Equation 5.12. Increased Carbon Dioxide Emissions

$$CO_{2,net} = BE_{CO_2,MSC} - PE_{CO_2,MSC}$$

Where,			Units
$CO_{2,net}$	=	Net increase in anthropogenic CO_2 emissions from electricity consumption and mobile and stationary combustion sources resulting from project activity during the reporting period. If result is <0, use a value of 0	tCO_2
$BE_{CO2,MSC}$	=	Total baseline CO_2 emissions from electricity consumption and mobile and stationary combustion sources during the reporting period (see equation below)	tCO_2
$PE_{CO2,MSC}$	=	Total project CO_2 emissions from electricity consumption and mobile and stationary combustion sources during the reporting period (see equation below)	tCO_2

All CO_2 emissions associated with electricity consumption and stationary and mobile combustion are calculated using the equation:

$$CO_{2,MSC} = \left(\sum_c QE_c \times EF_{CO_2,e}\right) + \left[\left(\sum_c QF_c \times EF_{CO_2,f}\right) \times 0.001\right]$$

Where,			Units
$CO_{2,MSC}$	=	Anthropogenic CO_2 emissions from electricity consumption and mobile and stationary combustion sources	tCO_2
QE_c	=	Quantity of grid-connected electricity consumed for each emissions source 'c'[28] during the reporting period	MWh
$EF_{CO2,e}$	=	CO_2 emission factor for electricity used[29]	tCO_2/MWh
QF_c	=	Quantity of fuel consumed for each mobile and stationary emission source 'c' during the reporting period	MMBtu or gallons
$EF_{CO2,f}$	=	Fuel-specific emission factor *f* from Appendix B	kg CO_2/MMBtu or kg CO_2/gallon
0.001	=	Conversion factor from kg to metric tons	

[28] Emissions from electricity generated by the BCS and consumed onsite, do not need to be reported, as the resulting CO_2 emissions are considered biogenic, CH_4 is captured by the BDE calculation and N_2O emissions are excluded as negligible.

[29] Refer to the version of the U.S. EPA eGRID most closely corresponding to the time period during which the electricity was used. Projects shall use the annual total output emission rates for the subregion where the project is located, not the annual non-baseload output emission rates. The eGRID tables are available from the U.S. EPA website: http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html

6 Project Monitoring

The Reserve requires a Monitoring Plan to be established for all monitoring and reporting activities associated with the project. The Monitoring Plan will serve as the basis for verification bodies to confirm that the monitoring and reporting requirements in this section and Section 7 have been and will continue to be met, and that consistent, rigorous monitoring and record-keeping is ongoing at the project site. The Monitoring Plan must cover all aspects of monitoring and reporting contained in this protocol and must specify how data for all relevant parameters in Table 6.1 (below) will be collected and recorded.

At a minimum the Monitoring Plan shall stipulate the frequency of data acquisition; a record keeping plan (see Section 7.2 for minimum record keeping requirements); the frequency of instrument field check and calibration activities; and the role of individuals performing each specific monitoring activity, as well as QA/QC provisions to ensure that data acquisition and meter calibration are carried out consistently and with precision. The Monitoring Plan shall also contain a detailed diagram of the BCS, including the placement of all meters and equipment that affect SSRs within the GHG Assessment Boundary (see Figure 4.1 and Appendix F).

For a project's second crediting period, the Monitoring Plan must also include procedures that the project developer will follow to ascertain and demonstrate that the project at all times passes the Legal Requirement Test (Section 3.5.2).

Project developers are responsible for monitoring the performance of the project and operating each component of the biogas collection and destruction system in a manner consistent with the manufacturer's recommendations.

6.1 Site-Specific Determination of Maximum Methane Potential (B_0)[30]

The determination of a site-specific value for maximum methane potential (B_0) is optional for manure from dairy facilities. Swine facilities must use the default values. For projects that choose this option for the quantification of emission reductions related to one or more manure streams being digested in the project's BCS, or the BCS effluent, the following criteria must be met in order to ensure accuracy and consistency of the site-specific B_0 values:

1. Manure samples for each eligible livestock category must be sampled prior to mixing with manure from other animal categories or any other waste streams. These samples shall be taken from the manure collection system, rather than from an individual animal.
    a. Scrape systems: Samples shall be collected from the freshly scraped manure.
    b. Flush systems: Samples shall be collected at the point that the flushed manure leaves the barn. Additional samples must be collected of the flush water prior to mixing with manure.
    c. BCS effluent: Samples shall be collected after the effluent has exited the digester and prior to any further treatment.

2. Sampling events shall occur during the time period between August and October, inclusive.
    a. Manure samples: For each eligible animal category, there shall be one single-day sampling event. A total of at least six samples of at least one half liter each must

[30] Background information on the development of this section can be found in Appendix E.

be taken during the event. Samples shall be taken one to three hours apart, and all samples of the same type shall be combined (i.e. dairy cow manure samples in one container). The composite sample shall be delivered to the testing laboratory as soon as possible following the collection of the final sample.[31]

b. Flush water samples: If the farm utilizes a flush system for manure collection, the flush water must be sampled prior to mixing with manure. Two samples of at least one liter shall be collected, one to three hours apart, during the manure sampling event. These samples shall be combined into one container and delivered to the testing laboratory as soon as possible.
c. Effluent samples: Two samples of at least one liter shall be collected, one to three hours apart, during the manure sampling event. These samples shall be combined into one container and delivered to the testing laboratory as soon as possible.[32]

3. All samples must be analyzed using a Biochemical Methane Potential (BMP) Assay procedure at an independent, third-party laboratory that is familiar and experienced with this test and ISO 11734.[33] The laboratory must be able to document at least three years of experience with the BMP assay, and must have procedures in place to maintain a consistent inoculum. The laboratory must maintain and follow a standard operating procedure that outlines the process used in undertaking BMP analysis at that laboratory, and which can be made available to the verifier upon request.

4. At least six test runs shall be conducted using material from the mixed manure sample (i.e. split the sample into two and test each in triplicate). Tests shall report the weight of VS for the sample (as kg of dry matter) as well as the volume of methane produced, in order to determine the maximum methane potential as m^3 CH_4/kg VS. If applicable, the flush water sample and effluent sample shall each be used for one test run in triplicate. The laboratory shall conduct an assay on the seed inoculum itself in order to control for its contribution to the methane potential of the manure samples. The laboratory shall also conduct a control assay with a substrate of known methane potential (such as glucose or cellulose) to verify correct procedures were followed and that the inoculum was viable. If the control assay differs from its established expected value by greater than 15%, all results from that batch of assays shall be discarded. Measurement of gas flow shall be corrected to standard temperature and pressure (60°F and 1 atm). Devices used to measure gas flow and methane content shall be properly installed and calibrated, such that they can provide results within +/- 5% accuracy.

5. After the manure sample has been analyzed, there should be at least six estimates for the methane potential. The site specific value for B_0 shall equal the 90% lower confidence limit of all assay results. For flush systems, the mean methane potential of the flush water results must be subtracted from the calculated methane potential of the flushed manure sample. For BCS effluent, the mean methane potential of the test results

[31] Note, while there is no prescribed timeline regarding how quickly samples must be delivered to a laboratory, the longer a sample is retained before testing, the lower the methane generating potential will be. This loss can be mitigated by storing and transporting samples at temperatures below 5°C.
[32] *Ibid*.
[33] For more information on BMP Assay analysis and procedures, see: Moody et al. “Use of Biochemical Methane Potential (BMP) Assays for Predicting and Enhancing Anaerobic Digester Performance.” (2009) http://sa.pfos.hr/sa2009/radovi/pdf/Radovi/r10-009.pdf

shall be used for the quantification. Additional sampling and assays may be carried out, and will reduce uncertainty and result in a final value that is closer to the mean.

Site-specific B_0 values determined using this procedure shall be valid for the reporting period during which the sampling occurred. Projects may elect to determine a site-specific B_0 value for only a subset of the eligible manure streams and utilize default values for the remainder. The verifier must confirm that sampling procedures conform to this section and that the personnel responsible for the sampling are trained and competent.

6.2 Biogas Control System Monitoring Requirements

The methane capture and control system must be monitored with measurement equipment that directly meters:

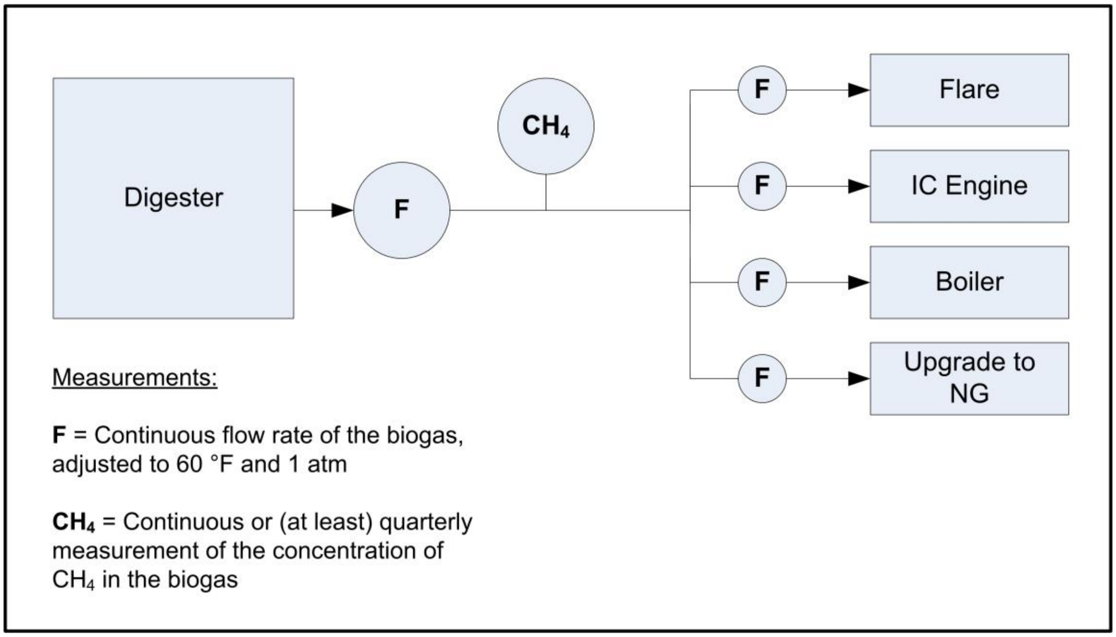
- The total flow of biogas, measured continuously and recorded every 15 minutes or totalized and recorded at least daily, adjusted for temperature and pressure, prior to delivery to the destruction device(s).
- The flow of biogas delivered to each destruction device (except as described below), measured continuously and recorded at least every 15 minutes or totalized and recorded at least daily, adjusted for temperature and pressure.
- The fraction of methane in the biogas, measured with a continuous analyzer or, alternatively, with at least quarterly measurements.
- The operational status of each destruction device (except as described below), measured and recorded at least hourly.

Flow data must be corrected for temperature and pressure at $60^{o}F$ and 1 atm, either internally or by following the guidance in Equation 5.6.

A single flow meter may be used to monitor the flow of gas to multiple destruction devices under certain conditions. If all destruction devices are of identical methane destruction efficiency (as described in Table B.7) and verified to be operational (i.e. there is recorded evidence of destruction), no additional steps are necessary for project registration. One example of this scenario would be a single meter used for a bank of multiple, identical engines that are in constant operation. If the destruction devices are not of identical efficiency, then the destruction efficiency of the least efficient device shall be applied to the flow data for this meter.
If there are any periods where the operational data show that one or more devices were not destroying methane, these periods are eligible for crediting, provided that the verifier can confirm all of the following conditions are met:

a. The destruction efficiency of the least efficient destruction device in operation shall be used as the destruction efficiency for all destruction devices monitored by this meter; and
b. All devices are either equipped with valves on the input gas line that close automatically if the device becomes non-operational (requiring no manual intervention), or designed in such a manner that it is physically impossible for gas to pass through while the device is non-operational; and
c. For any period where one or more destruction device(s) within this arrangement is not operational, it must be documented that the remaining operational devices have the capacity to destroy the maximum gas flow recorded during the period. For devices other than flares, it must be shown that the output corresponds to the flow of gas.

Figure 6.1 represents the suggested arrangement of the biogas flow meters and methane concentration metering equipment.



Note: The number of flow meters must be sufficient to track the total flow as well as the flow to each combustion device. The above example includes one more flow meter than would be necessary to achieve this objective.

Figure 6.1. Suggested Arrangement of Biogas Metering Equipment

Operational activity of the destruction devices shall be monitored and documented at least hourly to ensure actual methane destruction.

If for any reason the destruction device or the operational monitoring equipment (for example, the thermocouple on the flare) is inoperable, then all metered biogas going to the particular device shall be assumed to be released to atmosphere during the period of inoperability. In other words, during the period of inoperability, the destruction efficiency of the device must be assumed to be zero. In Equation 5.10, the monthly destruction efficiency (BDE) value shall be adjusted accordingly. See Box 6.1 below for an example BDE adjustment.

Box 6.1. Example BDE Adjustment

As an example, consider a situation where the primary destruction device is an open flare with a BDE of 96%, and it is found to be inoperable for a period of 5 days of a 30 day month. Assume that the total flow of biogas to the flare for the month is 3,000,000 scf, and that the total flow recorded for the 5 day period of inoperability is 500,000 scf. In this case the monthly BDE would be adjusted as follows:

$$BDE = \frac{[(0.96 \times 2{,}500{,}000) + (0.0 \times 500{,}000)]}{3{,}000{,}000} = 80\%$$

6.3 Biogas Measurement Instrument QA/QC

All gas flow meters[34] and continuous methane analyzers must be:

- In calibration (accurate to +/- 5% of the true value being measured) at time of installation. Calibration accuracy can be demonstrated through either a recent field check (as installed) or calibration by the manufacturer or a certified calibration service.
- Maintained per manufacturer's guidance, as well as cleaned and inspected on a quarterly basis, with the activities performed and as found/as left condition of the equipment documented.
- Field checked for calibration accuracy by an appropriately trained individual or a third-party technician with the percent drift documented, using either a portable instrument (such as a pitot tube)[35] or manufacturer specified guidance, at the end of but no more than 60 days prior to or after the end date of the reporting period.[36]
- Calibrated by the manufacturer or a certified calibration service per manufacturer's guidance or every 5 years, whichever is more frequent. Meters shall be calibrated to the range of conditions expected on site (e.g. pipe diameter, flow rate, temperature, pressure, gas composition) and as found/as left condition of the equipment documented.

If a stationary meter that was in use for 60 days or more is removed and not reinstalled during a reporting period, that meter shall either be field-checked for calibration accuracy prior to removal or calibrated (with percent drift documented) by the manufacturer or a certified calibration service prior to quantification of emission reductions for that reporting period.

If the field check on a piece of equipment reveals accuracy outside of a +/- 5% threshold, calibration by the manufacturer or a certified service provider is required for that piece of equipment, with as found/as left condition of the equipment documented.

For the interval between the last successful field check and any calibration event confirming accuracy below the +/- 5% threshold, all data from that meter or analyzer must be scaled according to the following procedure. These adjustments must be made for the entire period from the last successful field check until such time as the meter is properly calibrated and re-installed.

- For calibrations that indicate the flow meter was outside the +/- 5% accuracy threshold, the project developer shall estimate total emission reductions using i) the metered values without correction, and ii) the metered values adjusted based on the greatest calibration drift recorded at the time of calibration. The lower of the two emission reduction estimates shall be reported as the scaled emission reduction estimate.

[34] Field checks and calibrations of flow meters shall assess the volumetric output of the flow meter in SCF at 1 atm pressure and 60°F temperature.
[35] It is recommended that a professional third party calibration service be hired to perform flow meter field checks if using pitot tubes or other portable instruments, as these types of devices require professional training in order to achieve accurate readings.
[36] Instead of performing field checks, the project developer may instead have equipment calibrated by the manufacturer or a certified calibration service per manufacturer's guidance, at the end of but no more than 60 days prior to or after the end date of the reporting period to meet this requirement.

For example, if a project conducts field checks quarterly during a year-long verification period, then only three months of data will be subject at any one time to the penalties above. However, if the project developer feels confident that the meter does not require field checks or calibration on a greater than annual basis, then failed events will accordingly require the penalty to be applied to the entire year's data. Further, frequent calibration may minimize the total accrued drift (by zeroing out any error identified), and result in smaller overall deductions.

If a portable instrument is used (such as a handheld methane analyzer), the portable instrument shall be calibrated at least annually – or per the manufacturer's guidance, whichever is more frequent – by the manufacturer or at an ISO 17025 accredited laboratory. Portable methane analyzers shall be calibrated to a known reference gas prior to each use.

6.3.1 Missing Data

In situations where the flow rate or methane concentration monitoring equipment is missing data, the project developer shall apply the data substitution methodology provided in Appendix D. This methodology may also be used for periods where the project developer can show that the data are available but known to be corrupted (and where this corruption can be verified with reasonable assurance). If for any reason the monitoring equipment on any given destruction device is inoperable (for example, the thermocouple on the flare), then the destruction efficiency of that device must be assumed to be zero. For periods when it is not possible to use data substitution to fill data gaps, no emission reductions may be claimed. The methane flow volume for these days shall be zero, and the number of reporting days for that month shall be reduced to exclude the days of missing data (see Box 5.2).

During any period where the project is not claiming emission reduction credits and is not classifying the period as a venting event, the project developer must be able to demonstrate that project emissions were not greater than baseline emissions.

6.4 Monitoring Parameters

Provisions for monitoring other variables to calculate baseline and project emissions are provided in Table 6.1. The parameters are organized by general project factors then by the calculation methods.

Table 6.1. Project Monitoring Parameters

Equation Reference	Parameter	Description	Data Unit	Calculated (c) Measured (m) Reference (r) Operating Records (o)	Measurement Frequency	Comment
	Regulations	Project developer attestation to compliance with regulatory requirements relating to the manure digester project	All applicable regulations	n/a	Every verification period	Information used to demonstrate compliance with associated regulations and rules, e.g. criteria pollutant and effluent discharge limits.
	L	Type of livestock categories on the farm	Livestock categories	o	Monthly	See Appendix B, Table B.2.
Equation 5.1	$ER_{modeled}$	Avoided methane emissions associated with the project during the reporting period	tCO_2e	c	Every reporting period	Quantified using a modeled baseline scenario.
Equation 5.1	$BE_{modeled}$	Modeled baseline emissions during the reporting period	tCO_2e	c	Every reporting period	Quantified using a modeled baseline scenario.
Equation 5.1 Equation 5.5	PE_{CH4}	Total project methane emissions during the reporting period	tCO_2e	c	Every reporting period	Quantified using a modeled project scenario and metered methane destruction data.
Equation 5.1 Equation 5.12	$CO_{2,net}$	Net increase in anthropogenic CO_2 emissions from electricity and mobile/stationary combustion	tCO_2e	c	Every reporting period	
Equation 5.1	$ER_{metered}$	Avoided methane emissions associated with the project during the reporting period	tCO_2e	c	Every reporting period	Quantified using metered methane destruction data.
Equation 5.1 Equation 5.11	$BE_{metered}$	Aggregated quantity of methane collected and destroyed during the reporting period	tCO_2e	c	Every reporting period	Quantified using metered methane destruction data.

Equation Reference	Parameter	Description	Data Unit	Calculated (c) Measured (m) Reference (r) Operating Records (o)	Measurement Frequency	Comment
Equation 5.2	$BE_{CH4,AS,L}$	Total baseline methane emissions from anaerobic storage/treatment systems by livestock category, aggregated for reporting period	tCO_2e	c	Monthly	
Equation 5.2 Equation 5.4	$BE_{CH4,nAS,L}$	Total baseline methane emissions for the reporting period from non-anaerobic storage/treatment systems by livestock category	tCO_2e	c	Every reporting period	
Equation 5.3	$VS_{deg,AS,L}$	Monthly volatile solids degraded in each anaerobic storage system *AS*, for each livestock category *L*	kg	c, o	Monthly	Calculated value from operating records. Recommend Reserve Livestock Calculation Tool for all calculations.
Equation 5.3 Equation 5.4 Equation 5.10	$B_{0,L}$	Maximum methane producing capacity for manure by livestock category	(m^3 CH_4/ kg VS)	r	Every reporting period	See Appendix B, Table B.3.
Equation 5.3 Equation 5.8	$days_{mo}$	Calendar days per month	days	r	Monthly	See Box 5.2.
Equation 5.3 Equation 5.8	rd_{mo}	Reporting days during the current month	days	o	Monthly	See Box 5.2.
Equation 5.3	$VS_{avail,AS,L}$	Monthly volatile solids available for degradation in each anaerobic storage system, for each livestock category	kg	c, o	Monthly	Calculated value from operating records. Recommend Reserve Livestock Calculation Tool for all calculations.
Equation 5.3 Equation 5.8	f	van't Hoff-Arrhenius factor	n/a	c	Monthly	The proportion of volatile solids that are biologically available for conversion to methane based on the monthly temperature of the system. Recommend Reserve Livestock Calculation Tool for all calculations.
Equation 5.3 Equation 5.4 Equation 5.8 Equation 5.10	VS_L	Daily volatile solid production for each livestock category	(kg/animal/ day)	r, c	Every reporting period	Appendix B, Table B.3 and Table B.5a-d; see Box 5.1 for guidance on converting units from (kg/day/1000kg) to (kg/animal/day).

Equation Reference	Parameter	Description	Data Unit	Calculated (c) Measured (m) Reference (r) Operating Records (o)	Measurement Frequency	Comment
Equation 5.3 Equation 5.4 Equation 5.8 Equation 5.10	P_L	Average number of animals for each livestock category	population (# head)	o	Monthly	
Equation 5.3	$MS_{AS,L}$	Fraction of manure from each livestock category managed in the anaerobic waste handling system	%	o	Every reporting period	Reflects the percent of waste handled by the system components *S* pre-project. Each system component must have an MS value per livestock category. Within each livestock category, the sum of MS values (for all treatment/storage systems) equals 100%. See Appendix B, Table B.1.
Equation 5.3	$VS_{avail-1,AS}$	Previous month's volatile solids available for degradation in anaerobic system	kg	c	Monthly	
Equation 5.3	$VS_{deg-1,AS}$	Previous month's volatile solids degraded by anaerobic system	kg	c	Monthly	
Equation 5.3	E	Activation energy constant	cal/mol	r		15,175 cal/mol
Equation 5.3	T_{mo}	Average monthly temperature at location of the operation	°C	m/o	Monthly	Used for van't Hoff calculation and for choosing appropriate MCF value.
Equation 5.3	T_{ref}	Reference temperature	K	r		303.16 Kelvins
Equation 5.3	R	Ideal gas constant	cal/Kmol	r		1.987 cal/Kmol
Equation 5.4	$MS_{L,nAS}$	Fraction of manure from each livestock category *L* managed in the non-anaerobic waste handling system	%	o	Every reporting period	Reflects the percent of waste handled by the system components *S* pre-project. Each system component must have an MS value per livestock category. Within each livestock category, the sum of MS values (for all treatment/storage systems) equals 100%. See Appendix B, Table B.1.
Equation 5.4	$days_{rp}$	Number of days in the reporting period	days	o	Every reporting period	See Box 5.2.
Equation 5.4	MCF_{nAS}	Methane conversion factor for non-anaerobic storage/treatment system	%	r	Every reporting period	From Appendix B. Differentiate by livestock category.

Equation Reference	Parameter	Description	Data Unit	Calculated (c) Measured (m) Reference (r) Operating Records (o)	Measurement Frequency	Comment
Equation 5.4 Equation 5.9 Equation 5.10	rd_{rp}	Reporting days during the reporting period	days		Every reporting period	See Box 5.2.
Equation 5.5 Equation 5.6	$PE_{CH4,BCS}$	Methane emissions from the BCS	tCH_4	m, c	Every reporting period	Calculated for each month and summed for the reporting period.
Equation 5.5 Equation 5.8	$PE_{CH4,ET,AS}$	Methane emissions from the BCS effluent anaerobic treatment systems	tCH_4	m, c	Every reporting period	Calculated for each month and summed for the reporting period.
Equation 5.5 Equation 5.9	$PE_{CH4,ET,nAS}$	Methane emissions from the BCS effluent non-anaerobic treatment systems	tCH_4	m, c	Every reporting period	Calculated for the reporting period.
Equation 5.5 Equation 5.10	$PE_{CH4,other}$	Methane emissions from sources in the waste treatment and storage category other than the BCS and associated effluent treatment systems	tCH_4	m, c	Every reporting period	Calculated for the reporting period.
Equation 5.6 Equation 5.11	$CH_{4,metered,i}$	Metered amount of methane collected and destroyed by the BCS in month *i*	tCH_4	m, c	Monthly calculation from continuous data	Calculated from biogas flow and methane fraction meter readings (See *F* and $CH_{4,conc}$ parameters below).
Equation 5.6	BCE	Biogas capture efficiency of the anaerobic digester, accounts for fugitive emissions	fraction	r	Every reporting period	Use default value from Table B.4.
Equation 5.6 Equation 5.11	$BDE_{i,weighted}$	Methane destruction efficiency of destruction device(s)	fraction	r, c	Monthly	Actual efficiency of the system to destroy captured methane gas – accounts for different destruction devices.
Equation 5.6 Equation 5.7	$CH_{4,vent,i}$	Quantity of methane that is vented to the atmosphere due to BCS venting events	scf	c	Monthly	Calculated from average total flow of biogas from the digester and the number of days biogas is venting.
Equation 5.6	F	Volume of biogas from digester to destruction devices	scf	m	Continuously, aggregated monthly	Measured continuously from flow meter and recorded every 15 minutes or totalized and recorded at least once daily. Data to be aggregated monthly.

Equation Reference	Parameter	Description	Data Unit	Calculated (c) Measured (m) Reference (r) Operating Records (o)	Measurement Frequency	Comment
Equation 5.6	T_b	Temperature of the biogas	°R (Rankine)	m	Continuously, averaged monthly	Measured to normalize volume flow of biogas to STP. No separate monitoring of temperature is necessary when using flow meters that automatically measure temperature and pressure, expressing biogas volumes in normalized cubic feet.
Equation 5.6	P	Pressure of the biogas	atm	m	Continuously, averaged monthly	Measured to normalize volume flow of biogas to STP. No separate monitoring of pressure is necessary when using flow meters that automatically measure temperature and pressure, expressing biogas volumes in normalized cubic feet.
Equation 5.6 Equation 5.7	$CH_{4,conc}$	Methane concentration of biogas	fraction	m	At least quarterly	Samples to be taken at least quarterly. See Section 6.2 for metering guidance.
Equation 5.6	BDE_{DD}	Default methane destruction efficiency of a particular destruction device	%	r	Monthly	See Appendix B for default destruction efficiencies by device.
Equation 5.6	$F_{i,DD}$	Flow of biogas to a particular destruction device	scf	m	Monthly	See Section 6.2 for metering guidance.
Equation 5.6	F_i	Total volumetric flow of biogas to all destruction devices	scf	m	Monthly	See Section 6.2 for metering guidance.
Equation 5.7	MGS_{BCS}	Maximum biogas storage of the BCS system	scf	r	Every reporting period	Obtained from digester system design plans. Necessary to quantify the release of methane to the atmosphere due to an uncontrolled venting event.
Equation 5.7	F_{pw}	Average total daily flow of biogas from the digester for the entire week prior to the uncontrolled venting event	scf/day	m	Weekly	Average flow of biogas can be determined from the daily records from the previous week.
Equation 5.7	t	Number of days of the month that biogas is venting uncontrolled from the BCS system	days	m, o	Monthly	

Equation Reference	Parameter	Description	Data Unit	Calculated (c) Measured (m) Reference (r) Operating Records (o)	Measurement Frequency	Comment
Equation 5.8 Equation 5.9	$VS_{ET,i}$	Volatile solids to effluent treatment system *i*	kg/day	r, c	Every reporting period	If project uses effluent pond, equals 30% of the average daily VS entering the digester.
Equation 5.8 Equation 5.9	$B_{0,ET}$	Maximum methane producing capacity of VS dry matter	(m^3 CH_4/ kg VS)	c	Every reporting period	An average of the $B_{0,EF}$ value of the operation's livestock categories that contributes manure to the BCS.
Equation 5.8	$MS_{L,BCS}$	Fraction of manure from each livestock category managed in the BCS	fraction	o	Every reporting period	Used to determine the total VS entering the digester. The fraction should be tracked in operational records.
Equation 5.8	ETF_i	Fraction of the effluent that exits the digester that is sent to effluent treatment system		o, r	Every reporting period	Used to determine the amount of VS for each effluent treatment system. The percentage should be tracked in operational records, or the project developer may provide a technical reference to support this fraction.
Equation 5.9	$MCF_{ET,i}$	Methane conversion factor for effluent treatment system	%	r	Every reporting period	See Appendix B. Project developers should use the *liquid slurry* MCF value.
Equation 5.10	$MCF_{non\text{-}BCS}$	Management-weighted methane conversion factor for waste treatment and storage systems other than the BCS and associated effluent treatment systems	%	r	Every reporting period	Referenced from Appendix B.
Equation 5.10	MCF_S	Methane conversion factor for system component		r		See Table B.9.
Equation 5.10	$MS_{L,S}$	Manure from each livestock category managed in the baseline waste handling system	fraction	o	Every reporting period	Fraction of waste handled by the system component *S* pre-project. Each system component must have an MS value per livestock category. Within each livestock category, the sum of MS values (for all treatment/storage systems) equals 1. See Appendix B, Table B.1.
Equation 5.12	$BE_{CO2,MSC}$	Total baseline CO_2 emissions from electricity and mobile/stationary combustion during reporting period	tCO_2	c	Every reporting period	

Equation Reference	Parameter	Description	Data Unit	Calculated (c) Measured (m) Reference (r) Operating Records (o)	Measurement Frequency	Comment
Equation 5.12	$PE_{CO2,MSC}$	Total project CO_2 emissions from electricity and mobile/stationary combustion during reporting period	tCO_2	c	Every reporting period	
Equation 5.12	$CO_{2,MSC}$	Anthropogenic CO_2 emissions from electricity and mobile/stationary combustion	tCO_2	c	Every reporting period	
Equation 5.12	QE_c	Quantity of electricity consumed	MWh	o, c	Every reporting period	Electricity used by project for manure collection, transport, treatment/storage, and disposal.
Equation 5.12	$EF_{CO2,e}$	Emission factor for electricity used by project	tCO_2/MWh	r	Every reporting period	See Appendix B. If biogas produced from digester is used to generate electricity consumed, the EF is zero.
Equation 5.12	QF_c	Quantity of fuel used for mobile/stationary combustion sources	MMBtu or gallons	o, c	Every reporting period	Fuel used by project for manure collection, transport, treatment/storage, and disposal, and stationary combustion sources including supplemental fossil fuels used in combustion device.
Equation 5.12	$EF_{CO2,f}$	Fuel-specific emission factor for mobile/stationary combustion sources	kg CO_2/ MMBtu or kg CO_2/ gallon	r	Every reporting period	Refer to EPA eGRID for emission factors. If biogas produced from digester is used as an energy source, the EF is zero.

7 Reporting Parameters

This section provides requirements and guidance on reporting rules and procedures. A priority of the Reserve is to facilitate consistent and transparent information disclosure among project developers. Project developers must submit either a project monitoring report or a verified emission reduction report to the Reserve annually at minimum, depending on the verification option selected by the project developer.

7.1 Project Documentation

Project developers must provide the following documentation to the Reserve in order to register a livestock project:

- Project Submittal form
- Project diagram from Monitoring Plan – see Appendix F (not public)
- Completed Reserve Livestock Calculation Tool, if used (not public)
- Signed Attestation of Title form
- Signed Attestation of Voluntary Implementation form[37]
- Signed Attestation of Regulatory Compliance form
- Verification Report
- Verification Statement

Project developers must provide the following documentation each verification period in order for the Reserve to issue CRTs for quantified GHG reductions:

- Verification Report
- Verification Statement
- Project diagram from Monitoring Plan – see Appendix F (not public)
- Completed Reserve Livestock Calculation Tool, if used (not public)
- Signed Attestation of Title form
- Signed Attestation of Regulatory Compliance form
- Signed Attestation of Voluntary Implementation form (second crediting period only)

Unless otherwise specified, the above project documentation will be available to the public via the Reserve's online registry. Further disclosure and other documentation may be made available on a voluntary basis through the Reserve. Project forms can be found athttp://www.climateactionreserve.org/how/program/documents/. .

7.2 Record Keeping

For purposes of independent verification and historical documentation, project developers are required to keep all information outlined in this protocol for a period of 10 years after the information is generated or 7 years after the last verification. This information will not be publicly available, but may be requested by the verifier or the Reserve.

[37] A project developer only needs to attest that the project passes the Legal Requirement Test during its first verification period of a crediting period. Meeting the Legal Requirement Test is not required for the remainder of the first crediting period after initial verification.

System Information:

- All data inputs for the calculation of the baseline emissions and project emission reductions
- CO_2e annual tonnage calculations (including copies of the Reserve Livestock Calculation Tool, if used)
- Relevant sections of the BCS operating permits
- Executed Attestation of Title forms, Attestation of Regulatory Compliance forms, and Attestation of Voluntary Implementation form
- BCS information (installation dates, equipment list, etc.)
- Biogas flow meter information (model number, serial number, manufacturer's calibration procedures)
- Cleaning and inspection records for all biogas meters
- Field check results for all biogas meters
- Calibration results for all biogas meters
- Methane monitor information (model number, serial number, calibration procedures)
- Biogas flow data (for each flow meter)
- Biogas temperature and pressure readings (only if flow meter does not correct for temperature and pressure automatically)
- Methane concentration monitoring data
- Destruction device monitoring data (for each destruction device)
- Destruction device, methane monitor and biogas flow monitor information (model numbers, serial numbers, calibration procedures)
- Initial and annual verification records and results
- All maintenance records relevant to the BCS, monitoring equipment, and destruction devices

If using a calibrated portable gas analyzer for CH_4 content measurement:

- Date, time, and location of methane measurement
- Methane content of biogas (% by volume) for each measurement
- Methane measurement instrument type and serial number
- Date, time, and results of instrument calibration
- Corrective measures taken if instrument does not meet performance specifications

7.3 Reporting and Verification Cycle

To provide flexibility and help manage verification costs associated with livestock projects, there are three verification options to choose from after a project's initial verification and registration. Regardless of the option selected, project developers must report GHG reductions resulting from project activities during each reporting period. A "reporting period" is a period of time over which a project developer quantifies and reports GHG reductions to the Reserve. Under this protocol, the reporting period cannot exceed 12 months. A "verification period" is the period of time over which GHG reductions are verified. Under this protocol, a verification period may cover multiple reporting periods (see Section 7.3.4). The end date of any verification period must correspond to the end date of a reporting period.

A project developer may choose to utilize one option for the duration of a project's crediting period, or may choose different options at different points during a single crediting period. Regardless of the option selected, reporting periods must be contiguous; there may be no time gaps in reporting during the crediting period of a project once the initial reporting period has commenced.

7.3.1 Initial Reporting and Verification Period

While a reporting period cannot exceed 12 months, a project developer may register multiple reporting periods (i.e. more than 12 months of data) during a project's initial verification period. A project developer may also register a project's initial verification period as a zero-credit reporting period (see the Reserve Program Manual for more information on zero-credit reporting periods).

Once a project is registered and has had at least 3 months of emission reductions verified, the project developer may choose one of the verification options below.

7.3.2 Option 1: Twelve-Month Maximum Verification Period

Under this option, the verification period may not exceed 12 months. Verification with a site visit is required for CRT issuance. The project developer may choose to have a sub-annual verification period (e.g. quarterly or semi-annually).

7.3.3 Option 2: Twelve-Month Verification Period with Desktop Verification

Under this option, the verification period cannot exceed 12 months. However, CRTs may be issued upon successful completion of a desktop verification as long as: (1) site-visit verifications occur at two-year intervals; and (2) the verifier has confirmed that there have been no significant changes in data management systems, equipment, or personnel since the previous site visit. Desktop verifications must cover all other required verification activities.

In order to utilize this option, there are two additional requirements that must be satisfied:

1. Prior to a desktop verification commencing, the project developer must attest to the verifier that there have been no significant changes to the project's data management systems, project set up/equipment, or site personnel involved with the project since the last site-visit verification. For each verification period, the project developer must provide the following documentation for review by the verifier prior to the desktop verification commencing:
    a. A schematic of system equipment and configuration, detailing any changes since the previous site visit, and any other supporting documentation for system or operation changes
    b. A list of personnel performing key functions related to project activities (personnel who manage and perform monitoring, measurement, and instrument QA/QC activities for the project), and documentation of any personnel or roles or changes since the pervious site visit; this shall include documented handover of personnel changes, including personnel change dates
    c. The sections from the Monitoring Plan that summarize the data management systems and processes in place and a summary of any changes to the systems or processes since the previous site visit

2. Desktop verifications must be conducted by the same verification body that conducted the most recent site-visit verification.

For projects using this option, the initial verification in this cycle shall be a full verification, including a site visit, and shall cover a minimum of 3 months and maximum 12 months of project data. All subsequent verification periods under this option shall be 12-month verification periods. Projects that wish to upgrade to the latest protocol version from a previous version whilst simultaneously taking advantage of the desktop verification option shall be allowed to do so, provided:

i. The verification of the previous verification period (e.g. under Version 2.1, 2.2 or 3.0) was a full verification, including site visit, and covered a minimum of 3 months of project data, and
ii. The two additional requirements specified in Section 7.3.3 are satisfied.

Taking into consideration the Reserve's policy that a verification body may provide verification services to a project for a maximum of six consecutive years (see the Verification Program Manual, Section 2.6 for more information), Table 7.1 below details what the verification cycle might look under Option 2.

Table 7.1. Sample Verification Cycle under Option 2

Reporting Period	Verification Activity	Verification Body (VB)
Year 1 *(initial verification)*	Site-visit verification	VB A
Year 2	Desktop verification	VB A
Year 3	Site-visit verification	VB A
Year 4	Desktop verification	VB A
Year 5	Site-visit verification	VB A
Year 6	Desktop verification	VB A
Year 7	Site-visit verification	VB B *(new verification body)*
Year 8	Desktop verification	VB B

7.3.4 Option 3: Twenty-Four Month Maximum Verification Period

Under this option, the verification period cannot exceed 24 months and the project's monitoring report must be submitted to the Reserve for the interim 12 month reporting period. The project monitoring report must be submitted for projects that choose Option 3 to meet the annual documentation requirement of the Reserve program. It is meant to provide the Reserve with information and documentation on a project's operations and performance, and adherence to the project's monitoring plan. It is submitted via the Reserve's online registry, but is not a publicly available document. A monitoring report template for livestock projects is available at http://www.climateactionreserve.org/how/program/documents/. The monitoring report shall be submitted within 30 days of the end of the interim reporting period. The only exception to this requirement is for projects that verify under Option 3 as part of a protocol upgrade, and fall within the specific timeline outlined below.

Project developers that wish to upgrade to Version 4.0 of this protocol and immediately utilize the 24-month verification period shall be allowed to do so, provided that the verification of the previous verification period (e.g. under Version 2.0, 2.1, 2.2, or 3.0) was a full verification, including a site visit, and covered a minimum of 3 months of project data.

All project developers utilizing the 24-month verification period must submit the monitoring report within 30 days of the end of the interim reporting period.

Under this option, CRTs may be issued upon successful completion of a site-visit verification for GHG reductions achieved over a maximum of 24 months. CRTs will not be issued based on the Reserve's review of project monitoring plans/reports. Project developers may choose to have a verification period shorter than 24 months.

Taking into consideration the Reserve's policy that a verification body may provide verification services to a project for a maximum of six consecutive years (see the Verification Program Manual, Section 2.6 for more information), Table 7.2 below details what the verification cycle might look under Option 3.

Table 7.2. Sample Verification Cycle under Option 3

Reporting Period	Verification Activity	Verification Body (VB)
Year 1 *(initial verification)*	Site-visit verification	VB A
Year 2	Project monitoring plan and report submitted to Reserve	n/a
Year 3	Site-visit verification for years 2 & 3	VB A
Year 4	Project monitoring plan and report submitted to Reserve	n/a
Year 5	Site-visit verification for years 4 & 5	VB A
Year 6	Project monitoring plan and report submitted to Reserve	n/a
Year 7	Site-visit verification for years 6 & 7	VB B *(new verification body)*
Year 8	Project monitoring plan and report submitted to Reserve	n/a

8 Verification Guidance

This section provides verification bodies with guidance on verifying GHG emission reductions associated with installing a biogas control system for manure management on dairy cattle and swine farms. This verification guidance supplements the Reserve's Verification Program Manual and describes verification activities specifically related to livestock manure management projects.

Verification bodies trained to verify livestock projects must be familiar with the following documents:

- Climate Action Reserve Program Manual
- Climate Action Reserve Verification Program Manual
- Climate Action Reserve U.S. Livestock Project Protocol

The Reserve's Program Manual, Verification Program Manual, and project protocols are designed to be compatible with each other and are available on the Reserve's website at http://www.climateactionreserve.org.

In cases where the Program Manual and/or Verification Program Manual differ from the guidance in this protocol, this protocol takes precedent.

Only Reserve-approved verification bodies are eligible to verify livestock project reports. Verification bodies approved under other project protocol types are not permitted to verify livestock projects. Information about verification body accreditation and Reserve project verification training can be found on the Reserve website at http://www.climateactionreserve.org.

8.1 Standard of Verification

The Reserve's standard of verification for livestock projects is the U.S. Livestock Project Protocol (this document), the Reserve Program Manual, and the Verification Program Manual. To verify a livestock project report, verification bodies apply the guidance in the Verification Program Manual and this section of the protocol to the standards described in Sections 2 through 7 of this protocol. Sections 2 through 7 provide eligibility rules, methods to calculate emission reductions, performance monitoring instructions and requirements, and procedures for reporting project information to the Reserve.

8.2 Monitoring Plan

The Monitoring Plan serves as the basis for verification bodies to confirm that the monitoring and reporting requirements in Section 6 and Section 7 have been met, and that consistent, rigorous monitoring and record-keeping is ongoing at the project site. Verification bodies shall confirm that the Monitoring Plan covers all aspects of monitoring and reporting contained in this protocol and specifies how data for all relevant parameters in Section 6 are collected and recorded.

8.3 Verifying Project Eligibility

Verification bodies must affirm a livestock project's eligibility according to the rules described in this protocol. The table below outlines the eligibility criteria for livestock projects. This table does not present all criteria for determining eligibility comprehensively; verification bodies must also look to Section 3 and the verification items list in Table 8.2.

Table 8.1. Summary of Eligibility Criteria for a Livestock Project

Eligibility Rule	Eligibility Criteria	Frequency of Rule Application
Start Date	Projects must be submitted for listing within 6 months of the project start date	Once during first verification
Location	United States, its territories, and U.S. tribal areas	Once during first verification
Performance Standard Test	Installation of a biogas control system that captures and destroys methane gas from anaerobic manure treatment and/or storage facilities on livestock operations	Once during first verification
Anaerobic Baseline	Projects must demonstrate that the depth of the anaerobic lagoons or ponds prior to the project's implementation were sufficient to prevent algal oxygen production and create an oxygen-free bottom layer; which means at least 1 meter in liquid depth	Once during first verification
Legal Requirement Test	Signed Attestation of Voluntary Implementation form and additional documentation demonstrating that the project passes the Legal Requirement Test	Once during first verification for first crediting period; every verification for second crediting period
Regulatory Compliance	Signed Attestation of Regulatory Compliance form and disclosure of all non-compliance events to verifier, and monitoring; project must be in material compliance with all applicable laws	Every verification

8.4 Core Verification Activities

The U.S. Livestock Project Protocol provides explicit requirements and guidance for quantifying the GHG reductions associated with installing a BCS to capture and destroy methane gas from livestock operations. The Verification Program Manual describes the core verification activities that shall be performed by verification bodies for all project verifications. They are summarized below in the context of a livestock project, but verification bodies must also follow the general guidance in the Verification Program Manual.

Verification is a risk assessment and data sampling effort designed to ensure that the risk of reporting error is assessed and addressed through appropriate sampling, testing, and review. The three core verification activities are:

1. Identifying emission sources, sinks, and reservoirs
2. Reviewing GHG management systems and estimation methodologies
3. Verifying emission reduction estimates

Identifying emission sources, sinks, and reservoirs

The verification body reviews for completeness the SSRs identified for a project, such as energy use waste collection and transport, treatment and storage, and uncombusted methane from the biogas control system.

Reviewing GHG management systems and estimation methodologies

The verification body reviews and assesses the appropriateness of the methodologies and management systems that the livestock project operator uses to gather data and calculate baseline and project emissions. This includes the examination of assertions or assumptions regarding MS, the percentage of manure going to anaerobic treatment systems in the baseline, and the baseline lagoon cleaning frequency.

Verifying emission reduction estimates

The verification body further investigates areas that have the greatest potential for material misstatements and then confirms whether or not material misstatements have occurred. This involves site visits to the project to ensure the systems on the ground correspond to and are consistent with data provided to the verification body. In addition, the verification body recalculates a representative sample of the performance or emissions data for comparison with data reported by the project developer in order to double-check the calculations of GHG emission reductions.

8.5 Verification Period

Per Section 7.3, this protocol provides project developers three verification options for a project after its initial verification and registration in order to provide flexibility and help manage verification costs associated with livestock projects. The different options require verification bodies to confirm additional requirements specific to this protocol, and in some instances, to utilize professional judgment on the appropriateness of the option selected.

8.5.1 Option 1: Twelve-Month Maximum Verification Period

Option 1 does not require verification bodies to confirm any additional requirements beyond what is specified in the protocol.

8.5.2 Option 2: Twelve-Month Verification Period with Desktop Verification

Option 2 requires verification bodies to review the documentation specified in Section 7.3.3 in order to determine if a desktop verification is appropriate. The verifier shall use his/her professional judgment to assess any changes that have occurred related to a project's data management systems, equipment, or personnel and determine whether a site visit should be required as part of verification activities in order to provide a reasonable level of assurance on the project's verification. The documentation shall be reviewed prior to the COI/NOVA renewal being submitted to the Reserve, and the verification body shall provide a summary of its assessment and decision on the appropriateness of a desktop verification when submitting the COI/NOVA renewal. The Reserve reserves the right to review the documentation provided by the project developer and the decision made by the verification body on whether a desktop verification is appropriate.

8.5.3 Option 3: Twenty-Four Month Maximum Verification Period

Under Option 3 (see Section 7.3.4), verification bodies shall look to the project monitoring report submitted by the project developer to the Reserve for the interim 12 month reporting period as a resource to inform its planned verification activities. While verification bodies are not expected to provide a reasonable level of assurance on the accuracy of the monitoring report as part of verification, the verification body shall list a summary of discrepancies between the monitoring report and what was ultimately verified in the List of Findings.

8.6 Livestock Verification Items

The following tables provide lists of items that a verification body needs to address while verifying a livestock project. The tables include references to the section in the protocol where requirements are further specified. The table also identifies items for which a verification body is expected to apply professional judgment during the verification process. Verification bodies are expected to use their professional judgment to confirm that protocol requirements have been met in instances where the protocol does not provide (sufficiently) prescriptive guidance. For more information on the Reserve's verification process and professional judgment, please see the Verification Program Manual.

Note: These tables shall not be viewed as a comprehensive list or plan for verification activities, but rather guidance on areas specific to livestock projects that must be addressed during verification.

8.6.1 Project Eligibility and CRT Issuance

Table 8.2 lists the criteria for reasonable assurance with respect to eligibility and CRT issuance for livestock projects. These requirements determine if a project is eligible to register with the Reserve and/or have CRTs issued for the reporting period. If any requirement is not met, either the project may be determined ineligible or the GHG reductions from the reporting period (or sub-set of the reporting period) may be ineligible for issuance of CRTs, as specified in Sections 2, 3, and 6.

Table 8.2. Eligibility Verification Items

Protocol Section	Eligibility Qualification Item	Apply Professional Judgment?
2.1	Verify that the project meets the definition of a livestock project	No
2.2	Verify ownership of the reductions by reviewing Attestation of Title and other relevant contracts, documentation	No
3.2	Verify eligibility of project start date	No
3.2	Verify accuracy of project start date based on operational records	Yes
3.3	Verify that project is within its 10-year crediting period	No
3.4	Verify that all pre-project manure treatment lagoons/ponds/tanks were of sufficient depth to ensure an oxygen free bottom layer (> 1m)	Yes
3.4	Verify that the pre-project manure management system met the requirements of this section for the relevant period of time	Yes
3.4	If the project is a greenfield project, verify that the project site meets the definition of a greenfield	Yes
3.5.1	Verify that the project meets the Performance Standard Test	No
3.5.2	Confirm execution of the Attestation of Voluntary Implementation form to demonstrate eligibility under the Legal Requirement Test (initial verification only)	No
3.6	Verify that the project activities comply with applicable laws by reviewing instances of non-compliance provided by the project developer and performing a risk-based assessment to confirm the statements made by the project developer in the Attestation of Regulatory Compliance form	Yes
6	Verify that monitoring meets the requirements of the protocol. If it does not, verify that variance has been approved for monitoring variations	No
6	Verify that all gas flow meters and continuous methane analyzers adhered to the inspection, cleaning, and calibration schedule specified in the protocol. If they do not, verify that a variance has been approved for	No

Protocol Section	Eligibility Qualification Item	Apply Professional Judgment?
	monitoring variations or that adjustments have been made to data per the protocol requirements	
6	Verify that adjustments for failed calibrations were properly applied	No
6, Appendix D	If used, verify that data substitution methodology was properly applied	No

8.6.2 Quantification

Table 8.3 lists the items that verification bodies shall include in their risk assessment and re-calculation of the project's GHG emission reductions. These quantification items inform any determination as to whether there are material and/or immaterial misstatements in the project's GHG emission reduction calculations. If there are material misstatements, the calculations must be revised before CRTs are issued.

Table 8.3. Quantification Verification Items

Protocol Section	Quantification Item	Apply Professional Judgment?
4	Verify that all SSRs in the GHG Assessment Boundary are accounted for	No
5	Verify that the modeled baseline is compared with the total amount of methane metered and destroyed by the project, and the lesser of the two values is used as the baseline for the GHG reduction calculation	No
5.1	Verify that the livestock categories (L) are correctly differentiated	Yes
5.1	Verify that the project developer applied the correct VS and B_0 values for each livestock category	No
5.1, 6.1	If site-specific B_0 values were developed, verify that the sampling and analysis procedures were correctly followed	Yes
5.1	Verify that the fraction of manure (MS) handled by the different manure management system components (i.e. GHG source) is satisfactorily represented	Yes
5.1	Verify that the baseline lagoon cleaning frequency is satisfactorily represented	Yes
5.1	Verify that the project developer used methane conversion factors (MCF) differentiated by temperature	No
5.1	Verify that the methane baseline emissions calculations for each livestock category were calculated according to the protocol with the appropriate data	No
5.1	Verify that the project developer correctly aggregated methane emissions from sources within each livestock category	Yes
5.4	Verify that the project developer correctly monitored, quantified and aggregated electricity use	Yes
5.2, 5.4	Verify that the project developer correctly monitored, quantified and aggregated fossil fuel use	Yes
5.2, 5.4	Verify that the project developer applied the correct emission factors for fossil fuel combustion and grid-delivered electricity	No
5.2	Verify that the project developer applied the correct methane destruction efficiencies	No
5.2	Verify that the project developer applied the correct B_0 value for Modeled Project Methane Emissions from Anaerobic Treatment of BCS Effluent	No
5.2	Verify that the project developer correctly quantified the amount of uncombusted methane	No

Protocol Section	Quantification Item	Apply Professional Judgment?
5.2	Verify that methane emissions resulting from any venting event are estimated correctly	Yes
5.2, 5.4	Verify that the project emissions calculations were calculated according to the protocol with the appropriate data	No
5.2, 5.1	Verify that the project developer assessed baseline and project emissions on a month-to-month basis	No
5.2	Verify that the project developer correctly monitored and quantified the amount of methane destroyed by the project	No
5.3	Verify that the modeled methane emission reductions are compared with the *ex-post* methane metered and destroyed by the project, and the lesser of the two values is used to quantify project emission reductions	No

8.6.3 Risk Assessment

Verification bodies will review the following items in Table 8.4 to guide and prioritize their assessment of data used in determining eligibility and quantifying GHG emission reductions.

Table 8.4. Risk Assessment Verification Items

Protocol Section	Item that Informs Risk Assessment	Apply Professional Judgment?
6	Verify that the project Monitoring Plan is sufficiently rigorous to support the requirements of the protocol and proper operation of the project	Yes
6	Verify that the BCS was operated and maintained according to manufacturer specifications	No
6	Verify that appropriate monitoring equipment is in place to meet the requirements of the protocol	No
6	Verify that the individual or team responsible for managing and reporting project activities are qualified to perform this function	Yes
6	Verify that appropriate training was provided to personnel assigned to greenhouse gas reporting duties	Yes
6	Verify that all contractors are qualified for managing and reporting greenhouse gas emissions if relied upon by the project developer. Verify that there is internal oversight to assure the quality of the contractor’s work	Yes
7.2	Verify that all required records have been retained by the project developer	No

8.7 Completing Verification

The Verification Program Manual provides detailed information and instructions for verification bodies to finalize the verification process. It describes completing a Verification Report, preparing a Verification Statement, submitting the necessary documents to the Reserve, and notifying the Reserve of the project’s verified status.

9 Glossary of Terms

Accredited verifier	A verification firm approved by the Reserve to provide verification services for project developers.
Additionality	Manure management practices that are above and beyond business-as-usual operation, exceed the baseline characterization, and are not mandated by regulation.
Anaerobic	Pertaining to or caused by the absence of oxygen.
Anthropogenic emissions	GHG emissions resultant from human activity that are considered to be an unnatural component of the Carbon Cycle (i.e. fossil fuel combustion, deforestation etc.).
Biogas	The mixture of gas (largely methane) produced as a result of the anaerobic decomposition of livestock manure.
Biogas control system (BCS)	A system designed to capture and destroy the biogas that is produced by the anaerobic treatment and/or storage of livestock manure and/or other organic material. Commonly referred to as a "digester."
Biogenic CO_2 emissions	CO_2 emissions resulting from the combustion and/or aerobic decomposition of organic matter. Biogenic emissions are considered to be a natural part of the carbon cycle, as opposed to anthropogenic emissions.
Carbon dioxide (CO_2)	The most common of the six primary greenhouse gases, consisting of a single carbon atom and two oxygen atoms.
CO_2 equivalent (CO_2e)	The quantity of a given GHG multiplied by its total global warming potential. This is the standard unit for comparing the degree of warming which can be caused by different GHGs.
Direct emissions	Greenhouse gas emissions from sources that are owned or controlled by the reporting entity.
Emission factor	A unique value for determining an amount of a greenhouse gas emitted for a given quantity of activity data (e.g. metric tons of carbon dioxide emitted per barrel of fossil fuel burned).
Flare	A destruction device that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame.
Fossil fuel	A fuel, such as coal, oil, and natural gas, produced by the decomposition of ancient (fossilized) plants and animals.
Greenfield	For the purposes of this protocol, a livestock facility that has been in operation for less than two years at a site that had no prior manure management infrastructure.
Greenhouse gas	Carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O),

(GHG)	sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs) or perfluorocarbons (PFCs).
Global warming potential (GWP)	The ratio of radiative forcing (degree of warming to the atmosphere) that would result from the emission of one unit of a given GHG compared to one unit of CO_2.
Indirect emissions	Emissions that are a consequence of the actions of a reporting entity, but are produced by sources owned or controlled by another entity.
Livestock project	Installation of a biogas control system that, in operation, causes a decrease in GHG emissions from the baseline scenario through destruction of the methane component of biogas.
Metric ton (tonne, MT, t)	A common international measurement for the quantity of GHG emissions, equivalent to about 2204.6 pounds or 1.1 short tons.
Methane (CH_4)	A potent GHG with a GWP of 21, consisting of a single carbon atom and four hydrogen atoms.
MMBtu	One million British thermal units.
Mobile combustion	Emissions from the transportation of materials, products, waste, and employees resulting from the combustion of fuels in company owned or controlled mobile combustion sources (e.g. cars, trucks, tractors, dozers, etc.).
Nitrous oxide (N_2O)	A GHG consisting of two nitrogen atoms and a single oxygen atom.
Project baseline	A business-as-usual GHG emission assessment against which GHG emission reductions from a specific GHG reduction activity are measured.
Project developer	An entity that undertakes a project activity, as identified in the Livestock Project Protocol. A project developer may be an independent third party or the dairy/swine operating entity.
Reporting period	The period of time over which a project developer quantifies and reports GHG reductions to the Reserve. Under this protocol, the reporting period cannot exceed 12 months.
Stationary combustion source	A stationary source of emissions from the production of electricity, heat, or steam, resulting from combustion of fuels in boilers, furnaces, turbines, kilns, and other facility equipment.
van't Hoff-Arrhenius factor (*f*)	The proportion of volatile solids that are biologically available for conversion to methane based on the monthly temperature of the system.[38]

[38] Mangino, et al.

Verification	The process used to ensure that a given participant's greenhouse gas emissions or emission reductions have met the minimum quality standard and complied with the Reserve's procedures and protocols for calculating and reporting GHG emissions and emission reductions.
Verification body	An accredited firm that is able to render a verification opinion and provide verification services for operators subject to reporting under this protocol.
Verification period	The period of time over which GHG reductions are verified. Under this protocol, a verification period may cover multiple reporting periods (see Section 7.3.4). The end date of any verification period must correspond to the end date of a reporting period.

10 References

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Appendix A Associated Environmental Impacts

Manure management projects have many documented environmental benefits, including air emission reductions, water quality protection, and electricity generation. These benefits are the result of practices and technologies that are well managed, well implemented, and well designed. However, in cases where practices or technologies are poorly or improperly designed, implemented, and/or managed, local air and water quality could be compromised.

With regard to air quality, there are a number of factors that must be considered and addressed to realize the environmental benefits of a biogas project and reduce or avoid potential negative impacts. Uncontrolled emissions from combustion of biogas may contain between 200 to 300 ppm NOx. The anaerobic treatment process creates intermediates such as ammonia, hydrogen sulfide, orthophosphates, and various salts, all of which must be properly controlled or captured. In addition, atmospheric releases at locations off-site where bio-gas is shipped may negate or decrease the benefit of emissions controls on-site. Thus, while devices such as Selective Catalyst Reduction (SCR) units can reduce NOx emissions and proper treatment system operation can control intermediates, improper design or operation may lead to violations of federal, state, and local air quality regulations as well as release of toxic air contaminants.

With regard to water quality, it is critical that project developers and managers ensure digester integrity and fully consider and address post-digestion management of the effluent in order to avoid contamination of local waterways and groundwater resources. Catastrophic digester failures; leakage from pipework and tanks; and lack of containment in waste storage areas are all examples of potential problems. Further, application of improperly treated digestate and/or improper application timing or rates of digestate to agricultural land may lead to increased nitrogen oxide emissions, soil contamination, and/or nutrient leaching, thus negating or reducing benefits of the project overall.

Project developers must not only follow the protocol to register GHG reductions with the Reserve, they must also comply with all local, state, and national air and water quality regulations. Projects must be designed and implemented to mitigate potential releases of pollutants such as those described, and project managers must acquire the appropriate local permits prior to installation to prevent violation of the law.

The Reserve agrees that GHG emission reduction projects should not undermine air and water quality efforts and will work with stakeholders to establish initiatives to meet both climate-related and localized environmental objectives.

Appendix B Emission Factor Tables

Table B.1. Manure Management System Components

System	Definition
Pasture/Range/ Paddock	The manure from pasture and range grazing animals is allowed to lie as deposited, and is not managed.
Daily spread	Manure is routinely removed from a confinement facility and is applied to cropland or pasture within 24 hours of excretion.
Solid storage	The storage of manure, typically for a period of several months, in unconfined piles or stacks. Manure is able to be stacked due to the presence of a sufficient amount of bedding material or loss of moisture by evaporation.
Dry lot	A paved or unpaved open confinement area without any significant vegetative cover where accumulating manure may be removed periodically.
Liquid/Slurry	Manure is stored as excreted or with some minimal addition of water in either tanks or earthen ponds outside the animal housing, usually for periods less than one year. Per IPCC Guidelines, if manure contains less than 20% dry matter it can be considered liquid.
Uncovered anaerobic lagoon	A type of liquid storage system designed and operated to combine waste stabilization and storage. Lagoon supernatant is usually used to remove manure from the associated confinement facilities to the lagoon. Anaerobic lagoons are designed with varying lengths of storage (up to a year or greater), depending on the climate region, the volatile solids loading rate, and other operational factors. The water from the lagoon may be recycled as flush water or used to irrigate and fertilize fields.
Pit storage below animal confinements	Collection and storage of manure usually with little or no added water typically below a slatted floor in an enclosed animal confinement facility, usually for periods less than one year.
Anaerobic digester	Animal excreta with or without straw are collected and anaerobically digested in a large containment vessel or covered lagoon. Digesters are designed and operated for waste stabilization by the microbial reduction of complex organic compounds to CO2 and CH4, which is captured and flared or used as a fuel.
Burned for fuel	The dung and urine are excreted on fields. The sun dried dung cakes are burned for fuel.
Cattle and Swine deep bedding	As manure accumulates, bedding is continually added to absorb moisture over a production cycle and possibly for as long as 6 to 12 months. This manure management system also is known as a bedded pack manure management system and may be combined with a dry lot or pasture.
Composting – In-vessel*	Composting, typically in an enclosed channel, with forced aeration and continuous mixing.
Composting – Static pile*	Composting in piles with forced aeration but no mixing.
Composting – Intensive windrow*	Composting in windrows with regular (at least daily) turning for mixing and aeration.
Composting – Passive windrow*	Composting in windrows with infrequent turning for mixing and aeration.
Aerobic treatment	The biological oxidation of manure collected as a liquid with either forced or natural aeration. Natural aeration is limited to aerobic and facultative ponds and wetland systems and is due primarily to photosynthesis. Hence, these systems typically become anoxic during periods without sunlight.

*Composting is the biological oxidation of a solid waste including manure usually with bedding or another organic carbon source typically at thermophilic temperatures produced by microbial heat production.
Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Chapter 10: Emissions from Livestock and Manure Management, Table 10.18: Definitions of Manure Management Systems, p. 10.49.

Table B.2. Livestock Categories and Typical Animal Mass

Livestock Category (L)	Livestock Typical Animal Mass (TAM) in kg	
	2006 - 2008	2009 - 2010
Dairy cows (on feed)	604[b]	680[c]
Non-milking dairy cows (on feed)	684[a]	684[a]
Heifers (on feed)	476[b]	407[c]
Bulls (grazing)	750[b]	750[c]
Calves (grazing)	118[b]	118[c]
Heifers (grazing)	420[b]	351[c]
Cows (grazing)	533[b]	582.5[c]
Nursery swine	12.5[a]	12.5[a]
Grow/finish swine	70[a]	70[a]
Breeding swine	198[b]	198[c]

Sources for TAM:
[a.] American Society of Agricultural Engineers (ASAE) Standards 2005, ASAE D384.2.
[b.] Environmental Protection Agency (EPA), Inventory of US GHG Emissions and Sinks 1990-2006 (2007), Annex 3, Table A-161, pg. A-195.
[c.] Environmental Protection Agency (EPA), Inventory of US GHG Emissions and Sinks 1990-2010 (2012), Annex 3, Table A-191, pg. A-246.

Table B.3. Volatile Solids and Maximum Methane Potential by Livestock Category

Livestock category (L)	VS_L (kg/day/1000 kg mass)	$B_{0,L}$ [b] (m^3 CH_4/kg VS added)
Dairy cows	See Appendix B, Tables 5a-e	0.24
Non-milking dairy cows	5.56	0.24
Heifers	See Appendix B, Tables 5a-e	0.17
Bulls (grazing)	6.04[b]	0.17
Calves (grazing)	6.41[b]	0.17
Heifers (grazing)	See Appendix B, Tables 5a-e	0.17
Cows (grazing)	See Appendix B, Tables 5a-e	0.17
Nursery swine	8.89[b]	0.48
Grow/finish swine	5.36[b]	0.48
Breeding swine	2.71[b]	0.35

[a.] American Society of Agricultural Engineers (ASAE) Standards 2005, ASAE D384.2, VS_L(kg/day per animal) from table 1.b (p.2) converted to (kg/day/1000 kg mass) using average Live Weight (kg)values from table 5c (p.7).
[b.] Environmental Protection Agency (EPA) – Climate Leaders Draft Manure Offset Protocol, October 2006, Table IIa: Animal Waste Characteristics (VS, B_0, and N_{ex} rates), p. 18.

Table B.4. Biogas Collection Efficiency by Digester Type

Digester Type	Cover Type	Biogas Collection Efficiency (BCE) as a Decimal
Covered Anaerobic Lagoon	Bank-to-Bank, impermeable	0.95
	Partial area (modular), impermeable	(0.95) x (% area covered)
Complete mix, plug flow, or fixed film digester	Enclosed vessel	0.98
Two stages of differing types	With flow metered for each stage	$\frac{(BCE1) \times (Gasflow1) + (BCE2) \times (Gasflow2)}{Total\ biogas\ flow}$
	No separate flow metering	$(BCE1) \times 0.7 + (BCE2) \times 0.3$

Adapted from: U.S. EPA Climate Leaders, Offset Project Methodology for Managing Manure and Biogas Recovery Systems, 2008. Table IIf (original table has been expanded upon).

Table B.5a. 2010 Volatile Solid Default Values for Dairy Cows, Heifers, Heifers-Grazing and Cows-Grazing by State (kg/day/1000 kg mass)

State	VS Dairy Cow	VS Heifer	VS Heifer-Grazing	VS Cows-Grazing
Alabama	8.99	8.43	8.53	7.82
Alaska	7.98	8.43	9.98	8.89
Arizona	11.47	8.43	9.77	8.89
Arkansas	8.30	8.43	8.48	7.82
California	11.27	8.43	9.48	8.89
Colorado	11.54	8.43	9.27	8.89
Connecticut	10.22	8.43	8.62	7.87
Delaware	9.53	8.43	8.53	7.87
Florida	10.26	8.43	8.63	7.82
Georgia	10.03	8.43	8.49	7.82
Hawaii	8.43	8.43	9.77	8.89
Idaho	11.24	8.43	9.41	8.89
Illinois	10.19	8.43	7.78	7.47
Indiana	10.54	8.43	7.91	7.47
Iowa	10.67	8.43	7.64	7.47
Kansas	10.74	8.43	7.61	7.47
Kentucky	9.11	8.43	8.40	7.82
Louisiana	7.98	8.43	8.63	7.82
Maine	9.94	8.43	8.51	7.87
Maryland	10.00	8.43	8.51	7.87
Massachusetts	9.67	8.43	8.53	7.87
Michigan	11.42	8.43	7.83	7.47
Minnesota	10.25	8.43	7.83	7.47
Mississippi	8.59	8.43	8.53	7.82
Missouri	8.81	8.43	7.97	7.47
Montana	10.63	8.43	8.42	7.82
Nebraska	10.38	8.43	9.25	8.89
Nevada	11.08	8.43	8.01	7.47
New Hampshire	10.40	8.43	9.62	8.89
New Jersey	9.69	8.43	8.45	7.87
New Mexico	11.81	8.43	8.43	7.87
New York	10.69	8.43	9.50	8.89
North Carolina	10.54	8.43	8.61	7.87
North Dakota	9.92	8.43	8.31	7.82
Ohio	10.27	8.43	7.95	7.47
Oklahoma	9.59	8.43	7.90	7.47
Oregon	10.54	8.43	8.33	7.82
Pennsylvania	10.39	8.43	9.56	8.89
Rhode Island	9.76	8.43	8.66	7.87
South Carolina	10.02	8.43	8.61	7.87
South Dakota	10.59	8.43	8.19	7.82
Tennessee	9.56	8.43	8.12	7.47
Texas	10.87	8.43	8.21	7.82
Utah	10.86	8.43	8.42	7.82
Vermont	10.00	8.43	9.56	8.89
Virginia	10.09	8.43	8.52	7.87
Washington	11.50	8.43	8.25	7.82
West Virginia	9.15	8.43	9.73	8.89
Wisconsin	10.63	8.43	7.96	7.47
Wyoming	10.46	8.43	9.62	8.89

Source: Environmental Protection Agency (EPA). U.S. Inventory of GHG Sources and Sinks 1990-2010 (2012), Annex 3, Table A-192, page A-237.

Table B.5b. 2009 Volatile Solid Default Values for Dairy Cows, Heifers, Heifers-Grazing and Cows-Grazing by State (kg/day/1000 kg mass)

State	VS Dairy Cow	VS Heifer	VS Heifer-Grazing	VS Cows-Grazing
Alabama	9.13	8.42	8.61	7.90
Alaska	7.43	8.42	11.51	10.15
Arizona	11.35	8.42	11.23	10.15
Arkansas	8.24	8.42	8.53	7.87
California	10.97	8.42	8.13	7.70
Colorado	11.37	8.42	7.42	7.27
Connecticut	10.05	8.42	8.53	7.77
Delaware	9.54	8.42	8.29	7.77
Florida	10.08	8.42	8.71	7.90
Georgia	10.24	8.42	8.61	7.90
Hawaii	8.70	8.42	11.32	10.15
Idaho	11.07	8.42	10.86	10.15
Illinois	10.10	8.42	8.10	7.77
Indiana	10.48	8.42	8.20	7.77
Iowa	10.55	8.42	7.98	7.77
Kansas	10.77	8.42	7.38	7.27
Kentucky	8.91	8.42	8.52	7.90
Louisiana	8.01	8.42	8.68	7.87
Maine	9.86	8.42	8.43	7.77
Maryland	9.92	8.42	8.32	7.77
Massachusetts	9.71	8.42	8.43	7.77
Michigan	11.18	8.42	8.15	7.77
Minnesota	10.21	8.42	8.17	7.77
Mississippi	8.82	8.42	8.60	7.90
Missouri	8.83	8.42	8.33	7.77
Montana	10.42	8.42	7.83	7.27
Nebraska	10.36	8.42	7.42	7.27
Nevada	10.99	8.42	11.14	10.15
New Hampshire	10.30	8.42	8.37	7.77
New Jersey	9.81	8.42	8.34	7.77
New Mexico	11.74	8.42	11.06	10.15
New York	10.46	8.42	8.20	7.77
North Carolina	10.55	8.42	8.60	7.90
North Dakota	9.46	8.42	7.68	7.27
Ohio	10.06	8.42	8.28	7.77
Oklahoma	9.55	8.42	8.32	7.87
Oregon	10.36	8.42	11.03	10.15
Pennsylvania	10.25	8.42	8.20	7.77
Rhode Island	9.78	8.42	8.55	7.77
South Carolina	10.29	8.42	8.64	7.90
South Dakota	10.48	8.42	7.57	7.27
Tennessee	9.53	8.42	8.58	7.90
Texas	10.73	8.42	8.26	7.87
Utah	10.74	8.42	11.11	10.15
Vermont	9.93	8.42	8.23	7.77
Virginia	10.08	8.42	8.56	7.90
Washington	11.39	8.42	10.93	10.15
West Virginia	8.85	8.42	8.35	7.77
Wisconsin	10.46	8.42	8.33	7.77
Wyoming	10.08	8.42	7.72	7.27

Source: Environmental Protection Agency (EPA). U.S. Inventory of GHG Sources and Sinks 1990-2009 (2011), Annex 3, Table A-186, page A-225.

Table B.5c. 2008 Volatile Solid Default Values for Dairy Cows, Heifers, Heifers-Grazing and Cows-Grazing by State (kg/day/1000 kg mass)

State	VS Dairy Cow	VS Heifer	VS Heifer-Grazing	VS Cows-Grazing
Alabama	8.40	8.35	7.81	7.02
Alaska	7.30	8.35	10.05	9.02
Arizona	10.37	8.35	10.34	9.02
Arkansas	7.59	8.35	7.86	7.00
California	10.02	8.35	7.95	6.85
Colorado	10.25	8.35	7.69	6.46
Connecticut	9.22	8.35	7.67	6.90
Delaware	8.63	8.35	7.72	6.90
Florida	8.90	8.35	7.75	7.02
Georgia	9.07	8.35	7.85	7.02
Hawaii	7.00	8.35	10.26	9.02
Idaho	10.11	8.35	10.82	9.02
Illinois	9.07	8.35	8.07	6.91
Indiana	9.38	8.35	7.98	6.91
Iowa	9.46	8.35	8.27	6.91
Kansas	9.63	8.35	7.75	6.46
Kentucky	7.89	8.35	7.91	7.02
Louisiana	7.39	8.35	7.73	7.00
Maine	8.99	8.35	7.76	6.90
Maryland	9.02	8.35	7.76	6.90
Massachusetts	8.63	8.35	7.74	6.90
Michigan	10.05	8.35	7.99	6.91
Minnesota	9.17	8.35	8.04	6.91
Mississippi	8.19	8.35	7.82	7.02
Missouri	8.02	8.35	7.85	6.91
Montana	9.03	8.35	7.17	6.46
Nebraska	9.09	8.35	7.71	6.46
Nevada	9.65	8.35	10.49	9.02
New Hampshire	9.44	8.35	7.74	6.90
New Jersey	8.51	8.35	7.89	6.90
New Mexico	10.34	8.35	10.56	9.02
New York	9.42	8.35	8.02	6.90
North Carolina	9.38	8.35	7.83	7.02
North Dakota	8.40	8.35	7.43	6.46
Ohio	9.01	8.35	7.93	6.91
Oklahoma	8.58	8.35	8.08	7.00
Oregon	9.40	8.35	10.54	9.02
Pennsylvania	9.26	8.35	8.00	6.90
Rhode Island	8.94	8.35	7.60	6.90
South Carolina	9.05	8.35	7.81	7.02
South Dakota	9.45	8.35	7.50	6.46
Tennessee	8.60	8.35	7.86	7.02
Texas	9.51	8.35	8.21	7.00
Utah	9.70	8.35	10.51	9.02
Vermont	9.03	8.35	7.89	6.90
Virginia	9.02	8.35	7.87	7.02
Washington	10.36	8.35	10.77	9.02
West Virginia	8.13	8.35	7.74	6.90
Wisconsin	9.34	8.35	7.87	6.91
Wyoming	9.29	8.35	7.30	6.46

Source: Environmental Protection Agency (EPA). U.S. Inventory of GHG Sources and Sinks 1990-2008 (2010), Annex 3, Table A-181, page A-213.
For VS values for reporting years prior to 2008, please refer to the Livestock Project Protocol V3.0, Appendix B.

Table B.6. IPCC 2006 Methane Conversion Factors by Manure Management System Component/Methane Source 'S' [39]

MCF Values by Temperature for Manure Management Systems																				
	Average annual temperature (°C)																			
	Cool					Temperate											Warm			
System[a]	**<10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**>28**	**Source and comments**
Pasture/Range/Paddock	0.010					0.015											0.020			Judgment of IPCC Expert Group in combination with Hashimoto and Steed (1994).
Daily spread	0.001					0.005											0.010			Hashimoto and Steed (1993).
Solid storage	0.02					0.04											0.05			Judgment of IPCC Expert Group in combination with Amon et al. (2001), which shows emissions of approximately 2% in winter and 4% in summer. Warm climate is based on judgment of IPCC Expert Group and Amon et al. (1998).
Dry lot	0.010					0.015											0.020			Judgment of IPCC Expert Group in combination with Hashimoto and Steed (1994).
Liquid/slurry w/natural crust cover[40]	0.10	0.11	0.13	0.14	0.15	0.17	0.18	0.20	0.22	0.24	0.26	0.29	0.31	0.34	0.37	0.41	0.44	0.48	0.50	Judgment of IPCC Expert Group in combination with Mangino et al. (2001) and Sommer (2000). The estimated reduction due to the crust cover (40%) is an annual average value based on a limited data set and can be highly variable dependent on temperature, rainfall, and composition.
Liquid/slurry uncovered	0.17	0.19	0.20	0.22	0.25	0.27	0.29	0.32	0.35	0.39	0.42	0.46	0.50	0.55	0.60	0.65	0.71	0.78	0.80	Judgment of IPCC Expert Group in combination with Mangino et al. (2001).
Uncovered anaerobic lagoon	0.66	0.68	0.70	0.71	0.73	0.74	0.75	0.76	0.77	0.77	0.78	0.78	0.78	0.79	0.79	0.79	0.79	0.80	0.80	Judgment of IPCC Expert Group in combination with Mangino et al. (2001). Uncovered lagoon MCFs vary based on several factors, including temperature, retention time, and loss of volatile solids from the system (through removal of lagoon effluent and/or solids).
Pit storage below animal confinements (<1 month)	0.03					0.03											0.03			Judgment of IPCC Expert Group in combination with Moller et al. (2004) and Zeeman (1994). Note that the ambient temperature, not the stable temperature is to be used for determining the climatic conditions.
Pit storage below animal confinements (>1 month)	0.17	0.19	0.20	0.22	0.25	0.27	0.29	0.32	0.35	0.39	0.42	0.46	0.50	0.55	0.60	0.65	0.71	0.78	0.80	Judgment of IPCC Expert Group in combination with Mangino et al. (2001). Note that the ambient temperature, not the stable temperature is to be used for determining the climatic conditions.

[39] Adapted from 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Chapter 10: Emissions from Livestock and Manure Management, Table 10.17. MCF values shall be chosen based on the average temperature at the site for an entire calendar year, even if the reporting period does not exactly cover a calendar year.

[40] A "natural crust cover" is a naturally-forming layer that covers the majority of the liquid surface at a thickness sufficient to support communities of oxidizing bacteria, and which persists throughout the year. Evidence of such a cover (including the area covered, thickness, and persistence) must be provided by the project developer during verification in order to justify the use of this MCF value.

Anaerobic digester	0 - 1					0 - 1											0 - 1			Should be subdivided in different categories, considering amount of recovery of the biogas, flaring of the biogas and storage after digestion. Calculation with Formula 1.
Burned for fuel	0.10					0.10											0.10			Judgment of IPCC Expert Group in combination with Safley et al. (1992).
Cattle and swine deep bedding (<1 month)	0.03					0.03											0.30			Judgment of IPCC Expert Group in combination with Moller et al. (2004). Expect emissions to be similar, and possibly greater, than pit storage, depending on organic content and moisture content.
Cattle and swine deep bedding (>1 month)	0.17	0.19	0.20	0.22	0.25	0.27	0.29	0.32	0.35	0.39	0.42	0.46	0.50	0.55	0.60	0.65	0.71	0.78	0.90	Judgment of IPCC Expert Group in combination with Mangino et al. (2001).
Composting - in-vessel or aerated static pile[b]	0.005					0.005											0.005			Judgment of IPCC Expert Group and Amon et al. (1998). MCFs are less than half of solid storage. Not temperature dependant.
Composting - passive or intensive windrow[b]	0.005					0.010											0.015			Judgment of IPCC Expert Group and Amon et al. (1998). MCFs are slightly less than solid storage. Less temperature dependant.
Aerobic treatment	0.00					0.00											0.00			MCFs are near zero. Aerobic treatment can result in the accumulation of sludge which may be treated in other systems. Sludge requires removal and has large VS values. It is important to identify the next management process for the sludge and estimate the emissions from that management process if significant.

[a] Definitions for manure management systems are provided in Table B.1.
[b] Composting is the biological oxidation of a solid waste, including manure, usually with bedding or another organic carbon source, typically at thermophilic temperatures produced by microbial heat production.

Table B.7. Biogas Destruction Efficiency Default Values by Destruction Device

If available, the official source tested methane destruction efficiency shall be used in place of the default methane destruction efficiency. Otherwise, project developers have the option to use either the default methane destruction efficiencies provided, or the site specific methane destruction efficiencies, for each of the combustion devices used in the project case performed on an annual basis. Site-specific values must be provided by an independent air emissions testing body that is accredited by a state or local regulatory agency, or the Stack Testing Accreditation Council. Where a state/region does not have an appropriate accreditation system or accredited service providers, the project developer may look to another state/region to find suitably qualified service providers.

Biogas Destruction Device	Biogas Destruction Efficiency (BDE)*
Open Flare	0.96[2]
Enclosed Flare	0.995[2]
Lean-burn Internal Combustion Engine	0.936[2]
Rich-burn Internal Combustion Engine	0.995[2]
Boiler	0.98[2]
Microturbine or large gas turbine	0.995[2]
Upgrade and use of gas as CNG/LNG fuel	0.95[2]
Upgrade and injection into natural gas transmission and distribution pipeline	0.98[3]
Direct pipeline to an end-user	Per corresponding destruction device

Source:
[1] Seebold, J.G., et al., Reaction Efficiency of Industrial Flares, 2003
[2] The default destruction efficiencies for this source are based on a preliminary set of actual source test data provided by the Bay Area Air Quality Management District. The default destruction efficiency values are the lesser of the twenty fifth percentile of the data provided or 0.995. These default destruction efficiencies may be updated as more source test data are made available to the Reserve.
[3] The Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories gives a standard value for the fraction of carbon oxidized for gas destroyed of 99.5% (Reference Manual, Table 1.6, page 1.29). It also gives a value for emissions from processing, transmission and distribution of gas which would be a very conservative estimate for losses in the pipeline and for leakage at the end user (Reference Manual, Table 1.58, page 1.121). These emissions are given as 118,000kgCH4/PJ on the basis of gas consumption, which is 0.6%. Leakage in the residential and commercial sectors is stated to be 0 to 87,000kgCH4/PJ, which equates to 0.4%, and in industrial plants and power station the losses are 0 to 175,000kg/CH4/PJ, which is 0.8%. These leakage estimates are compounded and multiplied. The methane destruction efficiency for landfill gas injected into the natural gas transmission and distribution system can now be calculated as the product of these three efficiency factors, giving a total efficiency of (99.5% * 99.4% * 99.6%) 98.5% for residential and commercial sector users, and (99.5% * 99.4% * 99.2%) 98.1% for industrial plants and power stations.[41]

[41] GE AES Greenhouse Gas Services, Landfill Gas Methodology, Version 1.0 (July 2007).

Table B.8. CO_2 Emission Factors for Fossil Fuel Use

Fuel Type	Heat Content	Carbon Content (Per Unit Energy)	Fraction Oxidized	CO_2 Emission Factor (Per Unit Energy)	CO_2 Emission Factor (Per Unit Mass or Volume)
Coal and Coke	**MMBTU / Short ton**	**kg C / MMBTU**		**kg CO_2 / MMBTU**	**kg CO_2 / Short ton**
Anthracite Coal	25.09	28.26	1.00	103.62	2,599.83
Bituminous Coal	24.93	25.49	1.00	93.46	2,330.04
Sub-bituminous Coal	17.25	26.48	1.00	97.09	1,674.86
Lignite	14.21	26.30	1.00	96.43	1,370.32
Unspecified (Residential/ Commercial)	22.05	26.00	1.00	95.33	2,102.29
Unspecified (Industrial Coking)	26.27	25.56	1.00	93.72	2,462.12
Unspecified (Other Industrial)	22.05	25.63	1.00	93.98	2,072.19
Unspecified (Electric Utility)	19.95	25.76	1.00	94.45	1,884.53
Coke	24.80	31.00	1.00	113.67	2,818.93
Natural Gas (By Heat Content)	**BTU / Standard ft^3**	**kg C / MMBTU**		**kg CO_2 / MMBTU**	**kg CO_2 / Standard ft^3**
975 to 1,000 Btu / Standard ft^3	975 – 1,000	14.73	1.00	54.01	Varies
1,000 to 1,025 Btu / Standard ft^3	1,000 – 1,025	14.43	1.00	52.91	Varies
1,025 to 1,050 Btu / Standard ft^3	1,025 – 1,050	14.47	1.00	53.06	Varies
1,050 to 1,075 Btu / Standard ft^3	1,050 – 1,075	14.58	1.00	53.46	Varies
1,075 to 1,100 Btu / Standard ft^3	1,075 – 1,100	14.65	1.00	53.72	Varies
Greater than 1,100 Btu / Standard ft^3	> 1,100	14.92	1.00	54.71	Varies
Weighted U.S. Average	1,029	14.47	1.00	53.06	0.0546
Petroleum Products	**MMBTU / Barrel**	**kg C / MMBTU**		**kg CO_2 / MMBTU**	**kg CO_2 / gallon**
Asphalt & Road Oil	6.636	20.62	1.00	75.61	11.95
Aviation Gasoline	5.048	18.87	1.00	69.19	8.32
Distillate Fuel Oil (#1, 2, and 4) (diesel)	5.825	19.95	1.00	73.15	10.15
Jet Fuel	5.670	19.33	1.00	70.88	9.57
Kerosene	5.670	19.72	1.00	72.31	9.76
LPG (average for fuel use)	3.849	17.23	1.00	63.16	5.79
Propane	3.824	17.20	1.00	63.07	5.74
Ethane	2.916	16.25	1.00	59.58	4.14
Isobutene	4.162	17.75	1.00	65.08	6.45
n-Butane	4.328	17.72	1.00	64.97	6.70
Lubricants	6.065	20.24	1.00	74.21	10.72
Motor Gasoline	5.218	19.33	1.00	70.88	8.81
Residual Fuel Oil (#5 and 6)	6.287	21.49	1.00	78.80	11.80
Crude Oil	5.800	20.33	1.00	74.54	10.29
Naphtha (<401°F)	5.248	18.14	1.00	66.51	8.31
Natural Gasoline	4.620	18.24	1.00	66.88	7.36
Other Oil (>401°F)	5.825	19.95	1.00	73.15	10.15
Pentanes Plus	4.620	18.24	1.00	66.88	7.36
Petrochemical Feedstocks	5.428	19.37	1.00	71.02	9.18
Petroleum Coke	6.024	27.85	1.00	102.12	14.65
Still Gas	6.000	17.51	1.00	64.20	9.17
Special Naphtha	5.248	19.86	1.00	72.82	9.10
Unfinished Oils	5.825	20.33	1.00	74.54	10.34
Waxes	5.537	19.81	1.00	72.64	9.58

Source: EPA Climate Leaders, Stationary Combustion Guidance (2007), Table B-2 except:
Default CO_2 emission factors (per unit energy) are calculated as: Carbon Content × Fraction Oxidized × 44/12.
Default CO_2 emission factors (per unit mass or volume) are calculated as: Heat Content x Carbon Content × Fraction Oxidized × 44/12× Conversion Factor (if applicable). Heat content factors are based on higher heating values (HHV).

Table B.9. Volatile Solids Removed Through Solids Separation[42]

Type of Solids Separation	Volatile Solids Removed (fraction)
Gravity	0.45
Mechanical:	
Stationary screen	0.17
Vibrating screen	0.15
Screw press	0.25
Centrifuge	0.50
Roller drum	0.25
Belt press/screen	0.50

Table B.10. Baseline Assumptions for Greenfield Projects[43]

Baseline Assumption	Dairy Cattle Operations		Swine Operations
	>200 Mature Dairy Cows	<200 Mature Dairy Cows	
Anaerobic manure storage system	Flush system into an anaerobic lagoon with >30 day retention time	Flush system into an anaerobic lagoon with >30 day retention time	Flush system into an anaerobic lagoon with >30 day retention time
Non-anaerobic manure storage system(s)	Solids storage	Solids Storage	Solids Storage
MS_L	90% lagoon 10% solids storage	50% lagoon 50% solids storage	95% lagoon 5% solids storage
Lagoon cleaning schedule	Annually, in September	Annually, in September	Annually, in September

[42] U.S.EPA National Pollutant Discharge Elimination System (NPDES) Development Document, Chapter 5, "Industry Subcategorization for Effluent Limitations Guidelines and Standards". Adapted from Moser et al. (1999).
[43] The simplified assumptions contained within this table are based on the waste management system data compiled by the U.S. Environmental Protection Agency for the development of Table A-194 in Annex 3 of the U.S. Inventory of GHG Sources and Sinks 1990-2010 (2012).

Appendix C Summary of Performance Standard Development

The analysis to establish a performance standard for the U.S. Livestock Project Protocol was undertaken by Science Applications International Corporation (SAIC) and independent consultant Kathryn Bickel Goldman. It took place at the end of 2006. The analysis culminated in a paper that provided a performance standard recommendation to support the Reserve's protocol development process, which the Reserve has incorporated into the protocol's eligibility rules (see Section 33). This analysis was re-visited during the development of Version 4.0 of the protocol and, although there was no recommended change to the performance standard, this appendix has been updated to reflect more recent data and analysis.

The purpose of a performance standard is to establish a threshold that is significantly better than average GHG production for a specified service, which, if met or exceeded by a project developer, satisfies the criterion of "additionality." This protocol focuses on the following direct emission reduction activity: avoiding methane emissions from the anaerobic storage and treatment of livestock manure. Therefore, in this case the methane emissions correspond to GHG production, and manure treatment/storage correspond to the specified service.

The analysis to establish the performance standard evaluated U.S.- and California-specific data on dairy and swine manure management systems. Ultimately, it recommended a practice-based/technology-specific GHG emissions performance standard – i.e. the installation of a manure digester (or Biogas Control System (BCS), more generally). The paper was composed of the following sections:

- The livestock industry in the U.S. and California
- Livestock manure management practices
- GHG emissions from livestock manure management
- Data on livestock manure management practices in the U.S. and California
- Current and anticipated regulations in California impacting manure management practices
- Recommendation for a performance threshold for livestock operations
- Considerations for baseline determinations

The initial analysis from that paper can be found in earlier versions of the U.S. Livestock Project Protocol Performance Standard Appendix.[44] In this updated Performance Standard Appendix, The additional, California-specific analysis showed adoption rates similar to the rest of the country, and thus has been removed from this document to reflect the Reserve's decision to apply the same performance standard to all operations across the United States. Beef facility and animal information has also been removed as beef operations are not currently eligible under the Protocol.

[44] Climate Action Reserve U.S. Livestock Project Protocol V1.0-3.0, Appendix C, http://www.climateactionreserve.org/how/protocols/us-livestock/

C.1 Analysis of Common Practice

C.1.1 U.S. Data on Manure Management Practices

For the initial performance standard analysis, data from the Draft EPA Climate Leaders Offset Protocol for Managing Manure with Biogas Recovery Systems (2006) were used to assess national-level manure management practices. That protocol relied on data describing farm distribution and manure management systems from the Manure Management portion of the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2004 and used data on the number of farms by farm size and geographic location from the 2002 Census of Agriculture.[45]

Information compiled for the EPA's U.S. GHG Inventory also provided a breakdown of the assumed predominant manure management systems in use for dairy and swine operations. Table C.1 and Table C.3 show data compiled for the systems in place in 2006. Table C.2 and Table C.4 show the Reserve's approximate recreation of the same analysis using the most recently published numbers.[46]

Table C.1. Dairy and Swine Operations in the U.S. by Manure Management System (2006)

Animal	Number of Operations by Manure Management System						
	P/R/P	Anaerobic Digester	Lagoon	Liquid/ Slurry	Solid Storage	Deep Pit	Total
Dairy	72,487	62	4,453	4,345	9,494	1,147	91,989
Swine	53,230	18	6,571	6,303	1,129	11,643	78,894

Source: U.S. EPA Climate Leaders Offset Protocol for Managing Manure with Biogas Recovery Systems (2008), Table I.A.

Table C.2. Dairy and Swine Operations in the U.S. by Manure Management System (2012)

Animal	Number of Operations by Manure Management System						
	P/R/P	Anaerobic Digester	Lagoon	Liquid/ Slurry	Solid Storage	Deep Pit	Total
Dairy	56,075	185*	3,332	3,261	6,263	775	69,890
Swine	55,110	30	5,740	4,641	892	9,029	75,442

Source: U.S. EPA GHG Inventory (2012), U.S. EPA AgSTAR Database (2012), U.S. Dept. of Agriculture, 2007 Census of Agriculture

* There are three systems in operation that digest both swine and dairy manure. For the purpose of this analysis they are considered as dairy.

[45] EPA GHG Inventory Reports in subsequent years (including 2010) still rely on the results of the 2002 Census for this data.

[46] The equivalent analysis based on the 2007 census is unavailable in the same format from the EPA Climate Leaders program. The Reserve performed a similar analysis using data for manure management from the Inventory of U.S. Greenhouse Gas Emissions and Sinks (2012), data on the prevalence of anaerobic digesters from the U.S. EPA's AgSTAR database (Sept. 2012), and data on the number of farms by farms size and geographic location from the 2007 Census of Agriculture, the results of which are Table C.2 and Table C.4. This analysis may not have been performed in precisely the same way as the EPA Climate Leaders Program analysis; however it serves the purpose of evaluating the current state of the dairy and swine manure management practices. The following classification assumptions were made: 1. digester projects associated with farms of size are classified by based on other information in the AgSTAR database, if available, or assumed to be in the medium size class; 2. farms employing anaerobic digesters are subtracted from the USDA counts based on "Baseline System" or other information in the AgSTAR database, if available. Where the "Baseline System" is categorized as "Storage Tank or Pond or Pit," the farm is assumed to belong in the "Liquid/Slurry" category for Dairy and the "Deep Pit" category for Swine.

The distribution of livestock across different sized operations can be an important criterion when developing a livestock manure management performance standard. There is a general relationship between manure management practices and operation size, where larger operations (in terms of livestock numbers) tend to use manure management systems that treat and store waste in liquid form (i.e. flush or scrape/slurry systems), particularly in dairy and swine operations.[47]

Table C.3. Dairy and Swine Operations by Size and Manure Management System (2006)

Animal	Number of Operations by Farm Size and Manure Management System							
	Farm Size	P/R/P	Anaerobic Digester	Lagoon	Liquid/ Slurry	Solid Storage	Deep Pit	Total
Dairy	≥500 head	320	48	1,614	675	245	-	2,902
	200-499	3,213	9	617	652	54	-	4,546
	1-199	6,8954	5	2,223	3,017	9,195	1,147	84,541
Swine	≥2000 head	-	14	2,581	1,084	297	2,774	6,749
	200-2000	-	3	3,990	5,219	832	8,869	18,913
	1-199	53,230	1	-	-	-	-	53,231

Source: U.S. 2002 Census of Agriculture.

Table C.4. Dairy and Swine Operations by Size and Manure Management System (2012)

Animal	Number of Operations by Farm Size and Manure Management System							
	Farm Size	P/R/P	Anaerobic Digester	Lagoon	Liquid/ Slurry	Solid Storage	Deep Pit	Total
Dairy	≥500 head	312	154	1,824	710	284	-	3,284
	200-499	3205	25	502	531	44	-	4,307
	1-199	52559	6	1,006	2,020	5,934	775	62,299
Swine	≥2000 head	-	26	3,182	1,295	358	3,345	8,206
	200-2000	-	3	2,557	3,347	534	5,685	12,125
	1-199	55,110	1	-	-	-	-	55,111

Source: U.S. EPA GHG Inventory (2012), U.S. EPA AgSTAR Database (2012), U.S. Dept. of Agriculture, 2007 Census of Agriculture.

According to the Interim Draft Winter 2006 AgSTAR Digest used for the initial analysis, of 91,988 dairy and 78,894 swine farm operations in the United States, a total of 80 anaerobic digesters were in operation: 62 (0.07%) for dairy manure and 18 (0.02%) for swine manure.

Data were also disaggregated in the Climate Leaders protocol to determine whether digester installation was a common practice in any animal production operation size range. As was shown in Table C.3, even at large animal production operations, very few digester systems were in place. At dairy farms with ≥500 head, only 1.7% of manure management systems included digesters, and of swine farms with >2000 head, only 0.2% had digesters.

[47] U.S. Inventory of Greenhouse Gas Emissions and Sinks: 1990-2004 (and earlier editions), US Environmental Protection Agency, Report # 430-R-06-002, April 2006.

The most current information from the AgSTAR database (September 2012) shows that the number of anaerobic digesters in operation or under construction has nearly tripled at dairy farms and increased by more than 50% at swine farms. In terms of prevalence as a manure management practice across farms however, the practice remains the exception, rather than the rule. Currently there are 185 digesters at dairy farms (0.14%), and 30 at swine farms (0.03%). The number of digesters at the largest farms increased the most significantly, with 154 digesters at dairy farms with ≥500 head (4.69%), and 26 at swine operations with ≥2000 head (0.32%). Of the 185 dairy farms with anaerobic digesters in operation, 84 have participated in GHG offset programs; eight of the 30 swine farms with anaerobic digester have participated in GHG offset programs. Table C.5 shows the distribution and percentages of digesters in operation or under construction by size farm, compared to farms with other manure management practices; Table C.6 shows the same distribution, but does not include the digesters at farms participating in GHG offset programs.

The “natural” market penetration of anaerobic digesters on livestock facilities can be considered as the percentage of farms that choose this management option without the incentive provided by GHG offset programs. Table C.6 shows that the natural market penetration of anaerobic digesters on dairy and swine facilities in the U.S. remains very low. The highest rate of adoption is among dairy farms with ≥500 head, at 2.31%. However, this number conservatively includes anaerobic digestion facilities that are currently under construction. As many if not all of these facilities may actually be installed in response to GHG offset programs (which is often not known until they are operational and become publicly listed in one of these programs), even this small rate of adoption is likely to be overestimated by this analysis. If the anaerobic digesters that are under construction are all assumed to be GHG offset projects, then the natural market penetration of anaerobic digesters on dairy facilities of ≥ 500 head drops to 1.71%.

Table C.5. Dairy and Swine Operations by Size and Manure Management System (2012)

Animal	Number of Operations by Farm Size and Manure Management System							
	Farm Size	P/R/P	Anaerobic Digester	Lagoon	Liquid/ Slurry	Solid Storage	Deep Pit	Total
Dairy	≥500 head	312 9.49%	154 4.69%	1,824 55.53%	710 21.63%	284 8.66%	- -	3,284
	200-499	3,205 74.41%	25 0.58%	502 11.66%	531 12.32%	44 1.03%	- -	4,307
	1-199	52,559 84.37%	6 0.01%	1,006 1.61%	2,020 3.24%	5,934 9.52%	775 1.24%	62,299
	Total	56,075 80.23%	185 0.26%	3,332 4.77%	3,261 4.67%	6,263 8.96%	775 1.11%	69,890
Swine	≥2000 head	- -	26 0.32%	3,182 38.78%	1,295 15.78%	358 4.37%	3,345 40.76%	8,206
	200-1999	- -	3 0.02%	2,557 21.09%	3,347 27.60%	534 4.40%	5,685 46.88%	12,125
	1-199	55,110 99.998%	1 0.002%	- -	- -	- -	- -	55,111
	Total	55,110 73.05%	30 0.04%	5,740 7.61%	4,641 6.15%	892 1.18%	9,029 11.97%	75,442

Source: U.S. EPA GHG Inventory (2012), U.S. EPA AgSTAR Database (2012), U.S. Dept. of Agriculture, 2007 Census of Agriculture.

Table C.6. Dairy and Swine Operations by Size and Manure Management System (2012)
Not including those participating in a GHG offset program.

Animal	Number of Operations by Farm Size and Manure Management System							
	Farm Size	P/R/P	Anaerobic Digester	Lagoon	Liquid/ Slurry	Solid Storage	Deep Pit	Total
Dairy	≥500 head	312 *9.73%*	74 *2.31%*	1,824 *56.91%*	710 *22.17%*	284 *8.88%*	- -	3,204
	200-499	3,205 *74.47%*	21 *0.49%*	502 *11.67%*	531 *12.33%*	44 *1.03%*	- -	4,303
	1-199	52,559 *84.37%*	6 *0.01%*	1,006 *1.61%*	2,020 *3.24%*	5,934 *9.52%*	775 *1.24%*	62,299
	Total	56,075 *80.33%*	101 *0.14%*	3,332 *4.77%*	3,261 *4.67%*	6,263 *8.97%*	775 *1.11%*	69,806
Swine	≥2000 head	- -	19 *0.23%*	3,182 *38.81%*	1,295 *15.79%*	358 *4.37%*	3,345 *40.80%*	8,199
	200-1999	- -	2 *0.02%*	2,557 *21.09%*	3,347 *27.60%*	534 *4.40%*	5,685 *46.89%*	12,124
	1-199	55,110 *99.998%*	1 *0.002%*	- -	- -	- -	- -	55,111
	Total	55,110 *73.06%*	22 *0.03%*	5,740 *7.61%*	4,641 *6.15%*	892 *1.18%*	9,029 *11.97%*	75,434

Source: U.S. EPA GHG Inventory (2012), U.S. EPA AgSTAR Database (2012), U.S. Dept. of Agriculture, 2007 Census of Agriculture, open GHG offset program registries.

Finally, as anaerobic digesters are most likely to be installed on livestock facilities that already utilize liquid-based manure management systems, it is useful to examine the market penetration among only these facilities. Table C.7 shows that, among the total facilities utilizing liquid manure management systems, the natural market penetration of anaerobic digesters is 1.35% for dairy farms and 0.11% for swine farms.[48] The highest rate, seen among dairy farms of ≥500 head, is 2.84%. This continues to be an extremely low rate of adoption for anaerobic digestion technology.

[48] There is seemingly 100% market penetration on swine farms with <200 animals, due to the fact that there was only one farm in the dataset utilizing liquid manure management, and it also had an anaerobic digester. A greater trend of adoption of anaerobic digestion cannot be drawn from this single farm.

Table C.7. Dairy and Swine Operations Utilizing Liquid Manure Management, by Size and Manure Management System (2012)
Not including those participating in a GHG offset program.

Animal	Number of Operations by Farm Size Using Anaerobic Manure Management (Excluding GHG Offsets)			
	Farm Size	Anaerobic Digester	Liquid Manure Management	Total
Dairy	≥500 head	74 *2.84%*	2,534 *97.16%*	2,608
	200-499	21 *1.99%*	1,033 *98.01%*	1,054
	1-199	6 *0.16%*	3,800 *99.84%*	3,806
	Total	101 *1.35%*	7,367 *98.65%*	7,468
Swine	≥2000 head	19 *0.24%*	7,822 *99.76%*	7,841
	200-1999	2 *0.02%*	11,589 *99.98%*	11,591
	1-199	1 *100.00%*	- -	1
	Total	22 *0.11%*	19,410 *99.89%*	19,432

C.1.2 U.S. and State Manure Management Regulations

As a part of the Reserve's protocol management, regulatory developments are tracked through, among other outreach and research activities, reporting on regulatory requirements by project developers and verification bodies in the verification process. Of the farms with an anaerobic digester that have participated in GHG offset projects documented in EPA's AgSTAR program, 65 have listed their projects under the Reserve's U.S. Livestock Project Protocol. Twenty-seven projects have been registered with the Reserve, i.e., successfully undergone the verification process. This includes projects in four of the five top dairy producing states, namely, California, Wisconsin, Texas and Idaho. In states where registered Reserve projects are located, no state or federal regulations have been found that would require the use of a BCS.

C.2 Performance Standard Recommendation

The original SAIC report recommended that a performance standard apply to the control of methane emissions from dairy and swine livestock operations in the U.S. and California. In particular, the performance standard should be a technology-specific threshold that dairy or swine operators would meet. The recommended threshold would be the installation of a BCS (e.g. an anaerobic digester).

The report found that even under favorable conditions digesters were found on less than 1% of the dairies in California, which was found to be representative of the U.S. market; and that if a dairy operator chose to install a digester then the farmer would be managing waste in the 99th percentile. This constitutes above and beyond common practice. The report also found that the main barrier inhibiting the installation and use of digesters was cost. Cost studies performed by EPA's AgSTAR program and the California Electricity Commission indicated that significant subsidies and/or incentives were needed to encourage additional digester installations.

The Reserve adopted this performance standard recommendation based on the data available at the time of the SAIC report. While the number of anaerobic digesters has increased significantly, the market penetration of BCS technology remains quite low, especially among those farms which are not receiving revenues from GHG offset markets. Today a dairy operator who chooses to install a digester would be managing waste in the 98th percentile—a modest increase since the original analysis, but hardly a significant shift in common practice. Furthermore, cost continues to inhibit wider adoption of BCS technologies according to a recent EPA report on the status of anaerobic digester adoption.[49] In light of these facts, the Reserve will not alter the current performance standard, but will continue to monitor market developments in the future.

C.3 Renewable Energy Credits and Other Revenue Opportunities for Biogas-to-Energy Projects

Along with carbon credits, there are opportunities for farms installing digesters to earn additional revenues from a variety of sources that support renewable energy generation. These include loans and grants for developing biogas-to-energy projects and the sale of Renewable Energy Certificates (RECs) for use in a renewable portfolio standard (RPS) or a renewable portfolio goal (RPG)[50].

When considering additionality and the ability to generate RECs and CRTs from a livestock project, it is important to remember that the REC and CRT are created by two different but related activities. The REC is awarded for generating renewable electricity from the biogas collected by the BCS, whereas the CRT is awarded for the climate benefit created by the conversion of CH_4 in the biogas into CO_2 through combustion of the biogas. Under this protocol, projects are not required to generate electricity with collected biogas or send it to a natural gas pipeline. Rather, they are only required to destroy the biogas. So while a project may generate renewable electricity with its biogas, renewable energy generation is not an activity required or credited under this protocol.

As there are a number of active RPS, RPG and voluntary REC programs nationwide, the availability of revenue from the sales of RECs is inherently represented in the data analyzed to set the performance standard. Since this analysis shows that the installation of a digester is not common practice at dairy and swine farms, the Reserve does not limit a project's ability to generate or sell RECs. Due to the numerous barriers to implementation of an anaerobic digester project, their success typically relies on a complex array of factors, including multiple incentive program. Renewable energy incentives alone have not significantly increased the natural market penetration of these projects.

When considering additionality and the availability of public dollars to support the development of biogas-to-energy projects, the Reserve has identified numerous state and local programs to support such projects through grants, loans and payments. Although the Reserve's performance standard tests do not require individual project assessments of financial viability or returns, they are designed to reflect these factors in determining which projects are additional. Even with the funds available, the installation of anaerobic digesters according to this protocol is still very rare. Thus, even if a project does receive a grant or loan to support the generation of renewable

[49] U.S. Anaerobic Digester Status Report, October 2010, http://www.epa.gov/agstar/documents/digester_status_report2010.pdf
[50] Whereas compliance with an RPS is mandatory, RPGs set voluntary compliance targets.

energy from a biogas project, the performance standard and rules set forth in this protocol should ensure the additionality of the CRTs generated.

Beyond grants and loans for biogas-to-energy projects, there are two nationwide payment programs administered by USDA Natural Resource Conservation Service (NRCS) that support the installation of anaerobic digesters. Authorized by the 2008 Farm Bill, the Environmental Quality Incentives Program (EQIP), and the Chesapeake Bay Watershed Initiative (CBWI) are programs that provide payments to support the installation of a BCS and are implemented at the state- and county-level. NRCS expressly allows the sale of environmental credits from enrolled lands,[51] but does not provide any additional guidance on ensuring the environmental benefit of any mitigation payment stacked with an NRCS payment.

All NRCS programs share a common set of conservation practice standards that contain information on why and where the practice is to be applied, and set forth the minimum quality criteria that must be met during the application of that practice in order for it to achieve its intended purpose(s).

NRCS Conservation Practice Standard 366 – *Anaerobic Digester* (CPS 366) provides assistance to farmers for the treatment of manure and other byproducts of animal agricultural operations for one or more of the following reasons: to capture biogas for energy production, to manage odors, to reduce the net effect of greenhouse gas emissions, or to reduce pathogens.[52]

Data obtained from NRCS show that less than 0.3% of farms eligible for funding under CPS 366 (i.e., farms with anaerobic operations) have received NRCS funds to install a BCS.[53] In practice, only 9% of the farms that installed BCS since 2004 have received NRCS funds. Because the installation of anaerobic digesters is expensive, uncommon and generally not already funded by NRCS programs, the use of NRCS payments to help finance project activity is allowed under this protocol.

[51] EQIP, 7 CFR §1466.36; CSP, 7 CFR §1470.37.
[52] Natural Resources Conservation Service. (September 2009). Conservation Practice Standard, Anaerobic Digester, Code 366. State-specific conservation practice standards can be downloaded from http://efotg.sc.egov.usda.gov//efotg_locator.aspx.
[53] Based on 2004-2011 data obtained from NRCS Resource Economics, Analysis and Policy Division through personal communication.

Appendix D Data Substitution

This appendix provides guidance on calculating emission reductions when data integrity has been compromised either due to missing data points or a failed calibration. No data substitution is permissible for the operational status of destruction devices. Rather, the methodologies presented below are to be used only for the methane concentration and flow metering parameters. If operational data are missing for a destruction device, then the device shall be assumed to have been inoperable, and will be assigned a destruction efficiency of zero for that period.

D.1 Missing Data

The Reserve expects that projects will have continuous, uninterrupted data for the entire verification period. However, the Reserve recognizes that unexpected events or occurrences may result in brief data gaps.

The following data substitution methodology may be used only for flow and methane concentration data gaps that are discrete, limited, non-chronic, and due to unforeseen circumstances. Data substitution can only be applied to methane concentration *or* flow readings, but not both simultaneously. If data are missing for both parameters, no reductions can be credited.

Further, substitution may only occur when the following is true:

1. For methane concentration substitution, flow rates during the data gap must be consistent with normal operation.
2. For flow substitution, methane concentration rates during the data gap must be consistent with normal operations.

If corroborating parameters fail to demonstrate any of these requirements, no substitution may be employed. If the requirements above can be met, the following substitution methodology maybe applied:

Duration of Missing Data	Substitution Methodology
Less than six hours	Use the average of the four hours immediately before and following the outage
Six to 24 hours	Use the 90% lower or upper confidence limit of the 24 hours prior to and after the outage, whichever results in greater conservativeness
One to seven days	Use the 95% lower or upper confidence limit of the 72 hours prior to and after the outage, whichever results in greater conservativeness
Greater than one week	No data may be substituted and no credits may be generated

Note: It is conservative to use the upper confidence limit when calculating emissions from the BCS (Equation 5.6); however it is conservative to use the lower confidence limit when calculating the total amount of methane that is destroyed in the BCS Equation 5.10.

For periods when it is not possible to use data substitution to fill data gaps, no emission reductions may be claimed. The methane flow volume for these days shall be zero, and the number of reporting days for that month shall be reduced to exclude the days of missing data. This guidance is not to be used for venting events.

Appendix E Development of the B_0 Sampling and Analysis Methodology

With the release of Livestock Protocol Version 4.0, the Reserve has adopted a novel methodology for the sampling and analysis of livestock manure to determine maximum methane potential. In all previous versions of the protocol, the value of this term was defined by the default options provided in Table B.3, which were themselves sourced from the EPA Climate Leaders Draft Manure Offset Protocol. Other than a change in the value of the default for Dairy Cows with Version 2.1 from a “low roughage” value to a “high roughage” value, these default values have not changed since the first version of the protocol was adopted. Reserve staff have received feedback from stakeholders that in many cases, the default value for a particular animal category, especially Dairy Cows, is excessively conservative. Based on this feedback, the Reserve initiated a process to explore the options for updating the default values for maximum methane potential (B_0). After review of existing methodologies and literature related to manure methane potential, the Reserve determined that there is currently not a clear basis for establishing different default values. However, direct sampling and analysis were identified as an option that could be immediately provided as an alternative to the existing default values.

In 2009 the Reserve adopted the Organic Waste Digestion project protocol (updated to Version 2.0 in 2011). This protocol introduced a procedure for the determination of site-specific B_0 value for organic wastewater streams (OWD V2.0, Section 6.1.3.2). These requirements formed the basis for the development of a sampling and analysis procedure for livestock projects.

In early September, 2012, the Reserve solicited stakeholder interest for participation in the development process for this new methodology. A diverse group of 36 stakeholders representing carbon project developers, academia, government, livestock industry, GHG verification bodies, and others, responded to this request. These stakeholders then received a memorandum detailing the proposed methodology and were invited to a webinar on September 19, 2012 to provide feedback and engage in discussion. 22 individuals participated in the webinar discussion, providing a great deal of feedback and suggestions for improvement.

In addition to the public stakeholder consultation, Reserve staff worked directly with experts in industry and academia to further refine the methodology. The goal was to identify a sampling and testing regime that could consistently provide accurate estimates of the B_0 value of different manure streams, and that would be reasonably practical for implementation. The major considerations and decisions are addressed below.

Sampling Schedule

The sampling procedure requires that six samples be taken at regular intervals throughout the day. These individual samples are then combined into one composite sample to represent that event. The sampling procedure in the OWD protocol calls for 10 samples spaced out over at least one week. In consultation with expert stakeholders, it was determined that livestock manure will be less variable over such short timescales, and that the collection of multiple samples in a single day would be sufficient to control for sample variability and error. A more onerous sampling requirement would introduce additional resourcing requirements and costs disproportionate to any reduction in uncertainty/error.

The procedure also requires that the sampling event take place between the months of August through November (inclusive). The Reserve has limited the applicability of this procedure to dairy facilities, and expects that it will mainly be used for the determination of a site-specific B_0

for dairy cows. Thus, the timing of the sampling procedure is designed to avoid overestimating the B_0 value for this particular livestock category. Academic experts advised the Reserve that the methane generating potential of dairy cow manure tends to be positively correlated with milk production.[54] To ensure that the average B_0 value for the year is not overestimated, it is appropriate to avoid sampling the manure during periods of above-average milk production. Reserve staff used data from the National Agricultural Statistics Service[55] to examine monthly milk production trends. For the years 1998-2011, the milk production for each month (in lb/head) was compared to the average monthly milk production for that year. This process highlighted the months with above or below-average milk production, while controlling for the overall trend of increasing milk production year-over-year. Figure E.1 shows the results of this analysis and the consistent pattern of milk production during this 14 year period.

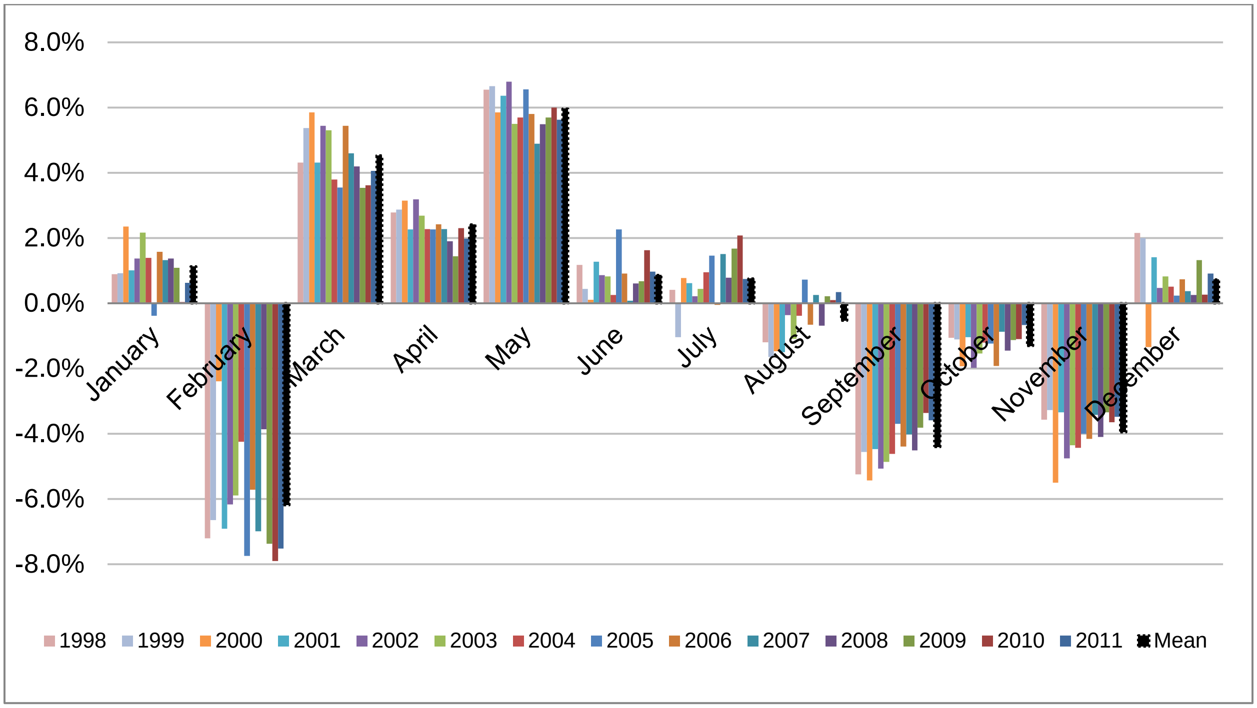


Figure E.1. Monthly Milk Production Trends as a Percent Change Over Annual Average Monthly Milk Production (1998-2011)

Based on this analysis the Reserve has limited the sampling period to August through November. These months consistently exhibit average- to below-average milk production, which should result in a conservative estimate of the annual average B_0 value.

Sample Source

The procedure instructs the user to obtain a manure sample that represents only a single animal category, prior to mixing with other residues (except for flush water in the case of flush systems). While certain stakeholders indicated through public comment that they would prefer to sample the entire waste stream as it enters the digester, there are two main reasons why this requirement was not amended:

[54] In the future, it may be possible to develop a default methane potential that is based directly on monthly milk production, though additional research is needed.
[55] Accessed from the USDA website at http://quickstats.nass.usda.gov/.

1. The waste stream entering the digester may contain ineligible materials which, while permitted to be processed by the project BCS, should not be represented in the quantification of baseline emissions.
2. The baseline quantification model is run on a monthly basis, using the actual animal population figures for that month. The relative populations of different animal categories may change during the year, resulting in an overall B_0 value for the manure from that facility that is variable through time. To use a composite B_0 value, representative of multiple animal categories, would create quantification inaccuracies if relative populations change from one month to the next (see Table E.1).

Table E.1. Effects of Relative Population Size on Composite B_0 Value

Animal Category	B_0 Value	Population in Month 1	Population in Month 2	Population in Month 3
Dairy Cows	0.24	2,000	800	3,000
Heifers	0.17	500	2,000	200
Calves	0.17	500	1,200	0
	Composite B_0 Value	***0.22***	***0.18***	***0.24***

There is an additional step for dairies that utilize a flush system for manure management, as the flush water is typically composed of some type of wastewater, which could have a significant methane potential. For these systems it is necessary to also sample the flush water inlet point prior to mixing with the manure, so that the methane potential of the flush water can then be subtracted from the methane potential of the sample.

Laboratory Analysis

The Reserve undertook research to determine whether standard procedures/processes existed for the professional analysis of B_0 potential. This research revealed that while there is currently no standard laboratory certification scheme within the US pertaining to this type of analysis, there are commonly-accepted methods for undertaking the relevant biochemical methane potential (BMP) analysis itself. The requirements to document a laboratory's experience and standard operating procedures were introduced to ensure rigor and consistency among testing bodies.

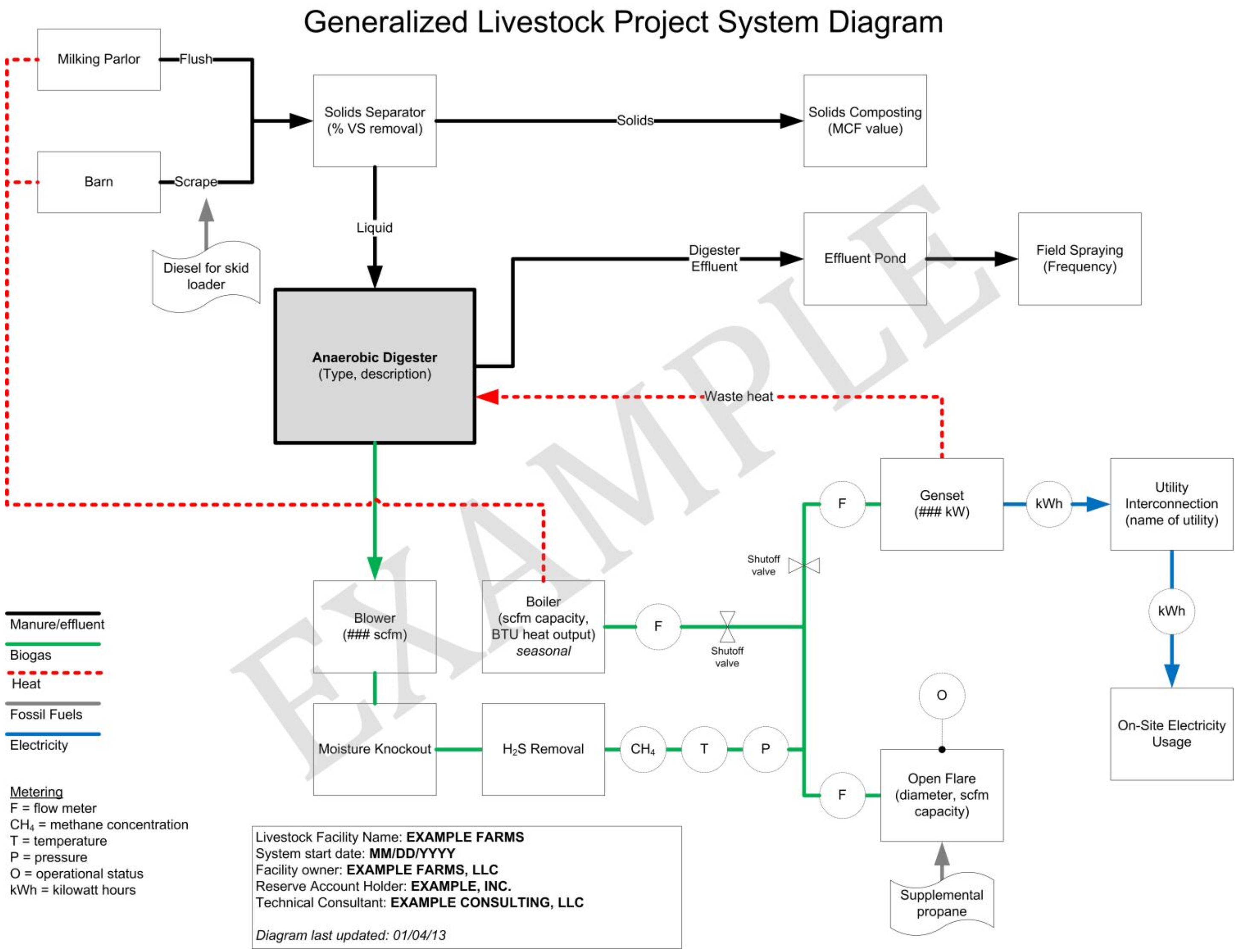
The Reserve consulted with commercial and university testing laboratories regarding the requirements for the biochemical methane potential (BMP) assay. The resulting requirements closely resemble the standard procedures of existing laboratories. It is necessary for the protocol to prescribe at least basic parameters for the BMP assay in order to ensure consistency among projects that hire different laboratories. The inclusion of a control assay was suggested by multiple laboratories as an important quality check on the viability of the seed inoculum that is used for the BMP assay.

Stakeholder Participation

The Reserve would like to thank the following stakeholders, in addition to others not listed here, for their participation in the research and development of this methodology.

David Belcher	Camco
Michael Carim	First Environment, Inc.
Dr. Craig Frear	Washington State University
Noel Gurwick	Smithsonian Environmental Research Center
Karen Haugen-Kozyra	The Prasino Group
Cortney Itle	Eastern Research Group, Inc.
Dr. Xiaomei Li	XY Green Carbon
Dr. John H. Martin, Jr.	Hall Associates
Carl Morris	Joseph Gallo Farms
Dr. Scott Subler	Environmental Credit Corp.
Peter Weisberg	The Climate Trust

Appendix F Sample Livestock Project Diagram



U.S. Livestock Project Protocol
Version 4.0
ERRATA AND CLARIFICATIONS

The Climate Action Reserve (Reserve) published its U.S. Livestock Project Protocol Version 4.0 (LSPP V4.0) in January 2013. While the Reserve intends for the LSPP V4.0 to be a complete, transparent document, it recognizes that correction of errors and clarifications will be necessary as the protocol is implemented and issues are identified. This document is an official record of all errata and clarifications applicable to the LSPP V4.0.[1]

Per the Reserve's Program Manual, both errata and clarifications are considered effective on the date they are first posted on the Reserve website. The effective date of each erratum or clarification is clearly designated below. All listed and registered livestock projects must incorporate and adhere to these errata and clarifications when they undergo verification. The Reserve will incorporate both errata and clarifications into future versions of the protocol.

All project developers and verification bodies must refer to this document to ensure that the most current guidance is adhered to in project design and verification. Verification bodies shall refer to this document immediately prior to uploading any Verification Statement to assure all issues are properly addressed and incorporated into verification activities.

If you have any questions about the updates or clarifications in this document, please contact Policy at policy@climateactionreserve.org or (213) 891-1444 x3.

[1] See Section 4.3.4 of the Climate Action Reserve Program Manual for an explanation of the Reserve's policies on protocol errata and clarifications. "Errata" are issued to correct typographical errors. "Clarifications" are issued to ensure consistent interpretation and application of the protocol. For document management and program implementation purposes, both errata and clarifications are contained in this single document.

Please ensure that you are using the latest version of this document

Errata and Clarifications (arranged by protocol section)

Section 3

1. Regulatory Compliance at Centralized Digesters (CLARIFICATION – July 21, 2016)

Section: 3.6 (Regulatory Compliance)

Context: This section states that, where a verifier determines that project activities have caused a material violation, no CRTs will be issued during the period(s) when the violation occurred. The guidance in this section does not specify how to address regulatory compliance for projects where manure is received from multiple farms and managed in a centralized BCS.

It is unclear whether a violation with respect to one manure source facility would jeopardize the ability of the project to receive credit from emission reductions related to manure from other source facilities. It may be possible for an offset project at a centralized digester to have CRTs issued to it for manure from compliant manure source facilities during a period of time when one or more manure source facilities are materially noncompliant with a regulation.

Clarification: The following text shall be inserted on page 7, at the end of Section 3.6:

"With respect to projects that accept and manage manure from multiple, discrete source facilities (separate from the project BCS in both physical location and management), it may be possible for a project developer to demonstrate that a regulatory violation at one source facility does not affect the eligibility of the entire project under this section. Project developers should contact the Reserve to discuss potential regulatory non-compliance issues."

Section 5

2. Accounting for Methane Emissions during Temporary Project Shutdown (CLARIFICATION – October 29, 2013)

Section: 5.3 (Calculating Project Methane Emissions)

Context: The last full paragraph on page 24 reads: "Although not common under normal digester operation, it is possible that a venting event may occur due to catastrophic failure of digester cover materials, the digester vessel, or the gas collection system. In the event that a catastrophic system failure results in the venting of biogas, the quantity of methane released to the atmosphere shall be estimated according to Equation 5.7 below."

Equation 5.7 on page 26 provides guidance for calculating the quantity of methane released during a venting event, which is added to the total Project Methane Emissions from the BCS, as calculated in Equation 5.6. Equation 5.7 accounts for two releases of biogas: the initial release of biogas being stored in the digester, and then the daily release of additional gas that is generated in the digester until the gas collection system is functional.

The intent of the current guidance is to account for situations where the project digester continues to receive and treat manure, but the gas collection system is discovered to be compromised. In situations where the project digester has been shut down for longer periods of time, biogas is typically released from the digester and then project manure directed to an anaerobic system (e.g. either the covers are taken off the digester or manure is diverted to open lagoons) that would meet the definition in Section 3.4. During such longer shutdowns, it has not been clear whether this entire period of time should be considered a venting event and, if so, how quantification of emissions should proceed.

Clarification: The following text shall be inserted between Equation 5.7 and Equation 5.8 on page 26:

"A venting event occurs when the project digester continues to process manure, but biogas is vented directly to the atmosphere (e.g. through a rip in a lagoon cover or a broken pipe). Projects that experience a venting event shall continue to use Equation 5.7 to calculate the resulting project methane emissions.

A project shutdown occurs when the project digester is no longer functional. This occurs when the project reverts to an open, uncontrolled, anaerobic manure treatment system (e.g. the manure is redirected to open, anaerobic lagoons, or the cover is completely removed from a covered lagoon digester and no heating or mixing occurs). A project shutdown is defined as a venting event on the day of the shutdown, and then a cessation of project operations until the BCS is once again operable.

In the case where the project BCS is shut down and the manure is treated in an open, uncontrolled, anaerobic system (meeting the definition in Section 3.4), the project scenario shall be assumed to be equal to the baseline scenario. In this case the project must quantify the release of stored biogas (MS_{BCS} in Equation 5.7) at the time that the system is shut down, but not the subsequent daily release of biogas from the open lagoons. In these situations the project will cease quantification of emission reductions until the BCS is once again operational."

3. Service Providers for Site-Specific Destruction Efficiency Testing (CLARIFICATION – January 21, 2014)

Section: 5.3 (Calculating Project Methane Emissions)

Context: Footnote 19 on page 25 provides guidelines for service provider accreditation. It is not clear what specific options are available and permissible for projects located in a state or locality which does not have an accreditation program for source test service providers. Footnote 26 on page 29 and the first full paragraph on page 69 in Appendix B contain similar language.

Clarification: The intent of this requirement is to ensure that any source testing conducted for the determination of a site-specific value for methane destruction efficiency is of a quality that would be acceptable for compliance by a regulatory body. The following text shall replace the last sentence of footnote 19 on page 25, of footnote 26 on page 29, and of the first full paragraph on page 69 of Appendix B:

> "If neither the state nor locality relevant to the project site offer accreditation for source testing service providers, projects may use an accredited service provider from another U.S. state or domestic locality. Alternatively, projects may choose a non-accredited service provider, under the following conditions: 1) the service provider must provide verifiable evidence of prior testing which was accepted for compliance by a domestic regulatory agency, and 2) the prior testing procedures must be substantially similar to

the procedures used for determining methane destruction efficiency for the project destruction device(s)."

Section 6

4. Monitoring Operational Status (CLARIFICATION – October 29, 2013)

Section: 6.2 (Biogas Control System Monitoring Requirements)

Context: The first and second paragraphs of page 35 in Section 6.2 states that "[o]perational activity of the destruction devices shall be monitored and documented at least hourly to ensure actual methane destruction. … If for any reason the destruction device or the operational monitoring equipment…is inoperable, then all metered biogas going to the particular device shall be assumed to be released to atmosphere…[and] the destruction efficiency of the device must be assumed to be zero."

Certain types of destruction devices, such as internal combustion engines and most large boiler systems, are designed in such a way that gas may not flow through the device if it is not operational. It has not been clear how the requirements of Section 6.2 apply to these devices.

Clarification: The first sentence of the first paragraph on page 35 shall be read to apply to all destruction devices in use during the reporting period. The paragraph on page 34 of Section 6.2 starting, "[a] single flow meter may be used…," shall not be construed to relax the requirement for hourly operational data for all destruction devices. Rather, that paragraph is allowing a specific metering arrangement during periods when one or more devices are known to be not operating. All destruction devices must have their operational status monitored and recorded at least hourly. If these data are missing or never recorded for a particular device, that device will be assumed to be not operating and will be assigned a destruction efficiency of zero for all flow data that are assigned to that device.

5. Meter Field Check Procedures (CLARIFICATION – October 29, 2013)

Section: 6.3 (Biogas Measurement Instrument QA/QC)

Context: The second paragraph below the first bulleted list of page 36 in Section 6.3 states that "[i]f the field check on a piece of equipment reveals accuracy outside of a +/- 5% threshold, calibration by the manufacturer or a certified service provider is required for that piece of equipment…"

Certain types of biogas flow meters and methane analyzers are susceptible to measurement drift due to buildup of moisture or contaminants on the metering sensor, even if the equipment itself is not out of calibration. If the as-found condition of the meter is outside of the accuracy threshold, but the as-left condition (after cleaning) is within the accuracy threshold, it is not clear whether a full calibration is still required for this piece of equipment. In some cases the manufacturer provides specific guidance to this effect.

Clarification: The following text shall be inserted after the second paragraph following the bulleted list on page 36:

"The as-found condition (percent drift) of a field check must always be recorded. If the meter is found to be measuring outside of the +/- 5% threshold for accuracy, the data must be adjusted for the period beginning with the last successful field check or calibration event up until the meter is confirmed to be in calibration. If, at the time of the failed field check, the meter is cleaned and checked again, with the as-left condition found to be within the accuracy threshold, a full calibration is not required for that piece of equipment. This shall be considered a failed field check, followed by a successful field check. The data adjustment shall be based on the percent drift recorded at the time of the failed field check. However, if the as-left condition remains outside of the +/- 5% accuracy threshold, calibration is required by the manufacturer or a certified service provider for that piece of equipment."

6. Methane Analyzer Factory Calibrations (CLARIFICATION – November 16, 2017)

Section: 6.3 (Biogas Measurement Instrument QA/QC)

Context: The fourth bullet in the list at the beginning of this section (page 36) states that "[all gas flow meters and continuous methane analyzers must be] calibrated by the manufacturer or a certified calibration service per manufacturer's guidance or every 5 years, whichever is more frequent."

The principle underlying this requirement is the need to ensure data integrity. More specifically, the intent of this requirement is that meters meet such requirement every time they are used to gather data that is used in project emission reduction quantification. If a meter was out of conformance with this calibration requirement during a portion of the reporting period when it is not in use, but is brought back into conformance with this requirement before again being used to gather data which is used for project emission reduction calculations, then the underlying intent of this requirement is met.

Clarification: The following text shall be inserted after the fourth bulleted point at the beginning of Section 6.3:

"Conformance with this requirement is only required during periods of time where data gathered by the meter are used for emission reduction quantification. Periods where the meter did not meet this requirement will not cause the project to fail this requirement, provided the meter was not being used for project emission reduction quantification during such periods, and provided the meter was brought back into conformance before being employed to gather data which is used for project emission reduction quantification."

Appendix D

7. Data Substitution when Operational Data are Missing (ERRATUM – October 29, 2013)

Section: Appendix D (Data Substitution)

Context: There are three parameters necessary for the quantification of biogas destruction: biogas flow volume, methane concentration, and operational status of the destruction device. Section D.1 on page 80 provides a methodology for the substitution of missing biogas flow or methane concentration data. Data on the operational status of a destruction device are not eligible for substitution. Substitution of one parameter (i.e. flow or concentration) is only allowed if both other parameters are successfully recorded during the data gap. Thus, to employ the data substitution methodology, it is required that the record of operational status be intact during the gap.

This data substitution methodology was originally developed to resolve incidents of missing methane destruction data in landfill gas projects. Under that project type, excluding the data gap entirely is equivalent to the use of a destruction efficiency (DE) value of zero, whereas the same is not true for a livestock project. In the case of the Livestock Project Protocol, there is additional guidance on page 35 of Section 6.2 that requires the use of a DE value of zero for periods where the destruction device is inoperable, or the operational data are missing. This procedure effectively provides substitution of missing operational data with the assumption that the device was inoperable during the data gap. The effect of this substitution is an increase in project emissions, resulting in a more conservative estimate of emission reductions, regardless of whether the ultimate estimate of emission reductions is based on the modeled baseline or the metered methane destruction.

Because of the nature of the quantification methodology for livestock projects, and the ways that it differs from that of landfill projects, it is appropriate and conservative to carry out flow or methane data substitution, even if the destruction device is inoperable. Under this protocol, the quantification of emission reductions will be more conservative than if the data substitution were not employed.

Correction: The guidance on page 35 of Section 6.2 shall supersede the guidance in Appendix D. The following text shall be inserted after the second paragraph of Section D.1 in Appendix D:

“If the destruction device is inoperable, or its operational data are missing, the destruction efficiency for the device shall be zero during that period of time. Data substitution may be employed for missing biogas flow or methane concentration data during periods of missing operational data, provided the dataset is able to fulfill all other requirements of this data substitution methodology. The data substitution methodology shall be employed in the manner resulting in the greatest level of conservativeness for the quantification of emission reductions.”

8. Data Substitution for Continuous Methane Data (CLARIFICATION – October 29, 2013)

Section: Appendix D (Data Substitution)

Context: The data substitution methodology in Appendix D may not be used for data gaps that are greater than seven days. However, the minimum measurement frequency for methane concentration data is once per quarter (three months). For projects that measure methane concentration at a frequency that is greater than quarterly, it is not clear how methane values should be applied during gaps of more than one week but less than an entire quarter.

Clarification: As long as a livestock project has at least one methane concentration reading per quarter, the project may satisfy the monitoring requirements in Section 6.2. A livestock project may have gaps between methane concentration readings that are greater than one week without this being considered “missing data” as it is conceived in Appendix D. Thus, project developers may devise a reasonable approach by which to assign a value to periods of time between recorded methane concentration values. The verifier shall confirm that the value(s) applied by the project is reasonable and conservative. No data substitution may be applied if there are no methane concentration readings during an entire quarter.

A.2.8 Ozone Depleting Substances Project Protocol v2.0

CLIMATE ACTION RESERVE

United States | Version 2.0 | June 27, 2012

Ozone Depleting Substances

Project Protocol

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Abbreviations and Acronyms

A/C	Air conditioning
AHRI	Air-Conditioning, Heating and Refrigeration Institute
CAA	Clean Air Act
CEMS	Continuous emissions monitoring system
CFC	Chlorofluorocarbons
CH_4	Methane
CO_2	Carbon dioxide
CPT	Comprehensive Performance Test
CRT	Climate Reserve Tonne
DOT	United States Department of Transportation
DRE	Destruction and removal efficiency
EPA	United States Environmental Protection Agency
GWP	Global warming potential
HBFC	Hydrobromofluorocarbons
HCFC	Hydrochlorofluorocarbons
HFC	Hydrofluorocarbons
HWC	Hazardous waste combustor
MACT	Maximum available control technology
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NIST	National Institute of Standards and Technology
ODS	Ozone depleting substances
PU	Polyurethane
RAL	RAL Quality Assurance Association
RCRA	Resource Conservation and Recovery Act
REFPROP	Reference Fluid Thermodynamic and Transport Properties Database
Reserve	Climate Action Reserve
TEAP	Technology and Economic Assessment Panel
WEEE	Waste Electrical and Electronic Equipment Directive

1 Introduction

The Climate Action Reserve U.S. Ozone Depleting Substances Project Protocol provides guidance to account for, report, and verify greenhouse gas (GHG) emission reductions associated with the destruction of high global warming potential ozone depleting substances (ODS) sourced from and destroyed within the U.S. that would have otherwise been released to the atmosphere. This project category includes ODS used in foam blowing agent and refrigerant applications. All destroyed ODS must be fully documented, chemically analyzed, and destroyed at a qualifying facility to be eligible for crediting under this protocol. All ODS must originate in the United States; potential project developers wishing to generate credits from the destruction of ODS originating outside of the United States must use the Climate Action Reserve's Article 5 Ozone Depleting Substances Project Protocol.

As the premier carbon offset registry for the North American carbon market, the Climate Action Reserve works to ensure environmental benefit, integrity and transparency in market-based solutions that reduce greenhouse gas emissions. It establishes high quality standards for carbon offset projects, oversees independent third-party verification bodies, issues carbon credits generated from such projects and tracks the transaction of credits over time in a transparent, publicly-accessible system. By facilitating and encouraging the creation of GHG emission reduction projects, the Climate Action Reserve program promotes immediate environmental and health benefits to local communities, allows project developers access to additional revenues and brings credibility and value to the carbon market. The Climate Action Reserve is a private 501c(3) nonprofit organization based in Los Angeles, California.

ODS project developers must use this document to quantify, verify and report GHG reductions with the Reserve. The protocol provides eligibility rules, methods to calculate reductions, performance-monitoring instructions, and procedures for reporting project information to the Reserve. Additionally, all projects must submit to annual, independent verification by ISO-accredited and Reserve-approved verification bodies. Guidance for verification bodies to verify reductions is provided in the Reserve's Verification Program Manual and Section 8 of this protocol.

This project protocol is designed to ensure the complete, consistent, transparent, accurate, and conservative quantification and verification of GHG emission reductions associated with an ODS destruction project.[1]

[1] See the WRI/WBCSD GHG Protocol for Project Accounting (Part I, Chapter 4) for a description of GHG reduction project accounting principles.

2 The GHG Reduction Project

2.1 Background

The term “ozone depleting substances” refers to a large group of chemicals known to destroy the stratospheric ozone layer when released into the atmosphere. ODS were historically used in a wide variety of applications including refrigerants, foam blowing agents, solvents, and fire suppressants. In addition to their potency as ozone depleting substances, the ODS addressed by this protocol also exhibit high global warming potentials (GWP). The GWP of these ODS range from several hundred to several thousand times that of carbon dioxide (see Table 5.1).

The adoption of the Montreal Protocol on Substances that Deplete the Ozone Layer[2] in 1987 laid out a global framework for the phase-out of the production of certain known ODS. The Montreal Protocol differentiated two separate phase-out schedules: one for the developing Article 5 countries[3] and a more rapid phase-out for the developed Non-Article 5 countries[4], including the United States. The current phase-out schedule for Class I and Class II ODS for the United States, as dictated by the Montreal Protocol, is presented below in Table 2.1. The United States incorporated this phase-out schedule in domestic regulations and also applied a “worst first” approach to HCFC (i.e. prioritizing production phase-outs according to the destructive potential of HCFC in the ozone layer). The U.S. schedule is also presented below in Table 2.1.

Table 2.1. Production Phase-Out Schedule of the Montreal Protocol[5,6]

Ozone Depleting Substance	Non-Article 5 Countries	U.S.
CFC (chlorofluorocarbons)	January 1, 1996	January 1, 1996
Halons	January 1, 1994	January 1, 1994
Carbon tetrachloride	January 1, 1996	January 1, 1996
Methyl chloroform	January 1, 1996	January 1, 1996
Methyl bromide	January 1, 2005	January 1, 2005
HBFC (Hydrobromofluorocarbons)	January 1, 1996	January 1, 1996
HCFC (hydrochlorofluorocarbons)	January 1, 1996: Freeze at baseline	January 1, 1996: Freeze at baseline
	January 1, 2004: cut by 35%	January 1, 2003: No production and no importing of HCFC-141b
	January 1, 2010: cut by 75%	January 1, 2010: No production and no importing of HCFC-142b and HCFC-22, except for use in equipment manufactured before 1/1/2010

2 http://ozone.unep.org/Ratification_status/montreal_protocol.shtml, and subsequent revisions and amendments.
3 See http://ozone.unep.org/Ratification_status/list_of_article_5_parties.shtml for a list of countries operating under Article 5.
4 See http://ozone.unep.org/Ratification_status/ for a list of all countries that have ratified the Montreal Protocol.
5 U.S. EPA, Phase-out of Class I Ozone Depleting Substances, available at: http://www.epa.gov/ozone/title6/phaseout/classone.html.
6 U.S. EPA, Phase-out of Class II Ozone Depleting Substances, available at: http://www.epa.gov/ozone/title6/phaseout/classtwo.html.

Ozone Depleting Substance	Non-Article 5 Countries	U.S.
	January 1, 2015: cut by 90%	January 1, 2015: No production and no importing of any HCFC, except for use as refrigerants in equipment manufactured before 1/1/2020
	January 1, 2020: cut by 99.5% (can only be used for refrigerator/AC servicing after this date)	January 1, 2020: No production and no importing of HCFC-142b and HCFC-22
	January 1, 2030: full phase-out	January 1, 2030: No production and no importing of any HCFC

The Montreal Protocol and the U.S. Clean Air Act[7] (CAA) control the production of ODS in the United States. However, neither framework requires the destruction of extant stocks of ODS. Rather, these stocks may leak to the atmosphere or may be recovered, recycled, reclaimed, and reused indefinitely, often in equipment with very high leak rates. Because the Montreal Protocol and Title VI of the CAA do not forbid the use of existing or recycled controlled substances beyond the phase-out dates, even properly managed ODS banks will eventually be released as fugitive emissions to the atmosphere.

Refrigerants

Prior to the 1996 production phase-out in the United States, equipment utilizing ODS refrigerants was preferred in a wide variety of applications. These applications include industrial and commercial refrigeration, cold storage, comfort cooling equipment (i.e. air conditioning), and various consumer applications. While the production of ODS refrigerants has been phased out (with the exception of certain HCFC), these substances are continually recovered, reclaimed and recycled to service old equipment. As such, use of these ODS is still widespread, and can be found everywhere from vehicle air conditioners to industrial chillers.

Despite regulations prohibiting their intentional release through servicing, use, and end of life, refrigerant ODS may be inadvertently released to the atmosphere at rates of up to 35 percent per year.[8]

Foams

The ODS CFC-11, CFC-12, HCFC-141b, and HCFC-22 were used as blowing agents in the production of foam prior to their mandated production phase-out in the United States. Many of the applications for which this foam was used, such as refrigeration or A/C units and building insulation, have extended lifetimes and these foams containing ODS will therefore be present in the waste stream for many years to come. When foam is disposed of, ODS blowing agent is released from the foam during shredding[9] and/or degradation in the landfill.[10]

[7] CAA, Title VI, Section 604(a).
[8] IPCC/TEAP. (2005). Special report: Safeguarding the Ozone Layer and the Global Climate System: Issues Related to Hydrofluorocarbons and Perfluorocarbons.
[9] Scheutz et al. (2007). Release of fluorocarbons from insulation foam in home appliances during shredding. *Journal of the Air & Waste Management Association.*
[10] Scheutz et al. (2007). Attenuation of fluorocarbons released from foam insulation in landfills. *Environmental Science & Technology*, *41*: 7714-7722.

2.2 Project Definition

For the purposes of this protocol, a project is defined as any set of activities undertaken by a single project developer resulting in the destruction[11] of eligible ODS at a single qualifying destruction facility within a 12-month period. Destruction may take place under one or more Certificates of Destruction. Each Certificate of Destruction must document the ODS destroyed. The ODS destroyed may come from a single origin (e.g. one supermarket) or from numerous sources. However, the entire quantity of eligible ODS destroyed must be documented on one or more Certificates of Destruction issued by a qualifying destruction facility.

Although project developers may engage in ongoing recovery, aggregation and destruction activities, destruction events that fall outside of the 12-month window designated for a project may only be counted as part of a separately registered project. Project developers may choose a shorter time horizon for a single project (e.g. 3 months or 6 months), but no project may run longer than 12 months.

In order for multiple Certificates of Destruction to be included under a single project, all of the following conditions must be met:

- The project developer and owner of emission reductions are the same for all ODS destroyed
- The qualifying destruction facility is the same for all Certificates of Destruction
- Project activities span a timeframe of no more than 12 months from the project's start date to completion of the last ODS destruction event
- No Certificate of Destruction is included as part of another project

For all projects, the end fate of the ODS must be destruction at either an approved Hazardous Waste Combustor (HWC) subject to the Resource Conservation and Recovery Act (RCRA), CAA, and the National Emissions Standards for Hazardous Air Pollutants (NESHAP) standards, or any other transformation or destruction facility that meets or exceeds the Montreal Protocol's Technology and Economic Assessment Panel (TEAP) standards provided in the *Report of the Task Force on Destruction Technologies*.[12] Non-RCRA permitted facilities cannot receive and destroy ODS materials that are classified as hazardous waste and must demonstrate compliance with the Title VI requirements of the CAA for destruction of ODS, as well as demonstrate destruction and removal efficiency (DRE) of 99.99 percent and emission levels consistent with the guidelines set forth in the aforementioned TEAP report (see Appendix C).

2.3 Eligible ODS

This protocol provides requirements and guidance for the accounting of GHG reductions from two general sources of ODS eligible under the project definition:

- **Refrigerants:** A project may recover or aggregate eligible ODS refrigerant (see Section 2.3.1) from industrial, commercial or residential equipment, systems, and appliances or stockpiles, and destroy it at a qualifying destruction facility.

[11] In this protocol, the term "destruction" is used to describe any activity that results in the elimination of ODS with an efficiency of 99.99 percent or higher. This definition incorporates both destruction and transformation technologies as defined by the EPA and the Clean Air Act (40 CFC 82).
[12] TEAP. (2002). Report of the Task Force on Destruction Technologies. *Volume 3B*.

- **Foams:** A project may extract eligible ODS blowing agent (see Section 2.3.2) from appliance foams and destroy the concentrated ODS foam blowing agent at a qualifying destruction facility; or, a project may destroy intact foam sourced from building insulation at a qualified destruction facility.

A single project may incorporate ODS obtained from one or both of these ODS source categories. Tracking procedures and calculation methodologies differ depending on the source of ODS. ODS sources not in one of the above categories, such as ODS that were used as or produced for use as solvents, medical aerosols or other applications are not eligible under this protocol.

2.3.1 Refrigerant Sources

This source category consists of ODS material produced prior to the U.S. production phase-out that could legally be sold into the U.S. refrigerant market.[13] The ODS must originate from domestic U.S. supplies; imported refrigerant is not eligible under this protocol. Project developers seeking to register projects involving the domestic destruction of imported refrigerant must use the Reserve's Article 5 Ozone Depleting Substances Project Protocol.

In the absence of a GHG reduction project, this material may be illegally vented or recovered for re-sale into the refrigerant recharge market. As described in Section 5, for GHG reduction calculation purposes, this protocol conservatively assumes that the refrigerant would be reclaimed.

Only destruction of the following ODS refrigerants is eligible for crediting under this protocol:

- CFC-11
- CFC-12
- CFC-13
- CFC-113
- CFC-114
- CFC-115

ODS extracted from a foam source for use in refrigeration equipment is not considered part of this source category, and must instead be considered as a foam source.

ODS sourced from the federal government is eligible if it meets the point of origin requirements detailed in Section 6.2.

Additionally, all refrigerant recovery, handling, and destruction must be performed in accordance with the reporting and operation requirements of Section 6.

2.3.2 Foam Sources

This source category consists of ODS blowing agent entrained in foams that, absent a GHG reduction project, would have been released at end-of-life. The ODS blowing agent must originate from U.S. foam sources; imported foams are not eligible under this protocol.

[13] Any ODS produced in association with a critical use or as by-product is ineligible.

Only the following ODS foam blowing agents are eligible to generate reductions under this protocol:

- CFC-11
- CFC-12
- HCFC-22
- HCFC-141b

To be eligible for crediting, the ODS blowing agent must be destroyed in one of two ways:

1. **ODS blowing agent extracted from appliance foam and destroyed.** The ODS blowing agent must be extracted from the foam to a concentrated form prior to destruction. This must be done under negative pressure to ensure that fugitive release of ODS cannot occur. The recovered ODS blowing agent must be aggregated, stored, and transported in cylinders or other hermetically sealed containers.

2. **Intact foam containing ODS blowing agent from buildings destroyed intact.** When the intact foam is separated from building panels, it must be stored, transported, and destroyed in sealed containers.

All blowing agent and foam collection, handling, extraction, and destruction must be performed in accordance with the reporting and operation requirements of Section 6.

2.4 The Project Developer

The "project developer" may be any entity that has an active account on the Reserve, submits a project for listing and registration with the Reserve, and is ultimately responsible for all project reporting and verification. Project developers may be ODS aggregators, facility owners, facility operators, or GHG project financiers. The project developer must have clear ownership of the project's GHG reductions. Ownership of the GHG reductions must be established by clear and explicit title, and the project developer must attest to such ownership each time the project is verified by signing the Reserve's Attestation of Title form.[14]

Neither the federal government nor a federal government agency is eligible to be a project developer under this protocol, but material sourced from the federal government may be eligible if it meets all protocol requirements (see Section 6.2).

[14] Attestation of Title form available at http://www.climateactionreserve.org/how/projects/register/project-submittal-forms/. Verification activities not related to confirming the Attestation of Title (such as site visits or project material eligibility confirmation) may commence prior to this form being uploaded to the Reserve.

3 Eligibility Rules

Projects that meet the definition of a GHG reduction project in Section 2.2 must fully satisfy the following eligibility rules in order to register with the Reserve.

Eligibility Rule I:	Location	→	*U.S. and its territories*
Eligibility Rule II:	Project Start Date	→	*No more than six months prior to project submission*
Eligibility Rule III:	Additionality	→	*Exceed legal requirements*
		→	*Meet performance standard*
Eligibility Rule IV:	Regulatory Compliance	→	*Compliance with all applicable laws*

3.1 Location

For ODS destruction to be eligible as a project under this protocol, all ODS must be sourced from stocks in the United States or its territories and destroyed within the United States or its territories. Project developers seeking to register projects involving the domestic destruction of imported ODS must use the Reserve's Article 5 Ozone Depleting Substances Project Protocol.

3.2 Project Start Date

The project start date is defined according to the commencement of project activities.

- For concentrated (non-mixed) ODS projects[15] that are not aggregated at the destruction facility, the project start date is the day that the project ODS departs the final storage or aggregation facility for transportation to the destruction facility.
- For concentrated (non-mixed) ODS projects where eligible material is aggregated at the destruction facility, the project start date is the day when destruction commences, as documented by a Certificate of Destruction.
- For mixed ODS projects, the project start date is the day that mixing procedures begin.

To be eligible, the project must be submitted to the Reserve no more than six months after the project start date.[16] Projects may always be submitted for listing by the Reserve prior to their start date.

3.3 Project Crediting Period

An ODS project includes a discrete series of destruction events over a 12-month period, beginning on the project start date. No destruction events may occur more than 12 months after the project start date. For the purposes of this protocol, it is assumed that, absent the project, the avoided ODS emissions would have occurred over a longer time horizon.

Under this protocol, the project crediting period is the period of time over which avoided emissions are quantified for the purpose of determining creditable GHG reductions. Specifically,

[15] As defined in Section 6.6.

[16] Projects are considered submitted when the project developer has fully completed and filed the required documents, available at http://www.climateactionreserve.org/how/projects/register/project-submittal-forms/.

ODS projects will be issued CRTs for the quantity of ODS that would have been released over a ten-year period following a destruction event. At the time the project is verified, CRTs are issued for all ODS emissions avoided by a project over the 10-year crediting period.

3.4 Additionality

The Reserve strives to register only projects that yield surplus GHG reductions that are additional to what would have otherwise occurred in the absence of a GHG market.

Projects must satisfy both of the following tests to be considered additional:

1. The Legal Requirement Test
2. The Performance Standard Test

3.4.1 The Legal Requirement Test

All projects are subject to a Legal Requirement Test to ensure that the GHG reductions achieved by a project would not otherwise have occurred due to international, federal, state or local regulations, or other legally binding mandates. A project passes the Legal Requirement Test when there are no laws, statutes, regulations, court orders, environmental mitigation agreements, permitting conditions, or other legally binding mandates requiring the destruction of ODS. To satisfy the Legal Requirement Test, project developers must submit a signed Attestation of Voluntary Implementation form[17] each time the project is verified (see Section 8).[18] In addition, the project's Monitoring and Operations Plan (Section 6) must include procedures that the project developer will follow to ascertain and demonstrate that the project at all times passes the Legal Requirement Test.

3.4.2 The Performance Standard Test

Projects pass the Performance Standard Test by meeting a performance threshold, i.e. a standard of performance applicable to all ODS destruction projects, established on an *ex ante* basis by this protocol.[19]

For this protocol, the Reserve uses a Performance Standard Test based on an evaluation of U.S. "common practice" for privately managed ODS. Because the Reserve has determined that destruction of ODS is not common practice in the United States (see Appendix B), all ODS destruction activities that meet the project definitions and other eligibility requirements pass the Performance Standard Test.

The Reserve will periodically re-evaluate the appropriateness of the Performance Standard Test, and if necessary, amend this protocol accordingly. Projects that meet the Performance Standard Test and other requirements of the version of this protocol in effect at the time of their submission are eligible to generate CRTs.

[17] Attestation of Voluntary Implementation form available at http://www.climateactionreserve.org/how/projects/register/project-submittal-forms/.
[18] Verification activities not related to confirming the Attestation of Voluntary Implementation (such as site visits or project material eligibility confirmation) may commence prior to this form being uploaded to the Reserve.
[19] A summary of the study to establish the Performance Standard Test is provided in Appendix B.

3.5 Regulatory Compliance

Projects must be in material compliance with all applicable laws (e.g. air, water quality, and safety) at all times during each reporting period, as defined in Section 5. The regulatory compliance requirement extends to the operation of destruction facilities where the ODS is destroyed, as well as the facilities where mixed ODS projects are mixed and sampled, and the transportation of the ODS to the destruction facility. These facilities and transportation events must meet applicable regulatory requirements during implementation of project activities. For example, any upsets or exceedances of permitted emission limits at a destruction facility must be managed in keeping with an authorized startup, shutdown, and malfunction plan.[20]

Project developers must attest that the project has met this requirement by signing the Reserve's Attestation of Regulatory Compliance[21] for each reporting period.[22] Projects are not eligible to receive CRTs for GHG reductions that occur as the result of project activities that are not in material compliance with regulatory requirements. Non-compliance solely due to administrative or reporting issues, or due to "acts of nature," will not affect CRT crediting.

Project developers are required to disclose in writing to the verifier any and all instances of non-compliance of the project with any law. If a verifier finds that a project is in a state of material non-compliance or non-compliance that is the result of negligence or intent, then CRTs will not be issued for GHG reductions that occurred during the period of non-compliance.

[20] 40 CFR 63.1206.
[21] Attestation of Regulatory Compliance form available at http://www.climateactionreserve.org/how/projects/register/project-submittal-forms/.
[22] Verification activities not related to confirming the Attestation of Regulatory Compliance (such as site visits or project material eligibility confirmation) may commence prior to this form being uploaded to the Reserve.

4 The GHG Assessment Boundary

The GHG Assessment Boundary delineates the GHG sources, sinks, and reservoirs (SSRs) that shall be assessed by project developers in order to determine the total net change in GHG emissions caused by an ODS project.[23]

Figure 4.1, Figure 4.2, and Figure 4.3 below provide a general illustration of the GHG Assessment Boundaries for different types of ODS destructions projects, indicating which SSRs are included or excluded from the boundary.

Table 4.1 gives greater detail on each SSR and provides justification for all SSRs and gases that are excluded from the GHG Assessment Boundary.

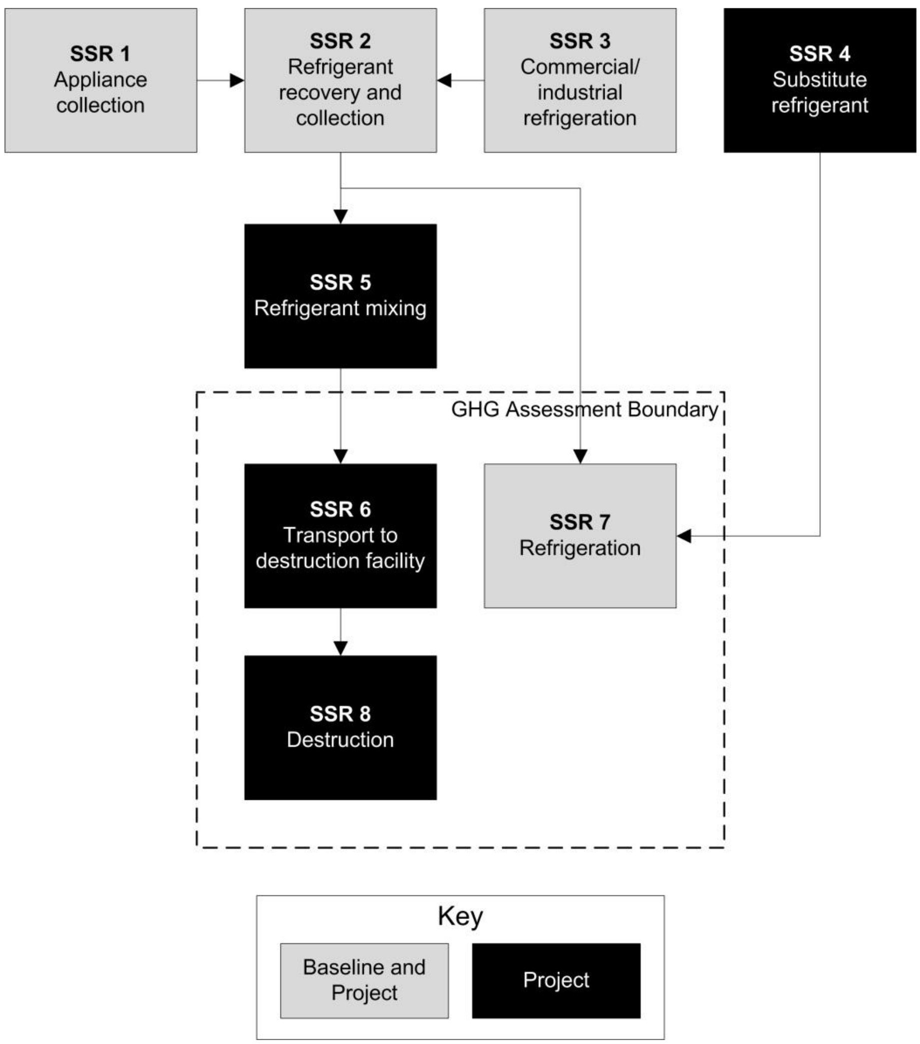

Figure 4.1. Illustration of the GHG Assessment Boundary for Refrigerant Projects

[23] The definition and assessment of SSRs is consistent with ISO 14064-2 guidance.

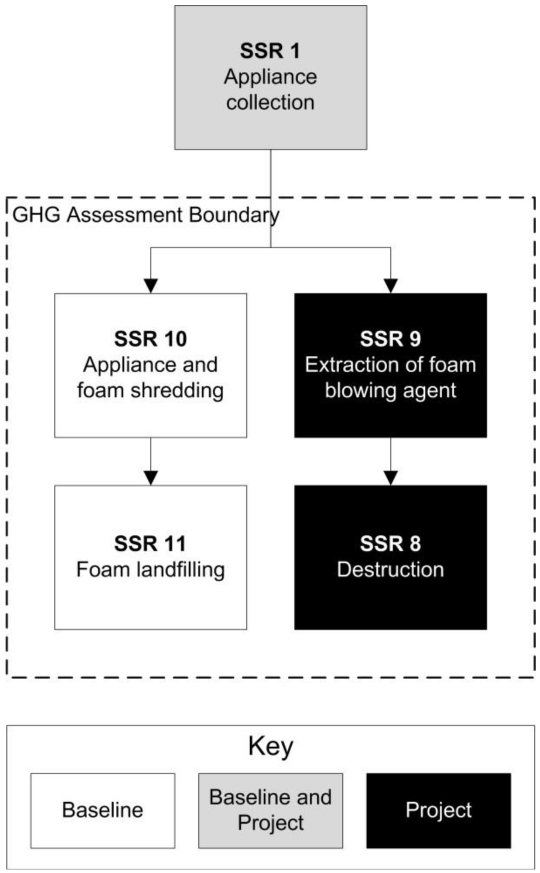

Figure 4.2. Illustration of the GHG Assessment Boundary for Appliance Foam Projects

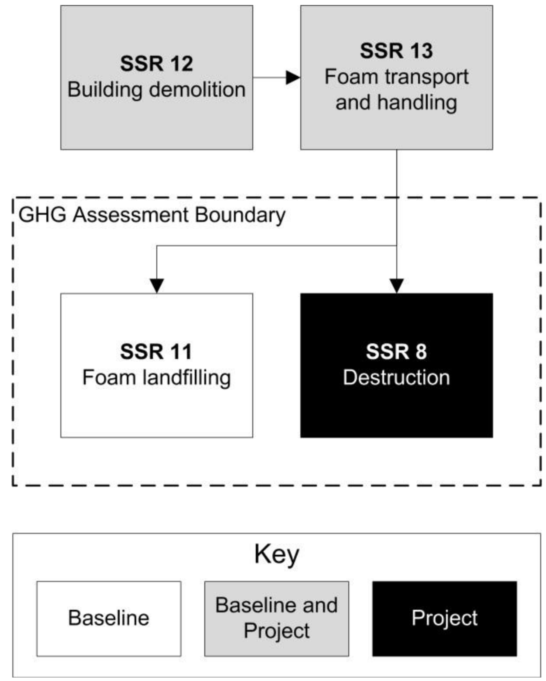

Figure 4.3. Illustration of the GHG Assessment Boundary for Building Foam Projects

Table 4.1. Summary of Identified Sources, Sinks, and Reservoirs

SSR		Source Description	Gas	Included (I) or Excluded (E)	Quantification Method	Justification/Explanation
1	Appliance collection	Fossil fuel emissions from the collection and transport of end-of-life residential appliances	CO_2	E	N/A	Excluded, as project activity is unlikely to affect emissions relative to baseline activity
			CH_4	E	N/A	Excluded, as project activity is unlikely to affect emissions relative to baseline activity
			N_2O	E	N/A	Excluded, as project activity is unlikely to affect emissions relative to baseline activity
2	Refrigerant recovery and collection	Emissions of ODS from the recovery and aggregation of refrigerant at end-of-life or servicing	ODS	E	N/A	Excluded, as project activity is likely to decrease these emissions. Therefore, exclusion is conservative
		Fossil fuel emissions from the recovery and aggregation of refrigerant at end-of-life or servicing	CO_2	E	N/A	Excluded, as project activity is unlikely to affect emissions relative to baseline activity
			CH_4	E	N/A	Excluded, as project activity is unlikely to affect emissions relative to baseline activity
			N_2O	E	N/A	Excluded, as project activity is unlikely to affect emissions relative to baseline activity
3	Commercial/ Industrial refrigeration	Emissions of ODS from equipment leak and servicing	ODS	E	N/A	Excluded, as project activity is unlikely to affect emissions relative to baseline activity
		Fossil fuel emissions from the operation of refrigeration and A/C equipment	CO_2	E	N/A	Excluded, as project activity is unlikely to affect emissions relative to baseline activity
			CH_4	E	N/A	Excluded, as project activity is unlikely to affect emissions relative to baseline activity

SSR		Source Description	Gas	Included (I) or Excluded (E)	Quantification Method	Justification/Explanation
			N_2O	E	N/A	Excluded, as project activity is unlikely to affect emissions relative to baseline activity
4	Substitute refrigerant production	▪ Emissions of substitute refrigerant occurring during production ▪ Fossil fuel emissions from the production of substitute refrigerants	CO_2e	E	N/A	Excluded, as this emission source is assumed to be very small
			CO_2	E	N/A	Excluded, as this emission source is assumed to be very small
			CH_4	E	N/A	Excluded, as this emission source is assumed to be very small
			N_2O	E	N/A	Excluded, as this emission source is assumed to be very small
5	Refrigerant mixing	Fossil fuel emissions from ODS mixing activities at mixing facility	CO_2 CH_4 N_2O	E	N/A	Excluded, as these emission sources are assumed to be very small
6	Transport to destruction facility	Fossil fuel emissions from the vehicular transport of ODS from aggregation point to final destruction facility	CO_2	I	**Baseline:** N/A **Project:** Estimated based on distance and weight transported	Project emissions will be small, and can be calculated using the default factor provided
			CH_4	E	N/A	Excluded, as this emission source is assumed to be very small
			N_2O	E	N/A	Excluded, as this emission source is assumed to be very small
7	Refrigeration	Emissions of ODS from leaks and servicing through continued operation of equipment	ODS	I	**Baseline:** Estimated based on market-weighted emission rates **Project:** N/A	Baseline equipment emissions will be significant for refrigerant sources, but are not applicable for foam sources
		Emissions of substitute from leaks and servicing through continued operation of equipment	CO_2e	I	**Baseline:** N/A **Project:** Estimated based on market-weighted emissions	Project equipment emissions will be significant for refrigerant sources, but are not applicable for foam sources

SSR		Source Description	Gas	Included (I) or Excluded (E)	Quantification Method	Justification/Explanation
		Indirect emissions from grid-delivered electricity	CO_2	E	N/A	Excluded, as project activity is unlikely to affect emissions relative to baseline activity
			CH_4	E	N/A	Excluded, as project activity is unlikely to affect emissions relative to baseline activity
			N_2O	E	N/A	Excluded, as project activity is unlikely to affect emissions relative to baseline activity
8	Destruction	Emissions of ODS from incomplete destruction at destruction facility	ODS	I	**Baseline:** N/A **Project:** Estimated based on ODS destroyed, or included in default deduction	Project emissions will be small, and can be calculated using the default factor provided
		Emissions from the oxidation of carbon contained in destroyed ODS	CO_2	I	**Baseline:** N/A **Project:** Estimated based on ODS destroyed, or included in default deduction	Project emissions will be small, and can be calculated using the default factor provided
		Fossil fuel emissions from the destruction of ODS at destruction facility	CO_2	I	**Baseline:** N/A **Project:** Estimated based on ODS destroyed, or included in default deduction	Project emissions will be small, and can be calculated using the default factor provided
			CH_4	E	N/A	Excluded, as this emission source is assumed to be very small
			N_2O	E	N/A	Excluded, as this emission source is assumed to be very small

SSR		Source Description	Gas	Included (I) or Excluded (E)	Quantification Method	Justification/Explanation
		Indirect emissions from the use of grid-delivered electricity	CO_2	I	**Baseline:** N/A **Project:** Estimated based on ODS destroyed, or included in default deduction	Project emissions will be small, and can be calculated using the default factor provided
			CH_4	E	N/A	Excluded, as this emission source is assumed to be very small
			N_2O	E	N/A	Excluded, as this emission source is assumed to be very small
9	Extraction of ODS blowing agent from appliance foam	Emissions of ODS released during the separation of foam from appliance	ODS	I	**Baseline:** N/A **Project:** Estimated based on recovery efficiency	Project emissions may be significant. Site specific recovery efficiency shall be used
10	Appliance and foam shredding	Emissions of ODS from the shredding of appliances for materials recovery, releasing ODS from foam	ODS	I	**Baseline:** Estimated based on total quantity of ODS destroyed and default shredding factors **Project:** N/A	Baseline shredding emissions will be significant for foam sources, but are non-applicable for refrigerant sources
11	Foam landfilling	Emissions of ODS released from foam disposed of in landfills	ODS	I	**Baseline:** Estimated based on release and degradation of ODS in landfill **Project:** N/A	Baseline emissions will be significant for foam sources, but are not applicable for refrigerant sources
		Emissions of ODS degradation products from foam disposed of in landfills	HFC, HCFC	E	N/A	Excluded, as this baseline emission source is assumed to be very small. This exclusion is conservative
		Fossil fuel emissions from the transport and placement of	CO_2	E	N/A	Excluded, as project activity is likely to decrease these emissions. Therefore, exclusion is conservative

SSR		Source Description	Gas	Included (I) or Excluded (E)	Quantification Method	Justification/Explanation
		shredded foam waste in landfill	CH_4	E	N/A	Excluded, as project activity is likely to decrease these emissions. Therefore, exclusion is conservative
			N_2O	E	N/A	Excluded, as project activity is likely to decrease these emissions. Therefore, exclusion is conservative
12	Building demolition	Emissions of ODS from the demolition of buildings and damage to foam insulation panels	ODS	E	N/A	Excluded, as project activity is unlikely to affect emissions relative to baseline activity
		Fossil fuel emissions from the demolition of buildings	CO_2	E	N/A	Excluded, as project activity is unlikely to affect emissions relative to baseline activity
			CH_4	E	N/A	Excluded, as project activity is unlikely to affect emissions relative to baseline activity
			N_2O	E	N/A	Excluded, as project activity is unlikely to affect emissions relative to baseline activity
13	Foam transport and handling	Emissions of ODS released from foam during transport and handling	ODS	E	N/A	Excluded, as project activity is unlikely to affect emissions relative to baseline activity
		Fossil fuel emissions from the transport and handling of building foam	CO_2	E	N/A	Excluded, as project activity is unlikely to affect emissions relative to baseline activity
			CH_4	E	N/A	Excluded, as project activity is unlikely to affect emissions relative to baseline activity
			N_2O	E	N/A	Excluded, as project activity is unlikely to affect emissions relative to baseline activity

5 Quantifying GHG Emission Reductions

GHG emission reductions from an ODS project are quantified by comparing actual project emissions to calculated baseline emissions. Baseline emissions are an estimate of the GHG emissions from sources within the GHG Assessment Boundary (see Section 4) that would have occurred in the absence of the ODS destruction project. Project emissions are actual GHG emissions that occur at sources within the GHG Assessment Boundary. Project emissions must be subtracted from the baseline emissions to quantify the project's total net GHG emission reductions (Equation 5.1).

A project may not span more than 12 months, and GHG emission reductions must be quantified and verified at least once for the entire project time length. The length of time over which GHG emission reductions are quantified and verified is called a "reporting period." Project developers may choose to have multiple reporting periods within a project or a project time length shorter than 12 months, if desired. The quantification methods presented below are specified for a single reporting period, which may be less than or equal to the entire project time length.

Equation 5.1. Total Emission Reductions

$$ER_t = BE_t - PE_t$$

Where,

			Units
ER_t	=	Total quantity of emission reductions during the reporting period	tCO_2e
BE_t	=	Total quantity of baseline emissions during the reporting period	tCO_2e
PE_t	=	Total quantity of project emissions during the reporting period	tCO_2e

5.1 Quantifying Baseline Emissions

Total baseline emissions must be estimated by calculating and summing the calculated baseline emissions for all relevant SSRs (as indicated in Table 4.1) using Equation 5.2 and the supporting equations presented below. This includes emissions from continued use of ODS in the secondary recharge market for refrigerants, and the emissions from end-of-life disposal for foams. Note that emissions shall be quantified in pounds throughout this section and converted into metric tons in Equation 5.2 below.

Equation 5.2. Total Baseline Emissions

$$BE_t = \frac{BE_{refr} + BE_{foam}}{2204.623}$$

Where,

			Units
BE	=	Total quantity of baseline emissions	tCO_2e
BE_{refr}	=	Total quantity of baseline emissions from refrigerant ODS	lb CO_2e
BE_{foam}	=	Total quantity of baseline emissions from ODS blowing agent	lb CO_2e
2204.623	=	Conversion from pounds to metric tons	lbs/t

Baseline emissions for an ODS destruction project include the total calculated baseline emissions from each eligible source category – ODS refrigerant and ODS blowing agent. If a project does not destroy any ODS from a particular source category, baseline emissions for that source category are assumed to be zero.

Table 5.1 provides the applicable GWP to be used for calculating baseline emissions in units of CO_2-equivalent tonnes.

Table 5.1. Global Warming Potential of Eligible ODS

ODS Species	100-year Global Warming Potential (CO_2e)[24]
CFC-11	4,750
CFC-12	10,900
CFC-13	14,400
CFC-113	6,130
CFC-114	10,000
CFC-115	7,370
HCFC-22	1,810
HCFC-141b	725

If, during verification, the verification body cannot confirm that a portion of the ODS that was sent for destruction was eligible, this portion of the material shall be considered ineligible. This ineligible ODS shall be excluded from baseline emission calculations. The quantity of ineligible ODS sent for destruction shall be subtracted from $Q_{refr,i}$, $BA_{app,i}$ or $BA_{build,i}$ prior to the calculation of Equation 5.3 or Equation 5.4 in order to calculate baseline emissions only for ODS that was confirmed to be eligible by the verification body. This quantity shall be determined by one of the following methods:

Option A: Confirmed weight and composition

If the project developer can produce data that, based on the verifier's professional judgment, confirm the weight and composition for the specific ODS that is deemed to be ineligible (or whose eligibility cannot be confirmed), these data shall be used to adjust the value of $Q_{refr,i}$, $BA_{app,i}$ or $BA_{build,i}$ accordingly.

Option B: Default values

If sufficient data are not available to satisfy the Option A requirements, then the most conservative estimate of the weight and composition of the ineligible container of ODS shall be used. Specifically, the composition of the ineligible container of ODS shall be assumed to be 100 percent of the ODS species with the highest GWP based on the composition analysis, and the relevant container that was deemed ineligible shall be assumed to have been full. If the project developer has only some of the data required for Option A (i.e. weight or composition, but not both), this may be used in place of the conservative assumptions above, as long as the data can be confirmed by the verification body. The resulting estimate of the weight of ineligible ODS shall be subtracted from the total weight of that ODS species destroyed in the project, not to exceed the actual amount of that ODS species destroyed. See Box 5.1 for an example of Option B.

[24]IPCC, Errata: Climate Change 2007, The Physical Science Basis, The Working Group I contribution to the IPCC Fourth Assessment Report, available at http://www.ipcc.ch/pdf/assessment-report/ar4/wg1/ar4-wg1-errata.pdf.

Box 5.1. Applying Option B to Adjust for Ineligible ODS After Destruction

This option shall be applied when multiple containers of ODS are combined into a single container for destruction, but the eligibility of the ODS in one or more of the original containers cannot be verified.

Example:

A refrigerant aggregator receives shipments of three different containers (A, B, and C), which are combined into one project container (Z) for destruction. During verification, the project developer is unable to produce documentation to verify the eligibility of container C.

Original Containers from Point of Origin	Maximum Container Volume	Composition
A	1000 L	unknown
B	500 L	unknown
C	500 L	unknown
Project container	**Weight**	**Composition**
Z	5000 lbs	50% CFC-11 50% CFC-12

Based on Option B above, the project developer must assume that the composition of container C was 100 percent CFC-12 and that the container was completely full. Using the temperature recorded on the composition analysis (62°F for this example), the maximum amount of ODS would be equal to the volume of the container (500 L) multiplied by the density of CFC-12 at 62°F (2.9553 lb/L), or 1,478 lbs. This amount is subtracted from the total amount of eligible ODS prior to quantification of emission reductions.

Resulting eligible ODS:

CFC-11: 2500 lbs
CFC-12: 2500 – 1478 = 1022 lbs

5.1.1 Calculating Baseline Emissions from Refrigerant Recovery and Resale

There are several emissions pathways for refrigerant ODS in the United States. At end-of-life and servicing, a significant portion of ODS may be lost through fugitive releases and low recovery efficiencies. However, a portion of the ODS refrigerant in the U.S. is recovered for resale in the secondary market for recharge of existing equipment. Whereas fugitive release and low recovery results in immediate release of the ODS to the atmosphere, recovery and reuse results in a more gradual release of ODS. To ensure that actual GHG reductions from ODS destruction are not overestimated, this protocol requires estimating baseline emissions according to the assumption that refrigerant ODS would be entirely recovered and resold (i.e. there would have been zero emissions from fugitive releases and low recovery).

Because of this simplified and conservative baseline assumption, there is no need to determine why refrigerants were removed from equipment, why equipment may have been decommissioned, or why a stockpile was not utilized. Instead, Equation 5.3 shall be used to estimate the baseline emissions that would have occurred over ten years had the destroyed ODS been used in existing refrigeration or air conditioning equipment. This equation requires the use of the ODS-specific GWP provided in Table 5.1, and emission rate (inclusive of both leak rate and servicing emissions) provided in Table 5.2.[25]

Equation 5.3. Baseline Emissions from Refrigerant ODS

$$BE_{refr} = \left[\sum_i \left(Q_{refr,i} \times ER_{refr,i} \times GWP_i \right)_i \right] \times (1 - VR)$$

Where, Units

BE_{refr}	=	Total quantity of refrigerant baseline emissions during the reporting period	lb CO_2e
$Q_{refr,i}$	=	Total quantity of eligible, pure refrigerant ODS *i* sent for destruction by the project	lb ODS
$ER_{refr,i}$	=	10-year cumulative emission rate of refrigerant ODS *i* (see Table 5.2)	%
GWP_i	=	Global warming potential of ODS *i* (see Table 5.1)	lb CO_2e/ lb ODS
VR	=	Deduction for vapor composition risk (see Section 5.3)	%

Table 5.2. Baseline Emission Rates for ODS Refrigerants

ODS Species	Annual Weighted Average Emission Rate (%/yr)[26]	10-year Cumulative Emission Rate (%/10 years)[27] (ER_{refr})
CFC-11	20%	89%
CFC-12	26%	95%
CFC-13	9%	61%
CFC-113	20%	89%
CFC-114	14%	78%
CFC-115	9%	61%

5.1.2 Calculating Baseline Emissions from Shredding and/or Landfilling ODS Foam Blowing Agents

Depending on the origin of the foam, there are two different predominant baseline practices applicable to foams containing ODS blowing agent. The two baseline practices identified by the Reserve are as follows:

Origin	Baseline Practice
Insulation foam recovered from appliances	The foam is shredded, and subsequently landfilled
Foam recovered from building demolition	The foam is landfilled

[25] See Appendix D for a summary of how these emissions rates were determined.
[26] EPA. (2011). EPA Vintaging Model. *Version VM IO file_v4.4_3.23.11*. CFC-12 estimates include data from private parties on mobile sources.
[27] 10-year cumulative emissions = 1-(1-leak rate)^{10}, or the percent of a given substance which will be released over ten years at a constant leak rate.

Equation 5.4 shall be used to calculate the ODS emissions that would have resulted from the assumed baseline practice applied to foams in the absence of the project. Baseline emissions include the total emissions that would have occurred as a result of foam shredding and landfilling.[28] In order to calculate total baseline emissions, projects destroying blowing agent extracted from appliance foam must calculate a project-specific recovery efficiency for use in Equation 5.4. Guidance on developing the recovery efficiency can be found in Appendix E.

[28] Temperatures achieved by landfill gas flares and engines are not high enough to achieve significant ODS destruction.

Equation 5.4. Baseline Emissions from ODS Blowing Agent

$$BE_{foam} = \sum_{i,j} \left[\left(BA_{app,i} + BA_{build,i} \right) \times ER_{i,j} \times GWP_i \right]$$

Where,			Units
BE_{foam}	=	Total quantity of ODS blowing agent baseline emissions	lb CO_2e
$BA_{app,i,}$	=	Total quantity of eligible ODS blowing agent *i* from appliance foam prior to treatment or processing, including blowing agent lost during processing	lb ODS
$BA_{build,i}$	=	Total quantity of eligible ODS blowing agent *i* from building foam sent for destruction	lb ODS
$ER_{i,j}$	=	Lifetime emission rate of ODS blowing agent *i* from application *j* at end-of-life (see Table 5.3)	%
GWP_i	=	Global warming potential of ODS *i* (see Table 5.1)	lb CO_2e/ lb ODS

$$BA_{app,i} = Q_{recover} + Q_{recover}\left(\frac{1-RE}{RE}\right)$$

Where,			Units
$BA_{app,i}$	=	Total quantity of ODS foam blowing agent in foam prior to treatment or processing, including ODS foam blowing agent lost during processing	lb ODS
$Q_{recover}$	=	Total quantity of eligible ODS foam blowing agent recovered during processing and sent for destruction, as determined according to Section 6.6	lb ODS
RE	=	Recovery efficiency of the ODS foam blowing agent recovery process[29] (see Appendix E for calculation of RE)	%

$$BA_{build} = Q_{foam} \times BA\%$$

Where,			Units
BA_{build}	=	Total quantity of ODS blowing agent *i* from building foam sent for destruction	lb ODS
Q_{foam}	=	Total weight of eligible foam with entrained ODS blowing agent sent for destruction	lbs
BA%	=	Mass ratio of ODS blowing agent entrained in building foam, as determined according to Section 6.4	% (0-1)

[29] RE is similar to the RDE defined in TEAP (2005) Report of the Task Force on Foam End-of-Life Issues, Table 6.1. RE, however, does not extend to the ODS destruction efficiency, which is handled separately under this protocol.

The total percent of ODS foam blowing agent that would be released throughout the end-of-life processing (i.e. 10-year emission rates) for each ODS foam blowing agent and foam origin is presented in Table 5.3. These values include emissions from:

1. ODS blowing agent released during foam shredding,[30] plus
2. ODS blowing agent released during foam compaction, plus
3. Landfilled ODS blowing agent that is released during anaerobic conditions (but is not degraded).

The Reserve recognizes that there is considerable uncertainty regarding the extent of anaerobic degradation of ODS foam blowing agents in U.S. landfills. According to TEAP (2005), the "extent to which [anaerobic degradation] needs to be stimulated in the landfill environment is still under review, but there is a possibility of some degradation occurring under non-optimized conditions."[31] Accordingly, the Reserve has incorporated a factor for anaerobic degradation to be conservative. The factors are drawn from Scheutz et al. (2007)[32] laboratory tests using degradation rates approximating those measured by the researchers in un-inoculated soil from a U.S. landfill. Because Scheutz et al. examined degradation rates under ideal conditions, however, the degradation rates used in this protocol are the lowest of the results reported. The degradation rates selected reflect the parameters derived from actual landfill conditions in the U.S., and more realistically estimate degradation in U.S. landfills; the higher values presented in Scheutz et al. reflect results based on parameters where degradation has been optimized through inoculation of the samples. While lower, the results used in this protocol are a conservative estimate based on laboratory analysis in a controlled environment.

Table 5.3. 10-Year Emission Rates of Appliance and Building Foam at End-of-Life

ODS Blowing Agent	Appliance ODS Blowing Agent 10-Year Emission Rate ($ER_{i,j}$)	Building ODS Blowing Agent 10-Year Emission Rate ($ER_{i,j}$)
CFC-11	44%	20%
CFC-12	55%	36%
HCFC-22	75%	65%
HCFC-141b	50%	29%

The values provided in Table 5.3 have been calculated based on the values in Table 5.4. These values are re-produced here for reference, but are not used directly in any of the calculations within this section.

[30] Note that the emissions from foam shredding have only been factored into the emission rates from appliance ODS blowing agents in Table 5.3, as building foam is not typically shredded before being landfilled.
[31] TEAP. (2005). Report of the Task Force on Foam End-of-Life Issues. *United Nations Environment Programme*, page 39.
[32] Scheutz, C., et al. (2007). Attenuation of insulation foam released fluorocarbons in landfills. *Environmental Science & Technology*, *41*: 7714-7722.

Table 5.4. Emissions from Shredding and Landfilling ODS Foam Blowing Agents

ODS Blowing Agent	Percent of ODS Blowing Agent Released During Shredding[a] (set to zero for demolition debris)	Percent of ODS Blowing Agent Released During Compaction[b]	Percent of Remaining ODS Blowing Agent Released During Anaerobic Conditions[c]	Percent of Released ODS Blowing Agent Not Degraded in Anaerobic Landfill Conditions[c]
CFC-11	24%	19%	35%	5%
CFC-12	24%	19%	52%	40%
HCFC-22	24%	19%	100%	57%
HCFC-141b	24%	19%	41%	29%

[a] Scheutz, C., et al. (2007). Release of fluorocarbons from insulation foam in home appliances during shredding. *Journal of the Air & Waste Management Association*, *57*: 1452-1460.
[b] Fredenslund, A., et al. (2005). Disposal of Refrigerators-Freezers in the U.S. : State of the Practice. *Technical University of Denmark*.
[c] Scheutz, C., et al. (2007). Attenuation of insulation foam released fluorocarbons in landfills. *Environmental Science & Technology*, *41*: 7714-7722.

5.2 Quantifying Project Emissions

Project emissions are actual GHG emissions that occur within the GHG Assessment Boundary as a result of project activities.

As shown in Equation 5.5, project emissions equal:

- Emissions from non-ODS substitutes (applicable only to refrigerant projects), plus
- Emissions from ODS foam blowing agent extraction (applicable only to appliance foam projects), plus
- Emissions from the transportation of ODS, plus
- Emissions from the destruction of ODS

Note that emissions shall be quantified in pounds throughout this section and converted into metric tons in Equation 5.5 below.

Equation 5.5. Total Project Emissions

$$PE = \frac{Sub_{ref} + BA_{pr} + Tr + Dest}{2204.623}$$

Where, Units

PE	=	Total quantity of project emissions during the reporting period	tCO_2e
Sub_{ref}	=	Total emissions from substitute refrigerant	lb CO_2e
BA_{pr}	=	Total quantity of ODS blowing agent from appliance foam released during ODS extraction	lb CO_2e
Tr	=	Total emissions from transportation of ODS (calculated using either the default value in Equation 5.8 or Equation 5.14)	lb CO_2e
Dest	=	Total emissions from the process associated with destruction of ODS (calculated using either the default value in Equation 5.8 or Equation 5.9 through Equation 5.13)	lb CO_2e
2204.623	=	Conversion from pounds to metric tons	lbs/t

5.2.1 Calculating Project Emissions from the Use of Refrigerant Substitutes

When refrigerant ODS are destroyed, continued demand for refrigeration will lead to the production and consumption of other refrigerant chemicals whose production is still legally allowed. Projects that destroy refrigerant ODS must therefore estimate the emissions associated with the non-ODS substitute chemicals that are assumed to be used in their place. Like the estimates of baseline emissions, substitute emissions shall be accounted for based on the projected emissions over a ten year crediting period.

Project emissions from the use of substitute refrigerants shall be calculated for all ODS refrigerant projects according to Equation 5.6 using the emission factors from Table 5.5. The use of site-specific substitute parameters (refrigerant, GWP, and leak rate) is not permitted.

Equation 5.6. Project Emissions from the Use of Non-ODS Refrigerants

$$Sub_{refr} = \sum_{i} \left(Qref_i \times SE_i \right)$$

Where,

			Units
Sub_{refr}	=	Total quantity of refrigerant substitute emissions	lb CO_2e
$Q_{refr,i}$	=	Total quantity of eligible, pure refrigerant *i* sent for destruction	lbs
SE_i	=	Emission factor for substitute(s) for refrigerant *i*, per Table 5.5	lb CO_2e/ lb ODS destroyed

ODS substitute emissions presented in Table 5.5 are based on the weighted average of expected new refrigerant supplies into the refrigeration market. These substitute refrigerants were modeled using the EPA Vintaging Model and data provided by industry sources. A summary of the ODS substitute emission rates analysis and calculations is provided in Appendix D. The analysis identified substitute emission factors for each ODS refrigerant covered under this protocol (see Appendix D).

Table 5.5. Refrigerant Substitute Emission Factors[33]

ODS Refrigerant	Substitute Emission Factors (lb CO_2e/lb ODS) (SE_i)
CFC-11	202
CFC-12	777
CFC-13	7144
CFC-113	220
CFC-114	659
CFC-115	1689

[33] See Appendix D for a summary of the development of these factors.

5.2.2 Calculating Project Emissions from ODS Blowing Agent Extracted from Appliance Foam

Projects that extract ODS blowing agent from appliance foam must account for the emissions of ODS that occur during processing, separation, and extraction using Equation 5.7. These emissions are calculated in Equation 5.7 based on the quantity of ODS blowing agent sent for destruction ($BA_{app,i}$, as calculated in Equation 5.4), and a project-specific recovery efficiency that represents the percentage of ODS that is *not* lost during these steps. The recovery efficiency must be calculated once per project according to the guidance provided in Appendix E. Although not required under this protocol, well-executed projects should be capable of keeping these emissions to no more than 10 percent of ODS blowing agent contained in the foam, per the recommendations of the TEAP *Report of the Task Force on Foam End-of-Life Issues*.[34]

Equation 5.7. Calculating Project Emissions from the Release of ODS Blowing Agent during Processing

$$BA_{pr} = \sum_i \left(BA_{app,i} \times (1 - RE) \times GWP_i \right)$$

Where,

			Units
BA_{pr}	=	Total quantity of ODS blowing agent from appliance foam released during ODS extraction	lb CO_2e
$BA_{app,i}$	=	Total quantity of appliance ODS foam blowing agent in foam prior to treatment or processing, including ODS foam blowing agent lost during processing (see Equation 5.4 to calculate this term)	lb ODS
RE	=	Recovery efficiency of the ODS foam blowing agent recovery process (see Appendix E to calculate RE)	%
GWP_i	=	Global warming potential of ODS *i* (see Table 5.1)	lb CO_2e/ lb ODS

5.2.3 Calculating Default Project Emissions from Transportation and Destruction

Projects must account for emissions that result from the transportation and destruction of ODS. Because these emission sources are both individually and in aggregate very small, the Reserve has developed default emission factors for ODS projects based on conservative assumptions and the SSRs outlined in Table 4.1[35]:

- 7.5 pounds CO_2e per pound ODS for refrigerant or extracted ODS blowing agent projects
- 75 pounds CO_2e per pound ODS for intact building foam projects

These emission factors aggregate both transportation and destruction emissions. Project developers have the option of using the default emission factors or using the guidance in Sections 5.2.4 and 5.2.5 to calculate project-specific emissions. Equation 5.8 shall be used to calculate ODS transportation and destruction emissions if default emission factors are used. If a project developer elects not to use the default emission factors, emissions associated with transportation and destruction of ODS must be calculated separately.

[34] TEAP. (2005). Report of the Task Force on Foam End-of-Life Issues. *United Nations Environment Programme*.
[35] See Appendix F for an explanation of how these default emission factors were derived.

Equation 5.8. Project Emissions from Transportation and Destruction Using the Default Emission Factors

$$Tr + Dest = \sum_i \left(Q_{ODS,i} \times EF_i \right)$$

Where,			Units
Tr+Dest	=	Total emissions from project transportation and destruction, as calculated using default emission factors	lb CO_2e
$Q_{ODS,i}$	=	Total quantity of ODS *i* sent for destruction in the project, including eligible and ineligible material	lb ODS
EF_i	=	Default emission factor for transportation and destruction of ODS *i* (7.5 for refrigerant or extracted ODS blowing agent projects, 75 for intact building foam projects)	lb CO_2e/ lb ODS

5.2.4 Calculating Site-Specific Project Emissions from ODS Destruction

Under this protocol, ODS must be destroyed at destruction facilities that demonstrate compliance with the TEAP recommendations.[36] These facilities are required to demonstrate their ability to achieve destruction efficiencies upwards of 99.99 percent for substances with thermal stability ratings higher than the ODS included under this protocol.[37] Associated with the operation of these facilities are emissions of CO_2 from the fuel and electricity used to power the destruction, as well as emissions of undestroyed ODS. Equation 5.9 through Equation 5.13 provide requirements for calculating emissions from ODS destruction in cases where project developers opt not to use the default factors provided in Section 5.2.3.

Equation 5.9. Project Emissions from the Destruction of ODS

$$Dest = FF_{dest} + EL_{dest} + ODS_{emissions} + ODS_{CO_2}$$

Where,			Units
Dest	=	Total emissions from the destruction of ODS	lb CO_2e
FF_{dest}	=	Total emissions from fossil fuel used in the destruction facility (Equation 5.10)	lb CO_2
EL_{dest}	=	Total indirect emissions from grid electricity used at the destruction facility (Equation 5.11)	lb CO_2
$ODS_{emissions}$	=	Total emissions of undestroyed ODS (Equation 5.12)	lb CO_2e
ODS_{CO2}	=	Total emissions of CO_2 from ODS oxidation (Equation 5.13)	lb CO_2

[36] TEAP: http://uneptie.org/ozonaction/topics/disposal.htm.
[37] ICF International. (2009). ODS Destruction in the United States of America and Abroad. *U.S. EPA*.

Equation 5.10. Fossil Fuel Emissions from the Destruction of ODS

$$FF_{dest} = \frac{\sum_k \left(FF_{PR,k} \times EF_{FF,k}\right)}{0.454}$$

Where, Units

FF_{dest}	=	Total carbon dioxide emissions from the destruction of fossil fuel used to destroy ODS	lb CO_2
$FF_{PR,k}$	=	Total fossil fuel *k* used to destroy ODS	volume fossil fuel
$EF_{FF,k}$	=	Fuel specific emission factor (see Appendix G)	kg CO_2/ volume fossil fuel
0.454	=	Conversion from kilograms to pounds	kg CO_2/ lb CO_2

Equation 5.11. Electricity Emissions from the Destruction of ODS

$$EL_{dest} = \left(EL_{PR} \times EF_{EL}\right)$$

Where, Units

EL_{dest}	=	Total carbon dioxide emissions from the consumption of electricity from the grid used to destroy ODS	lb CO_2
EL_{PR}	=	Total electricity consumed to destroy ODS	MWh
EF_{EL}	=	CO_2 emission factor for electricity used[38]	lb CO_2/ MWh

Equation 5.12. Calculating Project Emissions from ODS Not Destroyed

$$ODS_{emissions} = \sum_i Q_{ODS,i} \times 0.0001 \times GWP_i$$

Where, Units

$ODS_{emissions}$	=	Total emissions of undestroyed ODS	lb CO_2e
$Q_{ODS,i}$	=	Total quantity of ODS *i* sent for destruction in the project	lb ODS
0.0001	=	Maximum allowable percent of ODS fed to destruction that is not destroyed (0.01 percent)	
GWP_i	=	Global warming potential of ODS *i* (see Table 5.1)	lb CO_2e/ lb ODS

[38] Refer to the version of the EPA eGRID that most closely corresponds to the time period during which the electricity was used. Project shall use the annual total output emission rates for the subregion where the destruction facility is located, not the non-baseload output emission rates. The eGRID tables are available at http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

Equation 5.13. Calculating Project Emissions of CO_2 from the Oxidation of ODS

$$ODS_{CO_2} = \sum_i Q_{ODS,i} \times 0.9999 \times CR_i \times \frac{44}{12}$$

Where,			Units
ODS_{CO2}	=	Total emissions of CO_2 from ODS oxidation	lb CO_2
$Q_{ODS,i}$	=	Total quantity of ODS *i* sent for destruction in the project	lb ODS
0.9999	=	Minimum destruction efficiency of destruction facility	% (0-1)
CR_i	=	Carbon ratio of ODS *i* CFC-11: 12/137 CFC-12: 12/121 CFC-13: 12/104 CFC-113: 24/187 CFC-114: 24/171 CFC-115: 24/154 HCFC-22: 12/87 HCFC-141b: 24/117	mole C/ mole ODS
44/12	=	Ratio of CO_2 to C	mole CO_2/ mole C

5.2.5 Calculating Site-Specific Project Emissions from ODS Transportation

As part of any ODS destruction project, ODS will be transported from aggregators to destruction facilities, and emissions from this transportation must be accounted for under this protocol. Equation 5.14 must be used to calculate CO_2 emissions associated with the transport of ODS in cases where project developers choose not to use the default emission factors presented in Section 5.2.3. Emissions shall be calculated for each leg of the transportation process separately, and then summed according to Equation 5.14 below.

Equation 5.14. Calculating Project Emissions from the Transportation of ODS[39]

$$Tr = \sum_i \left(TMT_i \times EF_{TMT}\right)$$

Where,			Units
Tr	=	Total emissions from transportation of ODS	lb CO_2e
PMT_i	=	Pound-miles-traveled[40] for ODS *i* destroyed (to be calculated including the ODS, any accompanying material, and containers from point of aggregation to destruction)	pound-miles
EF_{PMT}	=	CO_2 emissions per pound-mile-traveled On-road truck transport = 0.000297 Rail transport = 0.0000252 Waterborne craft = 0.000048 Aircraft = 0.001527	lb CO_2 / pound-mile

[39]Derived from: U.S. EPA Climate Leaders, (2008). Optional emissions from business travel, commuting, and product transport.

[40] A pound-mile is defined as the product of the distance traveled in miles and the mass transported in pounds. Therefore, 500 lbs transported four miles is equal to 2,000 pound-miles.

5.3 Deduction for Vapor Composition Risk

For any given container of ODS, a portion of the container will be filled with liquid, and the remaining space will be filled with vapor. This protocol only requires that a liquid sample be taken for composition analysis. For containers that hold a mixture of ODS, the composition of ODS in the vapor may be different from the composition of ODS in the liquid due to differences in the thermodynamic properties of the chemicals. If the container holds chemicals that are not eligible for crediting, the quantification of emission reductions based on the analysis of liquid sample could overstate the actual reductions from the destruction of the material.

To address this risk, projects that destroy containers which contain more than one chemical must use Table 5.7 to determine their risk category and applicable value of *VR* to be applied to the calculation of baseline emissions for that container (Equation 5.3). Table 5.6 classifies the eligible ODS species as low or high pressure. For the purposes of this protocol, any ineligible chemical with a boiling point less than 32°F at 1 atm is considered high pressure.

The densities of the liquid and vapor phase components of the project container will be determined by the testing laboratory at the time that the composition analysis is carried out. The testing laboratory will calculate the densities of the liquid phase and vapor phase contents within the container. To support this calculation, the project developer shall provide the laboratory with the temperature of the project container (internal temperature if available, otherwise ambient temperature) at the time of sampling, as well as the volumetric capacity of the project container. Once the weight of the contents of the project container is known, the liquid fill level of the container may be determined using Equation 5.15.

Table 5.6. Eligible Low Pressure and High Pressure ODS

Low Pressure ODS	High Pressure ODS
CFC-11	CFC-12
CFC-113	CFC-13
CFC-114	CFC-115

Table 5.7. Determining the Deduction for Vapor Composition Risk

If the value of $Fill_{liquid}$ is:	AND the concentration of eligible low pressure ODS is:	AND the concentration of ineligible high pressure chemical is:	Then the vapor risk deduction factor (VR) for that container shall be:
> 0.70	N/A	N/A	0
0.50 – 0.70	> 1%	> 10%	0.02
< 0.50	> 1%	> 5%	0.05

The presence of eligible, high pressure ODS may mitigate the risk of over-crediting, so there are two scenarios where a container is exempt from a deduction otherwise required in Table 5.7:

1. The container holds an eligible, high pressure ODS (in any concentration) which has a lower boiling point than the ineligible, high pressure chemical, or
2. The container holds an eligible, high pressure ODS in a concentration greater than that of the ineligible, high pressure chemical.

If the container holds multiple eligible, high pressure ODS, the applicability of the above scenarios will be determined based on the ODS with the highest percent concentration. If the container holds multiple ineligible, high-pressure chemicals, the applicability of the above scenarios will be determined based on the chemical with the highest percent concentration.

This deduction applies to both mixed and non-mixed ODS projects as defined in Section 6.6.

Equation 5.15. Determining Liquid Fill Level in Project Container

$$Fill_{liquid} = \frac{M_{destroyed} - (\rho_{vapor} \times V_{container})}{(\rho_{liquid} - \rho_{vapor}) \times V_{container}}$$

Where,

			Units
$Fill_{liquid}$	=	Fill level of the liquid in the project container	fraction
$V_{container}$	=	Total volume of the project container	gal
$M_{destroyed}$	=	Total mass of the contents of the project container	lbs
ρ_{liquid}	=	Modeled density of the liquid material in the project container at the measured temperature	lbs/gal
ρ_{vapor}	=	Modeled density of the vapor material in the project container at the measured temperature	lbs/gal

6 Project Monitoring and Operation

The Reserve requires a Monitoring and Operations Plan to be established for all monitoring, operational, and reporting activities associated with ODS destruction projects. The Monitoring and Operations Plan will serve as the basis for verification bodies to confirm that the monitoring, operational, and reporting requirements in this section and Section 7 have been and will continue to be met, and that consistent, rigorous monitoring and record-keeping is ongoing for the project. The Monitoring and Operations Plan must cover all aspects of monitoring, operations, and reporting contained in this protocol and must specify how data for all relevant parameters in Table 6.2 (below) will be collected and recorded.

At a minimum the Monitoring and Operations Plan shall stipulate the frequency of data acquisition; a record keeping plan (see Section 7.3 for minimum record keeping requirements); and the role of individuals performing each specific monitoring or operational activity. The Monitoring and Operations Plan shall also contain a project diagram that illustrates the project ODS point(s) of origin, any reclamation facilities used, information on ODS transportation mode and transportation companies, mixing/sampling facilities, testing laboratories and the destruction facility (see Appendix H for a sample project diagram). The Monitoring and Operations Plan should also include QA/QC provisions to ensure that operations, data acquisition, and ODS analyses are carried out consistently and with precision.

Project developers are responsible for monitoring the performance of the project and ensuring that there is no double-counting of GHG reductions associated with ODS destruction. To achieve this, the Monitoring and Operations Plan must also include a description of how data will be provided to the Reserve ODS tracking system (Section 6.1).

Finally, the Monitoring and Operations Plan must include procedures that the project developer will follow to ascertain and demonstrate that the project at all times passes the Legal Requirement Test (Section 3.4.1).

6.1 Reserve ODS Tracking System

For the purposes of ensuring the integrity of ODS destruction projects, the Reserve maintains an online database of all destruction activities for which CRTs are registered and issued. Entries into this system within the Reserve software must be made by the project developer prior to the beginning of verification activities related to confirming that reductions have not been claimed by other parties for the destruction activity in question.[41]

All projects are required to have one or more Certificate(s) of Destruction accounting for all eligible ODS destroyed as part of that project. The following information shall be entered by the project developer into the Reserve software from the Certificate(s) of Destruction issued by the destruction facility, and a copy of the certificate(s) must be provided to the project verifier:

- Project developer (project account holder)
- Destruction facility
- Generator name
- Certificate of Destruction ID number

[41] Other verification activities (such as site visits) may commence prior to submission of information into the ODS tracking system.

- Start destruction date
- End destruction date
- Total weight of material destroyed (including eligible and ineligible material)

6.2 Point of Origin Documentation Requirements

Project developers are responsible for collecting data on the point of origin of each quantity of ODS, as defined in Table 6.1. The project developer must maintain detailed acquisition records of all quantities of ODS destroyed under the project. Project developers must be able to document the point of origin for all ODS that will be included in the project as defined below.

Table 6.1. Identification of Point of Origin

ODS	Defined Point of Origin
1. Refrigerant ODS stockpiled prior to February 3, 2010	Location of stockpile
2. Refrigerant ODS quantities less than 500 lbs	Location where ODS is first aggregated with other ODS to greater than 500 lbs
3. Refrigerant ODS quantities greater than 500 lbs	Site of installation where ODS is recovered
4. Refrigerant ODS purchased from U.S. Defense Logistics Agency (DLA) Disposition Services[42] auction	Location at the time of sale through a DLA Disposition Services auction
5. ODS blowing agent extracted from foam	Facility where ODS blowing agent is extracted
6. ODS blowing agent in building foam	Location of building from which foam was taken

For destroyed ODS where the point of origin is a reservoir-style stockpile (i.e. ODS was not stored in sealed containers), the date on which the ODS was stockpiled is established using "first-in/first-out" accounting. Specifically, the date on which a quantity of ODS was "stockpiled" is defined as the furthest date in the past on which the quantity of ODS contained in the reservoir was greater than or equal to the total quantity of all ODS removed from the reservoir since that date (including any ODS removed and destroyed as part of the project). The date must be established using management systems and logs that verify the quantities of ODS placed into and removed from the reservoir throughout the relevant period. Provided these conditions are met, and the stockpile follows the "first-in/first-out" accounting, the date on which a quantity of ODS was stockpiled may be established.

For stockpiles, documentation must confirm that the stockpile has been stored at the point of origin prior to February 3, 2010.

For ODS recovered by service technicians in individual quantities less than 500 pounds, the point of origin is defined as the facility where two or more containers were combined and exceeded 500 pounds in a single container. Those handling quantities less than 500 pounds in a single container need not provide the documentation required below. However, once smaller quantities are aggregated and exceed 500 pounds in a single container, tracking is required at that location and point in time forward.

For containers of ODS greater than 500 pounds (determined as the weight of eligible ODS within a single container), the project developer must provide documentation as to the origin of

[42] See Appendix B for more information.

the ODS within that container and when it was recovered. If it is shown that, prior to aggregation in the project container, the ODS was contained as a quantity greater than 500 pounds, then the documentation must extend back to this previous container and its point of origin. The project developer must provide documentation tracking the ODS back to a point in time and location where it was either a) contained or recovered as a quantity of less than 500 pounds, or b) recovered by a service technician as a quantity of greater than 500 pounds.

For refrigerant ODS purchased from a U.S. Defense Logistics Agency (DLA) Disposition Services auction, the point of origin is defined as the facility where the ODS is stored at the time of sale through the auction. Tracking is required from that location and point in time forward. Documentation must show that the ODS was purchased from a DLA Disposition Services auction and include a bill of sale with specifications about the amount and type of ODS purchased. It is possible that the point of origin documentation may not be generated at the point of origin as required below, but rather at the auction location, which is allowable. Refrigerant ODS sourced directly from federal government agencies or installations is not eligible under the protocol.

All data must be generated at the point of origin, except in the case of ODS purchased through DLA Disposition Services auction noted above. Documentation of the point of origin of ODS shall include the following:

- Facility name and physical address, including zip code
- For quantities greater than 500 pounds, identification of the system by serial number, if available, or description, location, and function, if serial number is unavailable
- Serial or ID number of containers used for storage and transport

6.3 Custody and Ownership Documentation Requirements

In conjunction with establishing the point of origin for each quantity of ODS, project developers must also document the custody and ownership of ODS beginning from the point of origin. These records shall include names, addresses, and contact information of persons/entities buying/selling material for destruction and the quantity of the material (the combined mass of refrigerant and contaminants) bought/sold. Such records may include Purchase Orders, Purchase Agreements, packing lists, bills of lading, lab test results, transfer container information, receiving inspections, freight bills, transactional payment information, and any other type of information that will support previous ownership of the material and the transfer of that ownership. The verifier will review these records and will perform other tests necessary to authenticate the previous owners of the material, the physical transfer of the product, and the title transfer of ownership rights of all emissions and emission reductions associated with destroyed ODS to the project developer, as documented through contracts, agreements or other legal documents.

6.4 Building Foam Requirements

The following information shall be collected and recorded related to ODS blowing agents from building insulation foam destroyed by the project:

- Building address
- Date of construction
- Blowing agent used
- Approximate building dimensions

All recovered foam pieces must be placed in air- and water-tight storage for transport to the destruction facility.

ODS blowing agent from building insulation foam may be destroyed intact without extraction of the blowing agent if the following procedures are followed to characterize the mass of foam and type(s) and mass ratio of ODS blowing agent contained in that foam.

1. The mass of the foam shall be determined through weight measurements taken at the destruction facility on a scale which has its calibration tested quarterly by a licensed service company, using certified test weights. A scale is considered calibrated if it is within the maintenance tolerance of the relevant National Institute of Standards and Technology (NIST) Handbook 44 accuracy class. If a scale is found to be outside of this tolerance it must be recalibrated.

2. The composition and mass ratio of the ODS foam blowing agent(s) present in the building insulation foam shall be determined based on a selection of a minimum two samples per building surface taken prior to demolition. Accordingly, a building with four exterior walls and a roof would be required to analyze a total of 10 samples: two for each wall, and two for the roof.

3. All samples must be collected and analyzed according to the following requirements:

   - Each foam sample shall be at a minimum two inches in length, two inches in width, and two inches thick
   - Each sample shall be placed and sealed in a separate waterproof, air-tight container, that is at minimum two millimeters thick for storage and transport
   - The analysis of ODS foam blowing agent content and mass ratio shall be done at an independent laboratory unaffiliated with the project developer
   - The analysis shall be done using the heating method to extract ODS foam blowing agent from the foam samples described in Scheutz et al. (2007):[43]
     - Each sample shall be prepared to a thickness no greater than one centimeter, placed in a 1123 mL glass bottle, weighed using a calibrated scale, and sealed with Teflon-coated septa and aluminum caps
     - To release the ODS blowing agent from the foam, the samples must be incubated in an oven for 48 hours at 140°C
     - When cooled to room temperature, gas samples must be redrawn from the headspace and analyzed using gas chromatography
     - The lids must be removed after analysis, and the headspace must be flushed with atmospheric air for approximately five minutes using a normal compressor. Afterwards, septa and caps must be replaced and the bottles subjected to a second 48-hour heating step to drive out the remaining ODS blowing agent from the sampled foam
     - When cooled down to room temperature after the second heating step, gas samples must be redrawn from the headspace and analyzed using gas chromatography

[43] Scheutz, C., Fredenslund, A.M., Tant, M., & Kjeldsen, P. (2007). Release of fluorocarbons from insulation foam in home appliances during shredding. *Journal of the Air & Waste Management Association*, *57:* 1452-1460.

- The mass of ODS blowing agent(s) recovered shall then be divided by the total mass of the initial foam samples prior to analysis to determine the mass ratio of each ODS foam blowing agent present

4. The results from all samples from a single building shall be averaged to determine the mass ratio of blowing agent to foam, and this value multiplied by the weight of destroyed foam. The result shall represent the total quantity of ODS blowing agent from building foams destroyed for that building, and shall be used for the quantity as BA_{build} in Equation 5.4.

These practices shall be documented in Monitoring and Operations Plan, and must be demonstrated during verification activities (see Section 8.6).

6.5 Appliance Foam Requirements

The following information shall be collected and recorded related to ODS blowing agent from appliance foams destroyed by the project:

- Number of appliances processed
- Facility at which ODS foam blowing agent is extracted to concentrated form
- Facility at which appliance de-manufacture occurs, if applicable

All appliance foam must be processed to recover and destroy concentrated ODS blowing agent. The following requirements must be met:

- The ODS blowing agent must be extracted from the foam to a concentrated form prior to destruction
- ODS blowing agent must be extracted under negative pressure to ensure that fugitive release of ODS is limited
- The recovered ODS blowing agent must be aggregated, stored, and transported in containers meeting U.S. Department of Transportation (DOT) standards for refrigerants

Extraction of the foam blowing agent may be performed using any technology capable of recovering concentrated ODS foam blowing agent. The processes, training, QA/QC, and management systems must be documented in the Monitoring and Operations Plan. The same process, as documented in the Monitoring and Operations Plan must be followed during project implementation and during the calculation of the project-specific recovery efficiency, as described in Appendix E.

Concentrated ODS blowing agent shall be measured according to the procedures provided in Section 6.6.

6.6 Concentrated ODS Composition and Quantity Analysis Requirements

The requirements of this section must be followed to determine the quantities of both ODS refrigerants and concentrated ODS blowing agent. Prior to destruction, the precise mass and composition of ODS to be destroyed must be determined. The following analysis must be conducted:

Mass shall be determined by individually measuring the weight of each container of ODS: (1) when it is full prior to destruction; and (2) after it has been emptied and the contents have been fully purged and destroyed. The mass of ODS and any contaminants is equal to the difference between the full and empty weight, as measured. The following requirements must be met when weighing the containers of ODS:

1. A single scale must be used for generating both the full and empty weight tickets at the destruction facility
2. The scale used must have its calibration tested quarterly by a licensed service company, using certified test weights. A scale is considered calibrated if it is within the maintenance tolerance of the relevant NIST Handbook 44 accuracy class. If a scale is found to be outside of this tolerance, it must be recalibrated
3. The full weight must be measured no more than two days prior to commencement of destruction per the Certificate of Destruction
4. The empty weight must be measured no more than two days after the conclusion of destruction per the Certificate of Destruction

Composition and concentration of ODS shall be established for each individual container by taking a sample from each container of ODS and having it analyzed for composition and concentration at an Air-Conditioning, Heating and Refrigeration Institute (AHRI) certified laboratory using the AHRI 700-2006 standard,[44] or its successor. The laboratory performing the composition analysis must not be affiliated with the project developer or the project beyond performing these services.

The following requirements must be met for each sample:

1. The sample must be taken while ODS is in the possession of the company that will destroy the ODS
2. Samples must be taken by a technician unaffiliated with the project developer[45]
3. Samples must be taken with a clean, fully evacuated sample bottle that meets applicable U.S. DOT requirements with a minimum capacity of one pound
4. The technician must ensure that the sample is representative of the contents of the container. All valves between the interior of the container and the sample port must be opened for a minimum of 15 minutes before the sample is taken
5. Each sample must be taken in liquid state
6. A minimum sample size of one pound must be drawn for each sample
7. Each sample must be individually labeled and tracked according to the container from which it was taken, and the following information recorded:
    a) Time and date of sample
    b) Name of project developer
    c) Name of technician taking sample
    d) Employer of technician taking sample
    e) Volume of container from which sample was extracted
    f) Ambient air temperature at time of sampling[46]
8. Chain of custody for each sample from the point of sampling to the AHRI laboratory must be documented by paper bills of lading or electronic, third-party tracking that includes proof of delivery (e.g. FedEx, UPS)

[44] AHRI. (2006). Standard 700-2006: Standard for Specifications for Fluorocarbon Refrigerants.
[45] For instances where the project developer is the destruction facility itself, an outside technician must be employed for taking samples.
[46] Projects that destroy ODS prior to the adoption date of this protocol may use proxy data from NOAA recording stations in the area.

All project samples shall be analyzed using AHRI 700-2006 or its successor to confirm the mass percentage and identity of each component of the sample. The analysis shall provide:

1. Identification of the refrigerant
2. Purity (%) of the ODS mixture by weight using gas chromatography
3. Moisture level in parts per million. The moisture content of each sample must be less than 75 percent of the saturation point for the ODS based on the temperature recorded at the time the sample was taken. For containers that hold mixed ODS, the sample's saturation point shall be assumed to be that of the ODS species in the mixture with the lowest saturation point that is at least 10 percent of the mixture by mass
4. Analysis of high boiling residue, which must be less than 10 percent by mass
5. Analysis of other ODS in the case of mixtures of ODS, and their percentage by mass

If any of the requirements above are not met, no GHG reductions may be verified for ODS destruction associated with that container. If a sample is tested and does not meet one of the requirements as defined above, the project developer may elect to have the material re-sampled and re-analyzed. While there is no limit to the number of samples that may be taken, the analysis results of all samples must be disclosed to the verification body, and the most conservative composition analysis from these samples shall be used for the quantification. If a project developer elects to have the material dried prior to resampling, the previous samples (prior to drying) may be disregarded.

Note that the threshold for moisture saturation will be difficult to achieve at very low temperatures, and it is recommended that sampling not occur if the ambient air temperature is below 32°F. Project developers may sample for moisture content and perform any necessary de-watering prior to the required sampling and laboratory analysis.

If the container holds non-mixed ODS (defined as greater than 90 percent composition of a single ODS species) no further information or sampling is required to determine the mass and composition of the ODS.

If the container holds mixed ODS, which is defined as less than 90 percent composition of a single ODS species, the project developer must meet additional requirements as provided in Section 6.6.1.

6.6.1 Analysis of Mixed ODS

If a container holds mixed ODS, its contents must also be processed and measured for composition and concentration according to the requirements of this section (in addition to the requirements of Section 6.6). The sampling required under this section may be conducted at the final destruction facility or prior to delivery to the destruction facility. However, the circulation and sampling activities must be conducted by a third-party organization (i.e. not the project developer), and by individuals who have been properly trained for the functions they perform. Circulation and sampling may be conducted at the project developer's facility, but all activities must be directed by a properly trained and contracted third-party. The project's Monitoring and Operations Plan must specify the procedures by which mixed ODS are analyzed. If the mixing and sampling are conducted at the destruction facility, then the most conservative result of the two samples shall be used to satisfy the requirements of Section 6.6. If the mixing and sampling do not occur at the destruction facility, then the most conservative composition analysis from the mixing facility samples shall be used for the quantification of emission reductions.

The composition and concentration of ODS on a mass basis must be determined using the results of the analysis of this section for each container. The results of the composition analysis in Section 6.6 shall be used by verifiers to confirm that the destroyed ODS is in fact the same ODS that is sampled under these requirements.

Prior to sampling, the ODS mixture must be circulated in a container that meets all of the following criteria:

1. The container has no solid interior obstructions[47]
2. The container was fully evacuated prior to filling
3. The container must have mixing ports to circulate liquid and gas phase ODS
4. The liquid port intake shall be at the bottom of the container, and the vapor port intake shall be at the top of the container. For horizontally-oriented mixing containers, the intakes shall be located in the middle third of the container.
5. The container and associated equipment can circulate the mixture via a closed loop system from the liquid port to the vapor port

If the original mixed ODS container does not meet these requirements, the mixed ODS must be transferred into a temporary holding tank or container that meets all of the above criteria. The weight of the contents placed into the temporary container shall be calculated and recorded. During transfer of ODS into and out of the temporary container, ODS shall be recovered to the vacuum levels required by the U.S. EPA for that ODS (see 40 CFR 82.156).[48]

Once the mixed ODS is in a container or temporary storage unit that meets the criteria above, circulation of mixed ODS must be conducted as follows:

1. Liquid mixture shall be circulated from the liquid port to the vapor port
2. A volume of the mixture equal to two times the volume in the container shall be circulated
3. Circulation must occur at a rate of at least 30 gallons/minute. Alternatively, circulation may occur at a rate that is less than 30 gallons/minute, as long as criterion #2 is achieved within the first 6 hours of mixing
4. Start and end times shall be recorded

Within 30 minutes of the completion of circulation, a minimum of two samples shall be taken from the bottom liquid port according to the procedures in Section 6.6. Both samples shall be analyzed at an AHRI approved laboratory per the requirements of Section 6.6. The mass composition and concentration of the mixed ODS shall be equal to the lesser of the two GWP-weighted concentrations.

6.7 Destruction Facility Requirements

Destruction of ODS must occur at a facility that meets all of the guidelines provided in Appendix C of this protocol and by the TEAP Task Force on Destruction Technologies[49]

[47] Mesh baffles or other interior structures that do not impede the flow of ODS are acceptable.
[48] EPA. Required Levels of Evacuation. Retrieved December 21, 2009, from http://www.epa.gov/Ozone/title6/608/608evtab.html.
[49] http://www.uneptie.org/ozonaction/topics/disposal.htm.

Any destruction facility that is regulated by U.S. EPA as a RCRA-permitted HWC is automatically considered a qualifying destruction facility under this protocol; no further testing for TEAP compliance is required.

Non-RCRA permitted facilities may also be deemed qualifying destruction facilities if they meet the pertinent guidelines reproduced in Appendix C. Destruction facilities must provide third-party certified results indicating that the facility meets all performance criteria set forth in Appendix C. Following the initial performance testing, project developers must demonstrate that the facility has conducted comprehensive performance testing at least every three years to validate compliance with the TEAP DRE and emissions limits as reproduced in Appendix C. No ODS destruction credits shall be issued for destruction that occurs at a facility that has failed to undergo comprehensive performance testing according to the required schedule, or has failed to meet the requirements of such performance testing.

At the time of ODS destruction, all destruction facilities must have a valid Title V air permit, if applicable, and any other air or water permits required by local, state, or federal law to destroy ODS. Facilities must document compliance with all monitoring and operational requirements associated with the destruction of ODS materials, as dictated by these permits, including emission limits, calibration schedules, and training. Any upsets or exceedances must be managed in keeping with an authorized startup, shutdown, and malfunction plan. Non-RCRA facilities must further document operation consistent with the TEAP requirements, as defined in this section and Appendix C.

Operating parameters during destruction of ODS material shall be monitored and recorded as described in the Code of Good Housekeeping[50] approved by the Montreal Protocol. This data will be used in the verification process to demonstrate that during the destruction process, the destruction unit was operating similarly to the period in which the DRE[51] was calculated. The DRE is determined by using the Comprehensive Performance Test (CPT)[52] as a proxy for DRE and is disclosed to the public in the destruction facility's Title V operating permit.

To monitor that the destruction facility operates in accordance with applicable regulations and within the parameters recorded during DRE testing, the following parameters must be tracked continuously during the entire ODS destruction process:

- The ODS feed rate
- The amount and type of consumables used in the process (not required if default project emission factor for transportation and destruction is used)
- The amount of electricity and amount and type of fuel consumed by the destruction unit (not required if default project emission factor for transportation and destruction is used)
- Operating temperature and pressure of the destruction unit during ODS destruction
- Effluent discharges measured in terms of water and pH levels
- Continuous emissions monitoring system (CEMS) data on the emissions of carbon monoxide during ODS destruction

[50] TEAP. (2006). Code of Good Housekeeping. *Handbook for the Montreal Protocol on Substances that Deplete the Ozone Layer, 7th Edition*.
[51] DRE disclosed in Title V operating permit.
[52] CPT must have been conducted with a less combustible chemical than the ODS in question.

The project developer must maintain records of all of these parameters for review during the verification process.

Destruction facilities shall provide valid Certificate(s) of Destruction for all ODS destroyed as part of the project. The Certificate of Destruction shall include:

- Project developer (project account holder)
- Destruction facility
- Generator name
- Certificate of Destruction ID number
- Serial, tracking or ID number of all containers for which ODS destruction occurred
- Weight of material destroyed from each container (including eligible and ineligible material)
- Type of material destroyed from each container (including all materials listed on laboratory analysis of ODS composition from sampling at the destruction facility)
- Start destruction date
- End destruction date

6.8 Monitoring Parameters

Prescribed monitoring parameters necessary to calculate baseline and project emissions are provided in Table 6.2 below. In addition to the parameters below that are used in the calculations provided in Section 5, project developers are responsible for maintaining all records required under Sections 6 and 7.

Table 6.2. ODS Project Monitoring Parameters

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating Records (o)	Comment
		Legal Requirement Test	N/A	For each reporting period		Must be monitored and determined for each reporting period
		Mass of ODS (or ODS mixture) in each container	mass of mixture	Per container	M	Must be determined for each container destroyed
		Concentration of ODS (or ODS mixture) in each container	mass ODS/ mass of mixture	Per container	M	Must be determined for each container destroyed
Equation 5.1	ER_t	Total quantity of emission reductions during the reporting period	tCO_2e	For each reporting period	C	
Equation 5.1, Equation 5.2	BE_t	Total quantity of baseline emissions during the reporting period	tCO_2e	For each reporting period	C	
Equation 5.1, Equation 5.5	PE_t	Total quantity of project emissions during the reporting period	tCO_2e	For each reporting period	C	
Equation 5.2, Equation 5.3	BE_{refr}	Total quantity of baseline emissions from refrigerant ODS	lb CO_2e	For each reporting period	C	
Equation 5.2, Equation 5.4	BE_{foam}	Total quantity of baseline emissions from ODS blowing agent	lb CO_2e	For each reporting period	C	
Equation 5.3, Equation 5.6	$Q_{refr,i}$	Total quantity of eligible refrigerant ODS *i* sent for destruction	lb ODS	For each reporting period	M	
Equation 5.3	$ER_{refr,i}$	10-year cumulative emission rate of refrigerant ODS *i*	0 - 1.0	N/A	R	See Table 5.1
Equation 5.3, Equation 5.4, Equation 5.7, Equation 5.12	GWP_i	Global warming potential of ODS *i*	lb CO_2e/ lb ODS	N/A	R	See Table 5.1

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating Records (o)	Comment
Equation 5.3	VR	Vapor risk deduction factor	% (0-1)	For each reporting period	R	See Table 5.7
Equation 5.4, Equation 5.7	$BA_{app,i,}$	Total quantity of ODS blowing agent *i* from appliance foam prior to treatment or processing, including blowing agent lost during processing	lb ODS	For each reporting period	C	
Equation 5.4	$BA_{build,i}$	Total quantity of ODS blowing agent *i* from building foam sent for destruction.	lb ODS	For each reporting period	C	
Equation 5.4	$ER_{i,j}$	Lifetime emission rate of ODS blowing agent *i* from application *j* at end-of-life (see Table 5.3)	% (0-1)	N/A	R	
Equation 5.4	$Q_{recover}$	Total quantity of ODS foam blowing agent recovered during processing and sent for destruction	lb ODS	For each reporting period	M	
Equation 5.4, Equation 5.7	RE	Recovery efficiency of the ODS foam blowing agent recovery process	% (0-1)	Once per project	C	See Appendix E for calculation of RE
Equation 5.4	Q_{foam}	Total weight of foam with entrained ODS blowing agent sent for destruction	lb	For each reporting period	M	
Equation 5.4	BA%	Mass ratio of ODS blowing agent entrained in building foam, as determined according to Section 6.4	% (0-1)	For each reporting period	M	
Equation 5.5, Equation 5.6	Sub_{refr}	Total emissions from substitute refrigerant	lb CO_2e	For each reporting period	C	
Equation 5.5, Equation 5.7	$BA_{pr,i}$	Total quantity of ODS foam blowing agent *i* from appliance foam released during ODS extraction	lb CO_2e	For each reporting period	C	

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating Records (o)	Comment
Equation 5.5, Equation 5.8, Equation 5.14	Tr	Total emissions from project transportation	lb CO_2e	For each reporting period	C	
Equation 5.5, Equation 5.8, Equation 5.9	Dest	Total emissions from the destruction process associated with destruction of ODS	lb CO_2e	For each reporting period	C	
Equation 5.6	SE_i	Emission factor for substitute emissions of refrigerant *i*	lb CO_2e/ lb ODS destroyed	Per container	R	See Table 5.5 for values and Appendix D for summary of the development of SE
Equation 5.8, Equation 5.12, Equation 5.13	$Q_{ODS,i}$	Total quantity of ODS *i* sent for destruction, including eligible and ineligible material	lb ODS	For each reporting period	M	
Equation 5.8,	EF_i	Default emission factor for transportation and destruction of ODS *i*	lb CO_2e/ lb ODS	N/A	R	Equal to 7.5 for refrigerant projects, and 75 for foam projects
Equation 5.9, Equation 5.10	FF_{dest}	Total emissions from fossil fuel used in the destruction facility	lb CO_2e	For each reporting period	C	Use only if calculating site-specific project emissions from ODS destruction
Equation 5.9, Equation 5.11	EL_{dest}	Total emissions from grid electricity at the destruction facility	lb CO_2e	For each reporting period	C	Use only if calculating site-specific project emissions from ODS destruction
Equation 5.10	$FF_{PR,k}$	Total fossil fuel *k* used to destroy ODS	lb CO_2e	For each reporting period	M	Use only if calculating site-specific project emissions from ODS destruction
Equation 5.10	$EF_{FF,k}$	Fuel specific emission factor	kgCO_2/ volume fuel	N/A	R	Use only if calculating site-specific project emissions from ODS destruction
Equation 5.11	EL_{PR}	Total electricity consumed to destroy ODS	MWh	For each reporting period	M	Use only if calculating site-specific project emissions from ODS destruction
Equation 5.11	EF_{EL}	Carbon emission factor for electricity used	lb CO_2/ MWh	N/A	R	Use only if calculating site-specific project emissions from ODS destruction

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating Records (o)	Comment
Equation 5.9, Equation 5.12	$ODS_{emissions}$	Total emissions of un-destroyed ODS	lb CO_2e	For each reporting period	C	Use only if calculating site-specific project emissions from ODS destruction
Equation 5.9, Equation 5.13	ODS_{CO2}	Total emissions of CO_2 from ODS oxidation	lb CO_2	For each reporting period	C	Use only if calculating site-specific project emissions from ODS destruction
Equation 5.13	CR_i	Carbon ratio of ODS *i*	mole C/ mole ODS	N/A	R	Use only if calculating site-specific project emissions from ODS destruction
Equation 5.14	PMT_i	Pound-miles-traveled for ODS *i* destroyed	pound-miles	For each reporting period	M	Use only if calculating site-specific project emissions from ODS transportation
Equation 5.14	EF_{PMT}	Mode-specific emission factor	$kgCO_2$/ pound-mile	N/A	R	Use only if calculating site-specific project emissions from ODS transportation
Equation 5.15	$Fill_{liquid}$	Liquid fill level in project container	% (0-1)	For each reporting period	C	
Equation 5.15	$V_{container}$	Volumetric capacity of project container	gallons	For each reporting period	O	
Equation 5.15	$M_{destroyed}$	Total mass of material destroyed in the project container	lbs	For each reporting period	M	
Equation 5.15	ρ_{liquid}	Density of the liquid phase material in the project container	lb/gal	For each reporting period	C	
Equation 5.15	ρ_{vapor}	Density of the vapor phase material in the project container	lb/gal	For each reporting period	C	

7 Reporting Parameters

This section provides requirements and guidance on reporting rules and procedures. A priority of the Reserve is to facilitate consistent and transparent information disclosure by project developers. Project developers must submit verified emission reduction reports to the Reserve at the conclusion of every project reporting period.

7.1 Project Documentation

Project developers must provide the following documentation to the Reserve in order to register an ODS destruction project.

- Project Submittal form
- Certificate(s) of Destruction (not public)
- Laboratory analysis of ODS composition from sampling at destruction facility (not public)
- Laboratory analysis of ODS composition from sampling at mixing facility, if applicable (not public)
- Project diagram from Monitoring and Operations Plan – see Appendix H (not public)
- Signed Attestation of Title form
- Signed Attestation of Regulatory Compliance form
- Signed Attestation of Voluntary Implementation form
- Verification Report
- Verification Statement

Project developers must provide the following documentation each reporting period in order for the Reserve to issue CRTs for quantified GHG reductions:

- Verification Report
- Verification Statement
- Certificate(s) of Destruction (not public)
- Laboratory analysis of ODS composition from sampling at destruction facility (not public)
- Laboratory analysis of ODS composition from sampling at mixing facility, if applicable (not public)
- Project diagram from Monitoring and Operations Plan – see Appendix H (not public)
- Signed Attestation of Title form
- Signed Attestation of Regulatory Compliance form
- Signed Attestation of Voluntary Implementation form

Unless otherwise specified, the above project documentation will be available to the public via the Reserve's online registry with the Certificate of Destruction tracking information from Section 6.1. Further disclosure and other documentation may be made available by the project developer on a voluntary basis. Project submittal forms can be found at http://www.climateactionreserve.org/how/projects/register/project-submittal-forms/.

7.2 Joint Verification

If desired, it is possible for a single project developer to register multiple concurrent ODS destruction projects at a single destruction facility (e.g. one involving domestically sourced ODS and a second involving ODS sourced from Article 5 countries). In such instances, the concurrent projects may be eligible for joint verification (see Section 8.1 for more detail).

Regardless of whether the project developer chooses to verify multiple projects through a joint project verification or pursue verification of each project separately, the documents and records for each project must be retained according to this section.

7.3 Record Keeping

For purposes of independent verification and historical documentation, project developers are required to keep all information outlined in this protocol for a period of 10 years after verification. This information will not be publicly available but may be requested by the verification body or the Reserve.

System information the project developer should retain includes:

- All data inputs for the calculation of the project emission reductions, including all required sampled data
- Copies of all permits, Notices of Violations (NOVs), and any relevant administrative or legal consent orders dating back at least three years prior to the project start date
- Executed Attestation of Title forms, Attestation of Regulatory Compliance forms and Attestation of Voluntary Implementation forms
- Destruction facility monitor information (CEMS data, DRE documentation, scale readings, calibration procedures, and permits)
- Verification records and results
- Chain of custody and point of origin documentation
- ODS composition and quantity lab reports

7.4 Reporting Period and Verification Cycle

ODS destruction projects may be no greater than 12 months in duration, measured from the project start date to completion of ODS destruction. As stated in Section 2.2, project developers may choose a shorter time horizon for their project (e.g. three months or six months), but no project may run longer than 12 months. At the project developer's discretion, a project may have one or more reporting periods as defined in Section 5.

8 Verification Guidance

This section provides verification bodies with guidance on verifying GHG emission reductions from ODS destruction projects developed to the standards of this protocol. This verification guidance supplements the Reserve's Verification Program Manual and describes verification activities in the context of ODS destruction projects.

Verification bodies trained to verify ODS projects must conduct verifications to the standards of the following documents:

- Climate Action Reserve Program Manual
- Climate Action Reserve Verification Program Manual
- Climate Action Reserve U.S. Ozone Depleting Substances Project Protocol

The Reserve's Program Manual, Verification Program Manual, and project protocols are designed to be compatible with each other and are available on the Reserve's website at http://www.climateactionreserve.org.

In cases where the Program Manual and/or Verification Program Manual differ from the guidance in this protocol, this protocol takes precedent.

Only ISO-accredited verification bodies trained by the Reserve for this project type are eligible to verify ODS destruction project reports. Verification bodies approved under other project protocol types are not permitted to verify ODS destruction projects. Information about verification body accreditation and Reserve project verification training can be found in the Verification Program Manual.

8.1 Joint Project Verification

Because of the possibility for a project developer to have projects under both the U.S. and Article 5 ODS Project Protocols occurring at a single destruction facility, project developers have the option to hire a single verification body to verify multiple projects under a joint project verification. This may provide economies of scale for the project verifications and improve the efficiency of the verification process. Joint project verification is only available as an option for a single project developer; joint project verification cannot be applied to multiple projects registered by different project developers at the same destruction facility.

Provided that the following elements are met, the verifier may, at his or her discretion, conduct a joint verification of two or more projects:

- The project developer has contracted with a single verification body for all projects involved
- All projects involved have an approved NOVA/COI form with designated site visit dates prior to the commencement of joint verification activities
- An appropriate verification plan covering all aspects of the individual projects involved has been prepared prior to any shared site visits or verification activities
- Project activities associated with all involved projects have commenced prior to the shared site visit or verification activity

Under joint project verification, each project, as defined by the protocol and the project developer, must still be registered separately in the Reserve system and each project requires its own verification process and Verification Statement (i.e. each project is assessed by the verification body separately as if it were the only project at the destruction facility). However, all projects may be verified together by a single site visit to the destruction facility or other common locations. Furthermore, a single Verification Report may be filed with the Reserve that summarizes the findings from multiple project verifications.

Finally, the verification body may submit one Notification of Verification Activities/Conflict of Interest (NOVA/COI) Assessment form that details and applies to all of the projects at a single destruction facility that it intends to verify.

If, during joint project verification, the verification activities of one project are delaying the registration of another project, the project developer can choose to forego joint project verification. There are no additional administrative requirements of the project developer or the verification body if a joint project verification is terminated.

8.2 Standard of Verification

The Reserve's standard of verification for ODS destruction projects is the U.S. Ozone Depleting Substances Project Protocol (this document), the Reserve Program Manual, and the Reserve Verification Program Manual. To verify an ODS destruction project report submitted by a project developer, verification bodies must apply the guidance in the Verification Program Manual and this section of the protocol to the standards described in Section 2 through 7 of this protocol. Sections 2 through 7 provide eligibility rules, methods to calculate emission reductions, operational requirements, performance monitoring requirements, and procedures for reporting project information to the Reserve.

8.3 Monitoring and Operations Plan

The Monitoring and Operations Plan serves as the basis for verification bodies to confirm that the monitoring, operational, and reporting requirements in Section 6 and Section 7 have been met, and that consistent, rigorous monitoring and record-keeping has been conducted. Verification bodies shall confirm that the Monitoring and Operations Plan covers all aspects of monitoring, operations, and reporting contained in this protocol and specifies how data for all relevant parameters in Table 6.2 are collected and recorded.

8.4 Verifying Project Eligibility

Verification bodies must affirm an ODS destruction project's eligibility according to the rules described in this protocol. The table below outlines the eligibility criteria for an ODS destruction project. This table does not represent all criteria for determining eligibility comprehensively; verification bodies must also look to Section 3 and the verification items list in Table 8.3.

Table 8.1. Summary of Eligibility Criteria

Eligibility Rule	Eligibility Criteria	Verification Frequency
Start Date	No more than six months prior to project submission	Once per project
Location of Destruction	United States and its territories	Once per project

Eligibility Rule	Eligibility Criteria	Verification Frequency
Point of Origin of ODS	Unites States and its territories	Each verification
Project Definition	▪ Project developer and GHG ownership is the same for all ODS destroyed ▪ A single destruction facility has been used for all ODS destruction ▪ All project activities span no more than 12 months from the project start date to the conclusion of destruction activities ▪ Eligible refrigerant ODS include CFC-11, CFC-12, CFC-13, CFC-113, CFC-114, CFC-115 ▪ Eligible ODS blowing agents include CFC-11, CFC-12, HCFC-22, HCFC-141b	Each verification
Performance Standard	Project destroys ODS refrigerant or ODS blowing agent that meet project definitions	Each verification
Legal Requirement Test	Signed Attestation of Voluntary Implementation form and monitoring procedures that lay out procedures for ascertaining and demonstrating that the project passes the Legal Requirement Test	Each verification
Regulatory Compliance Test	Signed Attestation of Regulatory Compliance form and disclosure of non-compliance to verifier; project must be in material compliance with all applicable laws	Each verification
Exclusions	▪ ODS sourced from outside of the U.S. ▪ ODS destroyed outside of the U.S. ▪ Solvents and medical aerosols ▪ Destruction of intact appliance foam ▪ ODS sourced from the federal government, except through DLA Disposition Services auction	Each verification

8.5 Core Verification Activities

The U.S. Ozone Depleting Substances Project Protocol provides explicit requirements and guidance for quantifying GHG reductions associated with the destruction of ODS sourced from the United States. The Verification Program Manual describes the core verification activities that shall be performed by verification bodies for all project verifications. These activities are summarized below in the context of an ODS destruction project, but verification bodies shall also follow the general guidance in the Verification Program Manual.

Verification is a risk assessment and data sampling effort designed to ensure that the risk of reporting error is assessed and addressed through appropriate sampling, testing, and review. The three core verification activities are:

1. Identifying emissions sources, sinks and reservoirs

2. Reviewing operations, GHG management systems, and estimation methodologies
3. Verifying emission reductions and estimates

Identifying emission sources, sinks, and reservoirs

The verification body reviews for completeness the sources, sinks, and reservoirs identified for a project, such as the ODS baseline emissions, substitute emissions, emissions from transportation, and emissions from the destruction of ODS.

Reviewing operations, GHG management systems and estimation methodologies

The verification body reviews and assesses the appropriateness of the operations, methodologies and management systems that the ODS project developer employs to perform project activities, to gather data on ODS collected and destroyed and to calculate baseline and project emissions.

Verifying emission reduction estimates

The verification body further investigates areas that have the greatest potential for material misstatements and then confirms whether or not material misstatements have occurred. This involves site visits to the project to ensure the ODS management, sampling and destruction systems on the ground correspond to and are consistent with data provided to the verification body. In addition, the verification body must recalculate a representative sample of the ODS destruction or emissions data for comparison with data reported by the project developer in order to double-check the calculations of GHG emission reductions.

8.6 Verification Site Visits

Project verifiers shall conduct one or more site visits for each project to assess operations, management systems, QA/QC procedures, personnel training, and conformance with the requirements of this protocol. Each of the sites identified in Table 8.2 shall be visited at least once every 12 months by the project verification body. If one verification body is contracted by multiple projects that involve a single facility, the verification body must only visit that facility once per 12 month period. However, the verification body may visit a facility more frequently if they deem it necessary. For each reporting period, the site visits required in Table 8.2 must have occurred no more than 12 months prior to the end date of the reporting period.

Table 8.2. Verification Site Visit Requirements

Project	Site Visit(s) Required
Refrigerant recovery and destruction: pure ODS	▪ Destruction facility ▪ One additional project facility[a]
Refrigerant recovery and destruction: mixed ODS	▪ Destruction facility ▪ ODS mixing & sampling facility ▪ One additional project facility[a]
Appliance foam collection, ODS foam blowing agent extraction, and destruction	▪ Facility where ODS foam blowing agent is extracted ▪ Destruction facility ▪ One additional project facility[a]
Building foam collection and destruction	▪ Lab performing ODS blowing agent mass ratio analysis ▪ Destruction facility ▪ One additional project facility[a]

[a] The verification body shall visit one additional facility within the project diagram, including but not limited to: a point of recovery, reclamation or aggregation, the project developer's offices, a point of origin, etc. The verification body shall choose this additional facility based upon the project specific risk assessment.

In addition to the site visits specified above, verification bodies may visit any additional sites deemed necessary to verify the project in the context of the project specific risk assessment. In the instance that multiple sampling facilities or foam processing facilities were employed in a single project, verification bodies must determine the appropriate number of facilities to visit, but a minimum of one visit per type of facility is required.

8.7 ODS Verification Items

The following tables provide lists of items that a verification body needs to address while verifying an ODS destruction project. The tables include references to the section in the protocol where requirements are further described. The table also identifies items for which a verification body is expected to apply professional judgment during the verification process. Verification bodies are expected to use their professional judgment to confirm that protocol requirements have been met in instances where the protocol does not provide (sufficiently) prescriptive guidance. For more information on the Reserve's verification process and professional judgment, please see the Verification Program Manual.

Note: These tables shall not be viewed as a comprehensive list or plan for verification activities, but rather guidance on areas specific to ODS destruction projects that must be addressed during verification.

8.7.1 Project Eligibility and CRT Issuance

Table 8.3 lists the criteria for reasonable assurance with respect to eligibility and CRT issuance for ODS destruction projects. These requirements determine if a project is eligible to register with the Reserve and/or have CRTs issued for the ODS destroyed. If any one requirement is not met, either the project may be determined ineligible or the GHG reductions from the ODS destroyed (or sub-set of the ODS destroyed) may be ineligible for issuance of CRTs.

Table 8.3. Project Eligibility Verification Items

Protocol Section	Project Eligibility Qualification Item	Apply Professional Judgment?
2.4	Verify that credits for destroyed ODS have not been claimed on the Reserve or any other registry, using Attestation of Title and Reserve tracking software	No
2.2	Verify that the project meets the definition of a U.S. ODS project	No
2.2	Verify that the destroyed ODS is sourced from the U.S.	Yes
2.2	Verify that the destroyed ODS has been phased out in the U.S.	No
2.2	Verify that the ODS was not used as or produced for use as solvents, medical aerosols or other ODS applications	Yes
2.4	Verify ownership of the reductions by reviewing Attestation of Title	No
2.2	Verify that the project activities involve a single project developer and a single qualifying destruction facility	No
Appendix C	Verify that the destruction facility meets the requirements of this protocol; if the facility is not a RCRA approved HWC, verify that it has been third-party certified as meeting the requirements of the TEAP *Report on the Task Force on HCFC Issues* in Appendix C and has successfully completed the comprehensive performance testing in Appendix C within the three years prior to the end date of destruction	No

Protocol Section	Project Eligibility Qualification Item	Apply Professional Judgment?
	activities	
3.2	Verify eligibility of project start date	No
3.2	Verify project start date based on records	No
2.2	Verify that project activities span no more than 12 months	No
2.3	Verify that the project was correctly characterized as a foam or refrigerant project	No
5.1	Verify that the appropriate baseline scenario was applied for each quantity of ODS destroyed	No
3.4.1	Confirm execution of the Attestation of Voluntary Implementation form to demonstrate eligibility under the Legal Requirement Test	No
6	Verify that the project Monitoring and Operations Plan contains procedures for ascertaining and demonstrating that the project passes the Legal Requirement Test at all times	Yes
3.4.2	Verify that the project meets the Performance Standard Test	No
3.5	Verify that the project activities comply with applicable laws by reviewing any instances of non-compliance provided by the project developer and performing a risk-based assessment to confirm the statements made by the project developer in the Attestation of Regulatory Compliance form	Yes
6	Verify that monitoring plans and procedures meet the requirements of the protocol; if they do not, verify that a variance has been approved for monitoring variations	Yes
6	Verify the Monitoring and Operations Plan includes a project diagram, and that the project diagram is complete, accurate, and up-to-date	No
	If any variances were granted, verify that variance requirements were met and properly applied	No

8.7.2 Conformance with Operational Requirements and ODS Eligibility

Table 8.4 lists the verification items to determine the project's conformance with the operational and monitoring requirements of this protocol, and the eligibility of discrete ODS sources. A subset of destroyed ODS may be deemed ineligible if it was obtained in a manner inconsistent with this protocol, or if documentation is insufficient. If any of Table 8.4 is not met, no CRTs may be issued for that quantity of ODS.

Table 8.4. Operational Requirement and ODS Eligibility Verification Items

Protocol Section	Operational Requirement and ODS Eligibility Items	Apply Professional Judgment?
6.1	For all ODS, verify that information has been correctly entered in Reserve tracking system and that the Certificate of Destruction entry is unique to this project	No
6.2	For all ODS, verify that the point of origin is correctly identified and documented	Yes
6.2, 6.6	For all ODS, verify that the point of origin documentation agrees with the data reported at the destruction facility (weight and composition) with no significant discrepancies	Yes
6.3	For all ODS, verify that the ODS can be tracked through retained chain of custody documentation from the Certificate of Destruction back to the point of origin	Yes
6.4, 6.5	For ODS blowing agents, verify that required data has been collected, per Section 6.4 and 6.5	No

Protocol Section	Operational Requirement and ODS Eligibility Items	Apply Professional Judgment?
6.4	For foam ODS blowing agent, verify that that the recovery efficiency has been calculated correctly per Appendix E	Yes
6.6	Verify that the scales used for measuring mass of ODS destroyed are properly maintained and tested for calibration quarterly	No
6.6	Verify that the weight of full and empty ODS containers was measured 48 hours prior to destruction commencing and 48 hours following completion, respectively	No
6.6	Verify that all ODS samples were taken by a third-party technician while in the possession of the destruction facility	No
6.6	Verify the chain of custody by which ODS sample was transferred from the destruction facility to the lab	No
6.6	Verify that all ODS was analyzed for composition and concentration at a lab approved under the AHRI 700-2006 standard or its successor	No
6.6	Verify that the calculation of ODS composition and mass concentration correctly accounted for moisture, mixing, and high boiling residue	No
6.6	For mixed refrigerants, verify that credits are only claimed for refrigerants eligible under this protocol	No
6.6.1	For mixed refrigerants, verify that proper recirculation occurred	No
6.6.1	For mixed refrigerants, verify that recirculation and sampling were performed by properly trained technicians	Yes
6.4	Verify that for destruction of ODS blowing agent from building foam, the correct procedures have been followed for determining the type and mass ratio of ODS in the foam	No
6.7	Verify that all permits are current at the destruction facility	No
6.7, Appendix C	Verify that the destruction facility where the ODS was destroyed has a documented destruction and removal efficiency greater than 99.99 percent, and that CPT was conducted with a material less combustible than the ODS destroyed	No
6.7, Appendix C	Verify that the destruction facility operated within the parameters under which it was tested to achieve a 99.99 percent or greater destruction and removal efficiency	No
6.7	Verify that the destruction facility monitored the parameters identified in Section 6.7	No
6.7	Verify that the Certificate of Destruction contains all required information	No

8.7.3 Quantification of GHG Emission Reductions

Table 8.5 lists the items that verification bodies shall include in their risk assessment and re-calculation of the project's GHG emission reductions. These quantification items inform any determination as to whether there are material and/or immaterial misstatements in the project's GHG emission reduction calculations. If there are material misstatements, the calculations must be revised before CRTs are issued.

Table 8.5. Quantification Verification Items

Protocol Section	Quantification Item	Apply Professional Judgment?
4	Verify that SSRs included in the GHG Assessment Boundary correspond to those required by the protocol and those represented in the project documentation	No
6.7	Verify that all destroyed ODS for which CRTs are claimed appear on a valid Certificate of Destruction	No

Protocol Section	Quantification Item	Apply Professional Judgment?
5.1	Verify that the baseline emissions were calculated with the appropriate emission rate(s) and aggregated correctly	No
5.2.1	Verify that the substitute emissions have been properly characterized, calculated, and aggregated correctly	No
5.1.2, 5.2.2	Verify that the recovery efficiency has been correctly applied for concentrated ODS blowing agent projects	No
5.2.3, 5.2.4	Verify that the project developer correctly quantified and aggregated electricity use, or that the default factor was applied	Yes
5.2.3, 5.2.4	Verify that the project developer correctly quantified and aggregated fossil fuel use, or that the default factor was applied	Yes
5.2.3, 5.2.4	Verify that the project developer applied the correct emission factors for fossil fuel combustion and grid-delivered electricity, or that the default factors were applied	Yes
5.2.3, 5.2.5	Verify that the project developer correctly quantified and aggregated transportation emissions, or that the default factor was applied	Yes
5.2.3, 5.2.4	Verify that emissions from incomplete ODS destruction and oxidation of ODS carbon have been correctly quantified and aggregated, or that the default factor was applied	Yes

8.7.4 Risk Assessment

Verification bodies will review the following items in Table 8.6 to guide and prioritize their assessment of data used in determining eligibility and quantifying GHG emission reductions.

Table 8.6. Risk Assessment Verification Items

Protocol Section	Item that Informs Risk Assessment	Apply Professional Judgment?
6	Verify that the project Monitoring and Operations Plan is sufficiently rigorous to support the requirements of the protocol and proper operation of the project	Yes
6	Verify that appropriate monitoring equipment is in place to meet the requirements of the protocol	Yes
6	Verify that the individual or team responsible for managing and reporting project activities are qualified to perform these functions	Yes
6.5	Verify that the required data on appliances from which foam was sourced has been collected and managed correctly	Yes
6	Verify that appropriate training was provided to personnel assigned to operations, record-keeping, sample-taking, and other project activities	Yes
6	Verify that all contractors are qualified for managing and reporting greenhouse gas emissions if relied upon by the project developer and that there is internal oversight to assure the quality of the contractor's work	Yes
7	Verify that all required records have been retained by the project developer	No

8.8 Completing Verification

The Verification Program Manual provides detailed information and instructions for verification bodies to finalize the verification process. It describes completing a Verification Report, preparing a Verification Statement, submitting the necessary documents to the Reserve, and notifying the Reserve of the project's verified status.

9 Glossary of Terms

Certificate of Destruction	An official document provided by the destruction facility certifying the date, quantity, and type of ODS destroyed.
Commencement of destruction process	When the ODS waste-stream is hooked up to the destruction chamber.
Commercial refrigeration equipment	The refrigeration appliances used in the retail food, cold storage warehouse or any other sector that requires cold storage. Retail food includes the refrigeration equipment found in supermarkets, grocery and convenience stores, restaurants, and other food service establishments. Cold storage includes the refrigeration equipment used to house perishable goods or any manufactured product requiring refrigerated storage.
Container	An air- and water-tight unit for storing and/or transporting ODS material without leakage or escape of ODS.
Destruction	Destruction of ozone depleting substances by qualified destruction, transformation or conversion plants achieving greater than 99.99 percent destruction and removal efficiency, in order to avoid their emissions. Destruction may be performed using any technology, including transformation, that results in the complete breakdown of the ODS into either a waste or usable by-product.
Destruction facility	A facility that destroys, transforms or converts ozone depleting substances using a technology that meets the standards defined by the UN Environment Programme Technology and Economic Assessment Panel Task Force on Destruction Technologies.[53]
Emission rate	The rate at which refrigerant is lost to the atmosphere, including emissions from leaks during operation and servicing events.
Generator	The facility from which the ODS material on a single Certificate of Destruction departed prior to receipt by the destruction facility. If the material on a single Certificate of Destruction was aggregated as multiple shipments to the destruction facility, then the destruction facility shall be the Generator.
Ozone Depleting Substances (ODS)	Ozone depleting substances are substances known to deplete the stratospheric ozone layer. The ODS controlled under the Montreal Protocol and its Amendments are chlorofluorocarbons (CFC), hydrochlorofluorocarbons (HCFC), halons, methyl bromide (CH_3Br), carbon tetrachloride (CCl_4), methyl chloroform (CH_3CCl_3), hydrobromofluorocarbons (HBFC) and bromochloromethane (CHBrCl). [54]

[53] United Nations Environment Programme. (2003). Report of the Fifteenth Meeting of the Parties to the Montreal Protocol on Substances that Deplete the Ozone Layer. *OzL.Pro.15/9*. Nairobi, November 11, 2003.
[54] Source: IPCC - http://www.mnp.nl/ipcc/pages_media/SROC-final/SROC_A2.pdf

Recovery efficiency	The percent of total ODS blowing agent that is recovered during the process of ODS blowing agent extraction.
Recharge	Replenishment of refrigerant agent (using reclaimed or virgin material) into equipment that is below its full capacity because of leakage or because it has been evacuated for servicing or other maintenance.
Reclaim	Reprocessing and upgrading of a recovered ozone depleting substance through mechanisms such as filtering, drying, distillation and chemical treatment in order to restore the ODS to a specified standard of performance. Chemical analysis is required to determine that appropriate product specifications are met. It often involves processing off-site at a central facility.
Recovery	The removal of ozone depleting substances from machinery, equipment, containment vessels, etc., into an external container during servicing or prior to disposal without necessarily testing or processing it in any way.
Reuse/recycle	Reuse of a recovered ozone depleting substance following a basic cleaning process such as filtering and drying. For refrigerants, recycling normally involves recharge back into equipment and it often occurs ‘on-site’.
Startup, shutdown, and malfunction plan	A plan, as specified under 40 CFR 63.1206, that includes a description of potential causes of malfunctions, including releases from emergency safety vents, that may result in significant releases of hazardous air pollutants, and actions the source is taking to minimize the frequency and severity of those malfunctions.
Stockpile	ODS stored for future use or disposal in bulk quantities at a single location. These quantities may be composed of many small containers or a single large container.
Substitute refrigerant	Those refrigerants that will be used to fulfill the function that would have been filled by the destroyed ODS refrigerants. These refrigerants may be drop-in replacements used in equipment that previously used the type of ODS destroyed or may be used in new equipment that fulfills the same market function.
Substitute emissions	A term used in this protocol to describe the greenhouse gases emitted from the use of substitute refrigerants in technologies that are used to replace the ODS destroyed in a project.
Transportation system	A term used to encompass the entirety of the system that moves the ODS from the point of aggregation to the destruction facility.

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Appendix A Summary of Legal Requirement Test Development

Management activities for ozone depleting substances are dictated in the United States by both the Montreal Protocol, to which the U.S. is a party, and the U.S. Clean Air Act. This appendix provides background information on both of these regulatory frameworks. Further, this appendix demonstrates that neither framework requires the destruction of ODS, and destruction therefore meets the Legal Requirement Test under the Climate Action Reserve U.S. Ozone Depleting Substances Project Protocol.

A.1 Montreal Protocol

The original Montreal Protocol, signed in 1987, was the first international treaty with binding commitments to protect stratospheric ozone. Since that time, the Montreal Protocol has been repeatedly strengthened by both controlling additional ODS as well as by moving up the date by which previously controlled substances must be phased out. The Montreal Protocol controls only production and consumption (production plus imports minus exports) and not emissions of ODS. There is no mandatory requirement to destroy ODS in the Montreal Protocol. Therefore, for analyses prepared under the Montreal Protocol, it is assumed that all ODS that are produced will eventually be released to the atmosphere, even though some developed countries have voluntary and/or mandatory requirements to destroy ODS.

Under the original Montreal Protocol agreement (1987), non-Article 5 countries were required to begin phasing out CFC in 1993 and achieve a 50 percent reduction relative to 1986 consumption levels by 1998. Under this agreement, CFC were the only ODS addressed. The London Amendment (1990) changed the ODS emission schedule by requiring the complete phase-out of CFC, halons, and carbon tetrachloride by 2000 in developed countries, and by 2010 in developing countries. Methyl chloroform was also added to the list of controlled ODS, with phase-out in developed countries targeted in 2005, and in 2015 for developing countries.

The Copenhagen Amendment (1992) significantly accelerated the phase-out of ODS and incorporated an HCFC phase-out for developed countries, beginning in 2004. Under this agreement, CFC, halons, carbon tetrachloride, methyl chloroform, and HBFC were targeted for complete phase-out in 1996 in developed countries. In addition, methyl bromide consumption was capped at 1991 levels.

The Montreal Amendment (1997) included the phase-out of HCFC in developing countries, as well as the phase-out of methyl bromide in developed and developing countries in 2005 and 2015, respectively.

The Beijing Amendment (1999) included tightened controls on the production and trade of HCFC. Bromochloromethane was also added to the list of controlled substances with phase-out targeted for 2002.

At the 19th Meeting of the Parties in Montreal in September 2007, the Parties agreed to an adjustment that more aggressively phases out HCFC in both developed and developing countries. Developed countries must reduce HCFC production and consumption by 75 percent of their baseline by 2010, 99.5 percent by 2020, and 100 percent by 2030. The 0.5 percent during the period 2020-2030 is restricted to the servicing of existing refrigeration and air-conditioning equipment and is subject to review in 2015. Developing countries must freeze production and consumption of HCFC in 2013 at their baseline and then reduce it by 10 percent in 2015, 35 percent by 2020, 67.5 percent by 2025, 97.5 percent by 2030 and 100 percent by 2040. The 2.5 percent during the period 2030-2039 is the average over that time frame (e.g. it can be five percent for five years and zero percent for the other five years), is restricted to the servicing of existing refrigeration and air-conditioning equipment, and is subject to review in 2015.

The result of the Montreal Protocol with its amendments and adjustments is that as of January 1, 2010, CFC, halons, methyl chloroform, carbon tetrachloride, methyl bromide, and bromochloromethane will be phased out of production in both developed and developing countries. Therefore any ongoing uses of these substances must be supplied from already existing stocks that were never used, or from recycled or reclaimed material. However, it should be noted that there are allowances for some ongoing limited production of these substances for certain essential uses and critical uses approved by the Montreal Protocol Parties (e.g. as process agents and for quarantine and pre-shipment uses). Also, production and use of these substances as feedstock is not considered production since they are consumed in the feedstock process. Destruction of ODS from these sources is not eligible under this protocol.

The Reserve's review of the U.S. commitment under the Montreal Protocol and its amendments indicates that destruction of ODS is not required in the U.S. at this time. Further, review of the Montreal Protocol makes clear that destruction is not required. The scope of the Montreal Protocol is limited to the production end of ODS management, and does not require destruction of extant stocks. As such, in reference to the Montreal Protocol and international law, destruction of U.S. sources of ODS meets the Legal Requirement Test.

A.2 Title VI of the Clean Air Act and 40 CFR 82

In 1988, the United States ratified the Montreal Protocol. By ratifying the Montreal Protocol and its subsequent amendments, the United States committed to a collaborative, international effort to regulate and phase out ODS, including CFC, HCFC, halons, carbon tetrachloride, methyl chloroform, methyl bromide, bromochloromethane, and HBFC.

The Montreal Protocol led to the inclusion of Title VI, Stratospheric Ozone Protection in the Clean Air Act Amendments of 1990. Title VI authorizes the EPA to manage the phase-out of ODS. Among the regulations established by EPA are requirements for the safe handling of ODS and prohibitions on the known venting or release of ODS into the atmosphere for the majority of applications, including refrigerants and fire suppressants. Therefore, as ODS are phased out, surplus ODS must be stored, reused (after recycling or reclamation) or destroyed.

EPA regulations issued under Sections 601-607 of the CAA phase out the production and import of ODS, consistent with the schedules developed under the Montreal Protocol. However, in the case of HCFC, EPA has used a "worst-first" approach to meet the Montreal Protocol required reduction caps. Under this approach, those HCFC with the highest ozone depletion potential (ODP) are phased out first. As of January 1, 2003, EPA banned production and import of HCFC-141b, the HCFC with the highest ODP. This action allowed the United States to reduce its consumption by 35 percent below the cap by the January 1, 2004 deadline and meet its obligations under the Montreal Protocol. As such, HCFC-141b is now entirely phased out and therefore eligible per this protocol.

In 2003 EPA issued baseline allowances for production and import of HCFC-22 and HCFC-142b, the two HCFC with the next highest ODP. The United States plans to meet the rest of the Montreal Protocol phase-out schedule through the following actions:

January 1, 2010	Ban on production and import of HCFC-22 and HCFC-142b except for on-going servicing needs in equipment manufactured before January 1, 2010.*
January 1, 2015	Ban on introduction into interstate commerce or use of HCFC except where the HCFC are used as a refrigerant in appliances manufactured prior to January 1, 2020.*
January 1, 2020	Ban on remaining production and import of HCFC-22 and HCFC-142b.*
January 1, 2030	Ban on remaining production and import of all other HCFC.*

* Certain additional exemptions apply, including exemptions for (1) HCFC used in processes resulting in their transformation or destruction, or (2) pre-authorized import of HCFC that are recovered and either recycled or reclaimed.

The Reserve's review of the CAA indicates that destruction of ODS is not required in the U.S. at this time. The CAA dictates a phase-out schedule for the production of ODS, and proffers guidance on handling, disposal, and other requirements but does not dictate that destruction of ODS occur. As such, in reference to the U.S. CAA and domestic law, destruction of U.S. sources of ODS meets the Legal Requirement Test.

Appendix B Summary of Performance Standard Development

The Reserve assesses the additionality of projects through application of a Performance Standard Test and a Legal Requirement Test. The purpose of a performance standard is to establish a standard of performance applicable to all ODS projects that is significantly better than average ODS management practice, which, if met or exceeded by a project developer, satisfies the criterion of "additionality." [55]

The sections below describe the analysis that forms the basis of the performance standard for each of the ODS sources within this protocol. The analysis included an examination of current practice related to 1) the destruction of ODS refrigerant and ODS foam blowing agent, and 2) the end-of-life treatment of foam.

B.1 Destruction of ODS from Refrigerants and Foam

Appendix A described the regulatory framework surrounding the end-of-life treatment of refrigerant and foam ODS and demonstrated that destruction is not required by law in the U.S. However, the Reserve looks not only at what the regulatory requirements are, but also at the prevailing practices in the industry. Therefore, with the project defined as destruction of ODS refrigerant or ODS blowing agent, the question remains: is destruction of ODS refrigerant and ODS blowing agent sourced within the U.S. standard practice or does it exceed standard practice?

For this analysis, the Reserve assessed common practice for CFC refrigerants and foams that have been phased out of U.S. production under the Montreal Protocol and U.S. Clean Air Act. This was done by comparing the proportion of recoverable ODS in the U.S. within a given year to the amount that was destroyed during that same time period to determine to what extent available ODS was being destroyed.

The Reserve's starting point for this assessment was U.S. EPA data records, including a report produced by ICF International entitled *ODS Destruction in the United States of America and Abroad* (2009). In addition to providing information on ODS destruction techniques and practices, the report supplies the specific quantity of ODS destroyed for the years 2003 and 2004 in the U.S.

The years 2003 and 2004 are particularly useful as they represent common practice before the initiation of carbon offset projects in the U.S. Subsequent to 2004, several ODS destruction projects were conducted for carbon credits on the Chicago Climate Exchange (CCX), and in possible anticipation of other offset programs. As such, destruction numbers from this post-2004 time period may artificially inflate the amount of ODS that is destroyed due to standard industry practice. The goal of this analysis is to determine what happened *in the absence* of a carbon incentive. Therefore, the 2003 to 2004 data represents a balance of current data on common practice *after* the CAA phase-out of ODS went into effect but *prior* to the availability of a carbon incentive.

[55] See the Climate Action Reserve's Program Manual for further discussion of the Reserve's general approach to determining additionality.

Table B.1. Destruction of ODS in the U.S.

CFC	2003 Destroyed (kg)	2004 Destroyed (kg)
CFC-11	58,846	109,884
CFC-12	23,709	62,364
CFC-114	464	4,044
CFC-115	4,401	6,737

Source: Reproduced from ICF, ODS Destruction in the United States of America and Abroad (2009), prepared for U.S. EPA.

While the 2003-2004 data above is useful because it is not yet influenced by the carbon market, it does nonetheless over-state the amount of destruction that took place during this time period because of the inclusion of ODS sourced from outside the U.S.

The applicability of this protocol is limited to ODS sourced from within the U.S. Therefore, the analysis of common practice must include only destroyed ODS that originated within the U.S. Several countries, including Canada and Australia, have taken a proactive approach to managing ODS and have strong ODS destruction programs that regularly send material to the U.S. for destruction. The Reserve compiled data from destruction facilities to determine the amount of destruction that could be attributed to these imports and subsequently subtracted from total U.S. destruction. Table B.2 presents this analysis including the resulting net U.S. destruction. To protect proprietary company data, Table B.2 provides only the aggregate amounts of ODS that was destroyed from imported stocks.

Table B.2. ODS Destroyed from Ineligible Imported Sources

ODS	Destroyed in U.S. (kg)		Imported for Destruction (kg)[56]		Net U.S. Sourced ODS Destroyed (kg)	
	2003	2004	2003[57]	2004	2003	2004
CFC-11	58,846	109,884	-	55,113	58,846	54,771
CFC-12	23,709	62,364	-	25,611	23,709	36,753
CFC-114	464	4,044	-	2,316	464	1,728
CFC-115	4,401	6,737	-	1,710	4,401	5,027

The goal of the performance standard is to determine the market penetration of a given activity. In order to determine the extent to which destruction occurred relative to the amount of ODS available in the U.S. prior to carbon incentives, the Reserve obtained data from U.S. EPA on the amount of ODS from refrigerant and foam that could be recovered for re-use and/or destruction in 2003 to 2004. The data source is U.S. EPA's Vintaging Model that tracks the type, age, refrigerant, leak rates, and other information for equipment and ODS applications within the U.S. market. By tracking this data through cooperation with industry, the U.S. EPA Vintaging Model is able to approximate when stocks of ODS will reach end-of-life.

At the Reserve's request, the U.S. EPA provided estimates of the quantity of ODS refrigerant that was contained in equipment reaching end-of-life in 2003-2004.[58] In addition to determining the amount of ODS that could be made available from refrigerants, the U.S. EPA provided

[56] Data provided by industry is presented anonymously to protect proprietary information.
[57] Data on imports could not be obtained for 2003. This results in a conservative performance standard analysis.
[58] The use of data from the U.S. EPA Vintaging Model into this protocol does not constitute an endorsement by EPA of the Climate Action Reserve or its methodology. Where actual measurements or other data was made available to and used by the Reserve in this protocol in lieu of the Vintaging Model data, this has been indicated in the protocol.

estimates of the number of residential refrigerators reaching end-of-life in 2003 and 2004. U.S. EPA assumed an ODS content of one pound CFC-11 foam blowing agent per refrigerator to establish the total amount ODS that could be made available for destruction from these appliances.

Table B.3. Recoverable ODS from End-of-Life Refrigeration Equipment and Foam Appliances in the U.S., 2003-2004[59]

ODS	Recoverable Refrigerant (kg)		Residential Refrigerator Foam at End of Life (kg)		Total Available for Destruction (kg)	
	2003	2004	2003	2004	2003	2004
CFC-11	717,140	700,310	3,499,545	3,516,364	4,216,685	4,216,674
CFC-12	12,725,841	10,997,307			12,725,841	10,997,307
CFC-114	154,710	154,710			154,710	154,710
CFC-115	1,833,654	2,207,326			1,833,654	2,207,326

Using the destruction data compiled by ICF International and the data on recoverable ODS refrigerants and ODS blowing agent from the U.S. EPA Vintaging Model, the Reserve derived the percentage of recoverable ODS that was destroyed in 2003-2004 (see Table B.4). Because the percentage of recoverable ODS destroyed was very low, the Reserve concluded that the destruction of refrigerant ODS without the incentive from the carbon market is not common practice. Therefore, any project that destroys the refrigerants listed in Table B.4 exceeds the performance standard.

Table B.4. Destruction of Recoverable, U.S. Sourced End-of-Life ODS

ODS	Total Available for Destruction (kg)		Domestic Sourced Destroyed (kg)		Performance Standard (Destroyed/Available)	
	2003	2004	2003	2004	2003	2004
CFC-11	4,216,685	4,216,674	58,846	54,771	1.40%	1.30%
CFC-12	12,725,841	10,997,307	23,709	36,753	0.19%	0.33%
CFC-114	154,710	154,710	464	1,728	0.30%	1.12%
CFC-115	1,833,654	2,207,326	4,401	5,027	0.24%	0.23%

The Reserve consulted with representatives from government, industry, and the destruction facilities responsible for ODS destruction to characterize the limited ODS destruction that did occur in 2003 to 2004. Although these representatives were unable to provide records indicating a precise breakdown of destruction purposes, they indicated that the destroyed ODS was primarily solvent that was deemed hazardous waste and required destruction, ODS destroyed by the U.S. government , and medical grade ODS. None of these sources are eligible under this protocol. Only a very small amount of highly contaminated ODS was sent for destruction by industry.

Under Version 1.0, ODS sourced from federal government installations or stockpiles was deemed ineligible. One reason for this decision was because some ODS sourced from the federal government was already being destroyed and it was suggested that this destruction was undertaken voluntarily as part of its existing commitment to responsible waste disposal. Since the issuance of Version 1.0, the Reserve has learned that the only ODS destroyed by the federal government is through a small number of demonstration projects and is not required by

[59] U.S. EPA. (2008). EPA Vintaging Model. *Version VM IO file_v4.2_10.07.08*.

any responsible waste disposal policies. While there is an executive order[60] that sets forth the following policy on ODS management, it does not mandate destruction:

"Each agency shall amend its personal property management policies and procedures to preclude the disposal of ODSs removed or reclaimed from its facilities or equipment, including disposal as part of a contract, trade, or donation, without prior coordination with the Department of Defense (DoD)."

The DoD operates an ODS Reserve to ensure adequate supplies of halons and refrigerants for weapons use. Communications with the staff at the DoD ODS Reserve have confirmed that there is no mandate or policy in place requiring or recommending the federal government destroy ODS. In fact, if there is excess refrigerant available from federal installations beyond the inventory needs of the DoD ODS Reserve, the refrigerant is turned over to the U.S. Defense Logistics Agency Disposition Services for resale to the public.

It is important to note that the federal government also comes to possess refrigerants through seizures of illegal material by U.S. Customs. This seized material would not be available through the U.S. Defense Logistics Agency Disposition Services, but rather through separate auctions conducted by U.S. Customs. ODS sourced from illegal seizures is not eligible under this protocol because it was not produced in the United States.

B.2 End-of-Life Treatment of Foam

The Reserve also reviewed separately the common practice in the end-of-life treatment of foams containing ODS blowing agents. Whereas U.S. EPA regulations prohibit the intentional release of ODS refrigerants to the atmosphere, there is no preclusion against disposal practices that result in release of ODS blowing agents.

According to the 2005 TEAP *Report of the Task Force on Foam End-of-Life Issues*, there is little or no experience with the recovery of foams from buildings or of the ODS contained within the foams. This is mainly because few buildings containing foam with ODS blowing agent have been demolished, deconstructed, or renovated yet. The average overall lifecycle of buildings in North America and other developed countries ranges from 30 to 50 years. Meanwhile, the common use of foam in insulation only really began in the mid 1970s after the energy crisis led to increased use of insulation. With an average turnover rate of building stock in North America of less than one percent per year, buildings with foam insulation are only just beginning to enter the waste stream. As a result, the management of ODS from building foam has not yet become a focus of regulators. Other factors that have prevented the recovery and destruction of building foam include challenges involved with separating foam from the building structure, the common practice of landfilling construction waste without any pretreatment (only 20 to 30 percent of building materials are recycled or sold in the United States), the very small proportion of ODS foam compared to overall construction waste, and a lack of regulations in the United States governing recovery of building foam insulation and the ODS contained therein.

The destruction of ODS from foam in appliances and equipment is also very limited in the U.S. The 2005 TEAP *Report of the Task Force on Foam End-of-Life Issues* describes the results of an AHAM survey which provides the following breakdown of common appliance disposal practices in the United States:

[60] Executive Order 13423 - "Strengthening Federal Environmental, Energy, and Transportation Management", March 29, 2007.

- 90 percent appliances shredded without blowing agent recovery and landfilled
- 7.5 percent appliances crushed whole and landfilled
- 1.5 percent appliances shredded with blowing agent recovery or destruction
- One percent appliances abandoned

As noted in the survey results, only 1.5 percent of appliances are being shredded with the containing foam blowing agent either being recovered for reuse in the refrigeration market or destroyed. This foam shredding and recovery is being driven mainly by state, local and utility energy efficiency initiatives with some program administrators adding a second requirement that the blowing agent must be recovered as well. Most of these programs are voluntary and meet their objectives by incentivizing early appliance retirement and recycling through rebates or discounts on new units. As noted in the TEAP report, the process for recovering ODS from appliance foam is costly and is currently not self-sustaining unless outside sponsorship is provided. Although U.S. EPA and others track information on the amount of foam that is being shredded and the blowing agent that is being recovered, there is no data available on the share of blowing agent that is being reused versus destroyed. According to industry analysts, most of the recovered blowing agent is being resold into the refrigeration market because of the economic incentive to do so. Destruction will only occur in cases where the utility or other entity participating in the appliance program specifically requests that this must take place. As a result, the destruction of ODS blowing agent is likely significantly less than the 1.5 percent share of appliances where the disposal includes management of the blowing agent.

Because the destruction of blowing agent from building foam does not occur and the destruction from appliances is very low, the Reserve concluded that the destruction of foam blowing agent is not common practice.

Appendix C Rules Governing ODS Destruction

This protocol requires that all ODS be destroyed at a destruction facility that is compliant with both the international standards specified in the TEAP *Report of the Task Force on Destruction Technologies*,[61] as well as the requirements of domestic law. This appendix provides a brief summary of the U.S. rules for destruction of ODS, and the criteria that must be met for a destruction facility to qualify under this protocol.

All ODS destruction is regulated under stratospheric ozone protection regulations under the Clean Air Act (CAA) (40 CFR 82). Additionally, because some ODS are classified as hazardous wastes (such as CFC-113, methyl chloroform, and carbon tetrachloride), facilities that handle these ODS are regulated under the Resource Conservation and Recovery Act (RCRA). Hazardous waste combustors (HWCs, e.g. incinerators) that destroy ODS classified as hazardous waste are also regulated by the Maximum Achievable Control Technology (MACT) standard under the CAA.

Under the authority of the CAA, the stratospheric ozone protection regulations (40 CFR Part 82, Subpart A) require that ODS be destroyed using one of the following destruction technologies approved by the Montreal Protocol Parties:

1. Liquid injection incineration
2. Reactor cracking
3. Gaseous/fume oxidation
4. Rotary kiln incineration
5. Cement kiln
6. Radio frequency plasma
7. Municipal waste incinerators (only for the destruction of foams)
8. Argon arc plasma

Additionally, if the substance is to be considered “completely destroyed” as defined in the regulations, it must be destroyed to a 98 percent destruction efficiency (DE). This is slightly different from the Montreal Protocol Technology and Economic Assessment Panel which recommends a destruction and removal efficiency (DRE) limit of 99.99 percent. DE is a more comprehensive measure of destruction than DRE as it includes emissions of undestroyed chemical from all points (e.g. stack gases, fly ash, scrubber, water, bottom ash), while DRE includes emissions of undestroyed chemical from the stack gas only. However, because of the relatively volatile nature of ODS and because, with the exception of foams, they are generally introduced as relatively clean fluids, one would not expect a very significant difference between DRE and DE.

Any destruction facility that is regulated by U.S. EPA as a RCRA-permitted HWC is automatically considered a qualifying destruction facility under this protocol.

Non-RCRA permitted facilities may also be deemed qualifying destruction facilities if they meet the pertinent guidelines provided by the TEAP *Report of the Task Force on Destruction Technologies*, and reproduced below. By inclusion here, the recommendations of the excerpted section of the TEAP report shall be binding on all non-RCRA destruction facilities. Destruction

[61] TEAP. (2002). Report of the Task Force on Destruction Technologies. *Volume 3B*.

facilities must provide third-party certified results indicating that the facility meets all performance criteria set forth below. Following the initial performance testing, project developers must demonstrate that the facility has conducted comprehensive performance testing at least every three years to validate compliance with the TEAP DRE and emissions limits as reproduced below.

(Reproduced in full from TEAP *Report of the Task Force on Destruction Technologies*, Chapter 2 (2002). References in the following section pertain to the *Report* document, not this protocol.)

CHAPTER 2

2.0 TECHNOLOGY SCREENING PROCESS

2.1 Criteria for Technology Screening

The following screening criteria were developed by the UNEP TFDT. Technologies for use by the signatories to the Montreal Protocol to dispose of surplus inventories of ODS were assessed on the basis of:

1. Destruction and Removal Efficiency (DRE)
2. Emissions of dioxins/furans
3. Emissions of other pollutants (acid gases, particulate matter, and carbon monoxide)
4. Technical capability

The first three refer to technical performance criteria selected as measures of potential impacts of the technology on human health and the environment. The technical capability criterion indicates the extent to which the technology has been demonstrated to be able to dispose of ODS (or a comparable recalcitrant halogenated organic substance such as PCB) effectively and on a commercial scale.

For convenience, the technical performance criteria are summarized in Table 2-1. These represent the minimum destruction and removal efficiencies and maximum emission of pollutants to the atmosphere permitted by technologies that qualify for consideration by the TFDT for recommendation to the Parties of the Montreal Protocol for approval as ODS destruction technologies. The technologies must also satisfy the criteria for technical capability as defined in Section 2.1.4.

Table 2-1: Summary of Technical Performance Qualifications[62]

Performance Qualification	Units	Diluted Sources	Concentrated Sources
DRE	%	95	99.99
PCDDs/PCDFs	ng-ITEQ/Nm^3	0.5	0.2
HCl/Cl_2	mg/Nm^3	100	100
HF	mg/Nm^3	5	5
HBr/Br_2	mg/Nm^3	5	5
Particulates (TSP)	mg/Nm^3	50	50
CO	mg/Nm^3	100	100

[62] All concentrations of pollutants in stack gases and stack gas flow rates are expressed on the basis of dry gas at normal conditions of 0ºC and 101.3 kPa, and with the stack gas corrected to 11 percent O_2.

2.1.1 Destruction and Removal Efficiency

Destruction Efficiency (DE)[63] is a measure of how completely a particular technology destroys a contaminant of interest – in this case the transformation of ODS material into non-ODS by-products. There are two commonly used but different ways of measuring the extent of destruction – DE and Destruction and Removal Efficiency (DRE).[64] For a more detailed explanation of how DRE is calculated, see section 4.2.1. The terms are sometimes interchanged or used inappropriately. DE is a more comprehensive measure of destruction than DRE, because DE considers the amount of the chemical of interest that escapes destruction by being removed from the process in the stack gases and in all other residue streams. Most references citing performance of ODS destruction processes only provide data for stack emissions and thus, generally, data is only available for DRE and not DE.

Because of the relatively volatile nature of ODS and because, with the exception of foams, they are generally introduced as relatively clean fluids, one would not expect a very significant difference between DRE and DE.

For these reasons this update of ODS destruction technologies uses DRE as the measure of destruction efficiency.

For the purposes of screening destruction technologies, the minimum acceptable DRE is:

- 95 percent for foams; and,
- 99.99 percent for concentrated sources.

It should be noted that measurements of the products of destruction of CFC, HCFC and halons in a plasma destruction process have indicated that interconversion of ODS can occur during the process. For example, under some conditions, the DRE of CFC-12 (CCl_2F_2) was measured as 99.9998 percent, but this was accompanied by a conversion of 25 percent of the input CFC-12 to CFC-13 ($CClF_3$), which has the same ozone-depleting potential. The interconversion is less severe when hydrogen is present in the process, but can nonetheless be significant.[65] For this reason, it is important to take into account all types of ODS in the stack gas in defining the DRE.

For the reasons described in the previous paragraph, the Task Force recommends that future calculations of DRE use the approach described below.[66]

[63] Destruction Efficiency (DE) is determined by subtracting from the mass of a chemical fed into a destruction system during a specific period of time the mass of that chemical that is released in stack gases, fly ash, scrubber water, bottom ash, and any other system residues and expressing that difference as a percentage of the mass of the chemical fed into the system.

[64] Destruction and Removal Efficiency (DRE) has traditionally been determined by subtracting from the mass of a chemical fed into a destruction system during a specific period of time the mass of that chemical alone that is released in stack gases, and expressing that difference as a percentage of the mass of that chemical fed into the system.

[65] Deam, R. T., Dayal, A. R., McAllister, T., Mundy, A. E., Western, R. J., Besley, L. M., Farmer, A. J. D., Horrigan, E. C., & Murphy, A. B. (1995). Interconversion of chlorofluorocarbons in plasmas. *J. Chem. Soc.: Chem. Commun. No. 3,* 347-348; Murphy, A. B., Farmer, A. J. D., Horrigan, E. C., & McAllister, T. (2002). Plasma destruction of ozone depleting substances, *Plasma Chem. Plasma Process, 22,* 371-385.

[66] Since different ODS have different ODP, consideration should be given to taking into account the ODP of each type of ODS present in the stack gas in calculating the DRE. An appropriate definition that takes into account the differences in ODP is: *DRE of an ODS is determined by subtracting from the number of moles of the ODS fed into a destruction system during a specific period of time, the total number of moles of all types of ODS that are released in*

DRE of an ODS should be determined by subtracting from the number of moles of the ODS fed into a destruction system during a specific period of time, the total number of moles of all types of ODS that are released in stack gases, and expressing that difference as a percentage of the number of moles of the ODS fed into the system.

In mathematical terms, $\mathrm{DRE} = \dfrac{N_1^{\mathrm{in}} - \sum_i N_i^{\mathrm{out}}}{N_1^{\mathrm{in}}}$

Where N_1^{in} is the number of moles of the ODS fed into the destruction system, and N_i^{out} is the number of moles of the *i*th type of ODS that is released in the stack gases.

2.1.2 Emissions of Dioxins and Furans

Any high temperature process used to destroy ODS has associated with it the potential formation (as by-products) of polychlorinated dibenzo-paradioxins (PCDDs) and polychlorinated dibenzofurans (PCDFs). These substances are among the products of incomplete combustion (or PICs) of greatest concern for potential adverse effects on public health and the environment. The internationally recognized measure of the toxicity of these compounds is the toxic equivalency factor (ITEQ),[67] which is a weighted measure of the toxicity for all the members of the families of these toxic compounds that are determined to be present.

The task force members note that the World Health Organization has developed a new system for calculating TEQs, however, most of the existing data on emissions is expressed in the former ITEQ system established in 1988.

For purposes of screening destruction technologies, the maximum concentration of dioxins and furans in the stack gas from destruction technologies is:

- 0.5 ng-ITEQ/Nm^3 for foams; and,
- 0.2 ng-ITEQ/Nm^3 for concentrated sources.

These criteria were determined to represent a reasonable compromise between more stringent standards already in place in some industrialized countries [for example, the Canada-Wide Standard of 0.08 ng/m^3 (ITEQ)], and the situation in developing countries where standards may be less stringent or non-existent. Although a previous standard of 1.0 ng/m^3 (ITEQ) had been

stack gases, weighted by their ODP relative to that of the feed ODS, and expressing that difference as a percentage of the number of moles of the ODS fed into the system.

[67] There are 75 chlorinated dibenzo-p-dioxins and 135 chlorinated dibenzofurans that share a similar chemical structure but that have a wide range in degree of chlorination and a corresponding wide range in toxicity. Of these, one specific dioxin [2,3,7,8-Tetrachlorodibenzo-p-dioxin, or (TCDD)] is the most toxic and best characterized of this family of compounds. Since PCDDs and PCDFs are generally released to the environment as mixtures of these compounds, the scientific community has developed a system of toxic equivalency factors (TEFs) which relate the biological potency of compounds in the dioxin/furan family to the reference TCDD compound. The concentration of each specific compound is multiplied by its corresponding TEF value, and the resulting potency-weighted concentration values are summed to form an expression of the mixture's overall toxic equivalence (TEQ). The result of this exercise is a standardized expression of toxicity of a given mixture in terms of an equivalent amount of TCDD (the reference compound). The internationally accepted protocol for determining TEQ – i.e. ITEQ – was established by NATO in 1988. [North Atlantic Treaty Organization/Committee on the Challenge of Modern Society. (1988). Scientific Basis for the Development of International Toxicity Equivalency Factor (I-TEF), Method of Risk Assessment for Risk Assessment of Complex Mixtures of Dioxins and Related Compounds. *Report No. 176*, Washington, D.C.]

suggested in the UNEP 1992 report, advances in technology in recent years, and the level of concern for emissions of these highly toxic substances justified a significantly more stringent level.

2.1.3 Emissions of Acid Gases, Particulate Matter and Carbon Monoxide

Acid gases are generally formed when ODS are destroyed and these must be removed from the stack gases before the gases are released to the atmosphere. The following criteria for acid gases have been set for purposes of screening destruction technologies:

- a maximum concentration in stack gases of 100 mg/Nm^3 HCl/Cl_2;
- a maximum concentration in stack gases of 5 mg/Nm^3 HF; and,
- a maximum concentration in stack gases of 5 mg/Nm^3 HBr/Br_2.

Particulate matter is generally emitted in the stack gases of incinerators for a variety of reasons and can also be emitted in the stack gases of facilities using non-incineration technologies. For the purposes of screening technologies, the criterion for particulate matter is established as:

- a maximum concentration of total suspended particulate (TSP) of 50 mg/Nm^3.

Carbon monoxide (CO) is generally released from incinerators resulting from incomplete combustion and may be released from some ODS destruction facilities because it is one form by which the carbon content of the ODS can exit the process. Carbon monoxide is a good measure of how well the destruction process is being controlled. For the purposes of screening technologies, the following criterion has been established:

- a maximum CO concentration in the stack gas of 100 mg/Nm^3.

These maximum concentrations apply to both foams and concentrated sources. They were set to be achievable by a variety of available technologies while ensuring adequate protection of human health and the environment.

2.1.4 Technical Capability

As well as meeting the above performance requirements it is necessary that the destruction technologies have been demonstrated to be technically capable at an appropriate scale of operation. In practical terms, this means that the technology should be demonstrated to achieve the required DRE while satisfying the emissions criteria established above. Demonstration of destruction of ODS is preferred but not necessarily required. Destruction of halogenated compounds that are refractory, i.e. resistant to destruction, is acceptable. For example, demonstrated destruction of polychlorinated biphenyls (PCBs) was often accepted as an adequate surrogate for demonstrated ODS destruction.

For this evaluation, an ODS destruction technology is considered technically capable if it meets the following minimum criteria:

- It has been demonstrated to have destroyed ODS to the technical performance standards, on at least a pilot scale or demonstration scale (designated in Table 2-2 as “Yes”).

- It has been demonstrated to have destroyed a refractory chlorinated organic compound other than an ODS, to the technical performance standards, on at least a pilot scale or demonstration scale (designated in Table 2-2 as “P,” which indicates that the technology is considered to have a high potential for application with ODS, but has not actually been demonstrated with ODS).

- The processing capacity of an acceptable pilot plant or demonstration plant must be no less than 1.0 kg/hr of the substance to be destroyed, whether ODS or a suitable surrogate.

These criteria of technical capability will minimize the risk associated with technical performance and ensure that destruction of ODS will be performed in a predictable manner consistent with protecting the environment.

Appendix B presents a detailed discussion of the selection of 1.0 kg/hr as the minimum capacity for a pilot plant in order to demonstrate technical capability, which represents a change from the criterion originally selected in the 1992 UNEP report.

Appendix D Development of Refrigerant Emissions Rates

Under this protocol refrigerant emissions are estimated in reference to the emission loss rates of the equipment into which those refrigerants would have been installed in the baseline. This appendix explains the methodology the Reserve followed to determine the protocol's prescribed emission rates for refrigerant baseline and project emissions.

As described in Appendix A, the CAA and 40 CFR 82 prohibit intentional venting of ODS to the atmosphere. However, due to the disperse nature of servicing and ODS recovery, a significant portion of ODS refrigerants are unintentionally lost during recovery. As a result, every year a significant quantity of ODS is released directly to the atmosphere during equipment servicing and handling, but due to the dispersed nature of these emissions it is difficult to determine the overall share that is being emitted rather than re-used.

The CAA allows the recovery and sale of reclaimed ODS to the refrigeration and air conditioning markets. In fact, because they can no longer be produced or imported, ODS refrigerants still have a high value for recovery and reuse. Whereas destruction of recovered ODS imposes a cost on industry, resale provides positive revenue from recovered ODS.

As previously noted, the share of ODS refrigerant that is recovered and sold to market versus the share that is released during servicing and end-of-life is unknown. To avoid overestimating emissions in the baseline, the conservative approach for estimating GHG reductions is to assume that all ODS is being recovered and recycled into the ODS end use market. The baseline scenario for refrigerants under this protocol is therefore defined as full recovery and recharge for refrigeration and air conditioning applications.

The population of equipment that utilizes ODS refrigerants is rapidly aging and approaching end of life. As such, this equipment exhibits relatively high emission rates and refrigerants are lost to the atmosphere at a rapid rate. For the purposes of this protocol, the baseline emissions of ODS are defined as the amount of ODS that would have been released over the ten-year crediting period had it not been destroyed, but rather been used to recharge existing equipment (see Figure D.1).

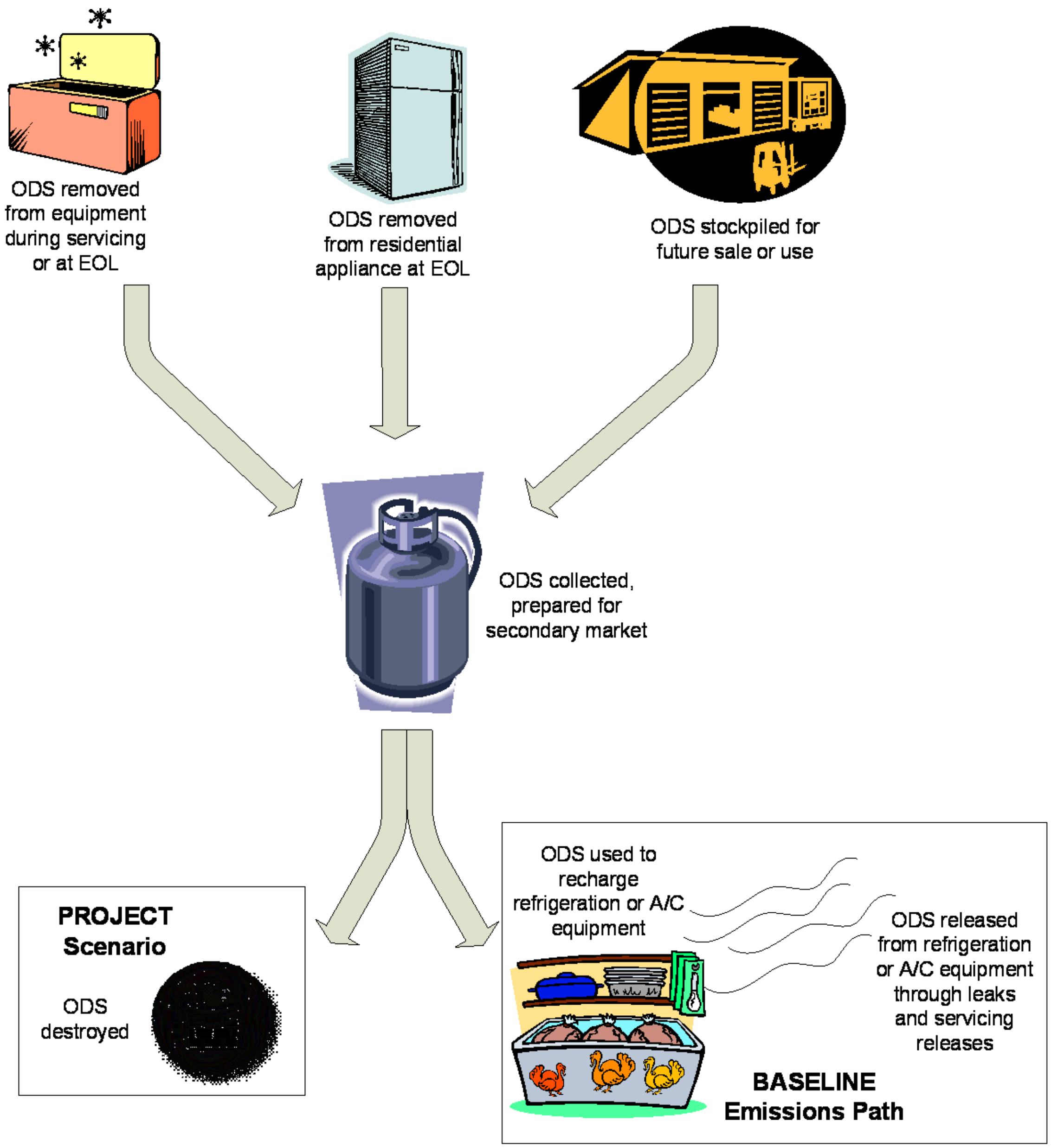


Figure D.1. Illustration of Refrigerant Project Baseline Scenario and Project Scenario

D.1 Baseline Emissions Rates

The refrigerant baseline scenario is defined as recirculation into the refrigerant re-sale market. This market can either be supplied by recovered, or recoverable, ODS refrigerant or refrigerant currently being stockpiled. Determining why refrigerant may have been removed from certain equipment – why a chiller may have been decommissioned or likewise, why excess supplies may exist and why a stockpile was not utilized – is beyond the scope of this protocol because it cannot be assessed in the standardized manner required by the Reserve. Therefore, to enable standardization the baseline is calculated from the time that ODS refrigerant has been recovered, and focuses on what would have happened to a given quantity of ODS refrigerant in the re-sale market. By defining the baseline in this way, the Reserve is able to utilize a single baseline for refrigerant removed from residential appliances (e.g. refrigerators or A/C units) and commercial or industrial equipment.

When ODS enters the re-sale market it could be used in any refrigeration or A/C equipment that needs servicing, regardless of whether it is for large refrigeration, large A/C, or mobile A/C. Since it is impossible to know the exact equipment that the destroyed ODS would have been used in, and the associated emission rate, the ODS baseline is defined as the weighted average of all end-use emission rates of ODS refrigerant in the market under the assumption that it would be absorbed into the overall market. The emission rate for refrigerants is defined as the total annual emissions resulting from both leaks and servicing events of the equipment that would have been recharged by the ODS refrigerant had it not been destroyed.

To determine the applicable weighted emission rate for each ODS refrigerant, the Reserve used data provided by the U.S. EPA from the Vintaging Model. This model compiles estimates of the type, age, refrigerant, leak rates, servicing emission rates, and other information for equipment and ODS applications within the U.S. market. The EPA has tracked this data through years of cooperation with industry, and as a result the EPA Vintaging Model is able to approximate when stocks of ODS will reach end-of-life, and the rates at which installed banks of ODS will be emitted from various equipment categories.

The Vintaging Model is based on industry surveys, engineering estimates, stakeholder feedback, and approximations of industry trends and technologies and is used primarily as a predictive tool rather than a tool for regulating industry. As a result, estimates of emission rates for individual equipment categories may be uncertain and may either over- or under-estimate actual emissions. However, at an aggregate level the model provides a reasonably accurate representation of ongoing emissions for the ODS market as a whole. Despite its limitations, the Vintaging Model represents a comprehensive data source on the U.S. ODS industry, and is therefore the best source for developing emission estimates for each source of ODS in the protocol.

The accuracy of the Vintaging Model increases with greater levels of data aggregation. That is, it likely more accurately estimates CFC emissions from the U.S. economy as a whole than it does CFC emissions from a specific end use like centrifugal chillers. In this protocol, the Reserve has aggregated data to an intermediate level. The categories provided in this protocol were selected because they were determined to be an appropriate balance of specificity and aggregation by the Reserve in consultation with the working group and stakeholders. While finer resolution data is presented in this appendix to illustrate the way in which the Reserve calculated these aggregated values, it should be stressed that each individual value is an approximation and not an exact value.

At the Reserve’s request, the EPA ran the Vintaging Model and provided data on the weighted average emission rates for CFC-11, CFC-12, CFC-114, and CFC-115 as indicated in Table D.1. These outputs are composites of emission rates associated with dozens of separate subcategories within the refrigeration market that are reflected in the Vintaging Model.

As illustrated in Table D.1, the resulting weighted average emission rates derived from the Vintaging Model are based on emissions from the Mobile A/C, Large Refrigeration, and Large A/C sub-sectors, as these were identified as the sub-sectors of the market where refrigerant recharge predominantly will occur in 2012.

The EPA Vintaging Model assumptions rely on the expected life of various types of equipment that utilize ODS. Because vehicles with CFC-12 systems are older than the assumed 12-year lifespan of a vehicle, the Vintaging Model indicated that no CFC-12 will be used in the automotive sector in 2012. Consultation with members of the refrigerant reclaim and wholesale industry indicated that CFC-12 is still being sold in large quantities for mobile A/C applications. In fact, upwards of 50 percent of the U.S. CFC-12 demand may be in the mobile market. The Reserve confirmed this finding through review of confidential sales records that indicated a majority of CFC-12 sales were intended for the automotive market. Accordingly, a 50 percent mobile market share has been assumed to be conservative, and the Vintaging Model data has been adjusted accordingly. For the mobile market the Reserve further assumed an emission rate of 40.7 percent (leak and servicing emissions) per year for CFC-12, and 18 percent emission rate for the replacement, HFC-134a.

As the EPA Vintaging Model does not track CFC-13 and CFC-113 as refrigerants, the Reserve used conservative assumptions to derive appropriate emission rates. Our understanding is that CFC-13 is used as a very low temperature refrigerant. Since the system size it is utilized in is uncertain, the Reserve assumed a large refrigeration system to be conservative. The California Air Resources Board (ARB) Compliance Offset Protocol for ODS projects utilizes a nine percent annual leak rate for large refrigeration systems, in accordance with the impact of California's Refrigerant Management Program. To be conservative and consistent with the ARB compliance protocol, the Reserve has used this same nine percent annual leak rate. CFC-113 is used primarily in chillers, much like CFC-11. The Reserve conservatively assumed that all CFC-113 went into large A/C applications. The same emission rate and substitution rate as CFC-11 were used, as the chemicals' application and use are similar. This is also consistent with the ARB compliance protocol.

The results, incorporating both industry and Vintaging Model data, are presented in Table D.1.

Table D.1. Weighted Average Annual Loss Rate Percent and Market Share for Class I ODS [68]

	2010 Weighted Average Annual Loss Rate Percent and Market Share for Class I ODS											
	CFC-11		**CFC-12**		**CFC-13**		**CFC-113**		**CFC-114**		**CFC-115**	
Refrigeration and A/C Sector	Market Share	Loss Rate	Market Share	Loss Rate	Market Share	Loss Rate	Market Share	Loss Rate	Market Share	Loss Rate	Market Share	Loss Rate
Mobile[69]	-	-	50%	41%	-	-	-	-	-	-	-	-
Large Refrigeration	3%	19%	33%	10%	100%	9%	-	-	-	-	100%	25%
Large AC	97%	20%	17%	14%	-	-	100%	20%	100%	14%	-	-
Market-Weighted Annual Loss Rate	**20%**		**26%**		**9%**		**20%**		**14%**		**25%**	
10-year Total Loss	**89%**		**95%**		**61%**		**89%**		**77%**		**94%**	

[68] EPA. (2011). EPA Vintaging Model. *Version VM IO file_v4.4_3.23.11.*
[69] The market share for mobile refrigeration was derived from industry surveys conducted by Reserve staff.

The categories identified in Table D.1 are weighted aggregates of the subsectors presented in Table D.2.

Table D.2. Characterization of Categories from the EPA Vintaging Model

Category	End Use
Large AC	Centrifugal Chillers
	Positive Displacement Chillers
Large Refrigeration	Large Retail Food
	Cold Storage
	Refrigerated Transport
	Industrial Process Refrigeration
Mobile	Mobile AC
	School & Tour Buses AC
	Transit Buses AC
	Trains AC
Small AC	Dehumidifiers
	Window Units
	Unitary A/C
	Water & Ground Source HP
	Packaged Terminal AC/HP
Small Refrigeration	Small and Medium Retail Food
	Household Refrigerated Appliances
	Ice Makers

Interviews with industry experts indicated that a large share of recoverable refrigerant is vented to the atmosphere directly rather than re-introduced as recycled or reclaimed material into the market. As this would result in 100 percent immediate release, calculating all refrigerant ODS baseline emissions according to a market emission rate as described above is conservative.

The weighted annual emission rates calculated in Table D.1 are used in the protocol to calculate baseline emissions from the release of ODS refrigerant in Equation 5.3.

D.2 Project Emissions Rates

By removing ODS refrigerant from the re-sale market through destruction projects, substitute refrigerants will be required to fulfill the U.S. refrigeration need. Much as predicting the baseline use of destroyed ODS is difficult and inappropriate, so too is predicting the specific refrigerant that will fill the void when the ODS is destroyed and the baseline does not come to pass because of the project. Therefore, the Reserve employed the same technique used for establishing the emissions rate of the baseline when developing a generic, weighted substitute GWP and emission rate for the project.

Substitute emissions for CFC-11, CFC-12, CFC-114, and CFC-115 are based on the weighted average of new market entrants for their respective refrigeration purposes as modeled by the EPA Vintaging Model for 2012. Pulling from industry expertise and internal EPA research, the Vintaging Model predicts that the ODS substitutes in Table D.3 through Table D.8 will be the dominant refrigerant substitutes. The model further provides the emission rates associated with each substitute, the relative charge size of the substitute required to meet the same refrigerant need as the replaced ODS,[70] and data on the market share attributable to each substitute. Using this information, the Reserve calculated the weighted average substitute emissions per pound of ODS destroyed.

The parameters of substitute emissions are used in the protocol to estimate the project scenario emissions associated with the use of substitute refrigerants in Equation 5.6.

[70] In many cases, more or less of a substitute refrigerant is needed to perform the same function as the replaced ODS.

Table D.3. Calculation of Substitute Emissions for CFC-11

Application	CFC-11 Recharge Market Share	ODS Substitute	Market Share Relative to Subsector (by weight)	Overall CFC-11 Market Share	GWP (CO_2e)	Relative Charge Size (lb Sub/lb ODS)	Sub Used to Replace One lb CFC-11 (lbs)	Loss Rate of Sub (%/yr)	10-year $lbCO_2e$/ODS Destroyed
Large Refrigeration	3%	HCFC-123	65%	2%	90	0.88	0.017	5%	1
		HFC-134a	35%	1%	1300	1.4	0.019	5%	8
Large AC	97%	HCFC-123	41%	33%	90	0.88	0.289	2%	7
		HFC-134a	59%	64%	1300	1.4	0.894	2%	186
					CFC-Sub Emissions ($lbCO_2e$/lbODS destroyed)				**202**

Table D.4. Calculation of Substitute Emissions for CFC-12

Application	CFC-12 Market Share of Recharge	ODS Substitute	Market Share Relative to Subsector (by weight)	Overall CFC-12 Market Share	GWP (CO_2e)	Relative Charge Size (lb Sub/lb ODS)	Sub Used to Replace One lb CFC-12 (lbs)	Loss Rate of Sub (%/yr)	10-year $lbCO_2e$/ODS Destroyed
Mobile	50%	HFC-134a	100%	50%	1300	.74	0.370	18%	415
Large Refrigeration	33%	HCFC-123	14%	8%	90	0.88	0.068	4%	1
		HFC-134a	34%	20%	1300	1.4	0.278	4%	73
		R-404A	36%	3%	2028	0.78	0.026	11%	130
		R-410A	1%	1%	1725	0.88	0.005	5%	2
		R-507A	16%	1%	3300	0.78	0.008	12%	95
Large AC	17%	HCFC-123	19%	2%	90	0.88	0.014	1%	0
		HFC-134a	78%	14%	1300	1.4	0.196	3%	59
		R-407C	3%	2%	1526	0.76	0.012	2%	1
		R-410A	1%	0%	1725	0.76	0.003	1%	0
					CFC-Sub Emissions ($lbCO_2e$/lbODS destroyed)				**777**

Table D.5. Calculation of Substitute Emissions for CFC-13

Application	CFC-13 Market Share of Recharge	ODS Substitute	Market Share Relative to Subsector (by weight)	Overall CFC-13 market share	GWP (CO_2e)	Relative Charge Size (lb Sub/lb ODS)	Sub Used to Replace One lb CFC-13 (lbs)	Loss Rate of Sub (%/yr)	10-year $lbCO_2e$/ODS Destroyed
Large Refrigeration	100%	HFC-23	100%	100%	11700	1	1.000	9%	7144
					CFC-Sub Emissions ($lbCO_2e$/lbODS destroyed)				**7144**

Table D.6. Calculation of Substitute Emissions for CFC-113

Application	CFC-113 Market Share of Recharge	ODS Substitute	Market Share Relative to Subsector (by weight)	Overall CFC-113 Market Share	GWP (CO_2e)	Relative Charge Size (lb Sub/lb ODS)	Sub used to Replace One lb CFC-113 (lbs)	Loss Rate of Sub (%/yr)	10-year $lbCO_2e$/ODS Destroyed
Large AC	100%	HCFC-123	34%	34%	77	0.88	0.299	2%	5
		HFC-134a	66%	66%	1300	1.4	0.925	2%	215
					CFC-Sub Emissions ($lbCO_2e$/lbODS destroyed)				**220**

Table D.7. Calculation of Substitute Emissions for CFC-114

Application	CFC-114 Market Share of Recharge	ODS Substitute	Market Share Relative to Subsector (by weight)	Overall CFC-114 Market Share	GWP (CO_2e)	Relative Charge Size (lb Sub/lb ODS)	Sub Used to Replace One lb CFC-114 (lbs)	Loss Rate of Sub (%/yr)	10-year $lbCO_2e$/ODS Destroyed
Large AC	100%	HFC-134a	100%	100%	1300	1.4	1.400	4%	659
					CFC-Sub Emissions ($lbCO_2e$/lbODS destroyed)				**659**

Table D.8. Calculation of Substitute Emissions for CFC-115

Application	CFC-115 Market Share of Recharge	ODS Substitute	Market Share Relative to Subsector (by weight)	Overall CFC-115 Market Share	GWP (CO_2e)	Relative Charge Size (lb Sub/lb ODS)	Sub used to Replace One lb CFC-115 (lbs)	Loss Rate of Sub (%/yr)	10-year lbCO_2e/ODS Destroyed
Large Refrigeration	100%	R-404A	68%	53%	2028	0.85	0.448	17%	999
		R-507A	31%	12%	3300	0.85	0.101	15%	691
		Non-ODP/GWP	1%	36%	0	1	0.355	15%	0
					CFC-Sub Emissions (lbCO_2e/lbODS destroyed)				**1689**

Appendix E Foam Recovery Efficiency and Calculations

The following methodology calculates the site- or process-specific recovery efficiency for blowing agent recovery projects, and uses this value for calculation of emission reductions in Section 5. Determination of accurate recovery efficiency allows baseline emissions and project emissions to be calculated in reference to the initial quantity of foam blowing agent diverted from baseline treatment.

The methodology prescribed in this appendix uses a mass balance approach similar to that utilized by the Waste Electrical and Electronic Equipment Directive (WEEE),[71] RAL Quality Assurance Association (RAL),[72] and other internationally recognized standards. However, applying these standards directly to projects using this protocol was deemed inappropriate for several reasons.

First, these standards are based on assumptions about the size of appliances, quantity of foam, and concentration of CFC foam blowing agent in the polyurethane (PU) foam found in Europe. The empirical work underlying these assumptions was conducted in Europe, and it is unclear whether these values are similar in the U.S. The Reserve's research indicates that U.S. appliances are larger, have a greater quantity of foam per appliance, and a higher concentration of CFC foam blowing agent in the PU foam.

Second, the existing international standards are intended to benchmark best practices in appliance recycling and ODS recovery. Accordingly, uncertainty in the assumptions of these standards (e.g. kg foam per appliance, concentration of ODS blowing agent) is acceptable provided that the standard is consistently applied from one project to the next. As such, these standards provide a means of comparison between processes or practices, but do not provide a mechanism by which to calculate losses of ODS that may occur during the project activity. As a GHG accounting methodology, this protocol must provide a mechanism for estimating project emissions that occur during recycling.

The methodology provided in this appendix differs in one significant way from the internationally accepted standards that precede it. The other standards dictate a minimum recover efficiency of 90 percent that must be demonstrated. This protocol does not specify a minimum recovery efficiency, but instead builds in an incentive to optimize ODS blowing agent recovery. For application in the U.S., where blowing agent recovery to a concentrated form is rare, this approach has several advantages.

While the Reserve fully endorses a 90 percent or higher recovery efficiency as the end goal, this method will allow gap or bridge technologies and processes with lower than 90 percent recovery to be eligible provided that emissions accounting is properly conducted and credited.

Additionally, higher recovery efficiencies – including those above 90 percent – are incentivized by minimizing project emissions (deducted at 100 percent) in the calculations, in addition to increasing the quantity of ODS recovered and destroyed (calculated only as released portion, per Equation 5.7).

[71] WEEE Forum. (2007). Requirements for the Collection, Transportation, Storage, Handling and Treatment of Household Cooling and Freezing Appliances containing CFC, HCFC, or HFC.
[72] RAL Deutsches Institut für Gütesicherung und Kennzeichnung e.V. (2007). Quality Assurance and Test Specifications for the Demanufacture of Refrigeration Equipment.

E.1 Calculating Recovery Efficiency

All appliance foam projects must calculate a recovery efficiency once per project based on a run of a minimum ten appliances. Basing this analysis on a number of appliances greater than ten will likely result in a higher calculated recovery efficiency due to the 90 percent upper confidence limit used for calculating the concentration of ODS blowing agent in the foam. A larger sample size will decrease uncertainty and thus lower the estimated blowing agent concentration and increase recovery efficiency; however, sampling of additional appliances will also increase testing costs.

The procedures below shall be used to calculate recovery efficiency.

Estimate initial blowing agent concentration

The concentration of ODS blowing agent in the PU foam prior to any appliance treatment shall either be assumed to equal to 14.9 percent (a conservative value identified by Fredenslund et al. (2005) for U.S. appliances[73]) or calculated according to the steps below. Calculating a sample-specific value allows project developers to document a lower ODS blowing agent concentration, which will result in a higher estimated recovery efficiency.

The following steps shall be followed to document a sample-specific ODS blowing agent concentration:

1. Cut four PU foam samples from each appliance (left side, right side, top, bottom) using a reciprocating saw. Samples must be at least four inches square and the full thickness of the insulation
2. Seal the cut edges of each foam sample using aluminum tape or similar product that prevents off-gassing
3. Individually label each sample to record appliance model, and site of sample (left, right, top, or bottom)
4. Analyze samples according to the procedures dictated for building foam in Section 6.4. Samples may be analyzed individually (four analyses per appliance), or a single analysis may be done using equal masses of foam from each sample (one analysis per appliance)
5. Based on the average of the samples for each appliance, calculate the 90 percent upper confidence limit of the concentration. The 90 percent upper confidence limit shall be used as the parameter BA_{conc} in the equations below

Extract the ODS blowing agent and separate foam residual

The ODS blowing agent from the sampled appliances must be collected and quantified according to the steps below.

1. Begin processing with all equipment shut down and emptied of all materials.
2. Process all sample appliances
3. Extract and collect concentrated BA. The mass of the recovered blowing agent shall be determined by comparison of the mass of the fully evacuated receiving containers to their mass when filled. This value shall be used as the parameter BA_{post} in the equations below

[73] Fredenslund, A. et al. (2005). Disposal of Refrigerators-Freezers in the U.S.: State of the Practice. *Technical University of Denmark.*

Separate foam residual

The quantity of foam in the processed appliances must be established either through use of a default value of 12.9 pounds per appliance,[74] or according to step the following steps. If the value of 12.9 pounds per appliance is used, it shall be multiplied by the number of appliances processed to determine $Foam_{res}$ in the calculation of recovery efficiency.

1. Separate and collect all foam residual, which may be in a fluff, powder, or pelletized form. Processes must be documented to demonstrate that no significant quantity of foam residual is lost in the air or other waste streams
2. If desired, manually separate non-foam components in the residual (e.g. plastic) to determine a percent of foam in residual. If performed, this analysis must be conducted on at least one kilogram of residual, and results may be no lower than 90 percent
3. Weigh the total recovered foam residual, and, if performed, multiply by the percent foam in residual, to calculate total mass of foam recovered. This value shall be used as the parameter $Foam_{res}$

Calculate recovery efficiency

To calculate the recovery efficiency, apply the calculated values to the equations below. The recovery efficiency (RE) calculated below shall be used in the calculations of Section 5.

$$BA_{init} = \frac{Foam_{res}}{(1 - BA_{conc})} \times BA_{conc}$$

Where,

			Units
$Foam_{res}$	=	Mass of foam recovered	lbs foam
BA_{conc}	=	Initial concentration of blowing agent in PU foam	lbs BA / lbs PU
BA_{init}	=	Initial quantity of blowing agent in appliances prior to treatment	lbs BA

$$RE = \frac{BA_{post}}{BA_{init}}$$

Where,

			Units
RE	=	Recovery efficiency	%
BA_{post}	=	Quantity of recovered blowing agent in concentrated form	lbs BA
BA_{init}	=	Initial quantity of blowing agent in appliances prior to treatment	lbs BA

[74] EcoSolutions Recycling. (2010). Foam content and CFC recovery in residential appliances. *EcoSolutions Recycling, Inc., Quebec*.

Appendix F Default Emission Factors for Calculating ODS Transportation and Destruction Emissions

F.1 Summary

The GHG Assessment Boundary for ODS destruction projects under the Reserve includes emissions in both the baseline and project scenario. These emission sources include the following:

Baseline	Project
▪ Emissions of ODS from foam shredding ▪ Emissions of ODS from foam landfilling ▪ Emissions of ODS from refrigerant applications	▪ Extraction of ODS blowing agent ▪ Emissions of substitute refrigerant applications ▪ CO_2 emissions from fossil fuel and electricity used in destruction facility ▪ CO_2 emissions from fossil fuel used in transport to destruction facility ▪ ODS emissions from incomplete destruction of ODS ▪ CO_2 emissions from ODS oxidation during destruction

All of these emission sources must be accounted for to ensure complete, accurate, and conservative calculations of project emission reductions. However, some of these emission sources are of a significantly greater magnitude than others, and some of the smaller sources are costly to track and verify, and difficult to assess. In order to lessen the burden on project developers and verifiers, the Reserve has calculated a standard deduction that can be applied to all projects to account for the following project scenario emissions:

1. CO_2 emissions from fossil fuel and electricity used by the destruction facility
2. CO_2 emissions from fossil fuel used for transporting the ODS to the destruction facility
3. ODS emissions from incomplete destruction of ODS
4. CO_2 emissions from ODS oxidation during destruction

The aggregate of these emission sources amounts to less than 0.5 percent of total emission reductions under even the most conservative assumptions. As a result, a conservative emission factor can be applied. This appendix provides background on the development of these default emission factors.

F.2 Methodology and Analysis

The Reserve created a model to conservatively calculate all emissions in the baseline and project scenario for ODS projects. The model incorporated all equations from Section 5. The equations that have been rolled up into this emission factor are Equation 5.9 through Equation 5.14.

In many cases, the equations used for estimating emissions required additional input and emissions factors. Where calculations required such inputs (e.g. electricity grid emission factors), the most conservative factors available were used. Fossil fuel emissions from the destruction process were calculated based on confidential industry records made available to the Reserve that describe the energy requirements associated with ODS destruction projects. The assumptions used in this analysis are as follows:

Parameter	Assumption
ODS_i =	1 tonne ODS
$FF_{PR,k}$ =	0.0009 MMBtu natural gas/lb ODS destroyed (for foams and refrigerants)
$EF_{FF,k}$ =	54.01 kg CO_2/MMBtu[75]
EL_{PR} =	0.0002 MWh/lb ODS destroyed for foam, 0.0018 MWh/lb ODS destroyed for refrigerants and extracted ODS blowing agent
EF_{EL} =	0.889 tCO_2/MWh[76]
TMTi =	2,000 miles
EF_{TMT} =	0.000297 $kgCO_2$/PMT[77]
CRi =	Actual per ODS
Foam weight =	8.5% ODS blowing agent by weight (foam weight used for transport and energy use)

Under these assumptions, and the equations provided in Section 5, the calculations provided the following results for different ODS project categories:

Table F.1. Project Emissions (Excluding Substitutes)
All quantities in tonnes CO_2/tonne ODS destroyed.

	Fossil Fuel Emissions from the Destruction	Electricity Emissions from the Destruction	Emissions from ODS Not Destroyed	Emissions from CO_2	Emissions from the Transportation of ODS	Total
CFC-11 refrigerant or extracted BA	0.04	3.53	0.47	0.32	0.59	4.95
CFC-12 refrigerant or extracted BA	0.04	3.53	1.07	0.36	0.59	5.59
CFC-114 refrigerant	0.04	3.53	1.00	0.47	0.59	5.63
CFC-115 refrigerant	0.04	3.53	0.74	0.47	0.59	5.36
CFC-11 building foam	0.42	41.50	0.47	0.32	6.99	49.70
CFC-12 building foam	0.42	41.50	1.07	0.36	6.99	50.35
HCFC-141b building foam	0.42	41.50	0.07	0.75	6.99	49.74

Because the ODS covered in this protocol have such high GWPs (750 to 10,900) even emissions of 50 tonnes CO_2e per tonne of ODS destroyed are relatively small compared to emissions of the overall baseline and project scenarios. For refrigerant projects, the emissions

[75] U.S. EPA Climate Leaders. (2007). Stationary Combustion Guidance. Note: The highest emission factor was selected to be conservative.
[76] U.S. EPA eGRID2007, Version 1.1 Year 2005 GHG Annual Output Emission Rates (December 2008). Note: the highest emission factor in the nation was selected to be conservative.
[77] U.S. EPA Climate Leaders. (2008). Optional emissions from business travel, commuting, and product transport. Note: the highest emitting mode of transportation was selected to be conservative.

amount to less than 0.15 percent of baseline emissions. For building foams, emissions from the four emission sources can be as high as five percent of baseline emissions.

F.3 Conclusion

To account for the emission sources analyzed above, project developers may apply a 7.5 tonne CO_2e/tonne ODS emission factor to all ODS refrigerant projects and to appliance ODS blowing agent projects. A 75 tonne CO_2e/tonne ODS emission factor must be applied to building ODS blowing agent projects that destroy intact foam. These default emission factors represent a conservative estimate of the potential emissions from the four selected sources and were derived using worst-case emission factors and empirical data.

Appendix G Emission Factor Tables

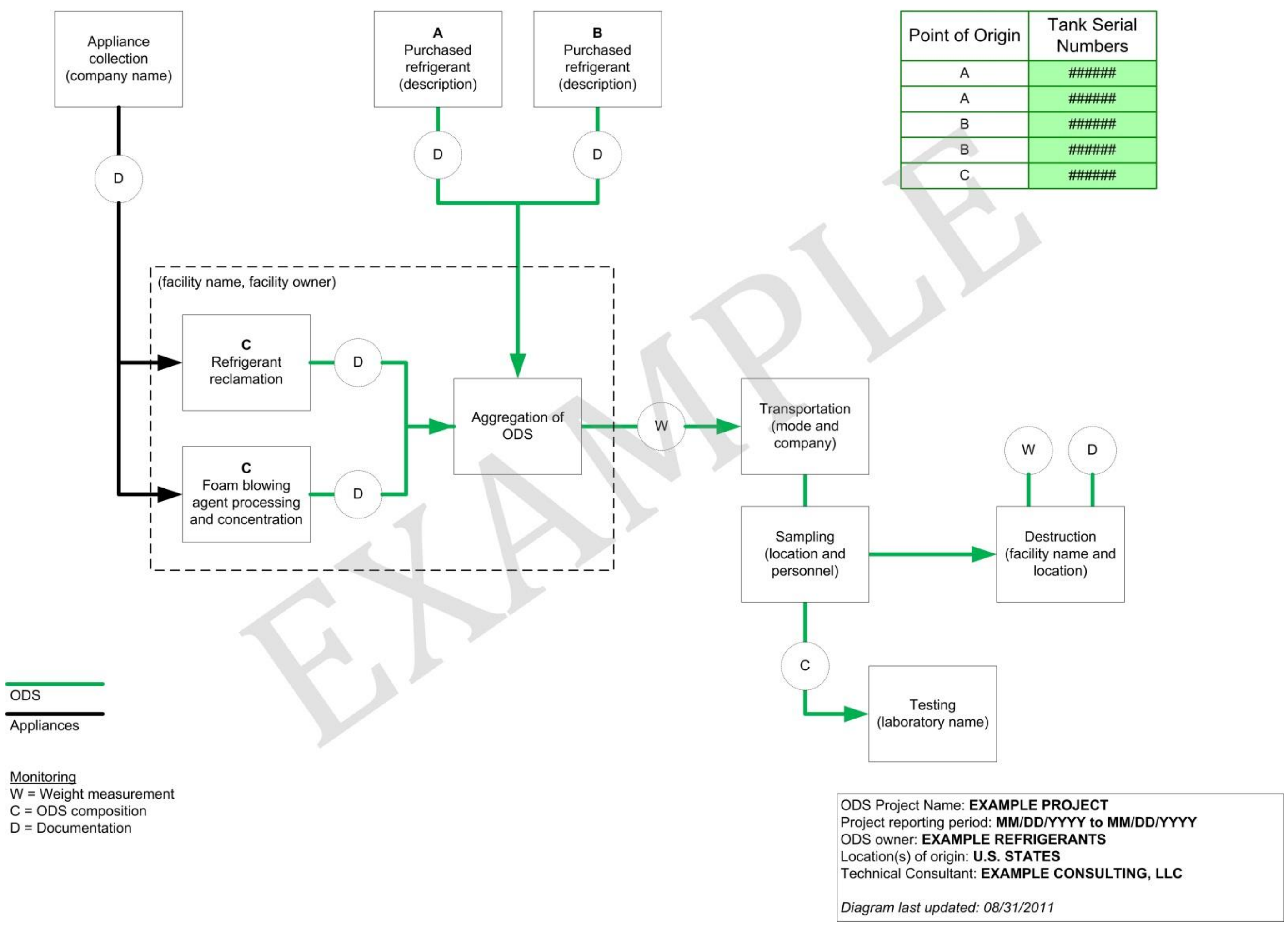
Table G.1. CO_2 Emission Factors for Fossil Fuel Use

Fuel Type	Heat Content	Carbon Content (Per Unit Energy)	Fraction Oxidized	CO_2 Emission Factor (Per Unit Energy)	CO_2 Emission Factor (Per Unit Mass or Volume)
Coal and Coke	**MMBtu / Short ton**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / Short ton**
Anthracite Coal	25.09	28.26	1.00	103.62	2,599.83
Bituminous Coal	24.93	25.49	1.00	93.46	2,330.04
Sub-bituminous Coal	17.25	26.48	1.00	97.09	1,674.86
Lignite	14.21	26.30	1.00	96.43	1,370.32
Unspecified (Residential/ Commercial)	22.05	26.00	1.00	95.33	2,102.29
Unspecified (Industrial Coking)	26.27	25.56	1.00	93.72	2,462.12
Unspecified (Other Industrial)	22.05	25.63	1.00	93.98	2,072.19
Unspecified (Electric Utility)	19.95	25.76	1.00	94.45	1,884.53
Coke	24.80	31.00	1.00	113.67	2,818.93
Natural Gas (By Heat Content)	**Btu / Standard cubic foot**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / Standard cub. ft.**
975 to 1,000 Btu / Std cubic foot	975 – 1,000	14.73	1.00	54.01	Varies
1,000 to 1,025 Btu / Std cubic foot	1,000 – 1,025	14.43	1.00	52.91	Varies
1,025 to 1,050 Btu / Std cubic foot	1,025 – 1,050	14.47	1.00	53.06	Varies
1,050 to 1,075 Btu / Std cubic foot	1,050 – 1,075	14.58	1.00	53.46	Varies
1,075 to 1,100 Btu / Std cubic foot	1,075 – 1,100	14.65	1.00	53.72	Varies
Greater than 1,100 Btu / Std cubic foot	> 1,100	14.92	1.00	54.71	Varies
Weighted U.S. Average	1,029	14.47	1.00	53.06	0.0546
Petroleum Products	**MMBtu / Barrel**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / gallon**
Asphalt & Road Oil	6.636	20.62	1.00	75.61	11.95
Aviation Gasoline	5.048	18.87	1.00	69.19	8.32
Distillate Fuel Oil (#1, 2 & 4)	5.825	19.95	1.00	73.15	10.15
Jet Fuel	5.670	19.33	1.00	70.88	9.57
Kerosene	5.670	19.72	1.00	72.31	9.76
LPG (average for fuel use)	3.849	17.23	1.00	63.16	5.79
Propane	3.824	17.20	1.00	63.07	5.74
Ethane	2.916	16.25	1.00	59.58	4.14
Isobutene	4.162	17.75	1.00	65.08	6.45
n-Butane	4.328	17.72	1.00	64.97	6.70
Lubricants	6.065	20.24	1.00	74.21	10.72
Motor Gasoline	5.218	19.33	1.00	70.88	8.81
Residual Fuel Oil (#5 & 6)	6.287	21.49	1.00	78.80	11.80
Crude Oil	5.800	20.33	1.00	74.54	10.29
Naphtha (<401 deg. F)	5.248	18.14	1.00	66.51	8.31
Natural Gasoline	4.620	18.24	1.00	66.88	7.36
Other Oil (>401 deg. F)	5.825	19.95	1.00	73.15	10.15
Pentanes Plus	4.620	18.24	1.00	66.88	7.36
Petrochemical Feedstocks	5.428	19.37	1.00	71.02	9.18
Petroleum Coke	6.024	27.85	1.00	102.12	14.65
Still Gas	6.000	17.51	1.00	64.20	9.17
Special Naphtha	5.248	19.86	1.00	72.82	9.10
Unfinished Oils	5.825	20.33	1.00	74.54	10.34
Waxes	5.537	19.81	1.00	72.64	9.58

Source: EPA Climate Leaders. (2007). Stationary Combustion Guidance. Table B-2 except:
Default CO_2 emission factors (per unit energy) are calculated as: Carbon Content × Fraction Oxidized × 44/12.
Default CO_2 emission factors (per unit mass or volume) are calculated as: Heat Content x Carbon Content × Fraction Oxidized × 44/12× Conversion Factor (if applicable).
Heat content factors are based on higher heating values (HHV).

Appendix H ODS Project Diagram Sample

Generalized ODS Project System Diagram



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U.S. Ozone Depleting Substances Project Protocol Version 2.0

ERRATA AND CLARIFICATIONS

The Climate Action Reserve (Reserve) published its U.S. Ozone Depleting Substances Project Protocol Version 2.0 (U.S. ODS V2.0) in June 2012. While the Reserve intends for the U.S. ODS V2.0 to be a complete, transparent document, it recognizes that correction of errors and clarifications will be necessary as the protocol is implemented and issues are identified. This document is an official record of all errata and clarifications applicable to the U.S. ODS V2.0.[1]

Per the Reserve's Program Manual, both errata and clarifications are considered effective on the date they are first posted on the Reserve website. The effective date of each erratum or clarification is clearly designated below. All listed and registered U.S. ODS projects must incorporate and adhere to these errata and clarifications when they undergo verification. The Reserve will incorporate both errata and clarifications into future versions of the U.S. ODS Project Protocol.

All project developers and verification bodies must refer to this document to ensure that the most current guidance is adhered to in project design and verification. Verification bodies shall refer to this document immediately prior to uploading any Verification Statement to assure all issues are properly addressed and incorporated into verification activities.

If you have any questions about the updates or clarifications in this document, please contact Policy at policy@climateactionreserve.org or (213) 891-1444 x3.

[1] See Section 4.3.4 of the Climate Action Reserve Program Manual for an explanation of the Reserve's policies on protocol errata and clarifications. "Errata" are issued to correct typographical errors. "Clarifications" are issued to ensure consistent interpretation and application of the protocol. For document management and program implementation purposes, both errata and clarifications to the U.S. ODS protocol are contained in this single document.

Errata and Clarifications (arranged by protocol section)

Section 5

1. Accounting for Non-ODS Material (CLARIFICATION – January 29, 2013)

Section: 5.1.1 (Calculating Baseline Emissions from Refrigerant Recovery and Resale)

Context: The protocol states that projects shall only include the weight of pure ODS when calculating emission reductions. There are additional specific adjustments that were not mentioned in the protocol and it may not be clear how these adjustments should be made. Specifically, project developers shall exclude the weight of high boiling residue (HBR) in their calculation of emission reductions.

Clarification: The definition of the term "$Q_{refr,i}$" in Equation 5.3 on page 21 shall read "Total quantity of pure refrigerant ODS *i* sent for destruction by the project." The total weight of material destroyed by the project shall be adjusted to exclude the weight of ineligible material, including high boiling residue, as determined by the laboratory analysis required in Section 6.6 (in the case of multiple laboratory analyses, the highest reported value for HBR shall be used). In any case where the composition of the single ODS species is less than 100%, the value of this term must be adjusted to reflect the weight of pure ODS for each eligible chemical.

For example, if a project destroys 1,000 lbs. of material that contains 5% high boiling residue and 95% eligible ODS *i*, the value of $Q_{refr,i}$ would be 902.5 lbs.

While water is also considered ineligible material, the moisture content requirement in Section 6.6 of the protocol (i.e. that the moisture content must be less than 75% of the saturation point for the ODS) already ensures that the weight of any moisture present will not have a material impact on the quantification of emission reductions. Thus the weight does not need to be adjusted to reflect the weight of moisture present in the sample.

2. Performance Requirements for Destruction Facilities (ERRATUM – July 16, 2015)

Section: 5.2.4 (Calculating Site-Specific Project Emissions from ODS Destruction)

Context: The protocol states that destruction "facilities are required to demonstrate their ability to achieve destruction efficiencies upwards of 99.99 percent for substances with thermal stability ratings *higher* than the ODS included under this protocol" (emphasis added). The reference cited for this statement explains a ranking system for the incinerability of ODS species based on their thermal stability. In this system, ODS species that are more thermally stable are more difficult to destroy. This results in a *lower* ranking. Thus, the lowest ranking (1) indicates the chemical that is most difficult to destroy, while the highest ranking (320) indicates the chemical that is easiest to destroy. The above-quoted statement in the U.S. ODS Project Protocol includes an error that communicates the opposite of the intended meaning of the statement.

Correction: The second sentence in the first paragraph of this section shall read:

"These facilities are required to demonstrate their ability to achieve destruction efficiencies upwards of 99.99 percent for substances with thermal stability rankings lower than the ODS included under this protocol."

Section 6

3. Determining the Mass of ODS Destroyed (CLARIFICATION – April 11, 2013)

Section: 6.6 (Concentrated ODS Composition and Quantity Analysis Requirements)

Context: The protocol requires that the mass of ODS destroyed by the project be determined using (1) the difference between the measured weight of each container when it is full prior to destruction and the measured weight after it has been emptied and (2) the composition and concentration of material destroyed as determined by laboratory analyses of samples from each container.

Clarification: The mass of ODS and any contaminants destroyed shall be considered equal to the difference between the full and empty weights of the containers, as measured by the scale at the destruction facility and recorded by the destruction facility on the weight tickets and the Certificate of Destruction. No adjustments shall be made by the project developer to the weights as measured and recorded by the destruction facility in calculating the mass of ODS and contaminants.

Verifiers shall confirm that the weights recorded on the weight tickets and the Certificate of Destruction by the destruction facility are used without adjustment to calculate emission reductions. The mass of eligible ODS shall then be determined using these weights and the results of the laboratory analyses.

A.2.9 Urban Tree Planting Project Protocol v2.0

CLIMATE ACTION RESERVE

Version 2.0 | June 25, 2014

Urban Tree Planting

Project Protocol

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Abbreviations and Acronyms

C	Carbon
CAL FIRE	California Department of Forestry and Fire Protection
CH_4	Methane
CO_2	Carbon dioxide
CRT	Climate Reserve Tonne
DBH	Diameter at Breast Height
FIA	Forest Inventory and Analysis Program of the U.S. Forest Service
GHG	Greenhouse gas
GIS	Geographical Information System
ISO	International Organization for Standardization
KML	Keyhole Markup Language (see glossary)
N_2O	Nitrous oxide
PDD	Project Design Document
PIA	Project Implementation Agreement
Reserve	Climate Action Reserve
RPF	Registered Professional Forester (California only)
SSR	Source, sink, or reservoir
UFM	Urban forest management
USFS	United States Forest Service
UTP	Urban tree planting
VOC	Volatile Organic Compound

1 Introduction

The Urban Tree Planting (UTP) Project Protocol provides requirements and guidance for quantifying the net climate benefits of activities that sequester carbon in woody biomass within an urban environment. The protocol provides project eligibility rules, methods to calculate a project's net effects on greenhouse gas (GHG) emissions and removals of carbon dioxide (CO_2) from the atmosphere ("removals"), procedures for assessing the risk that carbon sequestered by a project may be reversed (i.e. released back to the atmosphere), and approaches for long term project monitoring and reporting.

The goal of this protocol is to ensure that the net GHG reductions and removals caused by a project are accounted for in a complete, consistent, transparent, accurate, and conservative manner[1] and may therefore be reported to the Climate Action Reserve (Reserve) as the basis for issuing carbon offset credits (called Climate Reserve Tonnes, or CRTs). Additionally, it is the goal of the Reserve to ensure the protocol is as efficient and practical as possible for Project Operators.

As the premier carbon offset registry for the North American carbon market, the Reserve encourages action to reduce GHG emissions by ensuring the environmental integrity and financial benefit of emission reduction projects. The Reserve establishes high quality standards for carbon offset projects, oversees independent third-party verification bodies, issues carbon credits generated from such projects, and tracks the transaction of credits over time in a transparent, publicly-accessible system. The Reserve is a private 501(c)(3) nonprofit organization based in Los Angeles, California.[2]

Only projects that are eligible under and comply with the UTP Project Protocol may be registered with the Reserve. Section 8 of this protocol provides requirements and guidance for verifying the performance of project activities and their associated GHG reductions and removals reported to the Reserve.

1.1 About Urban Forests, Carbon Dioxide and Climate Change

Urban forests have the capacity to both emit and absorb CO_2, a leading greenhouse gas that contributes to climate change. Trees, through the process of photosynthesis, naturally absorb CO_2 from the atmosphere and store the gas as carbon in their biomass, i.e. trunk (bole), leaves, branches, and roots. Carbon may also be stored in the soils that support the urban forest, as well as the understory plants and litter on the urban forest floor. After trees are removed, their wood residue may be converted into mulch, with CO_2 gradually released to the atmosphere through decomposition. Carbon may continue to be sequestered for a substantial amount of time in wood products and in landfills. Carbon from urban forests may also be used to provide fuel for biomass energy. Urban trees can reduce summertime air temperatures and building energy use for air conditioning, thus reducing GHG emissions from electricity generation (Akbari 2002). In winter, trees can increase or decrease GHG emissions associated with energy consumed for space heating, depending on local climate, site features, and building characteristics (Heisler 1986).

[1] See the WRI/WBCSD GHG Protocol for Project Accounting (Part I, Chapter 4) for a description of GHG reduction project accounting principles.
[2] For more information, please visit www.climateactionreserve.org.

When trees are disturbed, through events like fire, disease, pests, or harvest, some of their stored carbon may oxidize or decay over time, releasing CO_2 into the atmosphere. The quantity and rate of CO_2 that is emitted may vary, depending on the particular circumstances of the disturbance. Depending on how urban forests are managed or impacted by natural events, they can be a net source of emissions, resulting in a decrease to the reservoir, or a net sink of emissions, resulting in an increase of CO_2 to the reservoir. In other words, urban forests may have a net negative or net positive impact on the climate.

2 Urban Tree Planting Definition and Requirements

For the purposes of this protocol, an Urban Tree Planting (UTP) Project is a planned set of activities designed to increase removals of CO_2 from the atmosphere, or reduce or prevent emissions of CO_2 to the atmosphere, through increasing and/or conserving urban forest carbon stocks.

A glossary of terms used in this protocol is provided in Section 9. Throughout the protocol, important defined terms are capitalized (e.g. "Urban Forest Owner").

2.1 Project Definition

A UTP Project is a project where new trees are planted in areas where trees have not been harvested with a primary commercial interest during the 10 years prior to the Project Commencement Date. Only planted trees and trees that regenerate from planted trees are eligible to be quantified for credits. Benefits from urban tree planting activities occur when the net CO_2e (CO_2e stored minus CO_2e emitted) associated with planted trees exceeds baseline tree planting CO_2e levels.

2.2 Urban Forest Owners

Credits for a UTP Project must be quantified from carbon that is owned by participating entities. An Urban Forest Owner is a corporation, a legally constituted entity (such as a utility or special district), city, county, state agency, educational campus, individual(s), or a combination thereof that has legal control of any amount of urban forest carbon[3] within the Project Area.

Control of urban forest carbon means the Urban Forest Owner has the legal authority to effect changes to urban forest carbon quantities (right to plant or remove, for example). Control of urban forest carbon occurs, for purposes of satisfying this protocol, through fee ownership, perpetual contractual agreements, and/or deeded encumbrances. This protocol recognizes the fee owner as the default owner of urban forest carbon where no explicit legal encumbrance exists. Individuals or entities holding mineral, gas, oil, or similar *de minimis*[4] interests without fee ownership are precluded from the definition of Urban Forest Owner.

2.3 Project Operators

A Project Operator must be one of the Urban Forest Owners or a legally created entity to represent the Urban Forest Owners. The Project Operator is responsible for undertaking a UTP Project and registering it with the Reserve, and is ultimately responsible for all project listing, monitoring, reporting, and verification. The Project Operator is responsible for any reversals associated with the project and is the entity that executes the Project Implementation Agreement (see below) with the Reserve.

In all cases where multiple Urban Forest Owners participate in a UTP Project, the Project Operator must secure an agreement from all other Urban Forest Owners that assigns authority to the Project Operator to include the carbon they own in the project, subject to any conditions imposed by any of the Urban Forest Owners to include or disallow any carbon they control and any provisions to opt out of the project.

[3] See definition of Carbon Stock in the glossary.
[4] *de minimis* control includes access right of ways and residential power line right of ways.

2.4 Project Implementation Agreement

A Project Implementation Agreement (PIA) is a required agreement between the Reserve and a Project Operator setting forth the Project Operator's obligation (and the obligation of its successors and assigns) to comply with the UTP Project Protocol.

3 Eligibility Rules

In addition to the definitions and requirements described in Section 2, projects must meet several other criteria and conditions to be eligible for registration with the Reserve, and must adhere to the following requirements related to their duration and crediting periods.

3.1 Project Location

Only those activities that occur within the Urban Area boundaries, defined by the most recent publication of the United States Census Bureau (http://www.census.gov/geo/maps-data/maps.html), are eligible to develop a project under this protocol. Projects must be entirely within the Urban Area boundary as of Project Commencement.

3.2 Project Area

The Project Area is the geographic extent of the UTP Project. The Project Area may be made up of consolidated or disaggregated polygons. A KML file must be submitted with the project to clearly identify the project boundaries. There are no size limits for UTP Projects.

No part of the Project Area can be included if commercial harvesting of timber has occurred in the Project Area in the past 10 years. Additionally, the issuance and transaction of credits will be suspended if commercial harvesting of timber products occurs any time during the project. Where the harvesting of commercial timber products is anticipated, the OPO should consider the use of a protocol that addresses the carbon stored in harvested wood products, such as the Reserve's Forest Protocol or the California Air Resource's Board Compliance Forest Protocol. Exceptions to the prohibition of harvesting commercial timber products are recognized where the provision of commercial timber products might be generated where harvests are conducted primarily for safety, salvage of material when trees are in decline, and developing improved resilience to wildfire and pests.

3.3 Project Commencement

The commencement date for a project is the date at which the Project Operator initiates an activity that will lead to increased GHG reductions or removals with long-term security relative to the project baseline. The earliest acceptable activity that demonstrates the commencement of project activities is a formal planning process by the Project Operator. Subsequent activities to planning, including the purchase of equipment for tree planting, site preparation, or planting trees, with a plan in place, also demonstrate a project has commenced. Once a UTP Project has commenced, new plantings can occur within the Project Area throughout the Project Life. Discrete and verifiable evidence that acceptable activity has occurred includes signed contracts and/or direct evidence of the recent activity.

To be eligible, the project must be submitted to the Reserve no more than six months after the project commencement date.[5] Projects may always be submitted for listing by the Reserve prior to their start date.

3.4 Additionality

The Reserve will only register projects that yield surplus GHG emission reductions and removals that are additional to what would have occurred in the absence of a carbon offset

[5] Projects are considered submitted when the project developer has completed and uploaded the appropriate project submittal forms to the Reserve software.

market (i.e. under "Business As Usual"). For a general discussion of the Reserve's approach to determining additionality, see the Reserve's Program Manual.[6]

Projects must satisfy the following tests to be considered additional.

3.4.1 Legal Requirement Test

UTP Projects must achieve GHG reductions or removals above and beyond any GHG reductions or removals that would result from compliance with any federal, state, or local law, statute, rule, regulation, or ordinance. Projects must also achieve GHG reductions and removals above and beyond any GHG reductions or removals that would result from compliance with any court order or other legally binding mandates. Deeded encumbrances, tree-planting and management ordinances, and contractual agreements, collectively referred to as Legal Agreements, may effectively control urban forest carbon and possess ownership rights to the carbon inventories controlled. Similarly, deeded encumbrances, tree planting and management ordinances, and contractual agreements may have an effect on urban forest carbon inventories beyond the control of any of the Urban Forest Owners.

Trees planted to fulfill a legal requirement are ineligible under this protocol. Legal requirements include any requirement issued by authority of a federal, state, or local jurisdiction to plant trees for any reason.

3.4.2 Performance Test

Projects must achieve GHG reductions or removals above and beyond any GHG reductions or removals that would result from engaging in Business As Usual activities, as defined by the requirements described below.

3.4.2.1 Performance Standard for Urban Tree Planting Projects

The performance standard metrics are based on the averages of data between the 50th and 100th percentiles. The data are based on the following data:

1. For Municipalities/counties: trees per capita.
2. Educational institutions: trees per acre of maintained landscaping.
3. Utilities: trees per ratepayer

Project Operators must include the performance standard level of planting in their baseline calculations as described in the Quantification Guidance supplemental to this protocol.

3.5 Project Crediting Period

The crediting period for UTP Projects is 25 years. Projects may be renewed for additional crediting periods with the prospect of incorporating updated technology into the project analysis. The initial baseline can be maintained for the crediting period. While the project can be renewed indefinitely, the baseline must be renewed at the end of the crediting period. Any previously issued credits are respected for the life of the project.

3.6 Minimum Time Commitment

Projects must monitor, report, and undergo verification activities for 100 years following the last credit issued to the project.

[6] Available at http://www.climateactionreserve.org/how/program/program-manual/.

3.7 Social and Environmental and Co-Benefits

All projects will provide climate benefits to the extent in which they generate credits. Urban forests provide many additional benefits, including environmental, social, and public health benefits. The ability to achieve additional environmental and social co-benefits depends on consideration of additional factors, some of which are described in this section. Only those projects where public and/or tribal entities participate in direct urban tree management activities (e.g., planting, tree distribution, etc.) are required to include the provisions for social and environmental co-benefits. However, these provisions may serve as suggestions to NGOs and other privately funded projects that may wish to enhance social and environmental co-benefits. Where required, the provisions must be described in the Project Design Document (PDD) and implemented throughout the Project Life. The Reserve has developed a tree-planting template that outlines elements that need to be addressed and provides important considerations that may be helpful in decision-making.[7] The template provides considerations that will enable verifiers to ensure progress is being achieved over time.

3.7.1 Social Co-Benefits

UTP Projects can create long-term climate benefits as well as providing other social and environmental benefits. Investment in projects has the potential to improve the quality of life for urban communities in a number of ways. Among other benefits, tree planting projects can improve air quality and reduce storm water runoff, provide shade, and increase property values by creating a more aesthetically pleasing environment. Projects also have the potential to create negative social externalities such as an uneven distribution of project benefits due to an uneven distribution of projects sites throughout a community (e.g. skewed toward more affluent communities).

Table 3.1. Social Co-Benefits of Urban Tree Planting Projects

Social Provisions	Elements to Include in the Project Design Document (PDD)
Equitable distribution of forest resources	Describe how the project will make progress toward achieving relatively equal distribution of tree canopy cover by neighborhood whenever possible.
Public participation	Establish guidelines to ensure adequate notification, opportunities for public participation, and documentation with regards to public activities with urban forest management.

3.7.2 Environmental Co-Benefits

The protocol has a goal of permanently removing greenhouse gases from the atmosphere by sustaining carbon benefits generated from urban forests for at least 100 years. Healthy urban forests can also provide a number of environmental benefits as well as create negative externalities. Projects have the potential to improve air quality and reduce storm water runoff and energy usage. They can also contribute to reduced biodiversity, introduce invasive species, and damage infrastructure. Inefficient water usage during maintenance can also put pressure on local and regional water supplies.

[7] Available at http://www.climateactionreserve.org/how/protocols/urban-forest/.

Table 3.2. Environmental Co-Benefits of Urban Tree Planting Projects

Environmental Provisions	Elements to Include in the Project Design Document (PDD)
Biodiversity	Describe how UTP Project activities will maintain and enhance biodiversity, including: 1. Benefits of tree species selection and composition to biodiversity within the project area. 2. Use of specific tree species, sizes and/or distributions to support unique habitat elements.
Native species	Describe how UTP Project activities will promote the use of native species, including: 1. Strengths and limitations of using native trees in the UTP Project. 2. Preferential treatment of native species.
Non-native species	Describe how UTP Project activities will limit and target the use of any non-native species, including: 1. Strengths and limitations of using non-native trees in the UTP Project. 2. Resistance to insects and disease.
Climate change resilience	Describe how UTP Project activities will enhance the resilience of the urban forest to climate change, including: 1. Ability of urban forest to adapt to climate change. 2. Resistance to natural disturbances.
Air quality	Describe how UTP Project activities will enhance air quality benefits, including: 1. Tree selection and distribution to reduce air pollutants. 2. Tree selection and distribution to reduce emissions of Biogenic Volatile Organic Compounds (BVOCs). 3. Design tree maintenance activities to reduce fossil fuel emissions.
Physical characteristics	Describe how UTP Project activities will enhance physical characteristics of the urban environment, including: 1. Tree shading. 2. Wind protection. 3. Minimize disturbance to city infrastructure (e.g. sidewalks, power lines, etc.)
Water Management	Describe how UTP Project activities will improve water management, including: 1. Increase infiltration and recharge of groundwater. 2. Reduce stormwater runoff. 3. Conserve water from urban forest management.

4 GHG Assessment Boundaries

The quantification of all included sources, sinks, and reservoirs (SSR) (Table 4.1 below) is described in the supplemental Quantification Guidance available on the Reserve's website.[8]

Table 4.1. Description of all Sources, Sinks, and Reservoirs

SSR	Source Description	Type	Gas	Included (I) or Excluded (E)	Justification/Explanation
UF-1	Standing live carbon (carbon in all portions of living trees)	Reservoir / Pool	CO_2	Included	Increases in standing live carbon stocks are likely to be a large Primary Effect of UTP Projects
UF-2	Shrubs and herbaceous understory carbon	Reservoir / Pool	CO_2	Excluded	For crediting purposes shrubs and herbaceous understory are excluded since changes in this reservoir are unlikely to have a significant effect on total quantified GHG reductions or removals. Furthermore, it is generally not practical to undertake measurements of shrubs and herbaceous understory accurate enough for crediting purposes.
UF-3	Standing dead carbon (carbon in all portions of dead, standing trees)	Reservoir / Pool	CO_2	Included	Standing dead wood is expected to be a small, but in rare cases substantial, portion of UTP Projects.
UF-4	Lying dead wood carbon	Reservoir / Pool	CO_2	Excluded	For crediting purposes lying dead wood carbon is excluded since changes in this reservoir are unlikely to have a significant effect on total quantified GHG reductions or removals. Changes associated with carbon projects are likely to increase lying dead wood. Furthermore, it is generally not practical to undertake measurements of lying dead wood accurate enough for crediting purposes.
UF-5	Litter and duff carbon (carbon in dead plant material)	Reservoir / Pool	CO_2	Excluded	Litter and duff carbon is excluded since changes in this reservoir are unlikely to have a significant effect on total quantified GHG reductions or removals. Furthermore, it is generally not practical to undertake measurements of litter and duff accurate enough for crediting purposes.

[8] http://www.climateactionreserve.org/how/protocols/urban-forest/

SSR	Source Description	Type	Gas	Included (I) or Excluded (E)	Justification/Explanation
UF-6	Soil carbon	Reservoir / Pool	CO_2	Excluded	Soil carbon is not anticipated to change significantly as a result of UTP Projects.
UF-7	Carbon in in-use forest products	Reservoir / Pool	CO_2	Excluded	Urban forests do not produce significant levels of wood products that persist for long enough periods of time to meet permanence requirements and UTP Projects will not substantially change wood product production.
UF-8	Forest product carbon in landfills	Reservoir / Pool	CO_2	Excluded	Urban forests do not produce significant levels of wood products and UTP Projects will not substantially change wood product production.
UF-9	Nutrient application	Source	N_2O	Excluded	The use of nitrogen-based fertilizers is not expected to be a significant source of emissions.
UF-10	Biological emissions from site preparation activities	Source	CO_2	Excluded	Biological emissions from site preparation are not quantified since projects that involve intensive site preparation activities are not eligible.
UF-11	Mobile combustion emissions from site preparation activities	Source	CO_2	Excluded	Mobile combustion CO_2 emissions from site preparation are not quantified since projects that involve intensive site preparation activities are not eligible.
			CH_4	Excluded	Changes in CH_4 emissions from mobile combustion associated with site preparation activities are not considered significant.
			N_2O	Excluded	Changes in N_2O emissions from mobile combustion associated with site preparation activities are not considered significant.
UF-12	Mobile combustion emissions from ongoing project operation and maintenance	Source	CO_2	Excluded	Mobile combustion CO_2 emissions from ongoing project operation and maintenance are unlikely to be significantly different from baseline levels, and are therefore not included in the GHG Assessment Boundary.
			CH_4	Excluded	CH_4 emissions from mobile combustion associated with ongoing project operation and maintenance activities are not considered significant.

SSR	Source Description	Type	Gas	Included (I) or Excluded (E)	Justification/Explanation
			N_2O	Excluded	N_2O emissions from mobile combustion associated with ongoing project operation and maintenance activities are not considered significant.
UF-13	Stationary combustion emissions from ongoing project operation and maintenance	Source	CO_2	Excluded	Stationary combustion CO_2 emissions from ongoing project operation and maintenance could include GHG emissions associated with electricity consumption or heating/cooling at Urban Forest Owner facilities or at facilities owned or controlled by contractors. These emissions are unlikely to be significantly different from baseline levels, and are therefore not included in the GHG Assessment Boundary.
			CH_4	Excluded	CH_4 emissions from stationary combustion associated with ongoing project operation and maintenance activities are not considered significant.
			N_2O	Excluded	N_2O emissions from stationary combustion associated with ongoing project operation and maintenance activities are not considered significant.

5 Quantifying Net GHG Reductions and Removals

This section provides general requirements and guidance for quantifying a UTP Project's net GHG reductions and removals. Detailed methodological approaches to quantifying GHG reductions and removals are provided in the Quantification Guidance document. The Reserve will issue Climate Reserve Tonnes (CRTs) to a project upon confirmation by an ISO-accredited and Reserve-approved verification body that the project's GHG reductions and removals have been quantified following the applicable requirements of this section (see Section 8 for verification requirements). The Reserve provides an Urban Tree Planting Calculation Tool on its website[9] to assist with the annual calculation of reductions and removals.

Quantification proceeds according to the steps below.

1. **Estimating baseline onsite carbon stocks**. The baseline is an estimate of what would have occurred in the absence of a project. To establish baseline onsite carbon stocks, the Project Operator must apply the appropriate performance test from Section 3.4.2 of this protocol to the Project Onsite Inventory at Project Commencement. The Project Onsite Inventory must have been developed according to the guidelines established in the Quantification Guidance. Baseline estimates are developed for a 100-year period. Generally, baselines do not change during this period absent findings of errors in initial calculation or reconciliation associated with methodological updates.

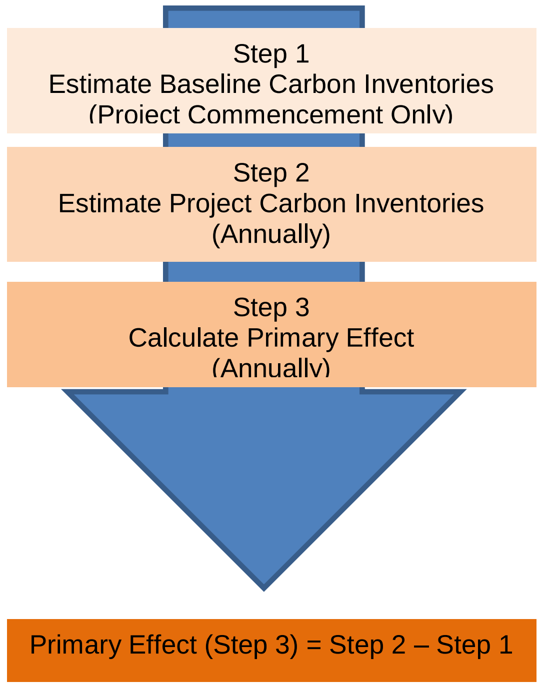
2. **Determining actual onsite carbon stocks**. Each year, the Project Operator must determine the project's actual onsite carbon stocks. This must be done by updating the UTP Project's forest carbon inventory for the current year, following the guidance in this section and in the Quantification Guidance. The estimate of actual onsite carbon stocks must be adjusted by an appropriate confidence deduction, as described in the Quantification Guidance.

3. **Calculating the project's Primary Effect**. Each year, the Project Operator must quantify the actual change in GHG emissions or removals associated with the project's intended ("primary") effect. For any given year, the Primary Effect is calculated by:
   a. Taking the difference between actual onsite carbon stocks for the current year and actual onsite carbon stocks for the prior year.[10]
   b. Subtracting from (a) the difference between baseline onsite carbon stocks for the current year and baseline onsite carbon stocks for the prior year.

4. Calculating total net GHG reductions and removals. For each year, total net GHG reductions and removals are calculated by summing a project's Primary and Secondary Effects. If the result is positive, then the project has generated GHG reductions and/or removals in the current year. If the result is negative, this may indicate a reversal has occurred (see Section 6).[11]

[9] http://www.climateactionreserve.org/how/protocols/urban-forest/
[10] For the purposes of calculating the project's Primary Effect, actual and baseline carbon stocks prior to the Project Commencement Date are assumed to be zero.
[11] A reversal occurs only if: (1) total net GHG reductions and removals for the year are negative; and (2) CRTs have previously been issued to the UTP Project.

The required formula for quantifying annual net GHG reductions and removals is presented in Equation 5.1. Net GHG reductions and removals must be quantified and reported in units of carbon dioxide-equivalent (CO_2e) metric tons.



Equation 5.1. Annual Net GHG Reductions and Removals

$$\boldsymbol{QR_y} = (\Delta\, \boldsymbol{AC_{onsite}} - \Delta\, \boldsymbol{BC_{onsite}})$$

Where,			Units
QR_y	=	Quantified GHG reductions and removals for year y	tCO_2e
$\Delta\ AC_{onsite}$	=	$(AC_{onsite,\ y}) - (AC_{onsite,\ y-1})$	tCO_2e
		Where,	
		$AC_{onsite,\ y}$ = Actual carbon (CO_2e) as inventoried for year y (y may be less than a year for the first Reporting Period following Project Commencement).	tCO_2e
		$AC_{onsite,\ y-1}$ = Actual carbon (CO_2e) as inventoried for year y-1	tCO_2e
$\Delta\ BC_{onsite}$	=	$(BC_{onsite,\ y}) - (BC_{onsite,\ y-1})$	tCO_2e
		Where,	
		$BC_{onsite,\ y}$ = Baseline onsite carbon (CO_2e) as estimated for year y (y may be less than a year for the first Reporting Period following Project Commencement).	tCO_2e
		$BC_{onsite,\ y-1}$ = Baseline onsite carbon (CO_2e) as estimated for year y-1	tCO_2e

5.1 Urban Tree Planting Baseline

To develop a project baseline for a UTP Project, Project Operators must provide a qualitative characterization of the regulatory framework governing tree planting activities within the Project Area and explain why trees planted as part of the project are outside of any framework requiring the planting of trees.

Projects use a performance standard value which provides guidance to quantifying baselines. The performance standard value is a value that represents the averages of data between the 50th and 100th percentiles for trees planted annually for classes based on the entity type (county, municipality, educational institution, or utility/special district), the entity's size (population, landscaped area, or ratepayer population), and the entity's geo-political region. Project Operators must match their entity with an urban forest class on the Reserve's Urban Forest Project Protocol webpage.

The performance standard value[12] is compared to the actual project trees planted and the resulting proportion is calculated in terms of CO_2e to calculate the baseline contribution. The baseline calculation contains provisions for the potential eventuality that the Project Area is saturated with planted trees. The Reserve's Urban Tree Planting Calculation Tool[13] assists Project Operators with the baseline calculation. A more technical description of the quantification of the UTP Project baseline can be found in the Quantification Guidance supplemental to this protocol.

[12] Available at http://www.climateactionreserve.org/how/protocols/urban-forest/.
[13] Available at http://www.climateactionreserve.org/how/protocols/urban-forest/.

6 Ensuring the Permanence of Credited GHG Reductions and Removals

Changes in urban forest management have the potential to enhance the rate of CO_2 absorption, providing removals, and reducing or eliminating emissions associated with the loss of trees (reductions). Reductions are not possible with UTP Projects. The Reserve requires that credited GHG reductions and removals be effectively “permanent.” For UTP Projects, this requirement is met by ensuring that the carbon associated with credited GHG reductions and removals remains stored for at least 100 years.

The Reserve ensures the permanence of GHG reductions and removals through three mechanisms:

1. The requirement for all Project Operators to monitor onsite carbon stocks, submit regular monitoring reports, and submit to regular third-party verification of those reports along with periodic onsite verifications for the duration of the Project Life.
2. The requirement for all Project Operators to sign a Project Implementation Agreement with the Reserve which obligates Project Operators to retire CRTs to compensate for reversals of GHG reductions and removals.
3. The maintenance of a Buffer Pool to provide insurance against reversals of GHG reductions and removals due to unavoidable causes (including natural disturbances such a fires, pest infestations or disease outbreaks).

GHG reductions and removals can be “reversed” if the stored carbon associated with them is released (back) to the atmosphere. Many biological and non-biological agents, both natural and human-induced, can cause reversals. Some of these agents cannot completely be controlled (and are therefore “unavoidable”), such as natural agents like fire, insects, pathogens, drought, and wind.

Other agents can be controlled, such as the human activities like land conversion. Under this protocol, reversals due to controllable agents are considered “avoidable”. As described in this section, Project Operators must contribute to the Reserve Buffer Pool to insure against reversals. If the quantified GHG reductions and removals in a given year are negative, and CRTs were issued to the UTP Project in any previous year, the Reserve will consider this to be a reversal regardless of the cause of the decrease.

The Buffer Pool is a holding account for project CRTs, which is administered by the Reserve. All UTP Projects must contribute a percentage of CRTs to a Buffer Pool any time they are issued CRTs for verified GHG reductions and removals. A project that has an Unavoidable Reversal will use Buffer Pool CRTs proportionally from all projects that have contributed to the pool to compensate for the reversal. Project Operators do not receive compensation for their contributions to the Buffer Pool.

If a project experiences an Unavoidable Reversal of GHG reductions and removals (as defined in Section 6.2.2), the Reserve will retire a number of CRTs from the Buffer Pool equal to the total amount of carbon that was reversed (measured in metric tons of CO_2). The Buffer Pool therefore acts as a general insurance mechanism against Unavoidable Reversals for all UTP Projects registered with the Reserve. The Reserve may determine to re-distribute CRTs to Project Operators in the future, or modify the amount of contributions to the Buffer Pool, if actual Unavoidable Reversals fluctuate significantly from the current evaluation of risks.

6.1 Contributions to the Buffer Pool

Projects may be affected by financial risks, management risks, social risks, risks from pollution, and risks from natural disturbances (disease/insects, wildfire, flooding, drought etc.). To compensate for these risks, each project must contribute 6% of their issued CRTs to the Buffer Pool.

6.2 Compensating for Reversals

The Reserve requires that all reversals be compensated through the retirement of CRTs. If a Reversal associated with a UTP Project was unavoidable (as defined below), then the Reserve will compensate for the reversal on the Project Operator’s behalf by retiring CRTs from the Buffer Pool. If a reversal was avoidable (as defined below) then the Project Operator must compensate for the reversal by surrendering CRTs from its Reserve account.

6.2.1 Avoidable Reversals

An Avoidable Reversal is any reversal that is due to the Project Operator’s negligence, gross negligence, or willful intent, including harvesting, development, and harm to the Project Area due to the Project Operator’s negligence, gross-negligence or willful intent. Requirements for Avoidable Reversals are as follows:

1. If an Avoidable Reversal has been identified during annual monitoring, the Project Operator must give written notice to the Reserve within thirty days of identifying the reversal. Additionally, if the Reserve determines that an Avoidable Reversal has occurred, it shall deliver written notice to the Project Operator.
2. Within thirty days of receiving the Avoidable Reversal notice from the Reserve, the Project Operator must provide a written description and explanation of the reversal to the Reserve.
3. Within four months of receiving the Avoidable Reversal notice, the Project Operator must retire a quantity of CRTs from its Reserve account equal to the size of the reversal in CO_2-equivalent metric tons (i.e. QR_y, as specified in Equation 5.1). In addition:
    a. The retired CRTs must be those that were issued to the project, or that were issued to other UTP Projects registered with the Reserve.
    b. The retired CRTs must be designated in the Reserve’s software system as compensating for the Avoidable Reversal.
4. Within a year of receiving the Avoidable Reversal notice, the Project Operator must provide the Reserve with a verified estimate of current onsite carbon stocks and the estimated quantity of the Avoidable Reversal.

6.2.2 Unavoidable Reversals

An Unavoidable Reversal is any reversal not due to the Project Operator’s negligence, gross negligence or willful intent, including, but not limited to, wildfires or disease that are not the result of the Project Operator's negligence, gross negligence or willful intent. Requirements for Unavoidable Reversals are as follows:

1. If the Project Operator determines there has been an Unavoidable Reversal, it must notify the Reserve in writing of the Unavoidable Reversal within six months of its occurrence.
2. The Project Operator must explain the nature of the Unavoidable Reversal and provide a verified estimate of onsite carbon stocks within one year so that the reversal can be quantified (in units of CO_2-equivalent metric tons).

If the Reserve determines that there has been an Unavoidable Reversal, it will retire a quantity of CRTs from the Buffer Pool equal to size of the reversal in CO_2-equivalent metric tons.

6.3 Disposition of Projects after a Reversal

If a reversal lowers the UTP Project's carbon stocks below its approved baseline carbon stocks, the project will be terminated as the original baseline approved for the project would no longer be valid. If a project is terminated due to an Unavoidable Reversal, a new project may be initiated and submitted to the Reserve for registration on the same Project Area. New projects may not be initiated on the same Project Area if the project is terminated due to an Avoidable Reversal.

7 Project Monitoring, Reporting, and Verification

This section provides requirements and guidance on project monitoring, reporting rules and procedures.

7.1 Project Documentation

Project Operators must provide the following documentation to the Reserve in order to register a UTP Project.

Table 7.1. Project Documentation Submittal Requirements

Document	When Submitted/Required
Project Submittal Form	Once, at project initiation when the Project Operator wishes to submit project concept to Reserve. Must be submitted within 6 months of the Commencement Date.
Project Design Document	Once, prior to initial verification.
Signed Attestation of Title Form	Prior to issuance of credits. Required at initial verification, onsite verification, and every optional desktop verification.
Signed Attestation of Regulatory Compliance Form	Prior to issuance of credits. Required at initial verification, onsite verification, and every optional desktop verification.
Signed Attestation of Voluntary Implementation Form	Once, prior to the issuance of credits as part of the initial verification.
Verification Report	Upon completion of verification and prior to issuance of credits. Required at initial verification, onsite verification, and every optional desktop verification.
Verification Statement	Upon completion of verification and prior to issuance of credits. Required at initial verification, onsite verification, and every optional desktop verification.
Project Implementation Agreement	Upon completion of verification and prior to issuance of credits. Required at initial verification, onsite verification, and every optional desktop verification.

Project submittal forms can be found at http://www.climateactionreserve.org/how/program/documents/.

All reports that reference carbon stocks must be submitted with the oversight of a Certified Arborist, a Certified Forester, a Certified Urban Forester, or Professional Forester so that professional standards and project quality are maintained. Any Certified Arborist, Certified Urban Forester, Professional Forester or Certified Forester preparing a project in an unfamiliar jurisdiction must consult with a Certified Arborist, Professional Forester or Certified Forester practicing forestry in that jurisdiction to understand all laws and regulations that govern urban forest practices within the jurisdiction. This requirement does not preclude the project's use of technicians or other unlicensed/uncertified persons working under the supervision of the Professional Forester, Certified Arborist, or Certified Forester.

All projects shall submit a shapefile as a KML that matches the maps submitted to depict the Project Area. The project's reported acres shall be based on the shapefile submitted to the

Reserve. The Reserve will create a file of all verified forest carbon projects on Google Maps for public dissemination.

7.1.1 Urban Forest Project Design Document

The Project Design Document (PDD) is a required document for reporting information about a project. The document is submitted at the initial verification. A PDD template has been prepared by the Reserve and is available on the Reserve's website.[14] The template is arranged to assist in ensuring that all requirements of the UTP Project Protocol are addressed. The template is required to be used by all projects. The template is designed to manage the varying requirements based on project type.

Each project must submit a PDD at the project's first verification. PDDs are intended to serve as the main project document that thoroughly describes how the project meets eligibility requirements, discusses summaries associated with developing data according to quantification requirements, outlines how the project complies with terms for additionality and describes how project reversal risks are calculated. All methodologies used by Project Operators and descriptions in the PDD must be clear in a way that facilitates review by verifiers, Reserve staff, and the public. PDDs must be of professional quality and free of incorrect citations, missing pages, incorrect project references, etc.

7.2 Monitoring Report

Monitoring is the process of regularly collecting and reporting data related to a project's performance. Annual monitoring of UTP Projects is required to ensure up-to-date estimates of project carbon stocks and provide assurance that GHG reductions or removals achieved by a project have not been reversed. Project Operators must conduct monitoring activities and submit monitoring reports according to the schedule and requirements presented in Section 7.2. Monitoring is required for a period of 100 years following the final issuance of CRTs to a project for quantified GHG reductions or removals.

Monitoring activities consist primarily of updating a project's forest carbon inventory, entering the updated inventory into the project's calculation worksheet, and submitting it to the Reserve at frequencies defined in Section 7.3. CRTs are only issued in years that the project data are verified, as described in Section 7.4.

A monitoring report must be prepared for each Reporting Period. Monitoring reports must be provided to verification bodies whenever a project undergoes verification. The monitoring report must be completed and submitted to the Reserve within 12 months of the end of the Reporting Period. When required verifications must be conducted as explained below, both the verification report and the monitoring report must be completed and submitted to the Reserve within 12 months of the end of the Reporting Period. Monitoring reports must include an update of the project's calculation worksheet. The project's calculation worksheet includes:

1. An updated estimate of the current year's carbon stocks in the reported carbon pools. Acceptable methodologies for updating the project's inventory are provided in the Quantification Guidance. The update is determined by:
    a. Including any new forest inventory data obtained during the Reporting Period.
    b. Applying growth estimates to existing inventory.

[14] http://www.climateactionreserve.org/how/protocols/urban-forest/

   c. Updating inventory estimates for removals and/or disturbances that have occurred during the Reporting Period.
2. The baseline carbon stock estimates for the current year, as determined following the requirements in Section 5 and approved at the time of the project's registration.
3. A preliminary calculation of total net GHG reductions and removals (or reversals) for the year, following the requirements in Section 5.
4. *A preliminary calculation of the project's Buffer Pool contribution.

In addition to data reported using the project calculation worksheet, the following must be submitted to the Reserve as part of a monitoring report.

Conditional reporting, as pertinent:

1. If a reversal has occurred during the previous year, the report must provide a written description and explanation of the reversal, whether the Reserve classified the reversal as Avoidable or Unavoidable, and the status of compensation for the reversal.

7.3 Reporting and Verification Cycles

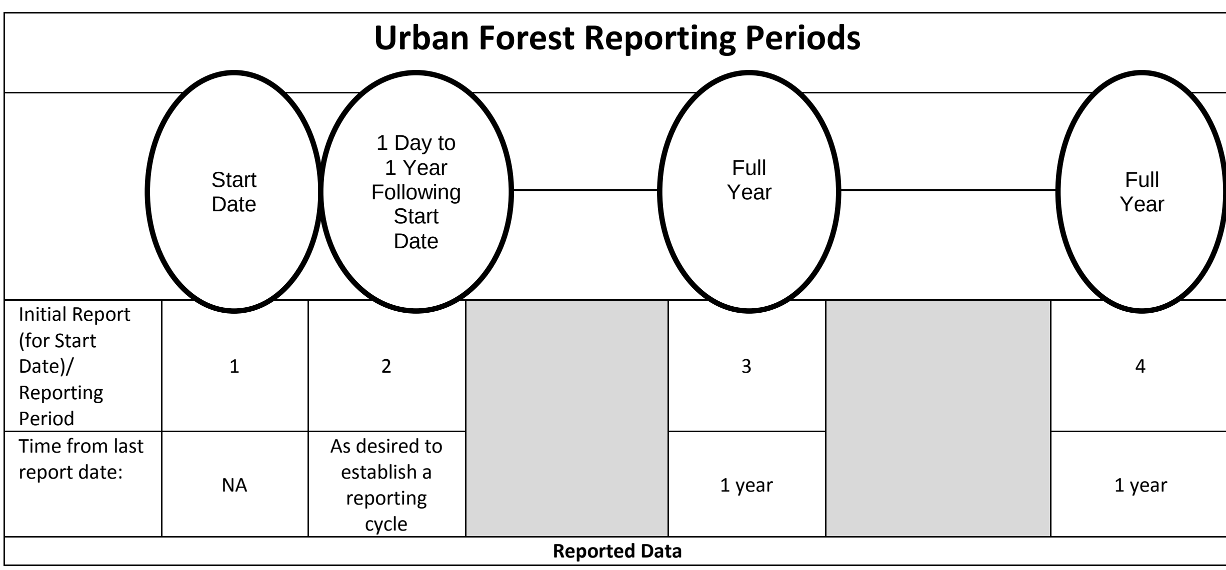
This section describes the required reporting and verification cycles. A UTP Project is considered automatically terminated (see Section 6.3) if the Project Operator chooses not to report data and undergo verification at required intervals.

7.3.1 Reporting Period Duration and Cycles

Projects must report their initial inventory data associated with the Project Commencement Date. Project Operators must report their project inventories annually with the exception of the Reporting Period immediately following Project Commencement, which can be any length of time up to one year. This enables Project Operators to establish an annual reporting cycle that is convenient for the entity.

Figure 7.1 displays the Reporting Periods in graphical form.

Reporting Periods must be contiguous, i.e. there must be no gaps in reporting during the crediting period of a project once the first Reporting Period has commenced.



Project Onsite Carbon Stocks	Yes	Yes		Yes		Yes
CRTs Issued upon Successful Verification?	No	Yes		Yes		Yes

Figure 7.1. Urban Tree Planting Reporting Periods

7.3.2 Verification Cycles

All projects must be initially verified within 30 months of being submitted to the Reserve. The initial verification of all project types must include a site visit, confirm the project's eligibility, and confirm that the project's initial inventory and the baseline have been established in conformance with the UTP Project Protocol. Subsequent verification may include multiple Reporting Periods and is referred to as the "Verification Period." The end date of any Verification Period must correspond to the end date of a Reporting Period.

Verification has both required frequencies and optional frequencies. Required verification is established on a temporal framework to ensure that ongoing monitoring of urban forest carbon stocks are accurate and up-to-date. Optional verification is at the Project Operator's discretion and may be conducted in the years in which verification is not required and the Project Operator wishes to receive credits. Required verifications are referred to as onsite verifications. Optional verifications are referred to as desk review verifications. Details of verification scheduling requirements are provided within this section.

Verification must be completed within 12 months of the end of the Reporting Period(s) being verified. For required verifications, failure to complete verification within the 12 month time period will result in account activities being suspended until the verification is complete. The project will terminate if the required verification is not completed within 36 months of the end of the Reporting Period(s) being verified. There is no consequence for failure to complete verification activities within 12 months for optional verifications.

7.3.3 Requirements of Onsite Verifications

Onsite verification is a verification in which project inventory data are verified through a process that audits data in the office as well as data in the field. The Reserve requires that an approved third-party verification body verify all reported data and information for a project and conduct a site visit for the Verification Period that coincides with Project Commencement and the end of every fifth Reporting Period following the Project Commencement Date. Buffer Pool contributions are also verified during onsite verifications.

7.3.4 Desk Review Verification

In between onsite verifications, the Project Operator may choose to have an approved third-party verification body conduct a desk review of annual monitoring reports as an optional verification. CRTs may be issued for GHG reductions/removals verified through such desk reviews.

Submission of annual monitoring reports to the Reserve is required even if the Project Operator chooses to forego desk review verification.

7.4 Issuance and Vintage of CRTs

The Reserve will issue Climate Reserve Tonnes (CRTs) for quantified GHG reductions and removals that have been verified through either onsite verifications or desk reviews. Onsite verification may determine that earlier desk reviews overestimated onsite carbon stocks. Any resulting downward adjustment to carbon stock estimates will be treated as a reversal (see Section 6). In this case, the Project Operator must retire CRTs in accordance with the requirements for compensating for a reversal (Section 6.2). Vintages are assigned to CRTs based on the proportion of days in a calendar year within a Reporting Period.

7.5 Record Keeping

For purposes of independent verification and historical documentation, Project Operators are required to keep all documents and forms related to the project for a minimum of 100 years after the final issuance of CRTs from the Reserve. This information may be requested by the verification body or the Reserve at any time.

7.6 Transparency

The Reserve requires data transparency for all projects, including data that displays current carbon stocks, reversals, and verified GHG reductions and removals. For this reason, all non-confidential project data reported to the Reserve will be publicly available on the Reserve's website.

8 Verification Guidance

This section provides guidance to Reserve-approved verification bodies for verifying GHG emission reductions associated with urban forest projects.

This section supplements the Reserve's Verification Program Manual,[15] which provides verification bodies with the general requirements for a standardized approach for independent and rigorous verification of GHG emission reductions and removals. The Verification Program Manual outlines the verification process, requirements for conducting verification, conflict of interest and confidentiality provisions, core verification activities, content of the verification report, and dispute resolution processes. In addition, the Verification Program Manual explains the basic verification principles of ISO 14064-3:2006 which must be adhered to by the verification body.

Verification bodies must read and be familiar with the following International Organization for Standardization (ISO) and Reserve documents and reporting tools:

- Urban Tree Planting Project Protocol (this document)
- Reserve Program Manual
- Reserve Verification Program Manual
- Reserve software
- ISO 14064-3:2006 Principles and Requirements for Verifying GHG Inventories and Projects

Only Reserve-approved urban forest project verification bodies are eligible to verify UTP Project reports. To become a recognized urban forest project verifier, verification bodies must become accredited under ISO 14065. Information on the accreditation process can be found on the Reserve website at http://www.climateactionreserve.org/how/verification/how-to-become-a-verifier/.

The verification of reports that reference carbon stocks must be conducted with the oversight of a Certified Arborist, a Professional Forester, or a Certified Forester,[16] managed by the Society of American Foresters, so that professional standards and project quality are maintained. Any Certified Arborist, Professional Forester or Certified Forester who is not currently working with urban forest activities within the Project Area must consult with a Certified Arborist, a Professional Forester, Certified Forester, or planning agency familiar with the practice of urban forestry in that jurisdiction to understand all laws and regulations that govern urban forest practice within the jurisdiction. The Reserve may evaluate and approve alternative professional credentialing requirements if requested, but only for jurisdictions where laws or regulations that govern professional urban forest management do not exist.

8.1 Standard of Verification

The Reserve's standard of verification for UTP Projects is the Urban Tree Planting Project Protocol, the Reserve Program Manual, and the Reserve Verification Program Manual. To verify a Project Operator's initial Project Design Document and annual monitoring reports, verification bodies apply the verification guidance in the Reserve's Verification Program Manual and this

[15] Found on the Reserve website at http://www.climateactionreserve.org/how/program/program-manual/.
[16] See www.certifiedforester.org.

section of the UTP Project Protocol to the requirements and guidance described in Sections 2 through 7 of the UTP Project Protocol.

This section of the protocol provides requirements and guidance for the verification of UTP Projects. This section describes the core verification activities and criteria that must be undertaken and addressed by a verification body in order to provide a reasonable level of assurance that the GHG removals or reductions quantified and reported by Project Operators are materially correct.

Verification bodies will use the criteria in this section to determine if there exists a reasonable assurance that the data submitted on behalf of the Project Operator to the Reserve addresses each requirement in the UTP Project Protocol, Sections 2 through 7. Project reporting is deemed accurate and correct if the Project Operator is in compliance with Sections 2 through 7.

Further information about the Reserve's principles of verification, levels of assurance, and materiality thresholds can be found in the Reserve's Verification Program Manual at http://www.climateactionreserve.org/how/program/program-manual/.

8.2 Project Verification Activities

Required verification activities for UTP Projects vary depending on whether the verification body is conducting an initial verification for registration on the Reserve, onsite verification, or an optional annual verification involving a desk review. The following sections contain guidance for all of these verification activities.

8.2.1 Initial Verification

Verifiers must ensure that the project has met the UTP Project Protocol criteria and requirements for eligibility, Project Area definition, additionality, quantification and calculation of baseline. The initial verification must include onsite verification. The verification body must assess and ensure the completeness and accuracy of all required reporting elements submitted in the Project Design Document.

8.2.2 Onsite Verification

Onsite verification involves review of the UTP Project's quantification, relevant attestations, soil carbon emissions associated with management activities, adherence to environmental and social safeguards (if applicable), and risk of reversal ratings. After a project's initial verification, subsequent site visits must assess and assure accuracy in measurement and monitoring techniques and onsite record keeping practices. Onsite verifications must be completed during the initial verification and for every fifth subsequent reporting cycle. That is, onsite verification is required every 5-years.

8.2.3 Optional Annual Verification

Optional annual verifications can occur according to preferences of the Project Operator. Credits can be verified and registered as the result of an optional annual verification. Optional annual verification occurs in the interim years between onsite verifications. The main focus of optional annual verifications is to assure that annual monitoring reports are complete and that reported project carbon inventories are within acceptable bounds, as described in the Quantification Guidance.

Table 8.1 displays the protocol sections that are verified at the initial verification, the onsite verification, and/or the optional annual verification.

Table 8.1. Verification Items and Related Schedules

Verification Items	Section of UTP Project Protocol	Initial	Site	Optional	Apply Professional Judgment[17]?
1. Project Definition	2.1 Urban Tree Planting	X			Yes
2. Urban Forest Owner	2.2 Urban Forest Owners	X	X		Yes
3. Project Operator	2.3 Project Operators	X	X		No
4. Project Implementation Agreement	2.4 Project Implementation Agreement	X	X	X	No
5. Project Location	3.1 Project Location	X			No
6. Project Area	3.2 Project Area	X			No
8. Project Commencement	3.3 Project Commencement	X			Yes
9. Additionality	3.4.1 Legal Requirement Test 3.4.2 Performance Test	X	X		Yes
	3.4.2.1 Performance Standard for Urban Tree Planting Projects	X			
10.Project Crediting Period	3.5 Project Crediting Period	X	X		No
11.Minimum Time Commitment	3.6 Minimum Time Commitment	X	X		No
12. Social and Environmental Co-Benefits	3.7 Social and Environmental Co-Benefits	X	X		Yes for public entities only
13. Social Co-Benefits	3.7.1 Social Co-Benefits	X	X		Yes for public entities only
14. Environmental Co-Benefits	3.7.2 Environmental Co-Benefits	X	X		Yes for public entities only
15. GHG Assessment Boundaries	4 GHG Assessment Boundaries	X	X		No
The verification topics below are linked to quantification requirements. The verification of project inventories is described in detail below this table. Verifiers shall assure that requirements associated with the references in this table have been satisfied and implement the specific guidance requirements for verifying inventories below.					
16. Quantifying Net GHG Reductions and Removals	5 Quantifying Net GHG Reductions and Removals 8.3 Verifying Carbon Inventories Urban Tree Planting Quantification Guidance	X	X	X	No
17. Urban Forest Protocol Baselines	5.1 Urban Tree Planting Baseline Urban Tree Planting Quantification Guidance: Baseline Development for Urban Tree Planting Projects	X			No
18. Permanence and Buffer Pool Contributions	6.1 Contributions to the Buffer Pool	X	X		No
19. Permanence and Compensating for Reversals	6.2 Compensating for Reversals 6.2.1 Avoidable Reversals 6.2.2 Unavoidable Reversals	X	X	X	No

[17] Verifiers must use professional judgment to verify protocol criteria which are not quantitative or can be measured completely with objective analysis.

8.3 Verifying Carbon Inventories

Verification bodies are required to verify carbon stock inventory calculations of all sampled and/or measured carbon pools within the Project Area. Inventories of carbon stocks are used to determine the project baseline and to quantify GHG reductions and removals against the project baseline over time. The method of verification of carbon inventories varies depending on whether the verification is part of the initial verification, onsite verification, or an optional verification. The verification elements and their periodicity are explained in this section.

Verification Item	Description	Verification Frequency
1 – Quantification of Carbon Estimates	Confirming that the methodology and requirements for quantifying carbon estimates specified in the Urban Tree Planting Quantification Guidance were implemented correctly and that the field measurements, use of biomass equations, and summary of project data meet minimum tolerance standards for accuracy, as part of onsite verification.	Initial onsite verification and every subsequent 5 years following initial onsite verification.
2 – Updated Data	Confirming that updated data are within acceptable bounds.	Optional, in years in between onsite verifications.

8.3.1 Verification of Urban Tree Planting Project Inventories

8.3.1.1 Office-Based Inventory Verification Activities

The verifier must progress through each successive step according to the guidance below. Verification activities may only proceed to field verification activities once the following items have been successfully verified:

1. Prior to verification of project inventories, **items 1 – 16** in Table 8.1 must be reviewed and deemed satisfactory by the verifier, both in terms of clear presentation and aligned with the protocol requirements.
2. Confirm that the **tree records** used in producing the project-level estimate of CO_2e are in a database, have latitude and longitude for each tree, and that the sum of individual CO_2e estimates for each tree equals the reported value for the project.
3. Confirm that the **confidence statistics** for canopy cover were correctly calculated and meet minimum requirements.

8.3.1.2 Field-Based Inventory Verification Activities

The verification effort must include a re-measurement of a subset of project data used to calculate the inventory estimate for the project. The data sampled by verifiers are individual trees. The verification strategy for all measured data is based on a comparison of randomly selected verifier measurements to Project Operator measurements in a process referred to as sequential sampling. Individual diameters (DBH) and total height must be measured for each tree. The minimum standards of measurement for verifiers are:

1. To the nearest inch for DBH measurements. DBH must be measured per the Urban Tree Planting Quantification Guidance.
2. To the nearest foot for height measurements.

Verification using the sequential sampling methodology requires the verification body to sequentially sample successive plots. Sequential approaches have stopping rules rather than fixed sample sizes. Verification is successful after a minimum number of successive plots in a sequence indicate agreement according to the tolerance thresholds established in the sequential sampling workbook. The evaluation of the three themes that utilize sequential sampling (CO_2e estimates from plots, current tree canopy area, and historical tree canopy area) shall utilize separate worksheets and include a copy of the results within the verification report.

Where sequential measurements from the verifier result in a trend of agreement with the Project Operator's data, as defined by established tolerance bounds, verification can proceed toward a finding of adequate accuracy. The number of trees measured by the verifier is based on stopping rules established by the Reserve. Where a high level of agreement is found between the Project Operator and the verifier, a finding of accuracy may be established with the minimal number of trees required by the Reserve. As variation between verifier estimates and Project Operators increases, the number of trees measured by the verifier must increase in order to work toward establishing a finding of accuracy. In cases where continued verifier effort does not result in agreement, the Project Operator must decide whether continued investment in verification effort is justified. Alternatively, verification can be suspended while the Project Operator improves the quality of the inventory and revises related project documentation.

The worksheet provided by the Reserve includes the established stopping rules. Where agreement between the verifier and the Project Operator is within specified tolerance bounds, verification of plot data is successful. For the field-based verification activities, the verifier must randomly select an initial set of 40 individual trees sampled by the Project Operator, maintaining the order of their selection in sequential order (1 – 40).

Verification Element	Description	Verification Frequency
1	**Measurement of Field Data**: The verifier must develop an initial strategy to efficiently visit the first 20 trees (1-20) in the list. The trees to not need to be visited and measured sequentially, but they all need to be visited prior to entering the data in the sequential sampling works. The verifier must measure the individual trees and calculate the CO_2e associated with each tree. The entries of tree summaries into the sequential sampling worksheet provided by the Reserve must be in the same order the trees were randomly selected.	Initial verification and each subsequent 5-year onsite verification.
2	**Data Quality Control**: Confirm that the tree records used in producing the project-level estimate of CO_2e are in a database, have latitude and longitude for each tree, and that the sum of individual CO_2e estimates for each tree equals the reported value for the project.	Initial verification and each subsequent 5-year onsite verification.
3	Confirm that the **confidence statistics** for canopy cover were correctly calculated and meet minimum requirements.	Initial verification and each subsequent 5-year onsite verification.

8.3.1.3 Optional Verification for Interim Years between Onsite Verifications

In the interim years between onsite verifications, OPOs can optionally have project stocks verified and receive credits. Verifiers shall compare current reported data with previously verified data and calculate if the reported data are within acceptable tolerance bounds. The tolerance bound is defined within 5% of the previous year's reported carbon stocks. Projects that utilize the optional verification must provide contribute 20% of the credits generated during the optional verification to a holding account. The holding account is reconciled to the project accounting in the reporting year that the project undergoes onsite verification. Data that are not within tolerance bounds must undergo the requirements for a 5-year onsite verification.

8.4 Completing the Verification Process

After completing the core project verification activities for a UTP Project, the verification body must do the following to complete the verification process:

1. Complete a verification report to be delivered to the Project Operator (public document).
2. Complete a detailed list of findings containing both immaterial and material findings (if any), and deliver it to the Project Operator (private document).
3. Prepare a concise verification statement detailing the vintage and the number of CRTs verified, and deliver it to the Project Operator (public document).
4. Verify that the number of CRTs specified in the verification report and statement match the number entered into the Reserve software.
5. Conduct an exit meeting with the Project Operator to discuss the verification report, list of findings, and verification statement and determine if material misstatements (if any) can be corrected. If so, the verification body and Project Operator should schedule a second set of verification activities after the Project Operator has revised the project submission.
6. If a reasonable level of assurance opinion is successfully obtained, upload electronic copies of the verification report, list of findings, verification statement, and verification activity log into the Reserve.
7. Return important records and documents to the Project Operator for retention.

The recommended content for the verification report, list of findings, and verification statement can be found in the Reserve's Verification Program Manual.[18] The Verification Program Manual also provides further guidance on quality assurance, negative verification statements, use of an optional project verification activity log, goals for exit meetings, dispute resolution, and record keeping.

[18] Available at http://www.climateactionreserve.org/how/program/program-manual/.

9 Glossary of Terms

Additionality	GHG emission reductions should occur as a result of specific GHG mitigation incentives; additionality is achieved when GHG reductions are beyond what would occur under business as usual operation and result from activities that are not mandated by regulation.
Allometric Equation	An equation that utilizes the genotypical relationship among tree components to estimate characteristics of one tree component from another. Allometric equations allow the below ground root volume to be estimated using the above-ground bole volume.
Avoidable Reversal	An avoidable reversal is any reversal that is due to the project operator's negligence, gross negligence, or willful intent, including harvesting, development, and harm to the project area.
Baseline	An estimate of GHG emissions and removals that would have occurred in absence of the project under business as usual operations.
Best Management Practices	Management practices determined by a state or designated planning agency to be the most effective and practicable means (including technological, economic, and institutional considerations) of controlling point and nonpoint source pollutants at levels compatible with environmental quality goals.[19]
Biological Emissions	For the purposes of the UTP Project Protocol, biological emissions are GHG emissions that are released directly from forest biomass, both live and dead, including forest soils. Biological emissions are deemed to occur when the reported tonnage of onsite carbon stocks, relative to baseline levels, declines from one year to the next.
Biomass	The amount of living matter comprising, in this case, a tree.
Bole	The trunk or main stem of a tree.
Buffer Pool	The buffer pool is a holding account for urban forest project CRTs administered by the Reserve. It is used as a general insurance mechanism against unavoidable reversals for all UTP projects registered with the Reserve.
Business As Usual	The activities, and associated GHG reductions and removals that would have occurred in the project area in the absence of incentives provided by a carbon offset market.

[19] (Helms, 1998)

Carbon Pool	A reservoir that has the ability to accumulate and store carbon or release carbon. In the case of forests, a carbon pool is the forest biomass, which can be subdivided into smaller pools. These pools may include above-ground or belowground biomass or roots, litter, soil, bole, branches and leaves, among others.
Carbon Sink	A carbon sink is any process, activity or mechanism that removes carbon dioxide from the atmosphere.
Carbon Source	A carbon source is any process or activity that releases carbon dioxide into the atmosphere.
Carbon Stock	A pool of stored carbon. Urban forest carbon stocks include biomass of the project trees. Include living and standing dead vegetation, woody debris and litter, organic matter in the soil, and harvested stocks such as wood for wood products and fuel.
Carbon Stock Change or Carbon Sequestration	The annual incremental change in carbon stocks.
C_{emis}	CO_2 and other GHG emissions from project maintenance activities, for example, due to vehicular or equipment use.
C_{proj}	Project carbon, i.e. carbon stored annually in project trees, reported as CO_2.
Certified Arborist	An arborist meeting the criteria having passed the test given by the International Society of Arboriculture (http://www.isa-arbor.com/certification/index.aspx).
Certified Forester	A professional with certified forester credentials managed by the Society of American Foresters (see www.certifiedforester.org). See also, Professional Forester.
Certified Urban Forester	An urban forester meeting the criteria and having passed the test created by the California Urban Forests Council, and now administered nationally by the Society of American Foresters.
Climate Reserve Tonnes (CRT)	One metric ton (tonne) of verified CO_2 equivalent emission reduction or sequestration.
CO_2-equivalent (CO_2e)	The quantity of a given GHG multiplied by its total global warming potential. This is the standard unit for comparing the degree of warming which can be caused by different GHGs.
Dry Weight (DW) Biomass	The weight of aboveground tree biomass when dried to 0% moisture content. Also known as oven-dry and bone-dry biomass. Convert from green biomass to dry weight biomass by multiplying by 0.56 for hardwoods or 0.48 for softwoods.

Entity	The individual, organization, agency or corporation that owns, controls, or manages urban trees.
Freshweight or Green Biomass	The weight of aboveground tree biomass when fresh (or green), which includes the moisture present at the time the tree was cut. The moisture content of green timber varies greatly among different species. The Reserve assumes that the moisture content of fresh weight biomass is 30%.
Global Warming Potential (GWP)	Factors used to convert emissions from GHGs other than carbon dioxide to their equivalent carbon dioxide emissions.
Greenhouse gas (GHG)	Greenhouse gases mean carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).
GHG Assessment Boundary	The GHG Assessment Boundary defines all the GHG sources, sinks, and reservoirs that must be accounted for in quantifying a project's GHG reductions and removals.
Inherent Uncertainty	The scientific uncertainty associated with calculating carbon stocks and greenhouse gas emissions.
KML	KML (Keyhole Markup Language) is an XML based file format used to display geographic data in an Earth browser such as Google Earth, Google Maps, and Google Maps for mobile.
Leakage	According to the Intergovernmental Panel on Climate Change: "the unanticipated decrease or increase in greenhouse gas benefits outside of the project's accounting boundary as a result of project activities."
Permanence	The requirement that GHGs must be permanently reduced or removed from the atmosphere to be credited as carbon offsets. For UTP projects, this requirement is met by ensuring that the carbon associated with credited GHG reductions and removals remains stored for at least 100 years.
Primary Effects	The project's intended changes in carbon stocks, GHG emissions or removals.
Professional Forester	A professional engaged in the science and profession of forestry. A professional forester is credentialed in jurisdictions that have professional forester licensing laws and regulations. Where a jurisdiction does not have a professional forester law or regulation then a professional forester is defined as having the certified forester credentials managed by the Society of American Foresters (see www.certifiedforester.org).
Project Activity	The carbon storage, emission reductions and emissions

	due to an urban tree planting project.
Project Area	The area inscribed by the geographic boundaries of a project.
Project Commencement (Project Commencement Date)	The commencement date is initiated by activities that increase carbon inventories and/or decrease emissions relative to the baseline.
Project Life	Refers to the duration of a project and its associated monitoring and verification activities.
Project Onsite Inventory	The inventory of trees eligible to generate emission reductions or removals in a project. Developed according to the guidelines in the Quantification Guidance.
Project Operator	One of the urban forest owners or a legally created entity to represent the urban forest owners that is responsible for undertaking a project.
Project Submission Date	The date that a project is submitted for listing in the Reserve program. The Reserve considers a project to be "submitted" when all of the appropriate forms have been uploaded to the Reserve's software system, and the project operator has paid a project submission fee.
Registered Consulting Arborist	An arborist meeting the criteria and having passed all the qualification requirements of the American Society of Consulting Arborists (http://www.asca-consultants.org/about/rca.cfm).
Reporting Uncertainty	The level of uncertainty associated with an entity's chosen method of sampling and/or inventorying carbon stock and calculation methodologies. Contrast with inherent uncertainty.
Reporting Period	The time period for which an entity is reporting its project activity and quantifying GHG reductions. This period will typically be 12 months, except for 1) the initial reporting period which begins at the project commencement date and may be more than 12 months, and 2) the second reporting period, which may be less than 12 months.
Reversal	A reversal is a decrease in the stored carbon stocks associated with quantified GHG reductions and removals that occurs before the end of the project life. Under this protocol, a reversal is deemed to have occurred if there is a decrease in the difference between project and baseline onsite carbon stocks from one year to the next, regardless of the cause of this decrease (i.e. if the result of (Δ AC_{onsite} - Δ BC_{onsite}) in Equation 5.1 is negative).
Secondary Effects	Unintended changes in carbon stocks, GHG emissions, or GHG removals caused by the project.
Sequestration	The process by which trees remove carbon dioxide from

	the atmosphere and transform it into biomass.
Start Date	See Project Commencement.
Tree	A woody perennial plant, typically large and with a well-defined stem or stems carrying a more or less definite crown with the capacity to attain a minimum diameter at breast height of five inches and a minimum height of 15 feet with no branches within three feet from the ground at maturity.[20]
Tree Residue	Aboveground biomass from urban trees (as distinguished from construction debris) that can be salvaged for reuse, such as mulch, wood products, or fuel for biomass power plant.
Unavoidable Reversal	An unavoidable reversal is any reversal not due to the project operator’s negligence, gross negligence or willful intent, including windstorms or disease that are not the result of the project operator's negligence, gross negligence or willful intent.
Urban Area	The most recent Urbanized Area definition provided by the United States Census Bureau at http://www.census.gov/geo/maps-data/maps/2010ua.html.
Urban Forest Owner	A corporation, legally constituted entity (such as a utility), city, county, state agency, individual(s), or combination thereof that has legal control (e.g. right to plant or remove, etc.) of any amount of urban forest carbon within the project area.
Urban Tree Planting Project (UTP Project, project)	A planned set of activities designed to increase removals of CO_2 from the atmosphere, or reduce or prevent emissions of CO_2 to the atmosphere, through increasing and/or conserving urban forest carbon stocks. An urban tree planting (UTP) project involves new trees being planted in areas where trees have not been harvested with a primary commercial interest over the past 10 years prior to project commencement. This does not include harvesting where the primary concern is for human safety or forest health. Only planted trees and trees that regenerate from planted trees are eligible to be quantified for credits. Benefits from urban tree planting activities occur when the CO_2e associated with planted trees exceeds baseline tree planting CO_2e levels.
Verification	The process of reviewing and assessing all of a project’s reported data and information by an ISO-accredited and Reserve-approved verification body, to confirm that the project operator has adhered to the requirements of this protocol.

[20] (Helms 1998)

Verification Cycle	The Reserve requires onsite verification of projects every five years, but project operators can choose to have more frequent 'desktop' verifications. In between site visits, desk reviews of project reports can be completed by an approved verification body. The Reserve will only issue CRTs for verified emission reductions.
Verification Period	The period of time over which GHG reductions/removals are verified. A verification period may cover multiple reporting periods. The end date of any verification period must correspond to the end date of a reporting period.

A.3 Verified Carbon Standard Protocols

A.3.1 Campus Clean Energy and Energy Efficiency

Approved VCS Methodology VM0025

Version 1.0, 12 February 2014
Sectoral Scopes 1 and 3

Campus Clean Energy and Energy Efficiency

The methodology was developed by Climate Neutral Business Network (CNBN) in collaboration with Bonneville Environmental Foundation based upon generous support from Chevrolet.

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1 SOURCES

The methodology uses the latest version of the following tools and guidance:

- VMD0038, Campus-Wide Module
- VMD0039, LEED-Certified Buildings Module
- US Environmental Protection Agency's ENERGY STAR Portfolio Manager® program[1]
- US Environmental Protection Agency's ENERGY STAR Target Finder tool[2]
- Clean Air Cool Planet Campus Carbon Calculator[3]
- CDM-EB67-A06-GUID Guidelines for sampling and surveys for CDM project activities and programme of activities

The methodology is based on approaches used in the following methodologies:

- VM0008 Weatherization of Single and Multifamily Homes (version 1.1)
- NM0302 Emission reductions in the cement production facilities of Holcim Ecuador S.A. (proposed CDM methodology)

The follow have also supported the development of the methodology:

- The American College and University Presidents' Climate Commitment (ACUPCC) GHG inventory reports[4]
- Efficiency Valuation Organization's International Performance Measurement and Verification Protocol (IPMVP) for guidance on methods determining energy savings (EVO-1000-1, 2010)[5]
- USGBC's LEED certification protocols[6]
- Portfolio Manager supporting documentation[7]

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[1] EPA. 2013: http://www.energystar.gov/buildings/facility-owners-and-managers/existing-buildings/use-portfolio-manager
[2] EPA. 2013: http://www.energystar.gov/index.cfm?c=new_bldg_design.bus_target_finder
[3] CACP. Aug, 2013: http://cleanair-coolplanet.org/campus-carbon-calculator/
[4] ACUPCC. 2013: http://rs.acupcc.org/
[5] EVO. 2010: http://www.evo-world.org/index.php?option=com_content&view=article&id=272&Itemid=379&lang=en
[6] USGBC. 2013: http://new.usgbc.org/leed[7] EPA. Nov, 2011. "Methodology for Greenhouse Gas Inventory Calculations" http://www.energystar.gov/ia/business/evaluate_performance/Emissions_Supporting_Doc.pdf?f655-cb13
[7] EPA. Nov, 2011. "Methodology for Greenhouse Gas Inventory Calculations"
http://www.energystar.gov/ia/business/evaluate_performance/Emissions_Supporting_Doc.pdf?f655-cb13
EPA. Mar, 2011. "ENERGY STAR Performance Ratings – Technical Methodology"
http://www.energystar.gov/ia/business/evaluate_performance/General_Overview_tech_methodology.pdf?9d9b-0c2d
EPA. Jul, 2013. "Portfolio Manager Technical Reference: ENERGY STAR Score"
http://www.energystar.gov/buildings/tools-and-resources/portfolio-manager-technical-reference-energy-star-score
http://www.energystar.gov/index.cfm?c=evaluate_performance.bus_portfoliomanager_model_tech_desc

2 SUMMARY DESCRIPTION OF THE METHODOLOGY

This methodology provides the procedures for quantifying reductions in scope 1 stationary combustion emissions and scope 2 electricity emissions achieved by college, university and school campuses in the United States. The methodology consists of two modules: *VMD0038, Campus-Wide Module*; and *VMD0039, LEED-Certified Buildings Module*, as follows:

1) Campus-Wide Module

   This module applies to projects targeting campus-wide emission reductions on existing college and university campuses in the United States (but does not apply to K-12 schools). Campuses may implement project activities that reduce scope 1 stationary combustion emissions and/or scope 2 electricity emissions. Campuses must meet the relevant additionality performance benchmark by applying a series of additionality benchmark tests. Emission reductions are quantified based on data from third-party GHG reporting programs (eg, ACUPCC, STARS and The Climate Registry) for each year relative to a three to five year adjusted baseline.

Additionality and Crediting Method	
Additionality	Performance Method
Crediting Baseline	Project Method

2) LEED-Certified Buildings Module

   This module applies to projects targeting emission reductions from LEED-certified New Construction or LEED-certified Existing Buildings located on college and university campuses and K-12 schools. The building must meet the relevant additionality performance benchmark. Emission reductions are quantified based on data generated using EPA's Target Finder tool for each year relative to a crediting benchmark or a three to five year adjusted baseline.

Additionality and Crediting Method	
Additionality	Performance Method
Crediting Baseline	Performance Method for New Construction and Existing Buildings B; Project Method for Existing Buildings A

This standardized methodology establishes multiple performance benchmarks which US colleges and schools can use to determine whether they have achieved a superior level of performance that would qualify as additional (additionality benchmark) and to quantify baseline emissions (crediting benchmark). Unlike project methods, performance methods are designed to identify the levels of performance (in terms of GHG emission reductions) in a given sector to allow for sector-wide benchmarking. Through extensive analyses of historical performance (outlined in the modules), this methodology establishes performance benchmarks for campus-wide emission reductions and LEED-certified building emission reductions that allow for a series of simple tests to be conducted to determine additionality and a crediting baseline. Stakeholder consultation was an important part of the development of this methodology, and the process and participants are described in Appendix 2.

Each module provides the detailed procedures for the given type of project activities, adding to the common requirements provided in this document. Each module has distinct specifications for applicability conditions, project boundary, baseline scenario, additionality, quantification of emission reductions, and monitoring. Where both campus-wide and building reductions are sought in combination for the same campus, both modules must be applied separately, and the relevant emission reductions netted out, as described in Section 8 below. Figure 1 below provides a conceptual route map illustrating how this methodology and its two modules are applied.

Projects must demonstrate right of use for any GHG emission reductions generated by the project, in accordance with the *VCS Standard* (for definition of *right of use* see VCS program document *Program Definitions*). Where right of use cannot be demonstrated for particular emission reductions (eg, for scope 2 emissions addressed by the project), the project proponent may choose to include only those emission reductions for which it can demonstrate right of use (eg, only include scope 1 emissions for LEED certified building projects). Emission reductions arising from a campus's third-party customer's use (eg, emission reductions achieved by a neighboring hospital which purchases energy from campus on-site energy generation) must be excluded from the project. Note that the consumption of energy services provided by off-site suppliers (eg, local industry) must be excluded from the scope 1 emissions and included in scope 2 emissions.

Where projects generate other forms of environmental credit (eg, renewable energy certificates (RECs)), the project must meet VCS rules and guidance on double counting (see *VCS Standard, Registration and Issuance Process,* and VCS guidance on double counting). For example GHG emission reductions that arise from the installation of renewable energy systems located on a campus, whose GHG-related attributes have been sold as RECs to other third parties must also be excluded from the quantification of emission reductions. Similarly, where RECs from off-site renewable installations are purchased by the campus, the lower GHG emissions or the respective grid emission factors associated with the RECs cannot be used to decrease project emissions in the quantification of emission reductions.

Emission reduction generated within a region subject to a carbon cap (eg, campuses' whose electricity emissions are included within a regulatory cap and trade program such as that in California) must meet the VCS rules regarding emission trading programs and other binding limits (ie, double counting) set out in the *VCS Standard*.

Where emission reductions are verified and intend to be issued as VCUs, project proponents must ensure that such VCUs are accurately reported in accordance with any procedures set out under any applicable third-party GHG reporting program under which the campus reports. The sale, transfer or retirement of any VCUs must be accurately reported to any applicable third-party GHG reporting program during the period where such sale, transfer or retirement occurs.

Figure 1: Conceptual Route Map for Methodology

Select project activities and determine appropriate module(s):
I. Campus-wide module for campus-wide activities
II. LEED-certified building module for LEED-certified building activities
III. Both modules for campus-wide *and* LEED-certified building activities

Campus-Wide	**LEED-Certified Buildings**
Applicability Conditions Determine whether activities qualify (eg, ACUPCC Carnegie classification of campus, use of third-party GHG reporting program, and activities implemented)	Applicability Conditions Determine whether activities qualify (LEED New Construction (NC), Existing Buildings A (EB-A), or Existing Building B (EB-B) and building classification higher education, higher education laboratory or K-12 School)
Project Boundary Determine the GHG sources, sinks and reservoirs for the project and whether new site areas can be excluded from the project boundary	Project Boundary Determine the GHG sources, sinks and reservoirs for the project
Baseline Scenario Determine the baseline scenario for the scope of GHG emission reductions that are additional, accounting for variance in square footage during the baseline period	Baseline Scenario Determine the baseline scenario for each building in the project by applying a crediting benchmark for NC and EB-B, or a historical baseline adjusted for energy efficiency improvements for EB-A
Additionality Determine which scope of emission reductions (ie, scope 1 stationary combustion emissions and/or scope 2 electricity emissions) are additional for the given project year, applying the regulatory surplus and performance benchmark tests, which account for variance in square footage during the baseline period and weather variances where necessary	Additionality Determine which buildings are additional for the given project year, applying the regulatory surplus and performance benchmark tests
GHG Emission Reductions Quantify the reductions for the relevant scope of emission reductions, adjusting for variance in square footage during the baseline period and project crediting period where necessary	GHG Emission Reductions Quantify the reductions for all additional buildings in the project using results generated from EPA's Target Finder tool anchored upon the appropriate property type and property use details

Monitoring Plan
Identify the data and parameters that need to be determined at validation, and those that need to be determined at each verification event.
Describe the plan for obtaining, recording, compiling and analyzing monitored data and parameters. Where both the campus-wide and LEED-certified buildings modules are applied, create a single monitoring plan.

Net GHG Emission Reductions
Where both the campus-wide and LEED-certified buildings modules are applied, quantify the net reductions by subtracting relevant LEED-certified building reductions from the campus-wide total.

3 DEFINITIONS

Definitions are specified in each of the modules referenced by this methodology.

4 APPLICABILITY CONDITIONS

This methodology applies to project activities that reduce emissions through the implementation of clean energy and/or energy efficiency activities at college and school campuses in the United States.

Projects applying this methodology must use the latest versions of one, or both, of the following modules:

1) VMD0038, Campus-Wide Module

2) VMD0039, LEED-Certified Buildings Module

Where the project applies one of these modules (ie, is implementing campus-wide activities *or* LEED-certified building activities), the project must meet the applicability conditions specified in the relevant module. Where the project applies both modules (ie, is implementing both campus-wide *and* LEED-certified building activities), the campus-wide activities must meet the applicability conditions set out in the campus-wide module, while the LEED-certified building activities must meet the applicability conditions set out in the LEED-certified buildings module.

Note that this methodology applies a standardized method and therefore must be used in preference to project methods (methodologies) available for the same project activities. Appendix 1 provides an indicative (non-exhaustive) list of project methods available for clean energy and energy efficiency projects.

5 PROJECT BOUNDARY

The procedures in the module being applied must be followed.

6 BASELINE SCENARIO

The procedures in the module being applied must be followed.

7 ADDITIONALITY

The procedures in the module being applied must be followed.

8 QUANTIFICATION OF GHG EMISSION REDUCTIONS AND REMOVALS

The procedures in the module being applied must be followed.

Where both campus-wide and building reductions are sought in combination from the same campus (ie, both the campus-wide and LEED modules have been applied), then the building reductions must be subtracted from the campus-wide reductions, as follows:

$$ER_y = ER_{y,cw} - ER_{y,lcb} \tag{1}$$

Where:

ER_y = Net GHG emission reductions in year y for the project
$ER_{y,cw}$ = Net GHG emission reductions in year y from campus-wide module
$ER_{y,lcb}$ = Net GHG emission reductions in year y from LEED-certified building module

Only the relevant scope of emissions used in the quantification of campus-wide emission reductions must be subtracted (ie, only stationary combustion emissions reductions from LEED-certified buildings must be subtracted from projects quantifying campus-wide stationary combustion emission reductions). The LEED certification documents contain all the relevant information regarding the contributions that each source of energy (ie, stationary combustion or scope 2 electricity) contributed to the building's total energy consumption. These may be used, if sub-metering of the LEED-certified building is not accessible, to assess the total portion of the emission reductions from LEED-certified buildings that should be subtracted. For example, if a project sought emission reductions from both campus-wide stationary combustion and LEED-certified buildings, and the stationary combustion energy sources represent 40% of the LEED-certified building's energy consumption, then 40% of the LEED-certified building's emission reductions must be deducted from the campus-wide emission reductions.[8]

9 MONITORING

For campus-wide activities, the monitoring procedures set out in the campus-wide module must be followed. For LEED-certified building activities, the monitoring procedures set out in the LEED-certified buildings module must be followed. Where both modules are applied, monitoring procedures from both modules must be followed to provide a single monitoring approach for the project.

10 REFERENCES

None

[8] Given that LEED-certified building emission reductions will be small compared to a campus-wide emission reductions, this represents a reasonable estimation process, recognizing that the percent contribution of a given scope of energy emissions to the total is a reasonable proxy for the proportion of reductions that it contributed to a LEED-certified building emission reductions total.

APPENDIX 1: SIMILAR PROJECT METHODS

Standardized methods are designed to identify superior performance within a given sector and the performance benchmarks within the methodology have been developed to ensure such environmental integrity. Where project activities meet the applicability conditions of this methodology and its respective modules, such projects should apply the methodology in preference to project methods available for the same project activities. Project proponents should contact the VCSA at secretariat@v-c-s.org if additional guidance or clarification is necessary when selecting an appropriate methodology.

Table 1 below lists the identified approved and pending methodologies under VCS and approved GHG programs that target project activities that could be included under the *Campus Clean Energy and Energy Efficiency* methodology (ie, such methodologies may also be applicable to certain subsets of project activities covered by this methodology). Note that this is provided for indicative purposes only and does not necessarily represent an exhaustive list.

Table 1: Methodologies Targeting Similar Project Activities

Methodology	Title	GHG Program
AMS-I.A.	Electricity generation by the user	CDM
AMS-I.D.	Grid connected renewable electricity generation	CDM
AMS-I.F.	Renewable electricity generation for captive use and mini-grid	CDM
AMS-I.J.	Solar water heating systems (SWH)	CDM
AMS-II.C.	Demand-side energy efficiency activities for specific technologies	CDM
AMS-II.E.	Energy efficiency and fuel switching measures for buildings	CDM
AMS-II.J.	Demand-side activities for efficient lighting technologies	CDM
AMS-II.K.	Installation of co-generation or tri-generation systems supplying energy to commercial building	CDM
AMS-II.L.	Demand-side activities for efficient outdoor and street lighting technologies	CDM
AMS-II.M.	Demand-side energy efficiency activities for installation of low-flow hot water savings devices	CDM
AMS-II.N.	Demand-side energy efficiency activities for installation of energy efficient lighting and/or controls in buildings	CDM
AMS-II.Q.	Energy efficiency and/or energy supply projects in commercial buildings	CDM
AMS-II.R	Energy efficiency space heating measures for residential buildings	CDM
AMS-III.AC.	Electricity and/or heat generation using fuel cell	CDM

AMS-III.AE.	Energy efficiency and renewable energy measures in new residential buildings	CDM
AMS-III.AR.	Substituting fossil fuel based lighting with LED/CFL lighting systems	CDM

APPENDIX 2: STAKEHOLDER CONSULTATION SUMMARY

The development of the methodology was generously sponsored by Chevrolet. Chevrolet's Carbon Reduction Initiative Environmental Advisory Board was instrumental in developing a draft white paper outlining the core framing and assumptions which would become this methodology. As part of this advisory board, a diverse group of stakeholders were consulted to refine the white paper and develop the performance benchmarks. This extensive stakeholder group included a diverse group of experts including AASHE, campus experts, environmental experts, college-focused NGO's, college sustainability officers, college business officers, carbon experts, and energy efficiency experts. A list of the experts involved with the stakeholder consultation is provided at the end of this appendix.

During the stakeholder consultation process many detailed questions relating to the design of the modules were discussed. These contributed to the refinements in the white papers, which were updated throughout this period. All stakeholders who reviewed the white papers therefore were able to review the performance benchmark. Particularly, detailed discussions of the following topics took place with the Environmental Advisory Board and USGBC:

- Baseline designs
- Project boundary definitions
- Applicability tests/conditions needed
- Provisions to avoid double counting
- Performance benchmark update processes
- Stratifications
- Performance benchmarks detailed analyses, based on performance curves, relative to percentile equivalents across each segment
- Carbon contribution to incremental capital analyses
- Refinements needed to fine tune the modules (eg, business as usual gains, square foot variances, inclusions/exclusions needed)
- Tests relative to attributable activities undertaken

The stakeholder dialogue was particularly helpful in confirming assumptions for key details and parameters in the modules. Not all discussions have been referenced here but, drawing upon key topics from the final white paper drafts, the main highlights in this category include:

Both modules:

- Refine performance benchmarks every five years – not sooner – to provide project proponents with sensible planning horizons; rather provide updated data on an interim basis to describe performance benchmark trends. Five years is consistent with VCS minimum requirements.
- Utility sign offs and other measures (especially regarding campus reporting of GHG reductions to ACUPCC, STARS etc.) to address double counting/double claiming.
- Project boundaries are appropriately specified to preclude GHG emission reductions resulting from RECs, energy services supplied to neighboring institutions etc.

Campus-wide module:

- The core foundation requires absolute reductions in both scope 1 and scope 2 electricity-based emissions.
- Selection of additionality benchmark as annual percentage improvement in stationary combustion emissions is appropriate. It conforms to VCS requirements, it closely aligns to campuses' ACUPCC reporting structures (which are over historical baselines) and thus encourages leadership capacity building in the sector, and it is consistent with precedent set by other performance methods under VCS.
- Stratify by Carnegie class, consistent with ACUPCC practice.
- Base the level of each additionality benchmark on the average annual percentage reduction by Carnegie class, not just a single percentile (eg, 85^{th}), to most accurately reflect superior performance achievement and minimize false positive/negatives.
- This approach generates performance benchmarks that are credible (around the 85^{th} percentile) relative to UNFCCC parameters and other VCS performance method precedents.
- Financial analysis of the carbon contributions was considered meaningful and providing leverage to deliver superior performance.
- Including a "positive" style test to document the steps taken to achieve the performances, based on leading campuses' ACUPCC Climate Action Reports, is credible and goes beyond other VCS performance method approaches.
- Screening for other potential drivers of performance has been thorough.
- Historical baselines are sound to use and well framed relative to variances for weather etc. Including variances to accommodate for weather changes makes sense if the historical reference period is short; otherwise, these variances are addressed by averaging over a longer historical reference period.
- It would be best to provide avenues in the module to accommodate variances for square footage outside reasonable parameters (declining or increasing more than 5 percent) rather than use an intensity style metric to determine additionality or quantify emission reductions. The latter introduces another orthogonal variable which then needs to be considered for variances relative to false positives and false negatives.
- Baseline adjustments reflecting US average energy efficiency gains should be made, not adjustments reflecting a five percent annual energy efficiency gain. The later would assume that campuses could go climate neutral very rapidly on a business as usual basis.

LEED-certified buildings module:

- Segmentations based on LEED proposed data is appropriate, using LEED overall averages where they feel the sample sets are otherwise too small.
- The average LEED-certified building Energy Star score is credible and the baselines selected make sense since the module then reflects a step-wise increase from national average ES score to average LEED-certified building Energy Star score.

- This approach generates performance benchmarks that are credible (around 86th percentile) relative to UNFCCC parameters and other VCS performance methodology precedents.
- Where EPA Portfolio Manager is not yet sufficiently robust for reporting/benchmarking purposes, it is appropriate to exclude campus laboratories from project consideration when comparisons need to be made to national benchmarks. However internal performance comparisons over time to an individual lab's performance improvements are appropriate. As a result, labs were excluded from EB-B pathway since ES 86 is a national benchmark, while labs are eligible to use EB-A (which compares the lab's EUI performance over time) and NC (where the building's EUI percent improvement over code has been independently assessed in detail through LEED certification). The exclusion of labs from the EB-B route may be reviewed again in year five when the performance parameters need to be updated.
- Including a "positive" style test to document the steps taken to achieve the performances, based on LEED's certification system, is credible and goes beyond other VCS performance method approaches.
- LEED Commercial Interior certifications could be included at a later stage but are too few and limited in energy efficiency scope to include at this stage.
- Baselines are well-defined and measurement approaches outlined in EPA Portfolio Manager are appropriate. Variances for many potential drivers are well-accommodated through Portfolio Manager's reporting system which accounts for such potential variances.
- Although EB-B could use the historical baseline for each building, since LEED does not collect this information for its certification system, it is appropriate to use ES 50 as the baseline.
- A one percent energy efficiency improvement factor is not needed as an adjustment for NC or EB-B to the baseline since EPA Portfolio Manager revises the ES 50 baseline each year to reflect current updated practices. It is only needed for EB-A which uses the project's historical baseline (but not needed for eligibility testing since the metric is EUI-based and thus already anchored on a per square foot basis).

The stakeholders consulted compromise the list of individuals acknowledged above in this methodology. Areas of expertise represented in this stakeholder group were as follows:

- Campus sustainability/energy/climate leadership (CSEC), 32 participants
- Campus financial leadership (CF), 30 participants
- Carbon methodology/project development (C), 23 participants
- Energy efficiency best practices (EE), 17 participants
- Business (B), 40 participants
- NGO (NGO), 6 participants
- Government/policy (G), 10 participants

DOCUMENT HISTORY

Version	Date	Comment
v1.0	12 Feb 2014	Initial version released

A.3.2 Cogeneration Facilities

NEW COGENERATION FACITILITES SUPPLYING LESS CARBON INTENSIVE ELECTRICITY TO GRID AND STEAM AND/OR HOT WATER TO ONE OR MORE GRID CUSTOMERS

SOURCE

This Methodology is based on elements of the following CDM methodologies:

- AM0029 V 02 " Baseline Methodology for Grid Connected Electricity Generation Plants Using Natural Gas";
- AM0048 "New Cogeneration facilities supplying electricity and/or steam to multiple customers and displacing grid/off grid electricity generation with more carbon intensive fuels".

This methodology also refers to the latest approved version of the following tools:

- Methodological "Tool for the demonstration and assessment of additionality";
- Methodological "Tool to calculate the emissions factor of an electricity system";
- Methodological "Combined tool to identify the baseline scenario and demonstrate additionality";
- Methodological "Tool to calculate baseline, project and/or leakage emissions from electricity consumption".

DEFINITIONS

Waste Heat A by-product thermal energy from machines or process equipment for which no useful application is found in the absence of project activity and which is demonstrated to be unused in other activities

Project Customer An industrial and/or commercial and/or residential entity receiving electricity, steam and/or hot water from the project facility. This may include the power grid, in the case of electricity and the steam and/or hot water generating facility or the entity that draws steam and/or hot water off a steam and/or hot water grid. Clusters of smaller residential or commercial customers can be considered as a single project customer.

Project Facility Combined heat and power generation facility developed as a project activity to supply electricity to the power grid and steam and/or hot water to grid/off-grid to any industrial, commercial and/or residential entities.

APPLICABILITY

- The project activity is the construction and operation of a new gas fired cogeneration plant which is connected to the electrical grid and where all the electricity produced other than that required to operate the cogeneration facility is exported to the grid;

- The geographical/physical boundaries of the baseline power grid can be clearly identified and information is publicly available to establish the grid emissions factor;

- Natural gas is sufficiently available in the region or country, for example future natural gas power capacity additions of similar size to that of the project activity are not constrained by the use of natural gas in the project activity;

- This methodology is only applicable to cases in which the steam and/or hot water that is to be displaced by the project activity is either produced for export to a steam/hot water grid or is drawn from a steam/hot water grid. It shall not be applied to situations in which it would lead to the displacement of steam and/or hot water that is generated at a project customer's installations to meet its heating/process requirements;

- Where the project activity results in the substitution of imported steam and/or hot water, the project proponent shall provide evidence to prove that the thermal energy which is displaced is that which the project customer(s) would have otherwise imported from the grid and not that which is self-generated, assuming that such option exists for the project customer(s);

- The methodology is applicable only to project customers that do not cogenerate electricity, steam and/or hot water in the baseline scenario;

- Only applicable to project customers that ensure that the equipment displaced by the project activity will not be sold for other purposes;

IDENTIFICATION OF THE BASELINE SCENARIO AND DEMONSTRATION OF ADDITIONALITY

STEP 1. Identification of realistic and credible alternative baseline scenarios that are consistent with current laws and regulations

Substep 1a. Define realistic and credible alternatives to the project activity.

Project proponents shall identify realistic and credible alternative(s) available to both the project developer and project customer(s) that enable electricity, steam and/or hot water:

- to be produced in similar quantities as by the project activity;
- to deliver similar services;
- to be provided at the same grade, quality or properties as those provided by the proposed VCS project activity .

In other words, they shall identify possible baseline scenario alternatives that enable:

- electricity to be generated and sold to the grid, for base or peak load service;
- steam at a required pressure and temperature to be generated, delivered and sold to one or more project customers;
- hot water to be generated at the required temperature and sold to one or more project customers.

The proposed VCS project activity constitutes an alternative means for both the project developer and the project customers to produce electricity and thermal energy (when the project customer is a District Heating Plant that produces steam and/or hot water) or to source or buy it from (when the project customer is a thermal energy end user connected to a District heating steam/hot water grid). Hence, project developer and project customers, be it through the actions they take or do not take, define what the most plausible baseline scenario would most likely be in the absence of the project activity. In the case of power generation, the baseline scenario is shaped by the actions taken or not by the project developer and other market players that sell power to the grid.

Hence, in establishing what the most likely baseline scenario is, baseline alternative scenarios shall be identified for both the project developer and the project customer(s). Technologies or practices that have been implemented previously or are currently being introduced in the relevant country and that constitute alternatives for an independent utility producer shall be considered as part of this exercise. Those technologies or practices that do not meet this condition, shall not be considered a baseline scenario alternative, because they would be a “first of their kind”.

Baseline alternative scenarios for the project participants are therefore related to the technology and circumstances but also to the investor’s line of business or activity.

It shall be noted that for the purpose of this methodology, actions taken by project customers which are energy end users (i.e. purchase thermal energy to use it for heating/ process needs as opposed to selling it on to project customers who in turn resell it to their own customers) and result in a reduction in the end user demand of energy in the form of steam and/or hot water are not considered to be alternatives to the project activity. This is because such actions do not constitute a similar product/service: the provision of electricity, steam and hot water, which in the case of the project activity is carried out in a less carbon intensive manner than that which would have otherwise occurred. i.e. from the utilization of waste heat to generate steam and/or hot water.

Energy efficiency measures that enable the production, transmission and distribution of thermal energy to the end users with a lesser amount of GHG generation which may be implemented in the future, during the crediting period however are considered for the purpose of calculating the baseline emissions, but not as part of the process for the selection of the most plausible baseline scenario, because they do not constitute alternative means to providing the same services as those provided by the project activity. Similarly, improvements in energy efficiency undertaken by the project customer(s) may lead to an increase or decrease in the efficiency with which each unit of thermal energy is produced, depending on the operating point on the boiler's efficiency – load curve. The baseline emissions calculations given in section (5) of this methodology take this into consideration.

Procedure for the identification of Baseline Scenario Alternatives to the project activity

The project proponent shall clearly indicate the amount of electricity, steam and/or hot water which the proposed project activity would generate, indicating whether the electricity which is planned to be generated is peak/base load power, as well as the conditions of the steam and hot water to be produced.

This establishes a common technical basis upon which to identify the baseline scenario alternatives.

Electricity, steam and or hot water in similar amounts, service type and quality may be delivered in a separate manner (e.g. a gas turbine generator set and steam and hot water boilers) or in an integrated manner (e.g. a Combined Heat and Power Plant).

Therefore, possible baseline scenario alternatives for the project participants (project developer and project customer(s) with regards to the production/provision of electricity, steam and hot water, may include, either a combination of different options to generate each of the utilities independently from one another (non-integrated options) or through combined heat and power systems, which provide all three of such utilities (integrated options):

Step A. Non integrated baseline scenario alternatives for the production of electricity, steam and hot water

A.1 Electricity production

The project activity involves the construction and operation of an energy plant that produces several utilities, one of which is electricity which is exported to the grid.

In assessing what baseline scenario alternatives exist for electricity generation it shall be noted that these need not consist solely of power plants of the same capacity, load factor and operational characteristics (i.e. several smaller plants or the share of a larger plant may be a reasonable alternative to this portion of the project activity). However all the options considered must be capable of delivering a similar service (e.g. peak vs. base load power).

The proponents shall include those power generation options that are available to them. In this sense, project proponents shall ensure that all relevant power plant technologies that have been recently constructed or are under construction or are being planned are considered when building the list of baseline scenario alternatives.

Alternatives for electricity generation include, amongst others, but are not limited to the following:

- grid connect power plants;
- new steam turbine power plants;
- new gas turbines power plants;
- new IC engine power plants.

The project proponents shall establish which of the identified baseline scenario alternatives can be considered credible and realistic alternatives

A.2 Thermal energy (Steam and/or hot water):

Baseline scenario alternatives that enable the production of the same quantity and grade of steam and/or hot water as the proposed project activity for export (if the project customer is a centralized district heating plant) or importing (where a project customer draws steam and/or hot water from a district heating grid) may include but are not limited to the following:

- continued generation of steam and/or hot water for export purposes to a district steam and or hot water grid, by a district heating plant;

- continued use of the existing sources of imported steam and or imported hot water by a project customer connected to the steam and/or hot water grid;

- waste heat derived steam and or hot water from waste heat sources available at the project customer's facility;

- the installation of standalone steam and or hot water generation equipment;

- the installation of steam and or hot water generation equipment for export into a district heating grid or supplying to a specific customer.

The outcome of step A will be the realistic baseline scenario alternatives for the combined production of electricity, steam and/or hot water from separate sources subject to the conditions given in Substep 1(a).

Step B. Integrated generation baseline scenario alternatives for the production electricity, steam and/or hot water (cogeneration of electricity, steam and/or hot water)

Integrated forms of generating the above mentioned utilities shall be considered, as they constitute alternatives to the production of electricity, steam and/or hot water. As indicated above, only those options that meet technical requirements and are available to the project participants established in Substep 1a shall be considered as possible baselines alternatives.

Combined heat and power baseline scenario alternatives may include:

1. Steam turbine CHP plant
    - CHP with back-pressure turbine
    - CHP with extraction / condensing turbine

2. CHP with gas turbine

3. Internal combustion (IC) reciprocating engine generator with waste heat recovery

4. Combined-cycle HP plant

The outcome of Step B will be realistic baseline alternatives for the co production of electricity, steam and/or hot water from an integrated energy facility subject to the conditions indicated in Substep 1 (a)

Outcome of Sub Step 1a: After having applied the above procedure realistic and credible alternatives baseline scenario that remain may include:

From Step A:

- One or more combinations of forms of generating electricity and thermal energy using independent technologies, and/or;

- Electricity from the grid and thermal energy from a district heating plant (continuation of existing practice).

From Step B

- One or more options of combined heat and power generation, including the VCS project activity without VER’s.

Substep 1.b: Consistency with mandatory laws and regulations:

Ensure that the baseline scenario alternatives identified above comply with mandatory laws and regulations. This assessment shall be carried as described in the “Tool for Demonstration and Assessment of Additionality”

Outcome of Step 1b: Identified realistic and credible alternative scenario(s) to the project activity that are in compliance with mandatory legislation and regulations taking into account the enforcement in the region or country and VCS decisions on national and/or sectoral policies and regulations.

STEP 2. Determination of additionality and the most plausible baseline scenario

The most plausible baseline scenario shall be the one that includes the most likely means of producing electricity, steam and hot water in the absence of the proposed VCS project activity. It is the result of the combination of the most likely baseline scenarios for both the project developer and the project customer(s).

After having applied the procedure given in Step 1, three (3) realistic baseline scenario alternative categories will have been identified. The definition of the most plausible baseline scenario shall be assessed from both the project developer and project customer(s) perspectives. The project proponent may demonstrate this by applying investment or barrier analysis as deemed appropriate.

Step 2.1: Assessment and demonstration of additionality

The project proponent shall demonstrate that the proposed project activity is not an attractive option for the project developer to undertake unless the project activity can be registered under the VCS.

Project proponent shall demonstrate additionality by applying either one or two of the following options:

Option 1: Investment analysis

Option 2: Barrier analysis

Project proponents may also elect to complete both options. The above options refer to Steps 2 and 3 of the "Tool for demonstration and assessment of additionality".

Additionality shall be demonstrated using the latest version of the "Tool for demonstration and assessment of additionality". Project participants can use either investment analysis or barrier analysis step. They may, if they wish so, use both the investment and barrier analysis steps.

OPTION 1. INVESTMENT ANALYSIS

Project proponents shall apply the latest version of the "Tool for demonstration and assessment of additionality" i.e., shall determine whether the proposed project activity is not:

(a) The most economical or financially attractive, or;

(b) Not economically attractive.

The indicator to be applied shall be either IRR, or the unit cost of producing electricity, thermal energy for steam and hot water.

The selection of the benchmark IRR shall be carried out according to the latest version of the "Tool for demonstration and assessment of additionality".

Where the unit cost of energy is the chosen indicator, the benchmark to be applied to the steam and/or hot water will depend on whether the project customer is:

a) A centralized steam and/or hot water generating facility purchasing steam and/or hot water from the project facility, in which case the benchmark is the unit purchase price or tariff of the thermal energy offered by the district heating plant to the project developer;

b) An importer of steam and or hot water from the grid, in which case the benchmark shall be the unit cost of thermal energy paid by the project customer which imports steam and or hot water from the grid.

In providing any benchmarks, the DOE shall be presented with supporting evidence, such as energy purchase agreements (in cases where the project customer is the central steam and or hot water generating facility), actual energy invoices or contracts (in the case of a project customer that imports thermal energy from the grid) where it is indicated in a transparent manner what the benchmark value is.

Calculation of the indicator

IRR

If IRR is chosen as the indicator then, the IRR calculation shall be applied to assess the additionality of the project activity following the guidance given in the latest version of the “Tool for demonstration and assessment of additionality”.

Unit cost of energy

Where unit cost of energy us the chosen indicator, the unit cost of electricity, steam and or heat to be provided by the project activity shall be calculated taking into account the investment, operation and maintenance costs, and the revenues excluding carbon but possibly including other sources of revenue as mentioned in the “Tool for Demonstration and Assessment of Additionality” and compared with that of the baseline scenario alternatives which provide those utilities. The approach used in such calculations shall be presented in a transparent manner in accordance with the “Tool for Demonstration and Assessment of Additionality”, in a way that shall enable the DOE to assess their appropriateness and reproduce the results presented by the project proponents. The calculations used to determine such indicators shall be presented to the DOE.

Present a clear comparison between the indicator values obtained for the various baseline scenario alternatives and the benchmark.

a) If the value of indicator for the project activity is such that it is not the most attractive amongst various baseline scenario options to produce the similar services and outputs, then the project activity shall be deemed additional.

b) If the indicator for the project activity is less favorable than the benchmark then the project activity cannot be considered the financially attractive or the most financially attractive and can be thus regarded as additional.

Sensitivity analysis

A sensitivity analysis shall be included to show whether the conclusion regarding the financial/economic attractiveness of the project activity without VCS is robust to reasonable variations in the critical assumptions. The investment analysis provides a valid argument in favor of additionality only if it consistently supports (for a realistic range of assumptions) that the project activity without VCS credits is unlikely to be the most financially/economically attractive option to the project developer.

The project proponent, who applies the new VCS methodology, shall provide evidences for the figures applied and used in the excel work sheets in order to be able to fully retrace the assumptions and calculations made under the investment analysis.

Determination of the most plausible baseline scenario

The most plausible baseline scenario shall be considered to be either of the following:

- the most economically attractive of the realistic and credible baseline scenario alternatives identified in Substep 1 b above that is in compliance with existing regulations, provided the emissions that would result from its implementation would be less than those resulting from the "continuation of existing practice" or "business-as-usual" baseline scenario alternative. If this is not the case, the baseline scenario shall be considered to be the continuation of the existing practice;

- the continuation of existing practice, in cases in which the only other possible baseline scenario alternative is for a project developer to invest in the project activity, but which has been determined not to be the most likely baseline scenario given the outcome of the investment analysis described above.

OPTION 2. BARRIER ANALYSIS

Determine whether the proposed project activity faces barriers that:

a) prevent the implementation of this type of project activity; and

b) do not prevent the implementation of at least one of the alternatives

The identified barriers are only sufficient grounds for demonstration of additionality if they would prevent the project developer from carrying out the proposed project activity undertaken without being registered as a VCS project activity. Barriers that prevent customers from purchasing the Electricity and thermal energy which the project activity produces are taken as barriers which the developer must also overcome.

The following sub-steps shall be used

Substep 2a: Identify the barriers that would prevent the implementation of the proposed VCS project activity

(1) Identify realistic and credible barriers that would prevent the implementation of the proposed project activity from being carried if the project activity was not

registered as a VCS project. Barriers must be addressed for both the project developer and the project customer (s).

(a) Investment barriers, other than economic/financial barriers in Step 2 above, inter alia:

   i. similar cogeneration activities have been implemented, but only through grants or other non commercial terms. Similar activities being those that rely on a broadly similar technology or practices, are of a similar scale, take place in a comparable energy sector environment with respect to the regulatory framework and are undertaken in the relevant country/region

   ii. no private capital is available from domestic or international capital markets due to real or perceived risks, as demonstrated by the country credit ratings or other country investment reports of a reputed origin

   iii. the investment required to deliver the energy produced by the project facility to the project customer (e.g. power lines, steam and hot water piping) is significant and the project developer is unable or unwilling to undertake it

(b) Technological barriers, inter alia:

   i. Skilled and/or properly trained labor to operate and maintain the technology are not available in the relevant country/region, which leads to an unacceptably high risk of equipment disrepair and malfunctioning or other underperformance.

   ii. Lack of infrastructure for implementation and logistics for maintenance of the technology.

   iii. Risk of technological failure: the technology failure risk in the local circumstances is significantly greater than for other technologies that provide the electricity, steam and/or hot water in quantities, grades and quality as those of the proposed project activity, as demonstrated by relevant scientific literature or technology manufacturer information. This is risk being a concern to both the project developer and the project customer.

(c) Barriers due to prevailing practice

   i. the project is the “first of its kind” either from a technological or business standpoint

(d) Barriers that prevent project customers from purchasing electricity, steam and/or hot water from the project facility

(e) Other barriers that the project developer or the project customer may face

Substep 2b. Show that the identified barriers would not prevent the implementation of at least one of the baseline scenario alternatives besides the propose project activity

(2) if the identified barriers also affect other baseline scenario alternatives identified as part of step 1, explain in what way those baseline scenario alternatives are less strongly affected by them than the proposed VCS project activity is. In other words, demonstrate that the identified barriers do not prevent the implementation of at least one of the baseline scenario alternatives. Any baseline scenario alternative that would be prevented by any barriers indicated above cannot be considered a "viable" alternative to the proposed project activity and shall thus be eliminated from further consideration.

Determination of additionality and the most plausible baseline scenario

- if there is only one baseline scenario alternative that is not prevented by any of the identified barriers and this scenario is not the project activity without being registered under the VCS, then this baseline scenario alternative shall be taken as the most plausible baseline scenario. In this case it shall be explained as indicated in the "Combined tool to identify the baseline scenario and demonstrate additionality" by using qualitative or quantitative arguments, how the registration of the VCS project activity will alleviate the barriers that prevent the proposed project activity from occurring.

- if there are more than one baseline scenario alternatives that are not prevented by any of the barriers, and these alternatives do not include the project activity without taking into account VERs, the project proponent shall explain how the registration of the VCS project activity will alleviate the barriers that prevent the proposed project activity from occurring.

  If the VCS alleviates those barriers, the project proponent may apply investment analysis to identify the most economically attractive of the baseline scenario alternatives that are not prevented by any of the barriers that the project activity faces. If the most economically attractive baseline scenario is a more carbon intensive alternative than the continuation of current practice then the project proponents may proceed to the following sections of this methodology, provided the baseline scenario is taken to be production of electricity by grid connected power sources and the production of steam and/or hot water is obtained from existing generating facilities. If on the other hand, it is determined that the most economically attractive scenario is a less GHG intensive alternative than the continuation of existing practice, then the methodology cannot be a applied.

Step 2.2: Common practice analysis

Demonstrate that the project activity is not common practice in the relevant country and sector by applying STEP 4 "Common Practice Analysis" as described in the latest version of the "Tool for the demonstration and assessment of additionality"

The relevant geographical area for undertaking the common practice analysis should in principle be the host country of the proposed CDM project activity. A region within the country could be the relevant geographical area if the framework conditions vary significantly within the country.

PROJECT BOUNDARY

The project boundary includes the site of the project facility(s) and the sites of the project customer(s).

CALCULATION OF EMISSION REDUCTIONS FROM THE PROJECT ACTIVITY

The emissions sources are given in table one below.

Table 1: Emissions sources included in or excluded from the project boundary

	Source	Gas	Included	Explanation/Justification
Baseline	Combustion of fossil fuels to produce electricity, steam and/or hot water at the project customer(s)' site, which provide steam and or hot water to the project customer site, and the power generating facilities connected to the grid.	CO_2	Yes	Main emissions source in the combustion of fossil fuel.
		CH_4	No	Excluded for simplification
		N_2O	No	Excluded for simplification.
Project activity	Combustion of natural gas to produce electricity, steam and/or hot water at the site of the project activity.	CO_2	Yes	Main emissions source in the combustion of natural gas.
		CH_4	No	Excluded for simplification
		N_2O	No	Excluded for simplification.

PROCEDURE FOR ESTIMATING LIFETIME OF THE BOILER(S)

The following approaches shall be taken into account to estimate the remaining lifetime of the boilers that would provide steam and hot water in the absence of the project activity:

a) The typical average technical lifetime of the type of equipment may be determined taking into account common practices in the sector and country (e.g. based on industry surveys, statistics, technical literature, etc.);

b) The practices of the responsible company regarding replacement schedules may be evaluated and documented (e.g. based on historical replacement records for similar equipment).

The time to replacement of the existing equipment in the absence of the project activity should be determined in on a case-by-case basis thus taking into consideration local conditions, existing practices and possible barriers to implementation of new projects or regulatory acts relating to the continuation of existing practices regarding steam and hot water generating equipment.

If in any year of the crediting period, new steam or hot water generating equipment is installed at the project customer's installations or at the installations that supply steam and or hot water to the project customer, it shall be assumed that all steam and or hot water that is displaced by the project activity would have otherwise been produced by using equipment with such performance characteristics.

In other words, should such situations occur during the crediting period, the baseline emissions factor will be recalculated based on Option B given for steam and hot water production (equations 8, 15 and 20), to reflect the assumption that in the absence of the project activity, the steam and hot water which is produced by the project facility would have been produced by more efficient steam and hot water generation technology.

The project proponents may opt to assume though that new more efficient equipment would have been installed to generate steam and hot water. In this case they shall assume that best available fossil fuel based steam or hot water generation technology would have been used. Or if they prefer, may opt to assume that the thermal generation efficiency of the equipment that would be installed is 100%. Either option may only be applied though in cases where the project proponents can demonstrate that the use of biomass is not likely to constitute a viable alternative to produce the heat that the project activity displaces

CALCULATION OF THE BASELINE EMISSIONS

The following approach to calculate the baseline emissions is only applicable to projects in which the most plausible baseline scenario has been identified to be the continuation of the existing practice, i.e. electricity supplied by the grid and steam and/or hot water produced by a district heating plant or sourced from a district heating plant.

The baseline scenario shall indicate what the baseline fuels are. The project proponent shall assess the potential for fuel switching and energy efficiency improvements under the baseline scenario as indicated below.

For the purpose of establishing the baseline emissions the project developer shall consider any changes that may impact on the baseline alternatives CO_2e intensity of the steam and/or hot water which it displaces. In this sense attention shall be paid to:

Fuel switching

- fuel switching taking place in the centralized steam and/or hot water generating facility that provides these sources of energy to the steam and hot water grids:

    - the project proponent first determines if the fuel changes are technically feasible using existing thermal energy generating equipment. This exercise is not carried out for electricity generation. For instance the proponents shall determine if the existing equipment is capable of utilizing more that one fuel, without major capital investment. This can be verified during validation. If not, then no additional considerations need to be undertaken in the crediting period and it will be assumed that the same fuel would have been used as has been in the past. If a fuel switch constitutes a possibility given the existing equipment, the project proponent shall monitor this on a yearly basis.

    - Alternatively, the project proponents may assume that natural gas is being used as the baseline fuel, in which case no monitoring in this respect shall be required. The project proponent may apply this default approach during the entire crediting period or for any specific year of the crediting period. This shall be clearly indicated in the monitoring reports presented the verifier.

Energy efficiency improvements

Energy efficiency improvements in thermal energy generation (when the project customer is a district heating plant) and transport of thermal energy to the project customer's factory gate (when the project customer is an end user) include:

- energy efficiency measures and projects the improve the efficiency with which thermal energy is generated at the thermal energy generating facility;

- improvements to the steam transport system from the point of generation to the point of delivery to a customer connected to the grid that lead to a reduction in the amount of energy losses, and hence CO_2 emissions per unit of thermal energy delivered to the point at which the project activity steam and or hot water are delivered to the project customer. This needs to be considered in cases in which the project proponents chose to apply a GHG intensity factor which is based on measured data;

- activities that increase the amount heat returned to the central generating system boiler house in the form of hot condensate and flash steam, which therefore reduce the CO_2 intensity of the steam which is produced.

The impact of such measures on the baseline emissions are dealt with in the baseline emissions calculation and monitoring sections of this methodology. Alternatively, the project proponents may apply default factors as suggested in this methodology. In either case the DOE shall verify the appropriateness of the data/factors applied.

This methodology is only applicable to situations in which the baseline scenario is the continuation of the current practice for producing electricity and heat from fossil fuel

The baseline emissions for this particular methodology are the sum of emissions from resulting from the generation of electricity, steam and hot water.

$$BE_y = BE_{el,y} + BE_{th,y} \quad (1)$$

Where:

$BE_{el,y}$	Baseline emissions resulting from electricity generation in the year y (in tonnes of CO_2e). Calculated below as per equation (2);
$BE_{th,y}$	Baseline emissions resulting from the production of steam and/or hot water supplied to project customer i in the year y (in tonnes of CO_2). Calculated below as per equation (3).

BASELINE EMISSIONS FROM ELECTRICITY GENERATION

Baseline emissions from electricity generation are calculated by multiplying the net electricity generated at the project plant ($EG_{P,y}$) with a baseline electricity grid CO_2 emission factor ($EGEF_{BL,CO_2,y}$) as follows:

$$BE_{el,y} = EG_{P,y} \cdot EGEF_{BL,CO_2,y} \quad (2)$$

For construction of large new power capacity additions under the CDM, there is a considerable uncertainty relating to which type of other power generation is substituted by the power generation of the project plant. As a result of the project activity, the construction of an alternative power generation technology could be avoided, or the construction of a series of other power plants could simply be delayed. Furthermore, if the project were installed sooner than these other projects might have been constructed, its near-term impact could be largely to reduce electricity generation in existing plants. This depends on many factors and assumptions (e.g. whether there is a supply deficit) that are difficult to determine and which change over time. In order to address this uncertainty in a conservative manner, project participants shall use for ($EGEF_{BL,CO_2,y}$) the lowest emission factor among the following options:

For the first crediting period:

Option 1 The build margin, calculated according to "Tool to calculate emission factor for an electricity system"; and

Option 2 The combined margin, calculated according to "Tool to calculate emission factor for an electricity system", using a 50/50 OM/BM weight.

BASELINE EMISSIONS FROM HEAT GENERATION

The baseline emissions from heat production ($BE_{th,y}$) are the sum of emissions from steam generation and hot water generation for sale to project customers:

$$BE_{th,y} = BE_{st,y} + BE_{hw,y} \tag{3}$$

Where:

$BE_{st,y}$ Baseline emissions resulting from the production of steam supplied to project customer i in the year y (in tonnes of CO_2). Calculated below as per equation (4);

$BE_{hw,y}$ Baseline emissions resulting from the production of hot water supplied to project customer i in the year y (in tonnes of CO_2). Calculated below as per equation (11).

The maximum amount of thermal energy in the form of steam and/or hot water, which is produced by the project activity during year y and which can be used for the purpose of determining the emissions reductions upon which VERs can be claimed, is defined as the maximum annual amount of thermal energy produced in the form of steam and/or hot water that has been produced over the three most recent years for which data is available in the pre-project steam and or hot water production facilities.

I. Baseline emissions from production of steam that is supplied to project customer i in year y (in tonnes of CO_2):

$$BE_{st,y} = \sum_i \sum_j \left(SC_{BL,j,y} \cdot SEF_{BL,i,y} \right) \qquad (4)$$

Where:

$SC_{BL,j,y}$ The amount of energy consumed in the form of steam by the project customer i, which is supplied by the project facility j in year y (in TJ). It is further obtained from equation (5).

$SEF_{BL,i,y}$ The baseline emission factor corresponding to the steam produced in project customer i's steam generating plant or sourced from the produced in a steam generating plant that supplies steam to a project customer i (in t CO_2/TJ), and obtained from equation (6) below.

The amount of energy consumed in the form of steam by the project customer i which is supplied by the project facility j in year y is given by:

$$SC_{BL,j,y} = SP_{BL,j,y} \cdot SDEN_{BL,j,y} \qquad (5)$$

Where:

$SP_{BL,j,y}$ Quantity of steam produced by the project facility j and supplied to the project customer i for year y, (in tonnes)

$SDEN_{BL,j,y}$ Specific enthalpy of steam leaving the project facility j (in TJ/tonne of steam supplied). This data shall be obtained from steam tables, using temperatures and pressure of the steam purchased.

The following options are provided to determine the baseline CO_2 emissions factor, $SEF_{BL,i,y}$ for the steam produced by the project customer i or by a steam generating plant that supplies a project customer i with steam (in tonnes of CO_2/TJ of steam) produced in year y.

Option I.A.

When actual data for the amount of fuel consumed and steam generated by the project customer i's steam generating plant or by the steam generating plant that supplies steam to a customer i is available, the baseline emission factor for the steam generated may be calculated as:

$$SEF_{BL,i,y} = \frac{44}{12} \cdot \frac{\sum_i \left(CEF_{FF,i,y} \cdot HEC_{BL,FF,st,i,y} \right)}{\sum_i HSC_{BL,i,y}} \quad (6)$$

Where:

$CEF_{FF,i,y}$ Carbon emission factor in year y corresponding to fossil fuel used by project customer i to generate steam or that which is used in a given steam generating plant to produce the steam which is sourced by the project customer i (in tonnes of C/TJ), shall be determined from the technical literature, from the project customer i, or the steam generating plant which supplies steam to the project customer i.

$HEC_{BL,FF,st,i,y}$ The energy associated with the fossil fuel consumed by the project customer i or the steam generating facility that supplied steam to the project customer i, in year y (in TJ). Calculated below in equation (7).

$HSC_{BL,i,y}$ The amount of energy contained in the steam generated by the customer i or the steam generating facility that supplied steam to the project customer i by burning fossil fuel (in TJ) in year y.

The present methodology offers two options upon which to establish $HEC_{BL,FF,st,i,y}$:

Option I.A.a.

The energy associated with the fossil fuel that was consumed by the project customer i for self-generation of steam or by the steam generating facility that supplied steam to the project customer is given by:

$$HEC_{BL,FF,st,i,y} = HFC_{BL,FF,st,i,y} \cdot NCV_{FF,i,y} \quad (7)$$

Where:

$HFC_{BL,FF,st,i,y}$ The quantity of fossil fuel consumed for steam generation by project customer i or that which was consumed by the steam generating plant that provided steam to the project customer i in year y (in tonnes)

$NCV_{FF,i,y}$ Net calorific value of the fossil fuel used by the project customer i in the scenario of self-generation or used by the steam generating plant that supplied steam to the project customer i in year y. Specific data may be provided by the project customer or from the technical literature (TJ/tonne)

Option I.A.b.

Alternatively, $HEC_{BL,FF,st,i,y}$ may be calculated from records of steam produced and the temperature and pressure conditions at which boiler feed water is supplied to and the steam generated from the boilers, as follows:

$$HEC_{BL,FF,st,i,y} = \frac{(HSC_{BL,i,y} - HSP_{BL,i,y} \cdot HSEN_{w,y}) \cdot 100}{\eta_{BL,st,i}} \qquad (8)$$

Where:

$HSC_{BL,i,y}$ The amount of energy contained in the steam which was generated by the customer i or that which was generated by the steam generating facility that provided steam to the project customer i, and which was obtained by burning fossil fuel (in TJ) in year y.

$HSEN_{w,y}$ The specific enthalpy of water entering the boiler at project customer i's steam generating facilities or the water entering the boiler at the steam generating facilities which supplied steam to the project customer i in year y.

$HSP_{BL,i,y}$ The quantity of steam produced by the project customer i or that which was produced by the generating facility that supplied the steam to the project customer i in year y (in tonnes of steam produced).

$\eta_{BL,st,i}$ The efficiency of project customer i's boiler or the efficiency of the boiler that supplied steam to the project customer i based on NCV (in %). This parameter shall be one of the following:

i) the highest measured value of boiler efficiency recorded over full range boiler test;

ii) the boiler's peak thermal efficiency as per manufacturer's information;

iii) efficiencies of boilers of similar design;

iv) a default boiler efficiency of 100%;

Note: heat losses associated with the transmissions and distribution of steam are assumed to be zero

Energy content (in TJ) of the steam generated by customer i or by the facility that supplied steam to the project customer i is given by:

$$HSC_{BL,i,y} = HSP_{BL,i,y} \cdot HSEN_{BL,i,y} \qquad (9)$$

Where:

$HSP_{BL,i,y}$	The quantity of steam produced by the project customer i or produced by the steam generating facility that supplied steam to the project customer i in year y (in tonnes of steam produced)
$HSEN_{BL,i,y}$	The specific enthalpy of the steam produced by project customer i or by the steam generating facilities that supplied steam to the project customer i in year y (in TJ/ tonne of steam produced).

Note for monitoring during the crediting period.

Option 1.A

Changes may be made to certain elements of the project customer's steam system (e.g. the condensate recovery system) that could result in a lower baseline emissions factor during the years of the crediting period. Additionally, changes in the type of fuel used may occur in any year y during the crediting period, which are likely to have occurred also in the absence of the project activity.

For the purpose of establishing the steam baseline emission factor in any given year y during the crediting period, the project proponent shall therefore:

a) establish the lowest specific heat consumption per unit of steam energy given by $\min(HEC_{BL,FF,st,i,y} / HSC_{BL,i,y})$ up till year y

b) multiply this value with the value of $\left(\frac{44}{12} \cdot CEF_{FF,i,y}\right)$ of the fuel used in year y

The baseline emissions factor for year y shall be the lowest between the value so calculated and that obtained from equation (6) above.

The purpose of this approach is to identify which year is the least energy intensive one, and assume that the improved performance would have not been lost over time. That is, in any year y it is always assumed that steam will be produced with the minimum amount of fossil fuel derived energy. It also aims to reflect the fact that changes in the fuel type being used in any year y may change to what has been previously the case, and that furthermore such changes would have also occurred in the absence of the project activity. If however in any year y, there is no fossil fuel consumption at the project customer's steam generating facility because all is displaced by the project activity, then the project proponent shall apply the lowest baseline emissions factor amongst the historical value for the three most recent years prior to the implementation of the project for which data is available and the values obtained during the years of the crediting period leading up to year y.

Note for cases in which a project customer uses steam produced by another steam generating plant:

Where the project customer is one that imports steam from generating facility, heat losses in transmission and distribution of that steam shall be considered nil. In other words, enthalpy data applied into the equations above shall be that which corresponds to the temperature and pressure conditions of the steam produced at the steam generating facility and not those existing of the steam at the point of off-take by the project customer. In this case, the steam baseline emissions factor shall be monitored as per the preceding note.

Option I.B.

The baseline CO_2 emissions factor per TJ of steam energy generated by customer i or by the steam generating facility that supplied steam to the project customer i, in the absence of the project activity can also be determined from boiler manufacturer's design data for customer i, and the fraction of heat recovered in the form of condensate, assuming no heat losses occur along the steam transmission and distribution lines, as follows:

$$SEF_{BL,i,y} = \frac{44}{12} \cdot \frac{CEF_{FF,i,y} \cdot (1 - X_{c,y}).100}{\eta_{BL,st,i}} \qquad (10)$$

Where:

$CEF_{FF,i,y}$ Carbon emission factor (in tonnes of C/TJ), corresponding to the fossil fuel consumption by customer i or the facility that provided steam to the project customer i in year y;

$\eta_{BL,st,i}$ Project customer i's boiler efficiency or the boiler efficiency of the steam generating plant that supplied steam to a project customer, based on NCV (in %).In the absence of boiler performance data, $\eta_{BL,st,i}$ can be determined by one of the following:

i) the highest measured value of boiler efficiency recorded over full range boiler test;

ii) the boiler's peak thermal efficiency as per manufacturer's information;

iii) efficiencies of boilers of similar design;

iv) a default boiler efficiency of 100%.

$X_{c,y}$ The fraction of the total energy contained in the steam which is produced by the steam generating facilities which is returned as hot condensate and flash steam where applicable, to the boiler house in year y. The values of $X_{c,y}$ can be obtained as follows:

Option 1. Based on historical/actual measured data

- from historical data:

Option 1a. When the mass of condensate and temperature and pressure conditions at which the condensate is returned to the boiler house condensate tank are known:

If this option is to be applied, then this calculation must be performed yearly during the crediting period to ensure that no improvements have been made that might lead to a further increase in the amount of energy recovered from the condensate. Should the value of the fraction so obtained in any year y be less than the historical maximum value (spanning the first year of the historical data used to establish the initial value of $X_{c,y}$ till year y-1 in the crediting period), the maximum value of $X_{c,y}$ during this period shall be taken. Energy returned to the boiler house in the form of hot condensate as well as from any flash steam recovered and thereafter used in a deaerator shall be accounted for.

Option 1.b When the mass of condensate recovered unknown, but temperature at which the condensate is returned to the condensate tank is known:

Calculate the heat recovered from the condensate entering the condensate tank by assuming that all the steam that condensed throughout the steam system is routed back to the boiler house condensate recovery tank, based upon the maximum temperature observed from historical records. In other words, assume that:

- no steam is used directly in a process
- all the steam that is condensed in heat exchangers is returned, i.e. no losses due to leaks (neither condensate nor live steam). Flash losses that occur across the steam traps are calculated by carrying out an enthalpy balance around

the condensate recovery tank at the tank's operating conditions

If this option is to be applied, then this calculation must be performed yearly to ensure that no improvements have been made that might lead to a further increase in the amount of energy recovered in the form of condensate that was present in the heat exchangers (e.g. if a condensate flash steam recovery project were to be implemented). Select the maximum condensate recovery temperature (at the condensate recovery tank) in the period spanning the first year of the historical data used to establish the initial value of $X_{c,y}$ till year y-1 in the crediting period, and use this value to establish the heat recovered from the condensate which is returned to the boiler in the form of condensate.

Option 2. Based on Default values

The following options assume that there are neither losses of condensate along the condensate piping nor losses to direct heating processes. The above assumptions overestimate the amount energy which can be recovered from this part of a steam system.

Option 2a If the existing condensate system is of the atmospherically vented condensate system type:

If the quantity and temperature at which the condensate is returned to the boiler house are not known, apply option 1b above but assume that the condensate which is obtained from the bottom of the condensate flash tank is pumped to the deaerator at 100°C to calculate the heat returned to the boiler in the form of hot condensate.

The proponents shall confirm annually if any changes to the design of the condensate system have been made that enable it to operate at a higher pressure, and thus recover more energy from the condensate routed to the condensate tank. Should this be the case, this default can no longer be applied.

Note: For such system condensate cannot exceed 100°C otherwise pump impeller cavitation /capitation would occur. Hence there is a practical limit to the amount of heat that can be recovered; in fact it would probably be somewhat lower than 100°C.

Option 2b. The project proponent may chose to calculate $X_{c,y}$ assuming that all the heat contained in the condensate in the heat transfer equipment is returned to the boiler. The calculation shall be performed based on enthalpy values of water, h_f, corresponding to the conditions at which the steam is generated according to the boiler manufacturer's design or the actual conditions.

II. Baseline emissions from production of hot water

The baseline emissions from the production of hot water in project customer i's installation or produced in the installation that supplied hot water to the project customer i are given by:

$$BE_{hw,y} = \sum_i \sum_j \left(HWC_{BL,j,y} \cdot HWEF_{BL,i,y} \right) \tag{11}$$

Where:

$HWC_{BL,j,y}$ The energy content in the hot water produced by the project facility j, which is purchased by project customer i in year y (in TJ);

$HWEF_{BL,i,y}$ The CO_2 baseline emissions factor corresponding to the hot water produced by the project customer i or produced by the hot water production plant that produces hot water which the project customer i uses in year y (in t CO_2/TJ)

The energy content in the hot water produced by the project facility j, which is purchased by project customer i in year y is obtained by the following equation:

$$HWC_{BL,j,y} = HWP_{BL,j,y} \cdot HWEN_{BL,j,y} \tag{12}$$

Where:

$HWP_{BL,j,y}$ The amount of hot water produced by project facility j and supplied to project customer i in year y (in tonnes);

$HWEN_{BL,j,y}$ The specific enthalpy of hot water produced by the project facility j in the year y (in TJ/tonne of water).

This part of the methodology considers situations in which a project customer i would have produced or obtained hot water from a hot water production plant. This hot water in the absence of the project activity would have been derived from either of the following sources of energy:

- fossil fuel, in directly fired hot water boilers, hwb (Option II.A.)

- steam, in steam to water heat exchangers, sthx (Option II.B.)

Option II.A. Hot water produced in boilers firing fossil fuels

The following alternatives are provided to determine the baseline CO_2 emissions factor associated to the production hot water in tonnes of CO_2/TJ where historical data is available.

Option II.A.a.

The baseline CO_2 emission factor associated with hot water production in boilers running on fossil fuel can be calculated as:

$$HWEF_{BL,i,y} = \frac{44}{12} \cdot \frac{\sum_i (CEF_{FF,i,y} \cdot HEC_{BL,FF,hwb,i,y})}{\sum_i HHWC_{BL,hwb,i,y}} \tag{13}$$

$CEF_{FF,i,y}$ Carbon emission factor corresponding to the fossil fuel used by the project customer i to produce hot water or used by the plant which supplied hot water to a project customer i in year y (in tonnes of C/TJ). Obtained from the relevant hot water generating plant or from the technical literature.

$HEC_{BL,FF,hwb,i,y}$ The energy associated with the fossil fuel consumed by customer i to self-generate hot water in a hot water boiler or that consumed by a hot water production plant that provides the hot water to the project customer i (in TJ) in year y.

$HHWC_{BL,hwb,i,y}$ The energy contained in the hot water, which was generated by the customer i from burning natural gas (in TJ) or which was produced by the facility that provided hot water to the project customer i in year y.

The present methodology offers two options upon which to determine $HEC_{BL,FF,hwb,i,y}$:

Option II.A.a.i

The energy associated with the fossil fuel consumed by a customer i to self-generate hot water in a hot water boiler or that which is used to generate hot water in a facility that supplied hot water to a project customer i given by:

$$HEC_{BL,FF,hwb,i,y} = HFC_{BL,FF,hwb,i,y} \cdot NCV_{FF,i,y} \tag{14}$$

Where:

$HFC_{BL,FF,hwb,i,y}$ The quantity of fossil fuel consumed for hot water generation in hot water boilers by the project customer i or by the plant that generated the hot water which customer i used for year y. This can be reported as mass units of the baseline fuel or in units of volume if data is provided on the mass density of the fossil fuel used (in tonnes)

$NCV_{FF,i,y}$ Net calorific value of the fossil fuel used in the hot water generating plant, whether this is the project customer i's facility or the plant that generated the hot water which the project customer i used, whichever is applicable,or specific data to be provided by the project customer for year y

Option II.A.a.ii

Alternatively, in the absence of suitable historical data for fossil fuel consumption or if preferred, $HEC_{BL,FF,hwb,i,y}$ may be calculated as follows:

$$HEC_{BL,FF,hwb,i,y} = \frac{(HHWC_{BL,hwb,i,y} - HHWP_{BL,hwb,i,y} \cdot HSEN_{w,y}) \cdot 100}{\eta_{BL,hwb,i}} \qquad (15)$$

Where:

$HHWC_{BL,hwb,i,y}$ The energy contained in the hot water, which was generated by the customer i or by the plant that provided the hot water to the project customer i, from burning fossil fuel (in TJ) in year y

$HSEN_{w,y}$ The specific enthalpy of water entering the hot water boiler in year y

$\eta_{BL,hwb,i}$ Customer i's hot water boiler's efficiency or that of the hot water generating plant that supplied hot water to the project customer i, based on NCV. The value of this parameter shall be one of the following:

a. the highest measured value of boiler efficiency recorded over full range boiler test;

b. the boiler's peak thermal efficiency as per manufacturer's information;

c. efficiencies of boilers of similar design;

d. a default boiler efficiency of 100%

The energy content of the hot water self-generated by project customer i, or by the hot water generating facility that supplies hot water to customer i, is given by:

$$HHWC_{BL,hwb,i,y} = HHWP_{BL,hwb,i,y} \cdot HHWEN_{BL,hwb,i,y} \tag{16}$$

Where:

$HHWP_{BL,hwb,i,y}$ The mass of hot water self-generated in hot water boilers by the project customer i or by the hot water generating plant that supplies hot water to customer i, in year y (in tonnes)

$HHWEN_{BL,hwb,i,y}$ The specific enthalpy of the hot water leaving project customer i's installation or that of the hot water leaving the facility that supplies hot water to the project customer i, in year y (in TJ/tonne of water)

Note for monitoring during the crediting period.

Option II Aa is based on actual performance data. However changes may be made to certain elements of the project customer's hot water system (e.g. the improved insulation) could result in a lower hot water baseline emissions factor during the years of the crediting period. Additionally, changes in the type of fuel used may occur in any year y during the crediting period, which are likely to have occurred also in the absence of the project activity.

The project proponents shall therefore:

a) establish the lowest specific heat consumption per unit of thermal energy given by $\min\left(HEC_{BL,FF,st,i,y} / HHWC_{BL,hwb,i,y}\right)$ up till year y

b) multiply the above value with $\left(\frac{44}{12} \cdot CEF_{FF,i,y}\right)$ of the fuel used in year y

The baseline hot water emissions factor for year y shall be the lowest between the value so calculated and that obtained from equation (13).

The purpose of this approach is to identify which year is the least energy intensive one, and assume that the improved performance would have not been lost over time. That is, in any year y it is always assumed that hot water will be produced with the minimum amount of fossil fuel derived energy. It also aims to reflect the fact that changes in the fuel type being used in any year y may change to what has previously been the case, and that furthermore such changes would have also occurred in the absence of the project activity. If however in any year y, there is no fossil fuel consumption at the project customer's hot water generating facility because all is displaced by the project activity, then the project proponent shall apply the lowest hot water baseline emissions factor amongst the one for the three most recent years prior to the implementation of the project for which data is available and the values obtained during the years of the crediting period leading up to year y.

Note for cases in which a project customer uses hot water produced by another hot water generating plant:

Where the project customer is one that imports hot water from a generating facility, heat losses in transmission and distribution of that hot water shall be considered nil. In other words, enthalpy data applied into the equations above shall be that which corresponds to the temperature of the water produced at the hot water generating facility and not those existing at the point of off-take by the project customer. In this case, the hot water emissions factor shall be monitored during the crediting period as per the preceding note.

Option II.A.b.

The baseline specific CO_2 emissions factor for a project customer "i" of the hot water generating facility that supplies hot water to a project customer i, can be determined from the hot water boiler manufacturer's design data and monitoring the difference between the boiler hot water outlet and inlet return temperatures as follows:

$$HWEF_{BL,i,y} = \frac{44}{12} \cdot \frac{CEF_{BL,i,y} \cdot 100}{\eta_{BL,hwb,i}} \cdot \frac{\Delta T_{P,i,y}}{\Delta T_{BL,i}} \qquad (17)$$

Where:

$CEF_{BL,i,y}$ Carbon emissions factor in tonnes CO_2/TJ corresponding to the fossil fuel used by customer i to produce the hot water, or by the hot water production plant that supplies the hot water which the project customer uses in year y

$\eta_{BL,hwb,i}$ Customer i's hot water boiler's efficiency or the efficiency of the facility that produces the hot water which project customer i uses, based on the NCV. The value of this parameter shall be one of the following:

a. the highest measured value of boiler efficiency recorded over full range boiler test;

b. the boiler's peak thermal efficiency as per manufacturer's information;

c. efficiencies of boilers of similar design;

d. a default boiler efficiency of 100%.

$\Delta T_{BL,i}$ Temperature difference between the water exiting the boiler and the water returning to it. The value applied shall be the lowest mean annual temperature difference over the three most recent years for which historical data is available. Alternatively, the design annual mean temperature difference may be considered as a default;

$\Delta T_{P,i,y}$ Temperature difference between the water exiting boiler and water returning in year y. The applied value shall be the lowest value during the historical period considered and the current year. Alternatively, the design annual mean temperature difference may be considered as a default.

Option II.B. Hot water produced from steam using heat exchangers

The following alternatives are provided to determine the baseline CO_2 emissions factor associated to the production hot water in tonnes of CO_2/TJ when this is produced from steam.

Option II.B.a.

The CO_2 baseline emission factor associated with hot water production in steam heat exchangers can be calculated based upon historical data as:

$$HWEF_{BL,i,y} = \frac{44}{12} \cdot \frac{\sum_i (SEF_{BL,i,y} \cdot HEC_{BL,st,sthx,i})}{\sum_i HHWC_{BL,sthx,i}} \qquad (18)$$

$SEF_{BL,i,y}$ The baseline emission factor for the production of steam which is used to produce the hot water (in tonnes CO_2/TJ), and obtained from equation (4).

$HHWC_{BL,sthx,i,y}$ The energy contained in hot water self generated by project customer i from steam or by the supplier of the hot water to a project customer i in a steam-to-water heat exchanger (in TJ) in year y

$HEC_{BL,st,sthx,i,y}$ The energy associated with the steam consumed by customer i to self-generate hot water or that which is consumed by the hot water production plant which produces the hot water that a project customer i uses, in a steam-to-water heat exchanger (in TJ) in year y

The energy contained in hot water self generated by project customer i from steam or obtained from the hot water generating plant that supplied this hot water to a project customer i, by means of a steam-to-water heat exchanger can be obtained by:

$$HHWC_{BL,sthx,i,y} = HHWP_{BL,sthx,i,y} \cdot HHWEN_{BL,hw,sthx,i,y} \quad (19)$$

$HHWP_{BL,sthx,i,y}$ The mass of hot water self-generated by the project customer i or by the hot water production plant that produced the hot water that a project customer i uses, by means of a steam-to-water heat exchanger during year y (in tonnes)

$HHWEN_{BL,hw,sthx,i,y}$ Specific enthalpy of water leaving the steam-to-water heat exchanger or exchangers of the project customer i, during year y.

The amount of energy consumed in the form of steam to produce hot water in the absence of the project activity (in TJ), $HEC_{BL,st,sthx,i,y}$, is given by:

Option II.B.a.i.

$$HEC_{BL,st,sthx,i,y} = HFC_{BL,NG,hwb,i,y} \cdot HHWEN_{BL,st,sthx,i,y} \quad (20)$$

$HFC_{BL,st,stbx,i,y}$ Quantity of steam consumed by the project customer i or the facility that generates the hot water which a project customer i used in year y (in tonnes)

$HHWEN_{BL,st,sthx,i,y}$ Difference of the specific enthalpy of steam entering and condensate leaving the heat exchanger in year y (in TJ/tonne of water)

Option II.B.a.ii.

Alternatively, in the absence of suitable actual steam consumption data, or if preferred, $HEC_{BL,st,sthx,i,y}$ may be calculated as follows:

$$HEC_{BL,st,sthx,i,y} = \frac{(HHWC_{BL,sthx,i,y} - HHWP_{BL,sthx,i,y} \cdot HSEN_{w,y}) \cdot 100}{\eta_{BL,sthx,i}} \quad (21)$$

Where

$HSEN_{w,y}$ The specific enthalpy of water entering the steam to water heat exchanger in year y

$\eta_{BL,sthx,i}$ The steam-to-water exchanger efficiency (%) of customer i’s hot water generating plant or that of the hot water generating plant that provides hot water to customer i, based on one of the following:

a. the highest measured annual value of heat exchanger efficiency;

b. the design heat exchanger efficiency;

c. efficiencies of steam-to-water heat exchangers of similar design;

d. a default heat exchanger efficiency of 100%.

Note for monitoring during the crediting period.

Changes may be made during the crediting period to elements of the hot water distribution system (e.g. improved insulation) that may reduce the amount of steam required to meet the thermal loads), which in turn will lead to changes in the baseline emissions factor of the hot water produced.

Changes may also occur to elements of the steam system from which the heat exchangers are fed, which may also lead to changes in the baseline emissions factor of the steam, and hence impact the baseline emissions factor for the hot water.

In establishing the value of the hot water baseline emissions factor to be applied in year y the project proponents shall therefore:

c) establish the lowest specific heat consumption per unit of thermal energy given by $\min(HEC_{BL,st,sthx,i,y} / HHWC_{BL,sthx,i,y})$ up till year y

d) multiply the above value with $SEF_{BL,i,y}$ corresponding to the year y

The baseline hot water emissions factor for year y shall be the lowest between the value so calculated and that obtained from equation (18).

The purpose of this approach is to identify which year is the least energy intensive one, and assume that the improved performance achieved in the hot water system would have not been lost over time. That is, in any year y it is always assumed that hot water will be produced with the minimum amount of steam energy.. If however in any year y, there is no steam consumption in the steam – hot water heat exchanger at the project customer's hot water generating facility because all of it is displaced by the project activity, then the project proponent shall apply the lowest hot water baseline emissions factor amongst the one obtained from the average of the three most recent years prior to the implementation of the project for which data is available and the values obtained during the years of the crediting period leading up to year y.

The project proponent shall ensure the steam baseline emissions factor is monitored annually and updated accordingly when applied to the above equations. The value for the baseline emissions factor of the steam to be applied in any year y shall be that obtained as per Section I above.

Option II.B.b.

The baseline CO_2 emissions factor for a customer i can be determined without having to resort to historical data of steam and/or hot water production from the steam-to-water heat exchanger manufacturer design data as follows:

$$HWEF_{BL,i,y} = \frac{44}{12} \cdot \frac{SEF_{BL,i,y} \cdot 100}{\eta_{BL,sthx,i}} \qquad (22)$$

Where:

$SEF_{BL,i,y}$ The baseline emission factor corresponding to the steam that is utilized either by the project customer i or the hot water production plant that supplies hot water to customer i in year y, whichever is the case (in tonnes CO_2/TJ). Obtained from equation 4.

$\eta_{BL,sthx,i}$ The efficiency of steam-to-water exchanger efficiency at customer i's installations or at the facility which supplies hot water to customer i, based on one of the following:

a. the highest measured annual value of heat exchanger efficiency;

b. the design heat exchanger efficiency;

c. efficiencies of heat exchangers of similar design;

d. a default heat exchanger efficiency of 100%.

Note for monitoring during the crediting period

Changes may be made during the crediting period to elements of the steam system from which the heat exchangers are fed may lead to changes in the baseline emissions factor of the steam used, and hence impact the baseline emissions factor for the hot water which is produced.

Therefore, the project proponent shall ensure the steam baseline emissions factor is monitored annually and updated accordingly when applied to the above equations. The value for the baseline emissions factor of the steam to be applied in year y shall be that obtained as per Section I above.

CALCULATION OF THE PROJECT EMISSIONS

Project emissions within the project boundary result from the combustion of natural gas within the project boundary:

$$PE_y = PE_{NG,P,y} \quad (23)$$

Where:

$PE_{NG,P,y}$ Project emissions resulting from combustion of natural gas within the project boundary (in t CO_2e) for the year y.

Those project emissions are respectively calculated as follows:

$$PE_{NG,P,y} = FC_{NG,P,y} \cdot NCV_{NG} \cdot EF_{NG,CO2,p} \quad (24)$$

Where:

$FC_{NG,P,y}$ Natural gas consumed within the project facility "j" (in tonnes/ normal m^3) in the year y.

NCV_{NG} Lower heating value of the natural gas combusted (in TJ/t or TJ/normal m^3). As per certificates from the natural gas supplier or from IPCC figures.

$EF_{NG,CO2,p}$ CO_2 emission factor for the combustion of natural gas (in t CO2/TJ). As per certificates from the natural gas supplier or from IPCC figures.

When calculating the term $FC_{NG,P,y}$, the project proponent may resort to using the formula below:

$$FC_{NG,P,y} = FC_{NG,P,C,y} + FC_{NG,P,H,y} \quad (25)$$

Where:

$FC_{NG,P,C,y}$ Natural gas consumed by the main equipment within the boundaries of the project facility j in year y (in tonnes/ normal m^3)

$FC_{NG,P,H,y}$ Natural gas consumed for supplementary firing within the boundaries of the project facility j in year y (in tonnes/ normal m^3).

CALCULATION OF THE LEAKAGE EMISSIONS

The project proponent should estimate the size of leakage emission from electricity consumption and assess if those leakages are higher than 1% of the calculated emission reductions from that project activity, in the event that the project activity were to draw electricity from the grid. If that is the case, those leakage emissions should be included in the leakage calculations.

Upstream emissions from fuel extraction, processing, liquefaction, transportation and regasification of Natural Gas (to be considered only when the project fuel is Natural Gas)

In this methodology, the following leakage emission sources shall be considered:

- Fugitive CH_4 emissions associated with fuel extraction, processing, liquefaction, transportation, regasification and distribution of natural gas used in the project plant and fossil fuels used in the grid in the absence of the project activity ($LE_{CH_4,y}$).
- In the case LNG is used in the project plant: CO_2 emissions from fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression into a natural gas transmission or distribution system ($LE_{LNG,CO_2,y}$).

$$LE_{US,y} = LE_{CH_4,y} + LE_{LNG,CO_2,y} \tag{26}$$

Where:

$LE_{CH_4,y}$	Leakage emissions due to fugitive upstream CH4 emissions in the year y in t CO2e
$LE_{LNG,CO_2,y}$	Leakage emissions due to fossil fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system during the year y in t CO2e

Fugitive methane emissions

For the purpose of determining fugitive methane emissions associated with the production – and in case of natural gas, the transportation and distribution of the fuels – project participants should multiply the quantity of natural gas consumed in all element processes i with a methane emission factor for these upstream emissions ($EF_{NG,upstream,CH_4}$), and subtract for all fuel types k which would be used in the absence of the project activity the fuel quantities multiplied with respective methane emission factors ($EF_{NG,upstream,CH_4}$), as follows:

$$LE_{CH_4,y} = \left[FF_{\Pr oject,y} \cdot NCV_{NG,y} \cdot EF_{NG,upstream,CH_4} - \sum_k FF_{Baseline,k,y} \cdot NCV_{NG,k} \cdot EF_{NG,upstream,CH_4} \right] \cdot GWP_{CH_4} \quad (27)$$

Where:

$LE_{CH_4,y}$	Leakage emissions due to upstream fugitive CH4 emissions in the year y in t CO2e
$FF_{\Pr oject,y}$	Quantity of natural gas combusted in all element processes during the year y in m³
$NCV_{NG,y}$	Average net calorific value of the natural gas combusted during the year *y* in /m³
$EF_{NG,upstream,CH_4}$	Emission factor for upstream fugitive methane emissions from production, transportation and distribution of natural gas in t CH4 per TJ fuel supplied to final consumers
$FF_{Baseline,k,y}$	Quantity of fuel type *k* (a coal or oil) that would be combusted in the absence of the project activity in all element processes during the year *y* in a volume or mass unit
$EF_{NG,upstream,CH_4}$	Emission factor for upstream fugitive methane emissions from production, transportation and distribution of natural gas in t CH4 per TJ fuel supplied to final consumers
GWP_{CH_4}	Global warming potential of methane valid for the relevant commitment period

Where reliable and accurate national data on fugitive CH4 emissions associated with the production, and in case of natural gas, the transportation and distribution of the fuels is available, project participants should use this data to determine average emission factors by dividing the total quantity of CH4 emissions by the quantity of fuel produced or supplied respectively. Where such data is not available, project participants may use the default values provided in Table 2 below. In this case, the natural gas emission factor for the location of the project should be used, except in cases where it can be shown that the relevant system element (gas production and/or processing/transmission/distribution) is predominantly of recent vintage and built and operated to international standards, in which case the US/Canada values may be used.

Note that the emission factor for fugitive upstream emissions for natural gas ($EF_{NG,upstream,CH_4}$) should include fugitive emissions from production, processing, transport and distribution of natural gas, as indicated in the Table 2 below. Note further that in case of coal the emission factor is provided based on a mass unit and needs to be converted in an energy unit, taking into account the net calorific value of the coal.

Table 2: Default emission factors for fugitive CH_4 upstream emissions

Activity	Unit	Default emission factor	Reference for the underlying emission factor range in Volume 3 of the *1996 Revised IPCC Guidelines*
Coal			
Underground mining	t CH4 / kt coal	13.4	Equations 1 and 4, p. 1.105 and 1.110
Surface mining	t CH4 / kt coal	0.8	Equations 2 and 4, p.1.108 and 1.110
Oil			
Production	t CH4 / PJ	2.5	Tables 1-60 to 1-64, p. 1.129 - 1.131
Transport, refining and storage	t CH4 / PJ	1.6	Tables 1-60 to 1-64, p. 1.129 - 1.131
Total	t CH4 / PJ	4.1	
Natural gas			
USA and Canada			
Production	t CH4 / PJ	72	Table 1-60, p. 1.129
Processing, transport and distribution	t CH4 / PJ	88	Table 1-60, p. 1.129
Total	t CH4 / PJ	160	
Eastern Europe and former USSR			
Production	t CH4 / PJ	393	Table 1-61, p. 1.129
Processing, transport and distribution	t CH4 / PJ	528	Table 1-61, p. 1.129
Total	t CH4 / PJ	921	
Western Europe			
Production	t CH4 / PJ	21	Table 1-62, p. 1.130
Processing, transport and distribution	t CH4 / PJ	85	Table 1-62, p. 1.130
Total	t CH4 / PJ	105	
Other oil exporting countries / Rest of world			
Production	t CH4 / PJ	68	Table 1-63 and 1-64, p. 1.130 and 1.131
Processing, transport and distribution	t CH4 / PJ	228	Table 1-63 and 1-64, p. 1.130 and 1.131
Total	t CH4 / PJ	296	

Note: The emission factors in this table have been derived from IPCC default Tier 1 emission factors provided in Volume 3 of the 1996 Revised IPCC Guidelines, by calculating the average of the provided default emission factor range.

CO_2 emissions from LNG

Where applicable, CO2 emissions from fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system ($LE_{LNG,CO_2,y}$) should be estimated by multiplying the quantity of natural gas combusted in the project with an appropriate emission factor, as follows:

$$LE_{LNG,CO_2,y} = FF_{Project,y} \cdot EF_{CO_2,upstream,LNG} \qquad (28)$$

Where:

$LE_{LNG,CO_2,y}$ Leakage emissions due to fossil fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or

	distribution system during the year y in t CO2e
$FF_{Project,y}$	Quantity of natural gas combusted in all element processes during the year *y* in m³
$EF_{CO_2,upstream,LNG}$	Emission factor for upstream CO2 emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, regasification and compression of LNG into a natural gas transmission or distribution system

CALCULATION OF THE EMISSION REDUCTIONS

The GHG emission reductions resulting from the project activity in the year y (ER_y) are calculated as in the equation below:

$$ER_y = BE_y - PE_y - LE_y \quad (29)$$

Where:

BE_y	Emissions in the baseline scenario for the year y. Calculated as in the equation given above.
PE_y	Emissions resulting from the project activity in the year y. Calculated as in the equation given above.
LE_y	Net leakage emissions resulting from the implementation and operation of the project activity. Calculated as in the equation given above.

The project proponent, who applies the new VCS methodology, should provide evidences for the figures applied and used in the excel work sheets in order to be able to fully retrace the assumptions and calculations made to determine the emissions reductions.

Data and parameters not monitored:

Data/parameter:	$SC_{BL,j,y}$
Data unit:	TJ
Description:	The amount of energy consumed in the form of steam by the project customer i, which is supplied by the project facility “j” in year y.
Source of data:	Calculated on the basis of the steam generation and the data for the steam enthalpy.

Measurement procedures (if any):	If applicable, energy content of steam can be directly measured.
QA/QC procedures	
Any comment:	-
Uncertainty level	Low: this parameter is calculated from variables which are monitored and subject to their own QA/QC procedures ($SP_{BL,j,y}$ and $SDEN_{BL,j,y}$). Alternatively, this could be measured by a heat meter, calibrated also following the QA/QC procedures applied in the data and parameters to be monitored section, which is similar also to that applied in other CDM approved methodologies such as AM0048.

Data/parameter:	$SEF_{BL,i,y}$
Data unit:	t CO_2/TJ
Description:	The baseline emission factor for the production of steam in project customer i for year y.
Source of data:	Actual performance data that is publicly available will be used for purpose. Otherwise, the project proponent may resort to historical data for the three most recent years for which data is available.
Measurement procedures (if any):	-
QA/QC procedures	-
Any comment:	
Uncertainty level	Low: two options are given in the meth to determine SEF: Option I.A., based on publicly available energy performance data on the amount of energy produced in the form of steam and energy consumed to produce it. The uncertainty level is in theory dependent mostly upon the how the amount of fossil fuel energy consumed is determined, namely $HEC_{BL,FF,st,i,y}$. The uncertainty level of this parameter is in turn considered to be low per se, and two options are given in turn to determine it as discussed in the table for $HEC_{BL,FF,st,i,y}$ Option I.B, based on default values and varying degrees of condensate recovery percentages with respect to the total amount of steam generated. Hence, the uncertainty level in this option is dependent primarily on how the fraction of heat recovered in the form of condensate is determined. This option relies on the use of efficiency values which are taken conservatively as those of the steam generating facilities of the project customers. It assumes that there are no transmission losses

	of heat. Such assumptions lead to a highly conservative estimate for the specific emissions because it assumes that once steam is generated from the boilers, there is no further loss of energy until the point of use. In practice, heat losses due to transmission tend to be of the order of 10%. The fossil fuel that needs to be burned to make up for these losses is ignored in our calculations, and this we feel is more than sufficient to compensate for even uncertainties, which as discussed we feel are low anyhow. Furthermore, all the options used to estimate the amount of energy recovered from the condensate that is formed assume that there are no condensate, nor heat losses between the point of condensate formation and entrance to the condensate recovery tank. This of course is highly conservative per se. There are two options given to determine Xc depending upon the availability of historical and actual data for quantity of condensate recovered and sent to the boiler house and condensate conditions of temperature and pressure. Where actual data is used, the maximum historical values are assumed, thereby assuming maximum energy recovery. The second option involves the use of default factors and requires annual verification to be carried out that the no changes have occurred that warrant a change in the applied default value.

Data/parameter:	$HEC_{BL,FF,st,i,y}$
Data unit:	TJ
Description:	The energy associated with the fossil fuel that was consumed by the project customer "i" during year y
Source of data:	Calculated on the basis of actual fuel consumption data that is publicly available.
Measurement procedures (if any):	-
QA/QC procedures	Ensure suitable standards for determining efficiency are applied if parameter is not determined from public sources. Check consistency with previously derived values and equipment design efficiency values
Any comment:	
Uncertainty level	There are two options given to determine $SEF_{BL,i,y}$, one based on a publicly reported data (Option 1 A) and the other based on default values (Option 1 B). Option 1A. The uncertainty level is considered to be low for this option if the central heating plant has to publicly report it heat production and fuel consumption figures to energy regulators. However if the central generating facility has only to report publicly its heat production figures and not its fossil fuel consumption ones, then in this case the uncertainty is potentially

	higher and additional measures need to be in place to ensure a low level of uncertainty. The methodology offers two alternatives to determine what the fossil energy consumption may be: Option I.A.a, which is based on publicly reported fuel consumption figures and fuel properties, which can be obtained from fuel suppliers, and which therefore is considered to be of low uncertainty Option I.A.b is based on the actual heat or steam production figures and conditions of boiler feedwater and steam, and the efficiency of the steam generating system. The efficiency of the steam generating equipment enables the project proponent to apply four options, each of which are more conservative than the other. Three of those options are: the manufacturer's quoted peak boiler efficiency, efficiencies of boilers of similar design, or a default value of 100% efficiency. The uncertainty level of these is low. The forth option is based on peak measured efficiencies, but this must be carried out by applying the standard procedures for boiler efficiency determinations. The use of a standard method, which relies on calibrated equipment and involves applying the highest value obtained over a full load range text in our opinion lead to a low level of uncertainty in the determination of the boiler efficiency in the event this option were to be applied. Option I B, which does not rely on reported energy production and consumption data but rather relies on similar boiler efficiency options given above. It offers an even lower uncertainty level In both cases above heat losses throughout the transmission system are ignored. Heat losses in steam transmission alone can amount to 5 – 10 % , and sometime even more in old systems, of energy produced by the generating facility. The calculations in the meth assume zero losses, and thus fuel to steam efficiency is significantly higher than what is in typical. Hence, the extra fossil fuel that needs to be burned to make up for these losses is not considered for the purpose of determining the amount of fossil fuel energy supplied to the steam generating facilities. This leads to a lower CO_2 emissions factor per unit energy of steam produced that will be the case in reality.

Data/parameter:	$HSC_{BL,i,y}$
Data unit:	TJ
Description:	The amount of energy contained in the steam which was generated by the customer i by burning fossil fuel during year y

Source of data:	Actual data that is publicly available will be used for purpose, or calculated using measured data (quantity of stem produced by customer i or the facility that supplies steam to customer i.
Measurement procedures (if any):	-
QA/QC procedures	Check for consistency with historical values if option involving the use of measured data is applied.
Any comment:	
Uncertainty level	Low: this data is publicly available and presented to energy authorities and the result of heat supplied to customers, or optional derived from monitored parameters subject to common QA/QC applied to measure similar parameters

Data/parameter:	$HFC_{BL,FF,st,i,y}$
Data unit:	tonnes
Description:	The quantity of fossil fuel consumed for steam generation by project customer i during year y.
Source of data:	Actual data that is publicly available will be used for this purpose.
Measurement procedures (if any):	-
QA/QC procedures	
Any comment:	
Uncertainty level	Low: if this is provided by the supplier of the steam as part of its duty to report this consumption to outside stakeholders. Data can also be crosschecked against historical data and compared to the amount of heat produced in the form of steam and supplied to the customers.

Data/parameter:	$\eta_{BL,st,i}$
Data unit:	**%**
Description:	Project customer i's boiler efficiency based on NCV (in %).
Source of data:	The highest measured value of boiler efficiency recorded over full range boiler test; the boiler's peak thermal efficiency as per manufacturer's information or a default boiler efficiency of 100%;
Measurement procedures (if any):	Full range boiler test if applicable
QA/QC procedures	Ensure suitable standards for determining efficiency are applied if relevant to the option chosen. Check consistency with similarly derived historical values and equipment design efficiency values
Any comment:	
Uncertainty level	Low: even in the case in which boiler efficiency is determined based measurements, these have to be done according to acceptable standards. It also involves taking the highest value of a full boiler efficiency load test which leads to a conservative determination of efficiency under this option. The remaining

	options involve an even higher degree of efficiency and to do not rely on any measured data, but rather on published data or very high conservative assumptions for boiler efficiency.

Data/parameter:	$HWC_{BL,j,y}$
Data unit:	TJ
Description:	The energy content in the hot water produced by the project facility j, which is purchased by project customer i in year y
Source of data:	If applicable, energy content of hot water can be directly measured.
Measurement procedures (if any):	-
QA/QC procedures	Where applicable meters shall be calibrated as per their data book. Measuring conditions shall be as per meters data book. Check consistency with historical monitored data. Crosscheck with invoices at project facility site
Any comment:	
Uncertainty level	Low: determined using QA/QC procedures commonly used in the CDM to temperature measurements.

Data/parameter:	$HWEF_{BL,i,y}$
Data unit:	t CO_2/TJ
Description:	The CO_2 emissions factor for the hot water produced in year y.
Source of data:	Actual data that is publicly available will be used for purpose.
Measurement procedures (if any):	-
QA/QC procedures	-
Any comment:	
Uncertainty level	Low: based partly on publicly reported data for heat production and fossil fuel consumption required to comply with energy legislation, or if applicable based on conservative and low level of uncertainty values of efficiency and publicly reported heat production figures, or in the absence of these on default values of low uncertainty level.

Data/parameter:	$HEC_{BL,FF,hwb,i,y}$
Data unit:	TJ
Description:	The energy associated with the fossil fuel consumed by customer i to self-generate hot water in a hot water boiler during year y.
Source of data:	Actual data that is publicly available will be used for purpose.
Measurement procedures (if any):	-
QA/QC procedures	-
Any comment:	

Uncertainty level	Low: same as for $HEC_{BL,FF,st,i,y}$ given above.

Data/parameter:	$HHWC_{BL,hwb,i,y}$
Data unit:	TJ
Description:	The energy contained in the hot water, which was generated by the customer i from burning fossil fuel during year y.
Source of data:	Actual data that is publicly available will be used for purpose.
Measurement procedures (if any):	-
QA/QC procedures	-
Any comment:	
Uncertainty level	Low: this data is publicly available and presented to energy authorities and the result of heat supplied to customers

Data/parameter:	$HFC_{BL,FF,hwb,i,y}$
Data unit:	tonnes
Description:	The quantity of fossil fuel consumed for hot water generation in hot water boilers by project customer i during year y. This can be reported as mass units of the baseline fuel or in units of volume if data is provided on the mass density of the natural gas used (in tonnes)
Source of data:	Actual data that is publicly available will be used for purpose.
Measurement procedures (if any):	-
QA/QC procedures	- .
Any comment:	
Uncertainty level	Low: if this is provided by the supplier of the hot water as part of its duty to report this consumption to outside stakeholders. Data can also be crosschecked against historical data and compared to the amount of heat produced in the form of steam and supplied to the customers.

Data/parameter:	$\eta_{BL,hwb,i}$
Data unit:	
Description:	Project customer i's hot water boiler's efficiency based on NCV.
Source of data:	The highest measured value of boiler efficiency recorded over full range boiler test; the boiler's peak thermal efficiency as per manufacturer's information or a default boiler efficiency of 100%
Measurement procedures (if any):	A full range boiler test if applicable.
QA/QC procedures	Ensure suitable standards for determining efficiency are applied if relevant to the option chosen. Check consistency with similarly derived historical values and equipment design efficiency values
Any comment:	

Uncertainty level	Low: even in the case in which boiler efficiency is determined based measurements, these have to be done according to acceptable standards. It also involves taking the highest value of a full boiler efficiency load test which leads to a conservative determination of efficiency under this option. The remaining options involve an even higher degree of efficiency and to do not rely on any measured data, but rather on published data or very high conservative assumptions for boiler efficiency.

Data/parameter:	$HHWC_{BL,sthx,i,y}$
Data unit:	TJ
Description:	The energy contained in hot water self generated by project customer i from steam, in a steam-to-water heat exchanger (in TJ) during year y.
Source of data:	Actual data that is publicly available will be used for purpose.
Measurement procedures (if any):	-
QA/QC procedures	-
Any comment:	
Uncertainty level	Low: if this data is publicly available and presented to energy authorities and the result of heat supplied to customers.

Data/parameter:	$HHWP_{BL,sthx,i,y}$
Data unit:	tonnes
Description:	The mass of hot water self-generated by the project customer i by steam-to-water heat exchanger during year y.
Source of data:	Actual data that is publicly available will be used for purpose.
Measurement procedures (if any):	-
QA/QC procedures	-
Any comment:	
Uncertainty level	Low: this data is publicly available and presented to energy authorities and quantifies the result of heat supplied to customers.

Data/parameter:	$HFC_{BL,st,stbx,i,y}$
Data unit:	tonnes
Description:	Quantity of steam consumed by the project customer for hot water production during year y.
Source of data:	Actual data that is publicly available will be used for this purpose.
Measurement procedures (if any):	-
QA/QC procedures	-
Any comment:	
Uncertainty level	Low: this data is publicly available and presented to energy

	authorities and quantifies the result of heat supplied to customers.

Data/parameter:	$\eta_{BL,sthx,i}$
Data unit:	
Description:	customer i's (in %) steam-to-water exchanger efficiency based on one of the following
Source of data:	The highest measured annual value of heat exchanger efficiency; the design heat exchanger efficiency or a default heat exchanger efficiency of 100%.
Measurement procedures (if any):	-
QA/QC procedures	Ensure suitable standards for determining efficiency are applied if relevant to the option chosen. Check consistency with similarly derived historical values and equipment design efficiency values if applicable.
Any comment:	
Uncertainty level	Low: provided suitable tests are conducted. Low: if any default value is chosen.

MONITORING METHODOLOGY

Monitoring procedures

Data for carbon content of fuel sources may be taken from IPCC. In the event that more recent or accurate scientific studies are produced and approved by the UNFCCC these data shall be used.

Official electricity generation and transmission company statistics is used to determine the grid electricity coefficient. This data is gathered from the utilities, whether on the national, regional or local level, as appropriate.

It is assumed that the data provided for the electricity grid and from individual facilities are available and transparent, in order to calculate the carbon coefficient of the electricity and steam and or hot water being displaced from project customers by the project activity.

Vintage and spatial level of data: the data is gathered on a national or regional power grid level to determine the combined margin.

As for the vintage of the data, the project developer should try and get three years of data prior to project implementation where to required in the baseline methodology. If three years of data is not available, then the project developer must use at least one complete year (two when it exists) and must demonstrate using evidence from credible sources to the DOE that additional data does not exist. Non-representative data is included unless there is a major outlying event. Should the project developer wish to exclude non-representative data they must be able to document why this is removed and this should be approved during validation.

When IPCC data is available, project proponents shall take into consideration that the Board agreed that the IPCC default values should be used only when country or project specific data are not available or difficult to obtain.

The project developer will have to ensure the completeness and accuracy of the data set during the baseline measurement year by installing, repairing, and calibrating meters as appropriate. Completeness/accuracy of data should be relatively easy to verify, and emissions reductions will not be included if the evidence does not demonstrate this point clearly. The project developer should obtain data on metering in the project and try and ascertain that the meter accuracy is 95% or greater – and that quality control procedures are in place to deal with defective meters and/or recalibrate them on a regular basis.

The project proponent shall also provided simplified diagrams illustrating the location of the monitoring points.

Data and parameters monitored

Data/parameter:	$EG_{P,y}$
Data unit:	MWh
Description:	Net electricity supplied to the power grid by the proposed project facility ‘j’ in year ‘y’(MWh/yr).
Source of data:	Electricity meter at the project facility ‘j’
Measurement procedures (if any):	Read electricity meter and store information until 2 years after the end of the crediting period.
Monitoring frequency	Monthly
QA/QC procedures	Meters shall be calibrated as per their data book. Measuring conditions shall be as per meters data book. Check consistency with historical monitored data. Crosscheck with invoices and electricity supply data at project facility site.
Any comment:	
Uncertainty level	Low, it follows QA/QC procedures and monitoring frequencies which are common to other CDM Monitoring methodologies such as AM0048

Data/parameter:	$CEF_{BL/P,FF,y}$
Data unit:	t C/TJ
Description:	Carbon emission factor corresponding to the fossil fuel used to produce steam or hot water as applicable. Carbon emission factor in year y corresponding to fossil fuel used by project customer i to generate steam/hot water or that which is used in a given steam/hot water generating plant to produce the steam/hot water which is sourced by the project customer i (in tonnes of C/TJ), shall be determined from the technical literature, from the project customer i, or the steam/hot water generating plant which supplies steam/hot water to the project customer i.
Source of data:	Obtained from the project customer ‘i’ / project facility ‘j’ or technical literature.
Measurement procedures (if any):	When IPCC data is available, project proponents shall take into consideration that the Board agreed that the IPCC default values should be used only when country or project specific data are not available or difficult to obtain.
Monitoring frequency	-
QA/QC procedures	-
Any comment:	-

Uncertainty level	Low, given external sources that provide it (fuel suppliers/government bodies, IPCC)

Data/parameter:	$EF_{BL,CO_2,y}$
Data unit:	t CO_2/MWh
Description:	Emission factor of the electricity grid to which the project facility "j" supplies the electricity generated. Determination of the emission factor will be made once at the validation stage based on an ex ante assessment, and once again at the start of each subsequent crediting period (if applicable). Regardless of whether option 1 (BM) or option 2 (CM) is chosen, the emission factor is also calculated ex-post as described in the "Tool to calculate emission factor for an electricity system".
Source of data:	Publicly available data on electricity generation within the respective power grid.
Measurement procedures (if any):	
Monitoring frequency	Calculated ex-post each year.
QA/QC procedures	As per "Tool to calculate emission factor for an electricity system"
Any comment:	-
Uncertainty level	Low, the data upon which the parameter is determined is obtained for official electricity sector statistics whilst the treatment of the data to the determine the parameter uses an approved CDM tool

Data/parameter:	$EF_{NG,upstream,CH_4}$
Data unit:	t CH_4/TJ
Description:	Emission factor for upstream fugitive methane emissions from production, transportation and distribution of natural gas.
Source of data:	Obtained from the project facility 'j' or table in the leakage section.
Measurement procedures (if any):	When IPCC data is available, project proponents shall take into consideration that the Board agreed that the IPCC default values should be used only when country or project specific data are not available or difficult to obtain.
Monitoring frequency	-
QA/QC procedures	-
Any comment:	-
Uncertainty level	Low, the source is an official third party (IPCC) or a host country official source

Data/parameter:	$EF_{CO_2,upstream,LNG}$
Data unit:	tCO_2/TJ

Description:	Emission factor for upstream CO_2 emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, regasification and compression of LNG into a natural gas transmission or distribution system
Source of data:	Where reliable and accurate data on upstream CO_2 emissions due to fossil fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system is available, project participants should use this data to determine an average emission factor. Where such data is not available, project participants may assume a default value of 6 tCO_2/TJ as a rough approximation
Measurement procedures (if any):	When IPCC data is available, project proponents shall take into consideration that the Board agreed that the IPCC default values should be used only when country or project specific data are not available or difficult to obtain.
Monitoring frequency	-
QA/QC procedures	-
Any comment:	-
Uncertainty level	Low, the source is an official third party (IPCC) or a host country official source

Data/parameter:	$SDEN_{BL,j,y}$
Data unit:	TJ/tonne
Description:	Specific enthalpy of steam leaving the project facility 'j' (in TJ/tonne of steam supplied).
Source of data:	This data shall be obtained from steam tables, using temperatures and pressure of the steam purchased.
Measurement procedures (if any):	Use monitored pressure and temperature of the steam to obtain specific enthalpy from steam tables.
Monitoring frequency	Monthly
QA/QC procedures	Meters shall be calibrated as per their data book. Measuring conditions shall be as per meters data book. Check consistency with historical monitored data.
Any comment:	-
Uncertainty level	Low, parameter is obtained from temperature and pressure data that is monitored and subject to QA/QC procedures applied in CDM monitoring methodologies such as AM0048 and AM0029, and publicly available steam tables

Data/parameter:	Steam temperature
Data unit:	°C
Description:	Temperature of steam purchased by project customer 'i'.

Source of data:	Temperature meters at project facility 'j'
Measurement procedures (if any):	Read temperature meter daily and calculate monthly average. Store information until 2 years after the end of the crediting period.
Monitoring frequency	Daily measurements and monthly average.
QA/QC procedures	Meters shall be calibrated as per their data book. Measuring conditions shall be as per meters data book. Check consistency with historical monitored data.
Any comment:	-
Uncertainty level	Low, parameter is monitored and subject to QA/QC procedures applied in CDM monitoring methodologies such as AM0048

Data/parameter:	Steam pressure
Data unit:	MPa
Description:	Pressure of steam purchased by project customer 'i'.
Source of data:	Pressure meters at project facility 'j'
Measurement procedures (if any):	Read pressure meter daily and calculate monthly average. Store information until 2 years after the end of the crediting period.
Monitoring frequency	Daily measurements and monthly average.
QA/QC procedures	Meters shall be calibrated as per their data book. Measuring conditions shall be as per meters data book. Check consistency with historical monitored data.
Any comment:	-
Uncertainty level	Low, parameter is monitored and subject to QA/QC procedures applied in CDM monitoring methodologies such as AM0048

Data/parameter:	$FC_{NG,P,y}$
Data unit:	Tonnes or m^3
Description:	Natural gas consumed within the boundary of the project facility (in tonnes/normal m^3) in the year y.
Source of data:	Purchase records and fuel data logs.
Measurement procedures (if any):	Store information until 2 years after the end of the crediting period.
Monitoring frequency	Daily measurement and monthly recorded.
QA/QC procedures	Meters shall be calibrated as per their data book. Measuring conditions shall be as per meters data book. Check consistency with historical monitored data. Crosscheck with purchase records.
Any comment:	-
Uncertainty level	Low, parameter is monitored and subject to QA/QC procedures applied in CDM monitoring methodologies such as AM0029

Data/parameter:	GWP_{CH_4}
Data unit:	tCO_2/tCH_4
Description:	Global warming potential of CH_4 valid for the commitment period. Obtained from IPCC.
Source of data:	-
Measurement procedures (if any):	-
Monitoring frequency	-
QA/QC procedures	-
Any comment:	-
Uncertainty level	Low, given external source that provides it (IPCC)

Data/parameter:	NCV_{NG} / $NCV_{FF,i,y}$
Data unit:	TJ/t
Description:	Lower heating value of the natural gas/fossil fuel combusted (in TJ/t or TJ/10^3 normal m^3).
Source of data:	As per purchase certificates or IPCC default data.
Measurement procedures (if any):	-
Monitoring frequency	-
QA/QC procedures	-
Any comment:	-
Uncertainty level	Low, the source is a credible host country source such as the fuel supplier of an third part source such as the IPCC.

Data/parameter:	$HWEN_{BL,j,y}$
Data unit:	TJ/tonne
Description:	The specific enthalpy of hot water produced by the project facility j in the year y (TJ/ tonne).
Source of data:	This data shall be obtained using temperature of the hot water purchased measured at the project facility 'j' using data from the steam tables.
Measurement procedures (if any):	Use monitored temperature of the hot water produced by the project facility 'j' to obtain specific enthalpy.
Monitoring frequency	Monthly
QA/QC procedures	Meters shall be calibrated as per their data book. Measuring conditions shall be as per meters data book. Check consistency with historical monitored data.
Any comment:	If heat meter is available, separate temperature readings are not

	required.
Uncertainty level	Low, provided the given QA/QC procedures and monitoring frequencies are adhered to. Where the parameter is determined based on measured temperature the enthalpy is determined from steam tables. Hence uncertainty is also low.

Data/parameter:	Hot water temperature
Data unit:	°C
Description:	Temperature of hot water purchased by project customer ‘i’.
Source of data:	Temperature meters at project facility ‘j’.
Measurement procedures (if any):	Read temperature meter daily and calculate monthly average. Store information until 2 years after the end of the crediting period.
Monitoring frequency	Daily measurements and monthly average.
QA/QC procedures	Meters shall be calibrated as per their data book. Measuring conditions shall be as per meters data book. Check consistency with historical monitored data.
Any comment:	-
Uncertainty level	Low, parameter is monitored and subject to QA/QC procedures and monitoring frequency applied in CDM monitoring methodologies such as AM0048 to similar variables

Data/parameter:	Water return temperature
Data unit:	°C
Description:	Temperature of warm water returned to hot water generating facility.
Source of data:	Temperature meters at project facility ‘j’.
Measurement procedures (if any):	Read temperature meter daily and calculate monthly average. Store information until 2 years after the end of the crediting period.
Monitoring frequency	Daily measurements and monthly average.
QA/QC procedures	Meters shall be calibrated as per their data book. Measuring conditions shall be as per meters data book. Check consistency with historical monitored data.
Any comment:	To be applied when using Option II.A.b.
Uncertainty level	Low, parameter is monitored and subject to QA/QC procedures and monitoring frequency applied in CDM monitoring methodologies such as AM0048 to similar variables

Data/parameter:	Steam condensate temperature
Data unit:	°C
Description:	Temperature of condensate from existing heat exchanger used by customer ‘i ‘ to produce hot water or by the supplier of hot water

	to customer i
Source of data:	Temperature meters
Measurement procedures (if any):	Store information until 2 years after the end of the crediting period.
Monitoring frequency	Daily measurements and monthly average.
QA/QC procedures	Meters shall be calibrated as per their data book. Measuring conditions shall be as per meters data book. Check consistency with historical monitored data.
Any comment:	To be used when applying Option II.B.a.i
Uncertainty level	Low, parameter is monitored and subject to QA/QC procedures and monitoring frequency applied in CDM monitoring methodologies such as AM0048 to similar variables. Where defaults are used, the validity of these defaults is verified annually to determine if significant changes have been made to operating conditions (pressure) of the condensate system or if flash steam recovery system is added or it operating pressure increased.

Data/parameter:	$HWP_{BL,j,y}$
Data unit:	tonnes/yr
Description:	The amount of hot water produced by project facility 'j' and supplied to project customer 'i' in the year y (in tonnes)
Source of data:	Measured at the project facility 'j'.
Measurement procedures (if any):	Read hot water meter and store information until 2 years after the end of the crediting period.
Monitoring frequency	Monthly
QA/QC procedures	Meters shall be calibrated as per their data book. Measuring conditions shall be as per meters data book. Check consistency with historical monitored data. Crosscheck with purchase receipts and hot water supply data at project site.
Any comment:	-
Uncertainty level	Low, the parameter is monitored and subject to QA/QC procedures which are common to those demanded in other CDM methodologies such as AM0029 and AM0048. It can be cross checked with billing information

Data/parameter:	$SP_{BL,j,y}$
Data unit:	tonnes/yr
Description:	Quantity of steam produced by the project facility 'j' and supplied to the project customer 'i' in the year y, (in tonnes)
Source of data:	Measured at the project facility 'j'.
Measurement procedures (if any):	Read steam meter and store information until 2 years after the end of the crediting period.

Monitoring frequency	Monthly
QA/QC procedures	Meters shall be calibrated as per their data book. Measuring conditions shall be as per meters data book. Check consistency with historical monitored data. Crosscheck with invoices and steam supply data at project site.
Any comment:	-
Uncertainty level	Low, the parameter is monitored and subject to QA/QC procedures which are common to those demanded in other CDM methodologies such as AM0029 and AM0048. It can be cross checked with billing information

GUIDANCE TO THE APPLICATION OF THE METHODOLOGY AND THE PREPARATION OF THE VCS PROJECT DESCRIPTION

1. Project location including geographic and physical information allowing the unique identification and delineation of the specific extent of the project should be provided in the PDD.

2. In line with the requirements of the VCS PD format, the project proponent, who applies the new VCS methodology, should provide a detailed description of:

(a)The scenario existing prior to the start of the implementation of the project activity, with a list of the equipment(s) and systems in operation at that time;

(b) The scope of activities/measures that are being implemented within the project activity, with a list of the equipment(s) and systems that will be installed and/or modified within the project activity/activities.

The project implementation schedule (precise schedule of works) should be described in detail with indication of the current status. Project proponents should indicate the source for the technical data provided in the PDD.

3. The technical specifications of the equipment installed at the site of the project activity should be disclosed together with the consumption of fuel, electricity, net calorific value of the fuel used together with detailed information on quality and quantity of heat and power generated.

4. When designing the monitoring plan in the VCS PD the project proponent should provide where possible an organigram illustrating the monitoring and reporting system organizational structure. Where possible, names of the staff with monitoring and reporting functions should be included in the PD.

5. The project proponent who applies the VCS methodology should describe how staff responsible for monitoring, recording and maintenance and calibration of monitoring equipment shall be trained.

6. Project emissions which are not addressed in the new methodology shall be calculated and compared with 1% of the overall average annual emissions reductions. They can only be excluded from further analysis they represent less than 1% of the total expected emission reductions.”

7. In cases where the project activity results in the decommissioning of a steam and/or hot water generating facility at the project customer’s site, the project proponent shall describe if there is any possibility that this may result in leakage. If it is deemed that leakage may occur, then the project proponent shall describe a means of estimating in a conservative manner what such leakage may be.

If however it is argued that the project activity results in the replacement of equipment and that the leakage due to the use of the replaced equipment in another activity can be neglected because the replaced equipment is scrapped, then an independent monitoring of the scrapping of the replaced equipment shall be implemented. The monitoring should include a check to ensure that the name plate of the equipment scrapped corresponds to that which has been replaced. For this purpose, scrapped equipment should be stored until such correspondence has been checked. The scrapping of replaced equipment should be documented and independently verified.

A.3.3 Electric Vehicle Charging Systems

VCS Methodology

VM0038

Methodology for Electric Vehicle Charging Systems

Version 1.0

18 September 2018

Sectoral Scopes 1 & 7

This methodology was developed by the Climate Neutral Business Network, a project of Strategic Environmental Associates Inc, based upon generous support from the EV Charging Carbon Coalition (EVCCC).

The EVCCC seeks to open up access to the carbon capital markets for EV charging systems in order to strengthen their business case fundamentals and accelerate deployment. Beyond GM's business case development, founding members include:

- Electrify America LLC/Audi of America
- Exelon
- EVgo Services LLC
- Siemens
- Connecticut Green Bank
- Carbon Neutral Cities Alliance (including Portland, San Francisco, Seattle, Palo Alto, NYC, Minneapolis, Vancouver BC, Sydney, Adelaide, AU)

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1 SOURCES

This methodology uses the latest version of the following module:

- *VMD0049 Activity Method for Determining Additionality of Electric Vehicle Charging Systems*

This methodology used the latest version the following tools:

- CDM methodological tool *Demonstration of additionality of small-scale project activities*
- CDM methodological *Tool for the demonstration and assessment of additionality*

This methodology is based upon approaches used in the following methodology:

- CDM methodology *AMS-III.C. Emission Reductions by Electric and Hybrid Vehicles*[1].

2 SUMMARY DESCRIPTION OF THE METHODOLOGY

Additionality and Crediting Method	
Additionality	• Projects eligible to apply module VMD0049: Activity method • All other projects: Project method
Crediting Baseline	Project method

This methodology applies to the charging of electric vehicles (EVs) through EV charging systems, including their associated infrastructure, whose GHG emission reductions are achieved through the displacement of emissions from conventional fossil fuel vehicles used for passenger and freight transportation as a result of the electricity delivered by the project chargers.

This methodology provides easy-to-use monitoring parameters to quantify emission reductions, and also establishes default factors for the estimation of certain parameters for projects located in the United States and Canada as an alternative to project-specific calculations.

Finally, this methodology is applicable globally, and provides a positive list for determining additionality for regions with less than five percent market penetration of electric vehicles. The positive list is found in VCS module *VMD0049 Activity Method for Determining Additionality of Electric Vehicle Charging Systems.*

[1] This methodology was based on AMS.III.C.,version 15.0. See CDM website: https://cdm.unfccc.int/methodologies/index.html

3 DEFINITIONS

In addition to the definitions set out in VCS document *Program Definitions*, the following definitions apply to this methodology:

Applicable Fleets

The class of EVs eligible and technically able to charge at EV chargers associated with the project. For LDV projects, these applicable fleets comprise[2] BEVs and PHEVs for L1 and L2 chargers, and BEVs for DCFCs. For HDV projects, these applicable fleets comprise the MDV/HDV electric vehicles eligible to charge at the project's set of EV chargers.

Associated Infrastructure (AI)

Stationary battery storage devices[3] and dedicated renewable energy systems (e.g., solar or biofuel from on-site or other locations which use dedicated direct transmission lines) integrated as part of EV charging systems and managed by their control units. Associated infrastructure includes on-site battery storage systems which can store and dispatch electricity to and/or from any on-site renewable power systems, the grid, and/or the EV batteries. Associated infrastructure also includes the EV batteries themselves and thus includes EV vehicle-to-grid (V2G) and EV to on-site battery exchanges of electricity.

Associated Infrastructure Metering Systems

Systems used to track electricity flows between AI devices, whether using meters and/or associated measurement systems within or external to the EV charger. These may include upstream metering on the grid-side of the adequate metering system (e.g., where meters are installed grid-side of an on-site battery) and/or downstream metering (e.g., where metering takes place within the charger unit itself, downstream of the on-site battery).

Battery Electric Vehicle (BEV)

An EV which relies exclusively upon electricity delivered from an external EV charging system for its power in order to propel its motion

Charging Networks

A collection of charging systems which service any given applicable fleet

Closed Charging Networks

A collection of charging systems for which composition of the applicable fleet is constrained to a particular sub-set of EVs whose composition and operating characteristics of both the applicable

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[2] There may be a very few PHEVs which also have the plug capability to charge at DCFCs (e.g., Mitsubishi Outlander); these are considered de minimis. Similarly, the BMW i3 REX (with range extender) is technically a PHEV, but only 5% of i3s use the range extender in practice. Moreover, Argonne National Laboratory and California classify the REX as a BEV, and therefore it is included in the BEV category for default factor calculation purposes in this methodology.

[3] For larger powered systems (e.g., 150kw, 320kw), stationary battery systems may become a more typical integrated part of the EV charging system infrastructure over time (e.g., to mitigate demand peak charges from utilities); they are controlled by the charging system's control unit and are located close to the site within the charging system's metering to the utility.

and comparable fleets can be specifically identified and documented (e.g., a transit agency's e-bus charging network)

Comparable Fleets
Those fossil-fuel vehicles whose travel characteristics have been defined to be comparable to the EVs in each applicable fleet as determined in Section 4 below

DC Fast Charger (DCFC)
A charger which provides direct current charging (typically at 200-1000V) from an off-board[4] charger with a power rating above 11kw. Typical DCFC ratings are 50kw, with the newest systems for passenger vehicles in the 150kw and 320 kw ranges. DCFC classifications are defined as:

- DCFC 50kw: capable of delivering maximum power from 11kw to 62.5kw
- DCFC 100kw: capable of delivering maximum power from 63kw to 110kw (i.e., 200A)
- DCFC 150kw: capable of delivering maximum power from 111kw to 160kw (i.e., 200A@800V or 350A@400V, some with cooled connectors)
- DCFC 320kw: capable of delivering maximum power from 161kw and 360kw (i.e., cooled connectors)
- DCFC 500kw: capable delivering maximum power from 361kw and above (i.e., different connectors)

Where no kw classification is specified in this methodology, DCFC includes all classes defined above.

Dedicated Renewable Energy
Renewable power (e.g., solar, wind, and bio-fuel) supplied either from sources on-site within the associated infrastructure of the project, or received from a dedicated supply source via a direct transmission line. These renewable sources represent a distinct segment, differentiated from the renewable electricity supplied via the broader grid. These dedicated renewables may also be delivered in part for use on the main grid.

Electric Vehicle (EV)
Vehicles, including BEVs and PHEVs, spanning both passenger cars, LDVs and HDVs, powered by the external electricity sources of charging systems. EVs do not include hybrid-only vehicles since they do not consume electricity from externally generated sources.

[4]See SAE standards:
http://grouper.ieee.org/groups/earthobservationsSCC/IEEE_SAE_J1772_Update_10_02_08_Gery_Kissel.pdf

EV Chargers

Charging dispensers and their metering systems including L1, L2 and/or DCFC units which provide electricity to EVs within an applicable fleet and which may form part of an EV charging system

EV Charging Systems

A set of EV chargers including L1, L2 and/or DCFC and their associated infrastructure (if any) which, when located at a given charging site, provide electricity to EVs within a given applicable fleet, and which may form part of a charging network

EV Market Share

The number of EVs on the road within a geographic region, expressed as a percentage of total vehicles on the road within a geographic region, segmented for applicable fleets across LDV and HDV sectors

Heavy Duty Vehicles (HDV)

Vehicles consistent with definitions provided by the governing national regulatory system(s) of the project location. HDVs may also include medium duty vehicles (MDVs). These must be consistent with the data sources used in the standardized tests and default ER factors applied, if any[5].

Kwh/100 Mile Ratings

Ratings as provided by credible national government/regulatory sources which establish the kwh consumed to travel 100 miles, sourced for each EV model within applicable fleets, and used to calculate the weighted average Applicable Fleet's Electricity Consumption (AFEC) rating

Level 1 Charger (L1)

A charger which provides 120V alternating current charging services to the vehicle's on-board charger with a power rating up to 1.8kw

Level 2 Charger (L2)[6]

A charger which provides 240V alternating current charging services to the vehicle's on-board charger with a power rating up to 20kw (typically from 3.3kw to 6.6 kw)

Light Duty Vehicles (LDV)

Cars and trucks consistent with definitions provided by the governing national regulatory system(s) of the project location. These must be consistent with the data sources used in the standardized tests and default ER factors applied, if any[7].

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[5] For example, in the United States, HDVs are specified as including both HDVs and those MDVs with Gross Vehicle Weight Ratings (GVWR) of more than 14,000lbs (typically from class 4 and above), consistent with the IHS Markit data sources applied in the development of the default factors. HDV vehicles include both e-buses and e-trucks.

[6] Note that, in London UK, L2 chargers have been referenced as fast chargers. And, DCFCs are referenced as rapid chargers. Regardless of nomenclature, the chargers will be defined against the technical criteria provided in this methodology.

[7] For example, in the United States, LDVs are specified as including vehicles with) GVWR up to and including 14,000lbs, (classes 1, 2, and 3) and must therefore include those Medium Duty Vehicles (MDVs) up to this same

Medium and Heavy Duty Electric Vehicle (HDV EV)

Medium duty and heavy duty vehicles (collectively defined as *HDV*) comprising both BEV and PHEV HDV electric vehicles, including e-buses and e-truck categories, which rely upon electricity delivered from external EV charging systems for their power

Miles per gallon (MPG) ratings

Mile per gallon ratings as provided by credible national government/regulatory sources establish the miles traveled per gallon of fuel consumed, for those fossil fuel vehicles deemed comparable per Section 4 to the EV's applicable fleet[8]

Open Charging Networks

A charging network where the applicable fleet is not constrained to a particular sub-set of EVs whose composition and operating characteristics of both the applicable and comparable fleets can be identified and documented, as with a closed charging network

Plug-in Hybrid Electric Vehicle (PHEV)

A vehicle combining an internal combustion engine and one or more electric motors, which must also be capable of receiving delivered electricity by plugging into an external EV charging system for its power in order to propel its motion

Private Charging Networks

Charging systems where charger access is limited to a defined applicable fleet. For example, residential chargers would be considered private since access is restricted, as would a city's chargers if their use was limited to the charging of the city's own EV fleet vehicles. Private refers to the limited degree of access to the chargers, not the charging system's owner's status (since public city chargers can use private charging networks). The composition of those EVs accessing the network need not be known (that is, both open (e.g., residential) and closed (e.g., e-bus transit agency charging) networks can be private if access is limited).

4 APPLICABILITY CONDITIONS

This methodology applies to project activities which install EV charging systems, including their associated infrastructure, in order to charge EV applicable fleets whose GHG emission reductions are achieved through the displacement of conventional fossil fuel vehicles used for passenger and freight transportation as a result of the electricity delivered by project chargers.

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weight limit, consistent with the IHS Markit data sources applied in the development of the default factors. This 14,000lbs GVWR values is based upon definitions used and supplied by IHS Markit data for light duty vehicles, whose data forms the basis for most US EV market analysis publications. Commercial applications in the 8500-14000 lb Class 2b and 3 are a de minimis proportion of total LDV's. See also: http://changingears.com/rv-sec-tow-vehicles-classes.shtml and https://www.afdc.energy.gov/data/10380 Lighter MDV's include the types of vehicles which also use the main LDV charging networks (e.g., retirement home vans).

[8] For countries using other metrics (e.g., ratings in Europe for CO2 per km), conversion guidance is given in Section 8 below.

Projects must comply with all applicability conditions set out below:

1) The applicable fleets of projects applying this methodology are limited to all LDV BEVs and PHEVs[9], and HDV EVs. For LDV projects, these applicable fleets comprise[10] BEVs and PHEVs for L1 and L2 chargers, and BEVs for DCFCs. For HDV projects, these applicable fleets comprise MDV/HDV electric buses and trucks, both BEV and PHEV, eligible to charge at the project's set of EV charging systems.

2) Project proponents must demonstrate that the EV models comprising the applicable fleet of the project are comparable to their conventional fossil fuel baseline vehicles using the following means:

    - Project and baseline vehicles belong to the same vehicle category (e.g., car, motorcycle, bus, truck, LDV, MDV, HDV);
    - Project and baseline vehicles have comparable passenger/load capacity (comparing the baseline vehicle with the respective project vehicle).

    Note that where project proponents apply the baseline emission default factors for MPG and AFEC determined for the US and Canada, this comparability requirement between applicable and comparable fleet models has already been completed and satisfied.

3) In order to demonstrate that double counting of emission reduction will not occur, the project proponent must maintain an inventory of EV chargers included in the project, including their L1/L2/DCFC classifications and unique identifiers; other measures may include disclosure of credit ownership to EV drivers. Double counting relative to any issued GHG credits[11] from projects that introduce EV fleets[12] will be addressed using the emission reduction discount adjustments in Section 8.4 below[13]. Where associated infrastructure and/or renewable power (on-site and/or direct transmission) are included in an EV charging system, this must be referenced and described in the charging system's inventory. Project documentation must also include the following for each EV charger:

    - Classification using the performance voltage, AC/DC basis and kw power specifications given for L1, L2 and DCFC 50/100/150/320/500 definitions

[9] Hybrid-only vehicles, which do not have batteries capable of receiving electricity to propel their motion, are not eligible under this methodology

[10] There may be a very few PHEVs which also have the plug capability to charge at DCFCs (e.g., Mitsubishi Outlander); these are considered de minimis. Similarly, the BMW i3 REX (with range extender) is technically a PHEV, but only 5% of i3s use the range extender in practice. Moreover, Argonne National Laboratory and California classify the REX as a BEV, and therefore it is included in the BEV category for default factor calculation purposes in this methodology.

[11] Credits for GHG emission reductions issued by a GHG program such as the American Carbon Registry (ACR) Climate Action Reserve (CAR), Verified Carbon Standard (VCS), or the UNFCCC's Clean Development Mechanism (CDM).

[12] For example, projects that apply CDM methodology AMS.III.C.

[13] Double counting related to any jurisdictional emission trading systems or commitments (e.g., cap-and-trade programs, etc.) must still be assessed per the VCS rules.

- Unique identifiers, including the geo-spatial coordinates and one other unique reference such as NEMA codes, customer codes, equipment serial numbers, charger ID codes, or AFDC ID codes

4) This methodology is applicable to EV charging systems utilizing AI to provide electricity to and from EVs, on-site batteries and renewables[14] under the condition that the AI must include adequate metering systems (e.g., meters/sub-meters and/or associated measurement systems). These metering systems must measure and accurately trace all electricity deliveries and receipts from all such interrelated associated infrastructure sources. This includes electricity sourced from/returned to the grid, dedicated renewable energy generated on-site (including RE sourced from direct transmission lines), on-site storage batteries, and/or the EV's on-board battery.

5) Projects with estimated annual emission reductions of over 60,000 tCO_{2e}[15] (large-scale) are permitted where project proponents can demonstrate that the project is located in a country with credible national data sources for GHG emission calculations. Otherwise, projects are limited to annual emission reductions equal to or under 60,000 tCO_{2e} (small-scale). Projects located in Annex I and II countries, and countries referenced by EIA data sources, are automatically eligible to be of any scale. All regions listed in module *VMD0049 Activity Method for Determining Additionality of Electric Vehicle Charging Systems* meet these criteria and thus are not limited in scale.

6) Project proponents must demonstrate proof of ownership of emission reductions which may be achieved through the following:

   - With the charging system owners through contractual agreements, terms of service, utility program participation rules, or other means, and/or
   - With EV drivers through disclosure of credit ownership (e.g., through dispenser notices, screen displays, terms of service, etc.).

5 PROJECT BOUNDARY

The project boundary is comprised of the following:

1) The applicable fleets for the project EV chargers;
2) The geographic boundaries where the EV charging systems are located;
3) The EV charging systems of the project activity including their electricity supply sources and associated infrastructure.

The greenhouse gases included in or excluded from the project boundary are shown in Table 1 below.

[14] AI may store and dispatch electricity both to and from multiple sources, both on site and regionally.
[15] The small and large scale boundary was drawn from CDM methodology AMS-III.C.

Table 1: GHG Sources Included In or Excluded From the Project Boundary

Source		Gas	Included?	Justification/Explanation
Baseline	Fossil fuel combustion of vehicles displaced by project activities	CO_2	Yes	Main emission source
		CH_4	Optional	May be excluded for simplification
		N_2O	Optional	May be excluded for simplification
		Other	No	Not Applicable
Project	Electricity consumption via grid	CO_2	Yes	Main emission source
		CH_4	Optional	May be excluded for simplification. Where included in the baseline, source must also be accounted in project emissions.
		N_2O	Optional	May be excluded for simplification. Where included in the baseline, source must also be accounted in project emissions.
		Other	No	Not Applicable.
	Renewables via on-site/direct transmission	CO_2	Yes	Main emission source
		CH_4	Optional	May be excluded for simplification. Where included in the baseline, source must also be accounted in project emissions.
		N_2O	Optional	May be excluded for simplification. Where included in the baseline, source must also be accounted in project emissions.
		Other	No	Not Applicable
	On-site battery storage	CO_2	Yes	Main emission source
		CH_4	Optional	May be excluded for simplification. Where included in the baseline, source must also be accounted in project emissions.
		N_2O	Optional	May be excluded for simplification. Where included in the baseline, source must also be accounted in project emissions.
		Other	No	Not Applicable
		CO_2	Yes	Derived emission source[16]

[16] The EV battery is a derived emission source based upon the kwh received from the grid, dedicated renewables and on-site battery. It does not have a separate independent emissions factor since any kwh the EV battery returns to the grid or the on-site battery are netted out (in NEC and NECT) against the kwh delivered to the EV from these sources using their respective emissions factors. See Equations 7, 8, and 9 and Appendix 2.

Source		Gas	Included?	Justification/Explanation
	EV battery storage in vehicle	CH_4	Optional	May be excluded for simplification. Where included in the baseline, source must also be accounted in project emissions.
		N_2O	Optional	May be excluded for simplification. Where included in the baseline, source must also be accounted in project emissions.
		Other	No	Not Applicable

6 BASELINE SCENARIO

The baseline scenario is the operation of comparable fleets (the comparability of baseline and project applicable fleet vehicles to be demonstrated as per indicators set out in applicability conditions in Section 4 above), that would have been used to provide the same transportation service in the absence of the project.

7 ADDITIONALITY

Project proponents applying this methodology must determine additionality using the procedure described below:

Step 1: Regulatory Surplus

Project proponents must demonstrate regulatory surplus in accordance with the rules and requirements regarding regulatory surplus set out in the latest version of the *VCS Standard*.

Step 2: Positive List

The applicability conditions of the latest version of VCS module *VMD0049 Activity Method for Determining Additionality of Electric Vehicle Charging Systems* represent the positive list. The positive list was established using the activity penetration option (Option A in the *VCS Standard*). Projects that meet all applicability conditions of this methodology and VCS module *VMD0049 Activity Method for Determining Additionality of Electric Vehicle Charging Systems* are deemed additional.

Step 3: Project Method

Where Step 2 is not applicable, project proponents may apply the following[17]:

- Where the project is small-scale, the project proponent must demonstrate that the project activity would otherwise not be implemented due to the existence of one or more

[17] When applying either tool, regardless of which entity is implementing the project, project proponents may demonstrate that barriers apply for charging service providers and/or their associated partners (e.g., installation customers, utilities, end-users, charging system network service providers, and EV manufacturer/retailer).

barrier(s) listed in the latest version of the CDM methodological tool *Demonstration of additionality of small-scale project activities*.

- Where the project is large-scale, the project proponent must apply the latest version of the CDM *Tool for the demonstration and assessment of additionality*.

8 QUANTIFICATION OF GHG EMISSION REDUCTIONS AND REMOVALS

8.1 Baseline Emissions

Baseline emissions are calculated by converting the electricity used to charge project applicable fleet vehicles at the EV chargers into distance travelled, and multiplying this by the emission factor for fossil fuels used by baseline comparable fleet vehicles to travel the same distance. Baseline emissions must be calculated as follows:

$$BE_y = \sum_{i,f} ED_{iy} * EF_{ify} * 100 * IR_i^{y-1} / (AFEC_{iy} * MPG_{iy}) \quad (1)$$

Where:

BE_y = Baseline emissions in year y (tCO_2e)
$ED_{i,y}$ = Electricity delivered by project charging systems serving applicable fleet i in project year y (kwh)
$EF_{j,f,y}$ = Emission factor for the fossil fuel f used by comparable fleet vehicles j in year y (tCO_2e/gallon)
$IR_{i,}$ = Technology improvement rate factor for applicable fleet i
$AFEC_{i,y}$ = Weighted average electricity consumption per 100 miles rating for EVs in applicable fleet i in project year y (kwh/100 miles)
$MPG_{i,y}$ = Weighted average miles per gallon rating for the fossil fuel vehicles comparable to each EV in applicable fleet i, in project year y (miles per gallon)

Default values for $MPG_{i,y}$, $AFEC_{i,y}$, $EF_{j,f,y}$, and $IR_{i,}$ across both LDV and HDV applicable fleets can be found in the parameter tables in Section 9.1 below for the United States and Canada.

The weighted average electricity consumption per 100 miles rating for EVs in applicable fleet *i,* is calculated as follows:

$$AFEC_{iy} = \sum_a (EV_{aiy} * EVR_{aiy}) / \sum_a EVR_{aiy} \quad (2)$$

Where:

$AFEC_{i,y}$ = Weighted average electricity consumption per 100 miles rating for EVs in applicable fleet i in project year y (kwh/100 miles)
$EV_{a,j,y}$ = Electricity consumption per 100 miles rating for model a EV in applicable fleet i in project year y (kwh/100 miles)
$EVR_{a,j,y}$ = Total number of model a EV in applicable fleet i on the road by project year y (cumulative number of EVs)

The weighted average miles per gallon rating for the comparable fleet associated with each applicable fleet *i*, is calculated as follows:

$$MPG_{iy} = \sum_a (MGP_{aiy} * EVR_{aiy}) / \sum_a EVR_{aiy} \quad (3)$$

Where:

$MPG_{i,y}$ = Weighted average miles per gallon rating for fossil fuel vehicles comparable to each EV in applicable fleet *i* in project year *y* (miles per gallon)

$MPG_{a,i,y}$ = Mile per gallon rating for the fossil fuel vehicle model deemed comparable to each EV model a from applicable fleet *i* in project year *y* (miles/gallon)

$EVR_{a,i,y}$ = Total number of EV models within applicable fleet *i* on the road by project year y (cumulative number of EVs)

Guidance regarding the calculation procedures for $AFEC_{i,y}$ and $MPG_{i,y}$ and their associated parameters is given in the parameter tables in Section 9.2 and applicability condition #2.

Further details for the calculation of the default values for $MPG_{i,y}$, $AFEC_{i,y}$, can be found in Appendix 1 and the accompanying *Default MPG and AFEC Workbook* on the Verra website.

8.2 Project Emissions

Project emissions include the electricity consumption associated with the operation of the applicable fleet and must be calculated as follows:

$$PE_y = \sum_{ij} EC_{ijy} * EFkw_{ijy} \quad (4)$$

Where:

PE_y = Project emissions in year *y* (tCO_2e)

$EC_{i,j,y}$ = Electricity consumed by project chargers sourced from region *j* serving applicable fleet *i* in project year *y* (kwh/year)

$EFkw_{i,j,y}$ = Emission factor (average) for the electricity sourced from region *j* consumed by project charging systems serving applicable fleet *i* in year *y* (tCO_2e/kwh)

Where “time-of-day” estimates (i.e., estimates segmented by time periods within a single 24-hour day) for project emissions are available, Equation 5 may be applied, thus replacing Equation 4, provided that:

1) There are no time periods in which electricity is provided but not accounted for within *PEy* (i.e., the sum of all such time-of-day time periods *t* equals 24 hours in any given full day within the project).

2) Time-of-day estimates for electricity emission factors $EFkwTOD_{i,j,t,y}$ are drawn from credible, applicable sources and are provided on at least an hourly basis (e.g., the regional Independent System Operation (ISO) or applicable utility generation sources).

$$PE_y = \sum_{ijt} ECTOD_{ijty} * EFkwTOD_{ijty} \quad (5)$$

Where:

PE_y	= Project emissions in year *y* (tCO_2e)
$ECTOD_{i,j,t,y}$	= Electricity consumed by project chargers sourced from region *j* serving applicable fleet *i* during time of day period *t* in project year *y* (kwh/time period *t*)
$EFkwTOD_{j,,j,t,y}$	= Emission factor for the electricity sourced from region *j* consumed by project chargers serving applicable fleet *i* during time of day period *t* in year *y* (tCO_2e/kwh)

Where ISO does not provide greenhouse gas emission factors on an hourly basis in region *j*, but does provide fuel consumption data for electricity generation on an hourly basis, $EFkwTOD_{ji,j,t,y}$ may be estimated on a weighted average basis as follows:

1) Projects must combine the hourly fuel consumption figures (typically given as the percentage of each type of fuel consumed that hour (e.g., 50% coal, 50% natural gas)) with the emission factors for these same fuels to create a weighted average emission rate for each hourly period.

2) Emission rates for each fuel must be drawn from the same source (e.g., ISO) or consistent publication sources for region *j.*

Equations supporting these fuel-consumption based time-of-day calculations for $EFkwTOD_{j,,jy}$ are given in the equation below:

$$\mathrm{EFkwTOD_{ijty}} = \sum_{\mathrm{f}} \mathrm{F\%_{ijtfy}} * \mathrm{EFkwF_{ijtfy}} \quad (6)$$

Where:

$EFkwTOD_{j,j,t,y}$	= Emission factor for the electricity sourced from region *j* consumed by project chargers serving applicable fleet *i* during time of day period *t* in year *y* (tCO_2e/kwh)
$EFkwF_{i,j,t,f,y}$	= Emission factor applicable for the fuel type *f* used to generate the kwh sourced from region *j* consumed by project charging systems serving applicable fleet *i* during time of day period t in year y (tCO_2e/kwh)
$F\%_{i,j,t,f,y}$	= Percentage of fuel type *f* used to generate the kwh during each time of day period *t*, sourced from region *j* and consumed by EV charging systems serving applicable fleet *i* in year *y* (%)

Where projects include associated infrastructure within their charging systems, project emissions must be quantified for all such sources *s* following Equation 7, which must replace Equation 4, where the following applies:

1) The electricity emissions factor for the on-site battery must be calculated using the net weighted average of the grid and on-site renewable emission factors as provided in Equation 8 below.

2) The charging system's metering system must adequately and accurately measure and trace such net electricity kwh provided to the charging system (i.e., deliveries minus receipts) from all electricity sourced from/returned to the grid and the dedicated renewables. This includes, for example, electricity sourced from the grid, dedicated renewables (e.g., on site) and delivered to the EV directly and/or via on-site batteries, net of kwh returned back to such sources from the EV batteries[18]. See Appendix 2 for guidance on adequate metering systems.

$$PE_y = \sum_{ijs} NEC_{ijsy} * EFkwAI_{ijsy} - \sum_{ij} LEC_{ijy} * EFkwonsitebatt_{ijy} \quad (7)$$

Where:

PE_y	= Total project emissions in year y (tCO_2e)
$NEC_{i,j,s,y}$	= Electricity consumed by EV charging systems supplied from associated infrastructure source *s* net of any kwh EV/charger returned to this same source within region *j* serving applicable fleet *i* in project year *y* (kwh/year)
$EFkwAI_{j,,j,s,y}$	= Emission factor for the electricity from each associated infrastructure source *s* within region *j* consumed by project chargers serving applicable fleet *i* in year *y* (tCO_2e/kwh)
$LEC_{j,,j,y}$	= Electricity provided to the grid and/or building from on-site storage battery within region *j* serving applicable fleet *i* in project year *y* (kwh/year)
$EFkwonsitebatt_{i,j,y}$	= Emission factor for the electricity from the on-site battery associated infrastructure source *s* within region *j* consumed by project charging systems serving applicable fleet *i* in year *y* (tCO_2e/kwh)

Where projects include associated infrastructure, the emission factor for electricity from on-site battery associated infrastructure must be calculated using the net weighted average of the grid and on-site renewable emission factors as follows:

$$EFkwonsitebatt_{ijy} = \sum_{z} ECB_{ijzy} * EFkwAIZ_{ijzy} \quad (8)$$

[18] It should be noted that metering systems for associated infrastructure can include "downstream" meters close to the EV, such as those provided by DCFC onboard meters, and "upstream" meters, located grid-side such as meters monitoring kwh delivered to the on-site batteries. Guidance provided in Appendix 2 is designed to assist the application of Eq 7 given the particular features of a project's adequate metering systems.

Where:

$EFkwonsitebatt_{i,j,y}$	= Emission factor for the electricity from the on-site battery associated infrastructure source *s* within region *j* consumed by project charging systems serving applicable fleet *i* in year *y* (tCO_2e/kwh)
$ECB_{i,j,z,y}$	= Electricity consumed by on-site battery from associated infrastructure sources *z*, which comprise only the grid-connected and dedicated renewable sources, within region *j* serving applicable fleet *i* in project year *y* (kwh/year)
$EFkwAI\text{-}Z_{i,j,z,y}$	= Emission factor for the electricity from the associated infrastructure sources *z*, which comprise only the grid-connected and dedicated renewable sources, within region *j* consumed by on-site batteries serving applicable fleet *i* in year *y* (tCO_2e/kwh)

Guidance for sourcing the emission factors for the other associated infrastructure sources *s* is provided in the monitoring parameter boxes found in Section 9; guidance regarding adequate metering systems is found in Appendix 2.

Where projects include associated infrastructure and estimates for time-of-day project emissions are available, Equation 9 may be followed, thus replacing Equations 4, 5 and 7, provided that:

- There are no time periods in which electricity is provided but not accounted for within *PEy* (i.e., the sum of all such time-of-day time periods, t, equals 24 in any given full day within the project)
- Time-of-day estimates for electricity emission factors, $EFkwTODAI_{j,j,s,t,y}$ are drawn from credible, applicable sources (e.g., the regional ISO or applicable utility generation source).
- Equation 7 must be applied to calculate $EFkwTODAI_{j,j,s,t,y}$ where electricity generation's hourly fuel consumption data is relied up to provide time-of-day emission rates for each associated infrastructure source (e.g., grid-derived electricity).
- The electricity emissions factor for the on-site battery must be calculated using the net and time weighted average of the grid and on-site renewable emission factors given in Equation 8.
- The provisions regarding the charging system's adequate metering systems as given for Equation 7 and 8 (including guidance offered in Appendix 2) also apply for Equation 9 in order to adequately and accurately measure and trace net electricity consumption (NECT) from sources *s*, but are applied during each time-of day period *t* provided that:
  - For time-of-day applications of associated infrastructure calculations pertaining to the NECT for an on-site battery's kwh delivered to the EV charger, metering must be applied "upstream", on the grid-side of the on-site battery. That is, for the calculation of NECT for an on-site battery, Equation 9 will, using upstream meters, calculate the kwh delivered to EV chargers via the on-site battery from grid and/or dedicated renewable sources during the time of day period t taking

into account *when* these kwh are actually delivered *to the on-site battery* (i.e., not when delivered from this battery to the EV charger), since the GHG impacts for these kwh arise on the grid system when they are first delivered into this associated infrastructure system (that is, are delivered to the on-site battery)

- For these applications, kwh supplied by the EV to the on-site battery can be set aside (since they return to the EV at a later date) unless, during a given time period *t*, the LECT less the kwh received by the on-site battery from grid and renewable sources less the on-site battery's stored kwh is greater than zero – that is, LECT is so large that it must have drawn upon the kwh delivered to the on-site battery from the EV

In the context of these NECT calculations for the on-site battery, note that the electricity supplied from the grid to the EV charging system directly, and the electricity supplied by the EV back to the grid during any time period *t* are considered separately in the calculation of NECT for the grid.

$$PE_y = \sum_{ijst} NECT_{ijsty} * EFkwTODAI_{ijsty} - \sum_{ijt} LECT_{ijty} * EFkwonsitebatt_{ijty} \quad (9)$$

Where:

PE_y	= Project emissions in year *y* (tCO_2e)
$NECT_{i,j,s,t,y}$	= Electricity consumed by project chargers supplied from associated infrastructure source *s* net of any kwh EV/charger returned to this same source during time-of-day period *t*, within region *j* serving applicable fleet *i* in project year y (kwh/time period *t*)
$EFkwTODAI_{i,j,s,t,y}$	= Emission factor for the electricity from associated infrastructure source *s* within region *j* consumed by project chargers serving applicable fleet *i* during time-of-day period *t* in year *y* (tCO_2e/kwh)
$LECT_{i,j,t,y}$	= Electricity provided to the grid and/or building from on-site storage battery during time-of-day period *t* within region *j* serving applicable fleet *i* in project year *y* (kwh/year)
$EFkwTODonsitebatt_{i,j,t,y}$	= Emission factor for the electricity from the on-site battery associated infrastructure source *s* during time-of-day period *t* within region *j* consumed by project chargers serving applicable fleet *i* in year *y* (tCO_2e/kwh)

8.3 Leakage

Leakage is not considered an issue under this methodology, and is therefore set at zero.[19]

8.4 Net GHG Emission Reductions and Removals

Net GHG emission reductions must be calculated as follows, including application of a discount factor, D_y, to adjust pro-rata where EV fleet credits have been issued within the project region:

$$ER_y = \left(BE_y - PE_y - LE_y\right) * D_y \tag{10}$$

Where:

ER_Y = Net GHG emissions reductions and removals in year *y* (tCO_2e)

BE_Y = Baseline emissions in year *y* (tCO_2e)

PE_y = Project emissions in year *y* (tCO_2e)

LE_y = Leakage in year *y* (tCO_2e)

D_y = Discount factor to be applied in year *y* (%)

Where:

$$D_y = ERC_y/(ERF_y + ERC_y) \tag{11}$$

Where:

D_y = Discount factor to be applied in year *y* (%)

ERC_y = Sum of GHG credits[20] issued by all projects under this methodology (or others which support the introduction of EV charging systems) across this project's applicable fleet *i* categories within this total project region in project year y-1 (tCO_2e)

ERF_y = Sum of GHG credits issued by all projects under methodologies which support the introduction of EV fleets (e.g., CDM AMS.III.C) located within this project's total region

[19] This is consistent with CDM methodology AMS-III.C, which sets leakage at zero. Further analysis of crediting substitution risks between ineligible and eligible EV chargers confirmed substitution risks to be de minimis in the US due to a number of factors. These include: the large distances between public DCFC's and unlikely substitution of public DCFC by public L2 charging; a very low portion of L2s are simultaneously public, accessible (e.g. not restricted workplaces) and excluded from project crediting period under VCS grandfathering rules (when 80-90% of L2 charging takes place in homes). Furthermore, L2 to L2 substitution between eligible and ineligible chargers in this de minimis segment can also be reciprocal reducing leakage still further.

[20] Credits for GHG emission reductions issued under GHG programs such as the American Carbon Registry (ACR) Climate Action Reserve (CAR), Verified Carbon Standard (VCS), or the UNFCCC's Clean Development Mechanism (CDM).

where the applicable fleet *i* categories are the same for both this EV charging system project and projects introducing EV fleets[21], in project year y-1 (tCO_2e)

Where no GHG credits have been issued for projects that introduce EV fleets in the EV charging system project's region, D_y will be 1 (i.e., there is no discount applied).

Where project proponents can demonstrate that the EV charging systems included in the project are comprised of a private or closed charging network (e.g., a private charging network that is in secure garages, or a closed charging network for e-buses owned by a transit agencies where chargers are reserved exclusively for its own public agency fleet), and can demonstrate that relative to this closed or private charging network, no GHG credits have been issued for the introduction of EVs using the network, then D_y will be 1 (i.e., there is no discount applied)[22].

Where GHG credits have been issued for projects that introduce EV fleets for a region larger than the proposed EV charging system project (e.g., a GHG project introducing a fleet of EVs U.S.-wide, while the EV charging system project is confined to one state), then a sensible pro-rata share of the GHG credits issued for the introduction of EV fleets can be estimated for the EV charging system project's region (e.g., using the pro-rata number of EVs on the road in the EV charging system project state compared to the total in the US, using sources such as ZEVFacts.com).

9 MONITORING

Project proponents must follow the monitoring procedures provided below, noting that Sections 9.1., 9.2 and 9.3 below set out parameters and requirements for monitoring projects.

9.1 Data and Parameters Available at Validation

In addition to the parameters given below, estimates for project parameters EF, AFEC, MPG, EV, EVR, $MPG_{a,I,y}$ and ED, which are found in section 9.2, will also be provided as needed at validation.

Data / Parameter:	IR_i
Data unit	Number
Description	Technology improvement factor for applicable fleet i in year y for default value BE calculations.

[21] Therefore, to determine *ERFy*, project proponents must assess projects that introduce EV fleets both based on their location and applicable fleet category to address any potential double counting between GHG credits issued for such projects which introduce fleets of EVs and the GHG credits issued for this EV charging system project.

[22] This is allowed as private and closed charging networks, even if publicly owned, are not subject to the risk that EV fleets with issued certified GHG credits would have access to its charging network, and the EV fleets that do use the network have not issued separate GHG credits of their own. Public charging system operating as open networks would not normally be able to demonstrate such lack of access and therefore must determine if a discount factor must be applied.

Equations	1
Source of data	CDM AMS-III.C which uses the same discount rate in baseline calculations
Value applied	If baselines are calculated using updated BEy parameters for each project year y, IR_i = 1 If default values are used for these BEy parameter calculations, For LDV applicable fleets, IR_i = 1 For HDV applicable fleets, IR_i = 0.99
Justification of choice of data or description of measurement methods and procedures applied	If the baseline is calculated each year using the applicable fleet and conventional fleet statistics in each project year y, then no technology improvement rates need to be applied (since annual accurate data is used each year) $IR_{i,y}$ is therefore set to be 1. IR_i when applied to LDV projects using default values is 1 because default values for MPG factors use individual, specific MPG figures for each fossil fuel vehicle comparable to each EV model in the applicable fleet (see Appendix 1). These MPG figures only change substantially when a fossil fuel model is re-designed/updated by manufacturers which takes place on a 7-10 year cycle: this timeframe is longer than the Verra five year update cycle for parameter updates. IR_i when applied to HDV projects using default values is 0.99 because the defaults values use market-wide, class based comparable MPG factors for default calculations rather than individual, specific MPG figures for the fossil fuel vehicles comparable to each EV model (see Appendix 1) provided that: • This 0.99 improvement rate is applied to each calendar year. • This rate is taken to be 0.99 consistent with the IR default in CDM-III.C. • For project year 1, IR^(y-1) must be 1 (since any number to power 0 is 1). See justification in MPG below.
Purpose of Data	Calculation of baseline emissions
Comments	For LDV projects, the default equivalent MPG are taken from specific comparable vehicles (rather than classes of vehicles) whose MPG are only likely to change with major model upgrades (and thus remain steady for many years).

9.2 Data and Parameters Available at Verification

Data / Parameter:	$EF_{j,f,y}$
Data unit	tCO_2 or CO_2e/gallon
Description	Emission factor for the fossil fuel *f* used by the fossil fuel vehicles deemed comparable to each EV in applicable fleet *i* in year *y*
Equations	1
Source of data	Use values from credible international or national government sources such as, for the US, the EPA emissions factor[23].
Value applied	<u>For LDV projects located in the US and Canada:</u> L1/L2 (BEV and PHEV average) = 0.0088 tCO_2 or 0.0088 tCO_2e per gallon DCFC (BEV average) = 0.0088 tCO_2 or 0.0088 tCO_2e per gallon <u>For HDV projects located in the US:</u> e-buses = 0.0102 tCO_2 or 0.0102 tCO_2e per gallon e-trucks = 0.0102 tCO_2 or 0.0102 tCO_2e per gallon Projects must apply the default value using units (CO_2 or CO_2e) consistent with their project boundary choices, consistent across all project activity sources.
Justification of choice of data or description of measurement methods and procedures applied	International and national government transportation fuel emission rates have been widely established and peer reviewed. US & Canada default values calculated in Appendix 1. Note that if countries provide EF fuel emission factors using slightly different units such as CO_2 per liter simple conversions must be made during validation One common conversation from CO_2 per liter to CO_2 per gallon is given below: CO2 per gallon = CO2 per liter * 3.785 Based upon conversion factors of: 1 gall = 3.785 liters
Purpose of Data	Calculation of baseline emissions
Comments	Calculated annually, based on the fuels consumed by the fossil fuel vehicles deemed comparable to the EV models on the road each year in the applicable fleet, unless default values for baseline calculations for LDVs and/or HDVs are used.

[23] https://www.epa.gov/sites/production/files/2015-11/documents/emission-factors_nov_2015.pdf

Data / Parameter:	$AFEC_{iy}$
Data unit	kwh/100 miles
Description	Weighted average electricity consumption per 100 miles rating for EVs in applicable fleet *i* in project year *y*
Equations	1 and 2
Source of data	Calculated in Equation 2
Value applied	<u>For LDV projects located in the US:</u> L1/L2 (BEV and PHEV average) = 33.32 DCFC (BEV average) = 31.88 <u>For HDV projects located in the US:</u> e-buses = 300 e-trucks = 140 <u>For LDV projects located in Canada:</u> L1/L2 (BEV and PHEV average) = 35.44 DCFC (BEV average) = 33.00
Justification of choice of data or description of measurement methods and procedures applied	Analysis calculations can be found in Appendix 1. Changes in the value of $AFEC_{iy}$ are very gradual over time. Default values for $AFEC_{iy}$ must be updated each 5 years alongside the activity method updates US & Canada default values calculated in Appendix 1.
Purpose of Data	Calculation of baseline emissions
Comments	Calculations for AFEC for open networks (where the exact EV models charging are not known) must be established using such data sources which must be compiled on a national basis (that is, for example, the number of BEV's of each model on the road in the US for open DCFC networks). Calculations for AFEC for closed networks (e.g. where the composition and operating characteristics of both the applicable and comparable fleets are known and documented, such as with transit agency e-bus fleets) may be made using the specific composition of these fleets (that is, for example, EVR must be the number of e-buses on the road for that particular transit agency fleet). For both open and closed networks, the individual EV model's EV ratings (kwh/100 miles) must be used as applicable to the government rating agencies from which they have been sourced, (e.g. nationally for US; supra-nationally for EU), including in the periodic update of default values.

	Note again that if EVs are rated using slightly different variables such as kwh/100 km in Europe simple conversions must be made during validation. One common conversation from kwh/100km to kwh/100 miles is given below: kwh per 100 miles = kwh per 100km * 0.6215 Based upon conversion factors of: 100 km = 62.15 miles

Data / Parameter:	MPG_{iy}
Data unit	miles per gallon
Description	Weighted average miles per gallon rating for fossil fuel vehicles deemed comparable to each EV in applicable fleet *i* in project year *y*
Equations	1 and 3
Source of data	Derived in Equation 3
Value applied	<u>For LDV projects located in the US:</u> L1/L2 (BEV and PHEV average) = 29.18 DCFC (BEV average) = 29.10 <u>For HDV projects located in the US:</u> e-buses = 4.34 e-trucks = 8.60 <u>For LDV projects located in Canada:</u> L1/L2 (BEV and PHEV average) = 29.65 DCFC (BEV average) = 27.71
Justification of choice of data or description of measurement methods and procedures applied	US & Canada default values calculated in Appendix 1 For LDV projects, changes in the value of MPG_{iy} are very gradual over time given that a particular EV model's comparable fossil fuel vehicle rating must remain relatively steady for many years until the vehicle is significantly re-engineered. Thus for LDV projects, the default equivalent MPG's are taken from specific comparable vehicles (rather than classes of vehicles) whose MPG's are only likely to change with major model upgrades (and thus remain static for many years). For HDV projects, the class average MPG has been taken as the source data (see Appendix 1) so the discount rate IR_i of 0.99 must still apply. Default values for MPG_{iy} must be updated each 5 years with the activity method updates.

Purpose of Data	Calculation of baseline emissions
Comments	Consistent with guidance provided in AFEC above, weighted average is calculated for project year y based upon the number of EVs of each EV model type a in applicable fleet i on the road in project year *y* (EVR_{aiy}) combined with the mile per gallon ratings for each of these EV model's comparable fossil fuel vehicle ($MPG_{a,I,y}$). Calculations for comparable fleet's average MPG for open networks (where the exact EV models charging are not known) must be established using such data sources which must be compiled on a national basis (that is, for example, the number of BEV's of each model on the road in the US for open DCFC networks). Calculations for these fleet's MPG for closed networks (e.g. where the composition and operating characteristics of both the applicable and comparable fleets are known and documented, such as with transit agency e-bus fleets) may be made using the specific composition of these fleets (that is, for example, EVR must be the number of e-buses on the road for that particular transit agency fleet). For HDV closed networks, if the composition and operating characteristics of both the applicable and comparable fleets are known and documented (e.g. for transit agency EV charging infrastructure where the MPG's for the agency's own baseline bus operations can be established as the agency's comparable fleet of fossil fuel buses) using any of the CDM AMS-III.C Approach 1, Options 1 – 5, paragraphs 32 - 37. For both open and closed networks, the individual fossil fuel model's MPG ratings must be used as applicable to the government rating agencies from which they have been sourced (e.g., nationally for US; supra-nationally for EU), including in the periodic update of default values. MPG_{iy} is calculated annually unless the default values for baseline calculations for LDVs and/or HDVs is used following Equation 4, which employs the default value $DMPG_{iy}$. US & Canada default values calculated in Appendix 1. If standard emission values are provided using different parameters (such as CO_2/km as fossil fuel vehicle emission factors in Europe) conversions to given variable units will be made. One common conversation from liters per 100 km to miles per gallon is given below:

	MPG = 235.24 / liters per 100 km Based upon conversion factors of: 1 gall = 3.785 liters 100 km = 62.15 miles

Data / Parameter:	EV_{aiy}
Data unit	kwh/100 miles
Description	Electricity kwh consumption per 100 miles rating for EV model a within applicable fleet *i* in project year *y*
Equations	2
Source of data	Use values from credible national governmental sources such as the ratings for the US provided by US DoE Fuel Economy program[24].
Value applied	N/A
Justification of choice of data or description of measurement methods and procedures applied	National, governmental ratings provide independent third party public source.
Purpose of Data	Calculation of baseline emissions
Comments	See guidance for AFEC above. For both open and closed networks, the EV_{aiy} ratings must be used as applicable to the government rating agencies from which they have been sourced, e.g. nationally for US; supra-nationally for EU.

Data / Parameter:	EVR_{aiy}
Data unit	Cumulative number of EVs
Description	Total number of EV model *a* within applicable fleet *i* on the road by project year *y*
Equations	2 and 3
Source of data	Use values from credible national governmental sources such as the statistics provided for the US provided by the Argonne National Laboratory's monthly email updates[25]

[24] https://www.fueleconomy.gov/feg/evsbs.shtml
[25] Such as the *U.S. E-Drive vehicle monthly updates_February 2017* provided via email by ANL. The main ANL web link is found here including the email address for the database manager: https://www.anl.gov/energy-systems/project/light-duty-electric-drive-vehicles-monthly-sales-updates
[25] https://www.fueleconomy.gov/feg/pdfs/guides/FEG2016.pdf

	Closed networks may also use the number of EV's on the road using their known composition and operating characteristics of the applicable fleets they serve.
Value applied	N/A
Justification of choice of data or description of measurement methods and procedures applied	Argonne National Laboratory is an independent, trusted government source of EV data for the US market.
Purpose of Data	Calculation of baseline emissions
Comments	This value is calculated for project year y based upon the cumulative number of EVs of each EV model type *a* in applicable fleet *i* on the road by project year *y*, consistent with AFEC guidance above. In the USA, statistics for the number of EVs on the road by model type is available from several sources including Argonne National Laboratory, in their monthly emails[26], which draws upon data from hybridcars.com[27].

Data / Parameter:	$MPG_{a,I,y}$
Data unit	miles/gallon
Description	Mile per gallon rating for fossil fuel vehicle model(s) deemed comparable to EV model a from applicable fleet *i* in project year *y*
Equations	3
Source of data	See guidance for MPG_{iy} above. Use values from credible national government sources such as the US rating found in the *2016 Fuel Economy Guide*[28] For both open and closed networks, the $MPG_{a,I,y}$ ratings must be used as applicable to the government rating agencies from which they have been sourced (e.g., nationally for US; supra-nationally for EU.)
Value applied	N/A

[26] See U.S. E-Drive vehicle monthly updates_February 2017 provided via email by ANL. https://www.anl.gov/energy-systems/project/light-duty-electric-drive-vehicles-monthly-sales-updates
[27] Argonne National Lab's (ANL) monthly emails uses data sourced from the hybridcars.com web site: http://www.hybridcars.com/december-2016-dashboard/ The main ANL web link is found here including the email address for the database manager: https://www.anl.gov/energy-systems/project/light-duty-electric-drive-vehicles-monthly-sales-updates
[28] https://www.fueleconomy.gov/feg/pdfs/guides/FEG2016.pdf

Justification of choice of data or description of measurement methods and procedures applied	National governmental ratings such as those found in the US Fuel Economy Guides for the US market are independent, trusted government sources of fuel consumption ratings.
Purpose of Data	Calculation of baseline emissions
Comments	If standard emission values are provided using parameters which already incorporate fuel emission factors such as CO_2/km ratings for fossil fuel vehicle emission factors in Europe then conversions to the appropriate combination of variables must be made to establish equivalence to the parameters in these equations. For example, in Europe, fossil fuel vehicle are rated in terms of CO_2 per km (given here as EFEU). Therefore, if the EV ratings are still given as kwh per 100 miles, then such a conversion would be: CO_2 per mile = $EF_{j,f,y}$ / $MPG_{a,l,y}$ = EFEU / 0.62.

Data / Parameter:	$ED_{i,y}$
Data unit	Kwh/year
Description	Quantity of electricity delivered to EV's by project chargers serving applicable fleet i in project year y
Equations	1
Source of data	kwh delivered to EV's for project charging network using systems' actual or estimated kwh values, as below. Note that for L2 chargers, the electricity delivered, ED, will be considered the same as electricity consumed by the chargers EC since L2's are highly efficient chargers with de minimis losses due to their own power consumption. (i.e. ED = EC) For DCFC, baseline emission calculations must use ED which must be based upon the kwh delivered to the EV's which is what the chargers' own internal smart DCFC's meter measure. (By contrast, for project emissions measurements which are based on the electricity consumed by the DCFC (where efficiency losses can be more material) kwh data can be sourced either A) from this ED provided that a DCFC efficiency factor is applied or B) from kwh data metered on the grid-side of the charging system and any associated AI. See EC, ECTOD, NEC and NECT parameter boxes below for PE applications.)
Value applied	Measured value based on kwh delivered by charging systems in year y

Description of measurement methods and procedures to be applied	The kwh delivered by the charging systems for each applicable fleet i must be sourced using the following hierarchy, where projects must apply first those listed highest on the list: 1) Actual kwh sourced using smart charger measurement systems or (for L2's only) on-site grid electricity meters 2) Estimates for a project's dumb network charger segments based upon the portions of the project which has available such smart network project averages or utility-style project user survey data applicable to these same segments (e.g. for each applicable fleet across comparable segments (public, workplace, residential etc)) 3) Investments to upgrade chargers to provide actual "smart" data results by installing technologies which effectively retrofit metering[29] 4) Use of reasonable regionally applicable pilot project data (such as local utility project results) for non-metered project chargers that don't have smart actual measurements when this pilot data reasonably corresponds to comparable utilization rates to those in the project 5) In the US, use of the Department of Energy/Idaho National Laboratory's (DoE/INL) EV Project data[30] to apply average kwh per charging event data which is provided across a) different settings (public, residential, non-private residential) and b) for each US state For #2 and 4, validator reviews must consider whether projects are applying "smart"/utility/pilot project data using an appropriate project segmentation basis, so that there is a reasonably comparable basis upon which chargers operate in the "dumb" and "smart" segments. This comparability provides a reasonable basis upon which to apply the representative smart segment averages to the corresponding dumb segments of the project. Use calibrated electricity meters/smart charging system measurement systems. Calibration must be conducted according to the equipment manufacturer's specifications.
Frequency of monitoring/recording	Measured actual data must be monitored and recorded on at least an annual basis; monitoring periods for metered data can be consistent with utility reports. Estimated consumption can be

[29] For example, EMotorWerks Juicebox
[30] https://avt.inl.gov/project-type/ev-project

	made on annual basis from sources which monitor using measured/actual or metered sources per the hierarchy above.
QA/QC procedures to be applied	The consistency of metered electricity consumption should be cross-checked with receipts from electricity purchases where applicable
Purpose of Data	Calculation of baseline emissions
Calculation method:	
Comments	N/A

Data / Parameter:	$EC_{i,y}$
Data unit	Kwh/year
Description	Quantity of electricity consumed by project chargers serving applicable fleet *i* in project year *y*
Equations	4
Source of data	kwh consumption for project charging network using systems' actual or estimated kwh values, as below Note that for L2 chargers, the electricity consumed EC will be considered the same as electricity delivered to the EV's by the chargers, ED, since L2's are highly efficient chargers with de minimis losses due to their own power consumption. (i.e. ED = EC) For DCFC, EC must be based upon the kwh consumed by the charging system (since efficiency losses can be more material for DCFC's). DCFC EC data can therefore either be sourced via: A) ED, the chargers' own internal smart DCFC's meter data, provided that a DCFC efficiency factor of 92.3% is applied to the smart charger metered data[31] or B) meters which are on the grid-side of the DCFC units/AI If a project can demonstrate to validators a more accurate efficiency factor for their particular DCFC systems (for example due to improvements in DCFC technology efficiencies over time) this updated accurate efficiency factor may be substituted for the 92.3% default efficiency value.
Value applied	Measured value based on kwh consumed by charging systems in year y For DCFC, using approach A, $EC_{i,y} = ED_{i,y}/0.923$

[31] The 92.3% DCFC efficiency factor is derived from Idaho National Lab powerpoint findings as reviewed with the VVB.

Description of measurement methods and procedures to be applied	The kwh consumed by the charging systems for each applicable fleet i must be sourced using the following hierarchy, where projects must apply first those listed highest on the list: 1) Actual kwh consumed using smart charger measurement systems or on-site electricity meters 2) Estimates for a project's dumb network charger segments based upon the portions of the project which has available such smart network project averages or utility-style project user survey data applicable to these same segments (e.g. for each applicable fleet across comparable segments (public, workplace, residential etc)) 3) Investments to upgrade chargers to provide actual "smart" data results by installing technologies which effectively retrofit metering[32] 4) Use of reasonable regionally applicable pilot project data (such as local utility project results) for non-metered project chargers that don't have smart actual measurements when this pilot data reasonably corresponds to comparable utilization rates to those in the project 5) In the US, use of the Department of Energy/Idaho National Laboratory's (DoE/INL) EV Project data[33] to apply average kwh per charging event data which is provided across a) different settings (public, residential, non-private residential) and b) for each US state For #7 and 9, validator reviews must consider whether projects are applying "smart"/utility/pilot project data using an appropriate project segmentation basis, so that there is a reasonably comparable basis upon which chargers operate in the "dumb" and "smart" segments. This comparability provides a reasonable basis upon which to apply the representative smart segment averages to the corresponding dumb segments of the project. Use calibrated electricity meters/smart charging system measurement systems. Calibration must be conducted according to the equipment manufacturer's specifications.
Frequency of monitoring/recording	Measured actual data must be monitored and recorded on at least an annual basis; monitoring periods for metered data can be consistent with utility reports. Estimated consumption can be made on annual basis from sources which monitoring using measured/actual or metered sources.

[32] For example, EMotorWerks Juicebox
[33] https://avt.inl.gov/project-type/ev-project

QA/QC procedures to be applied	The consistency of metered electricity consumption should be cross-checked with receipts from electricity purchases where applicable
Purpose of Data	Calculation of baseline and project emissions
Calculation method:	
Comments	N/A

Data / Parameter	$EFkw_{i,j,y}$
Data unit	tCO_2e/kwh
Description	Emission factor for the electricity sourced from region *j* consumed by project chargers serving applicable fleet *i* in year *y*
Equations	4
Source of data	Use credible government data sources such as, for the US, the regional eGRID emission factors published by EPA[34]
Description of measurement methods and procedures to be applied	The emission factor must be consistent with the region j from which electricity is sourced (e.g. for the US with the utility's eGRID region[35]). Published utility specific emission factors are allowed for the kwh consumed from that source consistent with VCS practices which allow well documented more local electricity sources' GHG emission factors to be applied. Average emission factors (not marginal) must be used Grid-sourced and dedicated renewable kwh is treated as having zero tCO2e/kwh. Biogenic sources used on-site to generate electricity are considered dedicated renewables. Other on-site biofuels used to generate electricity must apply and justify their own emission factors for the biofuel used, such as those referenced in the same EPA source from which the other fuel emission default factors (EF) were derived[36].
Frequency of monitoring/recording	Annual updates from these published sources
QA/QC procedures to be applied	
Purpose of data	Calculation of project emissions

[34] https://www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid
[35] https://www.epa.gov/sites/production/files/2017-02/documents/egrid2014_summarytables_v2.pdf
[36] https://www.epa.gov/sites/production/files/2015-07/documents/emission-factors_2014.pdf

Calculation method:	Look up value
Comments:	Region *j* represents any region from which electricity is sourced, each of which must have a well-documented emissions factor for the electricity provided. For US projects, electricity emissions must be estimated using the EPA regional eGRID emission rates, unless other more accurate local/regional sources are available (e.g. from utilities directly serving the charging network).

Data / Parameter	$ECTOD_{i,j,t,y}$
Data unit	Kwh/time period t
Description	Quantity of electricity consumed by project chargers sourced from region j serving applicable fleet i during time of day period t in project year y
Equations	5
Source of data	kwh consumption for project charging network using systems' actual values provided these are generated using time-of-day metering The same guidance provided for $EC_{i,y}$ relative to the sources of data for L2 and DCFC apply here. So L2 data can be sourced from kwh measured as delivered to EV's or consumed by the chargers since efficiency losses are de minimis. And DCFC data may either be sourced via A) DCFC's own internal smart meter systems, provided that a DCFC efficiency factor of 92.3% is applied; or B) meters which are on the grid-side of the DCFC units/AI. Thus again for DCFC, using approach A, the value applied would be $ECTOD_{i,j,t,y}/0.923$ If a project can demonstrate to validators a more accurate efficiency factor for their particular DCFC systems (for example due to improvements in DCFC technology efficiencies over time) this updated accurate efficiency factor may be substituted for the 92.3% default efficiency value.
Description of measurement methods and procedures to be applied	The kwh supplied by the charging systems applying time of day calculations in equation 6 must be sourced as follows: 1. Using actual time-of-day kwh measurements using smart charger measurement systems or on-site electricity meters, capable of recording/monitoring kwh consumption on at minimum an hourly basis

	3. Investments to upgrade chargers to provide such time-of-day actual data results are permitted provided they supply comparable hourly reporting Electricity meters' calibration must be conducted according to the equipment manufacturer's specifications.
Frequency of monitoring/recording	Data must be monitored continuously and recorded on at least an hourly basis.
QA/QC procedures to be applied	The consistency of metered electricity generation should be cross-checked with receipts from electricity purchases where applicable
Purpose of data	Calculation of project emissions
Calculation method:	
Comments:	The sum of all such time-of-day time periods, t, must equal 24 in any given full day within the project (i.e. there are no time periods in which electricity is provided but not accounted for within PEy). This is applicable only if PE emissions are to be calculated on a time-of-day basis.

Data / Parameter	$EFkwTOD_{j,j,t,y}$
Data unit	tCO_2e/kwh
Description	Emission factor for the electricity sourced from region j consumed by project chargers serving applicable fleet i during time of day period t in year y
Equations	5
Source of data	Use credible governmental or regional utility data sources such as, for the US, those published in the US by ISO's which rely upon utilities' hourly fuel consumption figures (e.g. see PJM publications[37]) Time of day estimates for electricity emission factors, $EFkw_{i,j,t,y}$ must be drawn from credible, applicable sources (e.g. the regional ISO or applicable utility generation sources).
Description of measurement methods and procedures to be applied	If $EFkwTOD_{j,j,y}$ has already been published by utilities in region j on an hourly basis, then these figures must be used. Since hourly EFkwTOD publications may not readily be available, if in region j utilities or ISOs are publishing time of day emission factors on a basis other than hourly, then projects may use this other basis provided it is accepted by validators as reasonable (for

[37] http://www.monitoringanalytics.com/data/marginal_fuel.shtml

	example PJM publishes on-peak and off-peak emission factors) in order to accommodate ISO/utility gradual improvements in best practices for time of day emission factor reporting[38]. If in region j, the ISO provides fuel consumption data on an hourly basis, $EFkwTOD_{j,j,y}$ may be estimated on a weighted average basis using equation 6 Grid-sourced and dedicated renewable kwh is treated as having zero tCO2e/kwh Biogenic sources used on-site to generate electricity are considered dedicated renewables. Other on-site biofuels used to generate electricity must apply and justify their own emission factors for the biofuel used, such as those referenced in the same EPA source from which the other fuel emission default factors (EF) were derived[39].
Frequency of monitoring/recording	Source data (for emission factor $EFkwTOD_{j,j,y}$) must be monitored continuously and recorded on at least an hourly or prevailing best practice basis.
QA/QC procedures to be applied	
Purpose of data	Calculation of project emissions
Calculation method:	If $EFkwTOD_{j,j,y}$ is estimated using hourly fuel consumption reports (e.g. from an ISO), the weighted average calculations are given in equation 6
Comments:	The sum of all such time-of-day time periods, t, must equal 24 in any given full day within the project (i.e. there are no time periods in which electricity is provided but not accounted for within PEy). This is applicable only if PE emissions are to be calculated on a time-of-day basis

Data / Parameter	$EFkwF_{j,j,t,f,\ y}$
Data unit	tCO_2e/kwh
Description	Emission factor applicable for the fuel type f used to generate the kwh during time of day period t sourced from region j consumed by project chargers serving applicable fleet i in year y
Equations	6

[38] There are no utility/ISO EFkw hourly published rates yet available (only fuel consumption rates) but as the PJM on-peak/off-peak publications indicate such TOD rates will become more accessible over time
[39] https://www.epa.gov/sites/production/files/2015-07/documents/emission-factors_2014.pdf

Source of data	Use credible governmental or regional utility data sources such as, for the US, those published in the US by ISO's which rely upon utilities' hourly fuel consumption figures (e.g. see PJM publications[40])
Description of measurement methods and procedures to be applied	If in region j, the ISO provides fuel consumption data on an hourly basis, $EFkwF_{j,j,t,f,y}$ may be estimated on a weighted average basis using equation 6 as follows: • Projects must combine the hourly fuel consumption figures (typically given as the percentage of each type of fuel consumed that hour (50% coal, 50% natural gas)) with the emission factors for these same fuels to create a weighted average emission rate for each hourly period. • Emission rates for each fuel must be drawn from the same (e.g. the ISO) or consistent publication sources for region j (noting that these need not be generated on an hourly basis but must be updated on at least an annual basis)
Frequency of monitoring/recording	Each fuel's emission rate need not be generated on an hourly basis but averages must be generated on at least an annual basis.
QA/QC procedures to be applied	
Purpose of data	Calculation of project emissions
Calculation method:	
Comments:	Applicable only if PE emissions are to be calculated on a time-of-day basis using utility/ISO hourly fuel consumption inputs

Data / Parameter	$F\%_{ijtfy}$
Data unit	%
Description	Percentage of fuel type f used to generate the kwh DURING EACH time of day period t, sourced from region j and consumed by project chargers serving applicable fleet I in year y
Equations	6
Source of data	Use credible governmental or regional utility data sources such as, for the US, those published in the US by ISO's which rely upon utilities' hourly fuel consumption figures (e.g. see PJM publications[41])

[40] http://www.monitoringanalytics.com/data/marginal_fuel.shtml
[41] http://www.monitoringanalytics.com/data/marginal_fuel.shtml

Description of measurement methods and procedures to be applied	The hourly fuel consumption figures are typically given as the percentage of each type of fuel consumed that hour (50% coal, 50% natural gas)).
Frequency of monitoring/recording	This fuel sourced parameter data must be monitored and recorded on at least an hourly basis. Since the emission factors for each fuel type f need not be generated on an hourly but can be supplied on an annual basis, the percentage of each fuel type f used to generate the kwh during each time period will be supplied for each such time period.
QA/QC procedures to be applied	Typically a look up value
Purpose of data	Calculation of project emissions
Calculation method:	
Comments:	Applicable only if PE emissions are to be calculated on a time-of-day basis using utility/ISO hourly fuel consumption inputs

Data / Parameter	$NEC_{i,j,s,y}$
Data unit	kwh/year
Description	Electricity consumed by project chargers supplied from associated infrastructure source s net of any kwh EV/charger returned to this same source within region j serving applicable fleet i in project year y
Equations	7
Source of data	Net kwh consumption/generation for project chargers must be secured for each associated infrastructure source (whether derived from the grid, dedicated renewables or the on-site battery) as actual net kwh values using chargers' adequate metering systems The same core guidance provided for $EC_{i,y}$ relative to the sources of data for L2 and DCFC apply here. So L2 data can be sourced from kwh measured as delivered to EV's by the charger meter or as the kwh consumed by the chargers from a grid-based source since losses are de minimis. And DCFC data may either be sourced via A) DCFC's own internal smart meter systems capable of differentiating the net kwh delivered to the EV's from each source s, provided that a DCFC efficiency factor of 92.3% is applied; or B) meters which are on the grid-side of the DCFC units/AI for each source s.

	Thus again for DCFC, using approach A, the value applied would be $NEC_{i,j,s,y}$ /0.923 If project can demonstrate to validators a more accurate efficiency factor for their particular DCFC systems (for example due to improvements in DCFC technology efficiencies over time) this updated accurate efficiency factor may be substituted for the 92.3% default efficiency value.
Description of measurement methods and procedures to be applied	Projects must track the net kwh consumption/generation for charging systems from across all potential associated infrastructure sources, s, (whether grid, dedicated renewable sources, on-site battery), net of kwh supplied back from the EV battery to such sources, using the charger's metering system to track such net kwh calculations. To apply equation 7, such net kwh values must be sourced as follows: 1) Using actual kwh consumption and generation measurements using on-site or smart chargers' metering systems, capable of recording/monitoring kwh both consumed and generated on at minimum a yearly basis 2) Investments to upgrade chargers to provide such net metered actual data results are permitted provided they supply comparable reporting Associated infrastructure sources, s, for which NEC is calculated include: • grid-connected electricity from region j • and/or dedicated renewable energy generated on-site (including RE sourced from direct transmission lines) • and/or the EV vehicle's on-board battery Each of the grid and renewables sources, s, must have a well-documented emissions factor for the electricity sourced and/or dispatched Project metering systems' calibration must be conducted according to the equipment manufacturer's specifications. Projects must incorporate adequate metering systems when applying Eq 7. Guidance for the design/application of such metering systems is provided in Appendix 2.
Frequency of monitoring/recording	Measured actual data must be monitored and recorded on at least an annual basis. Monitoring periods for metered net data can be consistent with reports which the charging systems' metering system provides.

QA/QC procedures to be applied	The consistency of net metered electricity generation should be cross-checked with receipts and invoices from electricity purchases and sales where applicable
Purpose of data	Calculation of project emissions
Calculation method:	
Comments:	The charging system's metering system must adequately and accurately measure and traces such electricity deliveries and receipts from these associated infrastructure sources, (including for example electricity sourced from/returned to the grid, on-site/dedicated renewables, on-site batteries, EV batteries). Applicable only if PE emissions are to be calculated on a net metered basis integrating multiple associated infrastructure sources, s. Note: time of day, hourly monitoring of EV charging/associated infrastructure deliveries and receipts is not a necessary requirement to apply Equation 7. For combined associated infrastructure metering and time of day PE estimates, see parameters for equation 9.

Data / Parameter	$EFkwAI_{i,,j,s,y}$
Data unit	(tCO_2e/kwh)
Description	Emission factor for the net electricity from each associated infrastructure source s within region j consumed by project chargers serving applicable fleet i in year y
Equations	7
Source of data	Each of associated infrastructure source, s, must have a well-documented emissions factor for the electricity it supplies and/or dispatches as follows: • Grid-connected electricity from region j must follow the same procedures as for parameter $EFkw_{i,j,y}$ in Equation 4 (see above) • Dedicated renewable energy generated on-site, including renewable energy sourced via direct transmission lines, must set emission factors at zero • On-site storage batteries must assume the weighted average emission factor based upon the proportionate net consumption of grid and dedicated renewable energy at the charging system (see equation 8)

Description of measurement methods and procedures to be applied	For grid-connected electricity, see procedures for parameter $EFkw_{i,j,y}$ in Equation 4 For dedicated renewables, emission factors are set at zero. For on-site storage batteries, the calculations are given in equation 8. Projects must incorporate adequate metering systems when applying Eq 7 and 8. Guidance for the design/application of such metering systems is provided in Appendix 2.
Frequency of monitoring/recording	Annual, per procedures for parameter $EFkw_{i,j,y}$ in Equation 4
QA/QC procedures to be applied	
Purpose of data	Calculation of project emissions
Calculation method:	For on-site batteries see equation 8
Comments:	Applicable only if PE emissions are to be calculated on a net metered basis integrating multiple associated infrastructure sources, s. Note: time of day, hourly monitoring of EV charging/associated infrastructure deliveries and receipts is not a necessary requirement to apply Equation 7. For combined associated infrastructure metering and time of day PE estimates, see parameters for equation 9.

Data / Parameter	$LEC_{j,,j,y}$
Data unit	kwh/year
Description	Electricity provided to the grid and/or building from on-site storage battery within region j serving applicable fleet i in project year y (kwh/year)
Equations	7
Source of data	From on-site battery/charging system's adequate measurement systems
Description of measurement methods and procedures to be applied	LEC arises if on-site batteries provide kwh back to the grid or local building (for example if used as back up generators/sources of power). These kwh are not supplied to the EV charging system

	and do not result in EV miles drive and so are deducted out in Eq 7. Projects must incorporate adequate metering systems when applying Eq 7. Guidance for the design/application of such metering systems is provided in Appendix 2. Project metering systems' calibration must be conducted according to the equipment manufacturer's specifications.
Frequency of monitoring/recording	Measured actual data must be monitored and recorded on at least an annual basis.
QA/QC procedures to be applied	The consistency of such kwh should be cross-checked with other information sources where applicable
Purpose of data	Calculation of project emissions
Calculation method:	
Comments:	Applicable only if PE emissions are to be calculated on a net metered basis integrating multiple associated infrastructure sources, s. Note: time of day, hourly monitoring of EV charging/associated infrastructure deliveries and receipts is not a necessary requirement to apply Equation 7. For combined associated infrastructure metering and time of day PE estimates, see parameters for equation 9.

Data / Parameter	$EFkwonsitebatt_{i,j,s,y}$
Data unit	(tCO_2e/kwh)
Description	Emission factor for the electricity from the on-site batteries as associated infrastructure sources s within region j consumed by project chargers serving applicable fleet i in year y
Equations	8
Source of data	See data sources for Equation 8 variables below
Description of measurement methods and procedures to be applied	The emission factors for the on-site battery as an associated infrastructure source are calculated using the net weighted average of the grid and on-site renewable emission factors given using equation 8 • On-site storage batteries must assume the weighted average emission factor based upon the proportionate net consumption of grid and dedicated renewable energy at the charging system (using equation 8)

	Projects must incorporate adequate metering systems when applying Eq 8. Guidance for the design/application of such metering systems is provided in Appendix 2.
Frequency of monitoring/recording	Annual
QA/QC procedures to be applied	As for equation 8 variables below
Purpose of data	Calculation of project emissions
Calculation method:	
Comments:	Applicable only if PE emissions are to be calculated on a metered basis integrating multiple associated infrastructure sources, s.

Data / Parameter	$ECB_{i,j,z,y}$
Data unit	kwh/year
Description	Electricity consumed by on-site battery from associated infrastructure sources z, which comprise only the grid-connected and dedicated renewable sources, within region j serving applicable fleet i in project year y
Equations	8
Source of data	As for $NEC_{i,j,s,y}$ in equation 7
Description of measurement methods and procedures to be applied	As for $NEC_{i,j,s,y}$ in equation 7 Projects must incorporate adequate metering systems when applying Eq 8. Guidance for the design/application of such metering systems is provided in Appendix 2. In particular, metering systems must need to measure the kwh delivered to the onsite battery from grid and/or renewable sources as distinct from those delivered directly to the EV charger from the grid and/or dedicated renewable sources
Frequency of monitoring/recording	As for $NEC_{i,j,s,y}$ in equation 7
QA/QC procedures to be applied	
Purpose of data	Calculation of project emissions
Calculation method:	As for $NEC_{i,j,s,y}$ in equation 7
Comments:	Applicable only if PE emissions are to be calculated on a metered basis integrating multiple associated infrastructure sources, s,

	when these sources are grid-connected electricity and dedicated renewable energy.

Data / Parameter	$EFkwAI\text{-}Z_{j,,j,z,y}$
Data unit	(tCO_2e/kwh)
Description	Emission factor for the electricity from the associated infrastructure sources, z, which comprise only the grid-connected and dedicated renewable sources, within region j consumed by on site battery serving applicable fleet i in year y
Equations	8
Source of data	As for $EFkwAI_{j,,j,s,y}$ for grid connected and renewable energy in equation 7
Description of measurement methods and procedures to be applied	As for $EFkwAI_{j,,j,s,y}$ for grid connected and renewable energy in equation 7 Projects must incorporate adequate metering systems when applying Eq 8. Guidance for the design/application of such metering systems is provided in Appendix 2.
Frequency of monitoring/recording	As for $EFkwAI_{j,,j,s,y}$ for grid connected and renewable energy in equation 7
QA/QC procedures to be applied	
Purpose of data	Calculation of project emissions
Calculation method:	As for $EFkwAI_{j,,j,s,y}$ for grid connected and renewable energy in equation 7
Comments:	Applicable only if PE emissions are to be calculated on a metered basis integrating multiple associated infrastructure sources, s, when these sources are grid-connected electricity and dedicated renewable energy.

Data / Parameter	$NECT_{i,j,s,t,y}$
Data unit	Kwh/time period t
Description	Electricity consumed by project chargers supplied from associated infrastructure source s net of any kwh EV/charger returned to this same source during time-of-day period t, within region j serving applicable fleet i in project year y
Equations	9

Source of data	Net electricity consumed by project chargers during time-of-day period t from associated infrastructure sources s, within region j serving applicable fleet i in project year y The same core guidance provided for $EC_{i,y}$ relative to the sources of data for L2 and DCFC apply here. So L2 data can be sourced from kwh measured as delivered to EV's by the charger meter or as the kwh consumed by the chargers from a grid-based source since losses are de minimis. And DCFC data may either be sourced via A) DCFC's own internal smart meter systems capable of differentiating the net kwh delivered to the EV's from each source s during time period t, provided that a DCFC efficiency factor of 92.3% is applied; or B) meters which are on the grid-side of the DCFC units/AI for each source s and time period t. Thus again for DCFC, using approach A, the value applied would be $NECT_{i,j,s,t,y}$ /0.923 If a project can demonstrate to validators a more accurate efficiency factor for their particular DCFC systems (for example due to improvements in DCFC technology efficiencies over time) this updated accurate efficiency factor may be substituted for the 92.3% default efficiency value.
Description of measurement methods and procedures to be applied	Follow those for parameters $EC_{i,j,t,y}$ in equation 5 and $NEC_{i,j,s,y}$ in equation 7 Projects must incorporate adequate metering systems when applying Eq 9. Guidance for the design/application of such metering systems, considered as applied to each time period t, is provided in Appendix 2. In addition, for time of day applications of associated infrastructure calculations pertaining to the NECT for an on-site battery's kwh delivered to the EV charger, metering must be applied "upstream", on the grid-side of the on-site battery. That is for the calculation of NECT for an on-site battery, Eq 9 must, using upstream meters, calculate the kwh delivered to EV chargers via the on-site battery from grid and/or dedicated renewable sources during the time of day period t taking into account *when* these kwh are actually delivered *to the on-site battery* (not when delivered from this battery to the EV charger) since the GHG impacts for these kwh arise on the grid system when they are first delivered into this associated infrastructure system (that is are delivered to the on site battery) For these applications, kwh supplied by the EV to the on-site battery can be set aside (since they return to the EV at a later

	date) unless, during a given time period t, the LEC less the kwh received by the on site battery from grid and renewable sources less the on-site battery's stored kwh is greater than zero – that is LEC is so large that it must have drawn upon the kwh delivered to the on-site battery from the EV In the context of these NECT calculations for the on-site battery, it should be noted that the kwh supplied from the grid to the EV charging system directly – and those kwh supplied by the EV back to the grid – during any time period t are still considered separately in the calculation of NECT for the grid.
Frequency of monitoring/recording	Follow those for parameters $EC_{i,j,t,y}$ in equation 5 and $NEC_{i,j,s,y}$ in equation 7
QA/QC procedures to be applied	Follow those for parameters $EC_{i,j,t,y}$ in equation 5 and $NEC_{i,j,s,y}$ in equation 7
Purpose of data	Calculation of project emissions
Calculation method:	
Comments:	Follow those for parameters $EC_{i,j,t,y}$ in equation 5 and $NEC_{i,j,s,y}$ in equation 7 Applicable only if PE emissions are to be calculated on a time-of-day basis when also incorporating charging systems' associated infrastructure sources on a metered basis.

Data / Parameter	$EFkwTOD\text{-}AI_{i,j,s,t,y}$
Data unit	tCO_2e/kwh
Description	Emission factor for the electricity from associated infrastructure source s within region j consumed by project chargers serving applicable fleet i during time-of-day period t in year y
Equations	9
Source of data	Follow those for parameters $EFkwTOD_{j,,j,t,y}$ in equation 5 and $EFkwAI_{j,,j,s,y}$ in equation 7
Description of measurement methods and procedures to be applied	Follow those for parameters $EFkwTOD_{j,,j,t,y}$ in equation 5 and $EFkwAI_{j,,j,s,y}$ in equation 7 Projects must incorporate adequate metering systems when applying Eq 9. Guidance for the design/application of such metering systems, considered as applied to each time period t, is provided in Appendix 2.

Frequency of monitoring/recording	Follow those for parameters $EFkwTOD_{j,,j,t,y}$ in equation 5 and $EFkwAI_{j,,j,s,y}$ in equation 7
QA/QC procedures to be applied	
Purpose of data	Calculation of project emissions
Calculation method:	Follow those for parameters $EFkwTOD_{j,,j,t,y}$ in equation 5 and $EFkwAI_{j,,j,s,y}$ in equation 8
Comments:	Follow those for parameters $EFkwTOD_{j,,j,t,y}$ in equation 5 and $EFkwAI_{j,,j,s,y}$ in equation 8 Applicable only if PE emissions are to be calculated on a time-of-day basis when also incorporating charging systems' associated infrastructure sources on a net metered basis.

Data / Parameter	$LECT_{j,,j,t,\ y}$
Data unit	kwh/time period *t*
Description	Electricity provided to the grid and/or building from on-site storage battery during time-of-day period t within region j serving applicable fleet i in project year y (kwh/year)
Equations	9
Source of data	From on-site battery/charging system's adequate measurement systems
Description of measurement methods and procedures to be applied	Project metering systems' calibration must be conducted according to the equipment manufacturer's specifications. Projects must incorporate adequate metering systems when applying Eq 9. Guidance for the design/application of such metering systems, considered as applied to each time period t, is provided in Appendix 2.
Frequency of monitoring/recording	Measured actual data must be monitored and recorded on at least an annual basis.
QA/QC procedures to be applied	The consistency of such kwh should be cross-checked with other information sources where applicable
Purpose of data	Calculation of project emissions
Calculation method:	
Comments:	Applicable only if PE emissions are to be calculated on a net metered basis integrating multiple associated infrastructure sources, s.

Data / Parameter	$EFkwTODonsitebatt_{i,j,s,t,y}$
Data unit	tCO_2e/kwh
Description	Emission factor for the electricity from the on-site battery during time-of-day period t (both on-site infrastructure and EV on-board batteries) associated infrastructure source s within region j consumed by project chargers serving applicable fleet i in year y
Equations	9
Source of data	See data sources for Equation 8 variables above
Description of measurement methods and procedures to be applied	The emission factors for one associated infrastructure source -- for the on-site battery -- are calculated using the net weighted average of the grid and on-site renewable emission factors given using equation 8, but this time applied for each time-of-day period t On-site storage battery must assume the weighted average emission factor based upon the proportionate net consumption of grid and dedicated renewable energy at the charging system (using equation 9 applied during each time of day period basis) Projects must incorporate adequate metering systems when applying Eq 9. Guidance for the design/application of such metering systems, considered as applied to each time period t, is provided in Appendix 2.
Frequency of monitoring/recording	Consistent with the practices applied for monitoring the $EFkwTOD\text{-}AI_{i,j,s,t,y}$ in equation 9
QA/QC procedures to be applied	As for equation 8 variables
Purpose of data	Calculation of project emissions
Calculation method:	
Comments:	Applicable only if PE emissions are to be calculated on a metered basis integrating multiple associated infrastructure sources, s, on a time-of-day basis.

Data / Parameter	D_y
Data unit	%
Description	Discount factor to be applied in year y
Equations	10 and 11
Source of data	See data sources for data parameters in equation 13

Description of measurement methods and procedures to be applied	Discount factor applied if GHG credits have been issued in the project region for GHG credits issued for projects that introduce EV fleets (e.g. using the CDM AMS-III.C EV fleet methodology)
Frequency of monitoring/recording	Annual
QA/QC procedures to be applied	
Purpose of data	Calculation of emission reductions
Calculation method:	Look up value
Comments:	If there are no GHG credits issued for projects that introduce EV fleets in the project region, D_y must be 1 (ie there is no discount applied). Private networks can also demonstrate that D = 1 if there is no access to chargers beyond a defined set of EV's for which it can be demonstrated that no GHG credits from projects that introduce EV fleets have been issued. See guidance in section 8.4 regarding open and closed networks. If GHG credits have been issued for projects that introduce EV fleets for a region larger than the proposed EV charging project (e.g. the project introducing EVs is US-wide while the EV charging system project is confined to one state), then a sensible pro-rata share of the GHG credits issued to projects that introduce EV fleets can be made (e.g. using the pro-rata number of EV's on the road in the EV charging system project state compared to the total in the US, using sources such as ZEVFacts.com).

Data / Parameter	ERC_y
Data unit	tCO_2e
Description	Sum of GHG credits issued by all projects under this methodology (or others which support the introduction of EV charging systems) across this project's applicable fleet *i* categories within this total project region in project year y-1
Equations	11
Source of data	VCS (and other voluntary and regulated credit registries if they develop similar EV charging system methodologies), with GHG credits issued from EV charging system projects within this same project's region (e.g. for complementary charging networks)

Description of measurement methods and procedures to be applied	Simple tallies of the total GHG credits issued from EV charging system project year 1 through year y-1 within this project's region These GHG credits include those issued under this VCS charging system methodology (or similar ones developed by other certification groups) whose credits arise within the same region as this project but cover credits issued from complementary charging network systems (e.g. workplace chargers from a complementary project located in the same region as this project's residential chargers).
Frequency of monitoring/recording	Annual
QA/QC procedures to be applied	
Purpose of data	Calculation of emission reductions
Calculation method:	Look up values
Comments:	N/A

Data / Parameter	ERF_y
Data unit	tCO_2e
Description	Sum of GHG credits issued by all projects under methodologies which support the introduction of EV fleets (e.g., CDM AMS.III.C) within this project's same total region where the applicable fleet *i* categories are the same for both this EV charging system project and projects introducing EV fleets, in project year y-1
Equations	11
Source of data	VCS and other voluntary and regulated credit registries, with GHG credits issued from projects that introduce EV fleets within the project region
Description of measurement methods and procedures to be applied	Simple tallies of the total GHG credits issued for projects that introduce EV fleets within this project's region from project year 1 through year y-1 These GHG credits are those issued under EV fleet methodologies such as CDM AMS-III.C whose credit potentially double count with those issued through EV charging system projects where the applicable fleet of the EV charging system project include those that were introduced in the EV fleet project
Frequency of monitoring/recording	Annual

QA/QC procedures to be applied	
Purpose of data	Calculation of emission reductions
Calculation method:	
Comments:	If GHG credits have been issued projects introducing EV fleets for a region larger than the proposed EV charging system project (e.g. the project introducing EVs s US-wide while the EV charging system project is confined to one state), then a sensible pro-rata share of the GHG credits issued to the project that introduced EV fleets can be made (e.g. using the pro-rata number of EV's on the road in the EV charging system project state compared to the total in the US, using sources such as ZEVFacts.com).

9.3 Description of the Monitoring Plan

The project proponent must establish, maintain and apply a monitoring plan and GHG information system that includes criteria and procedures for obtaining, recording, compiling and analyzing data, parameters and other information important for quantifying and reporting GHG emissions.

All data collected as part of monitoring should be archived electronically and be kept at least for two years after the end of the last project crediting period. All data must be monitored unless indicated otherwise in the tables above.

Project reporting must include the following information for EV charging systems included in a project:

For activities monitored once up-front during project validation or as new project activity instances are admitted to a grouped project during verification:

1) Inventory and geographic location for each EV charging system included in the project.
2) Where EV charging systems' AI is utilized to provide electricity to EVs, in order to store and dispatch electricity to and from multiple sources, both on site and regionally, the monitoring plan must include plans for how data will be processed from the AI's metering systems (e.g., meters/sub-meters and/or associated measurement systems). Guidance for such metering is provided in Appendix 2.
3) Review of any previously issued VCUs for EV charging projects to verify that there is no overlap of ownership with chargers included in the project description, for example, using the unique EV charging identifiers supplied in the project description's EV charging system inventory. For grouped projects, such verification must apply to any new project activity instances and for new chargers subsequently added to the grouped project (e.g.,

by referencing the unique EV charging identifiers for these new project activity instances in project monitoring reports).

4) Review of any previously issued EV fleet credits to confirm the value established for the discount factor, *Dy*.

For activities monitored each year during verification for credit issuance:

1) Data on electricity consumption consistent with guidance provided in the parameter boxes above for each EV charger, which must be reported in a consistent manner with supporting data, such as invoices or utility or on site meter records. Where projects include LDV and HDV applicable fleets, electricity consumption must be monitored separately.

2) Supporting documentation used to determine parameters for use in quantification of annual baseline emissions if default factors (per Appendix 1) are not used.

The project proponent must establish and apply quality management procedures to manage data and information. Written procedures must be established for each measurement task outlining responsibility, timing and record location requirements. Record keeping practices must include:

- Electronic recording of values of logged parameters for each monitoring period
- Offsite electronic back-up of all logged data
- Maintenance of all documents and records in a secure and retrievable manner for at least two years after the end of the project crediting period.

Quality assurance/quality control procedures must also be applied to add confidence that all measurements and calculations have been made correctly. These may include, but are not limited to:

- Protecting monitoring equipment (sealed meters and data loggers)
- Protecting records of monitored data (hard copy and electronic storage)
- Checking data integrity on a regular and periodic basis (manual assessment, comparing redundant metered data, and detection of outstanding data/records)
- Comparing current estimates with previous estimates to identify any abnormal readings
- Providing sufficient training to project participants to install and maintain project devices
- Establishing minimum experience and requirements for operators in charge of project and monitoring
- Performing recalculations to make sure no mathematical errors have been made

10 REFERENCES

US Environmental Protection Agency (2017). *eGRID2014v2 Summary Table.*

US Department of Energy (2018). *Model Year 2016 Fuel Economy Guide.*

Idaho National Laboratory. *The EV Project*. Retrieved from https://avt.inl.gov/project-type/ev-project

Zhou, Y. *Light Duty Electric Drive Vehicles Monthly Sales Updates*. Retrieved from Argonne National Laboratory: https://www.anl.gov/energy-systems/project/light-duty-electric-drive-vehicles-monthly-sales-updates

APPENDIX 1: CALCULATION OF BASELINE DEFAULT VALUES FOR THE US AND CANADA

This appendix outlines the basis for the calculation of the optional default values used in the baseline emission calculations for U.S. LDV and HDV projects, and Canadian HDV projects. Values used to calculate the default value results were presented to the VVB via a separate Excel workbook during the approval process of the methodology.

Projects must apply the default value using units for EF (CO_2 or CO_2e) consistent with their project boundary choices, consistent across all project activity sources.

LDV Weighted Averages in the United States

Weighted averages for LDVs are based upon:

- The total number of each BEV and PHEV model on the road by end of 2015, based upon cumulative US sales data for 2010-2015 sourced from Argonne National Laboratories' monthly emails and web site[42]
- Kwh/100 mile and MPG ratings sourced from www.fueleconomy.gov or the 2016 Fuel Economy Guide, https://www.fueleconomy.gov/feg/pdfs/guides/FEG2016.pdf
- Gasoline was the fuel which the comparable fossil fuel cars consumed

The simple weighted average has been calculated for each applicable fleet (BEV+PHEV and BEV) based upon the number of EV models of each type on the road by end of 2015 multiplied by its corresponding kwh/100 mile value (AFEC) and equivalent fossil fuel vehicle's MPG value (MPG), which are listed in the table below.

Table A1: LDV Project Default Value Table

Applicable fleet	$AFEC_{iy}$	MPG_{jy}	EF_{jy}
L1/L2 (BEV and PHEV average)	33.32	29.18	19.56 lbs CO2/gal = 0.0088 tCO2/gal or 0.0088 tCO_2e/gal
DCFC (BEV average)	31.88	29.10	19.56 lbs CO2/gal = 0.0088 tCO2e/gal or 0.0088 tCO_2e/gal

HDV Weighted Averages in the United States

Each of these e-bus and e-truck weighted averages are based upon:

- The total number of each e-bus and e-truck models on the road in the US by beginning of 2017, based upon on data sourced from IHS Markit

[42] Argonne National Lab's (ANL) monthly emails uses data sourced from the hybridcars.com web site: http://www.hybridcars.com/december-2016-dashboard/ The main ANL web link is found here including the email address for the database manager: https://www.anl.gov/energy-systems/project/light-duty-electric-drive-vehicles-monthly-sales-updates

- The corresponding GWV classification for each model of e-bus and e-truck on the road, based upon data sourced from IHS Markit
- Kwh/mile data sourced for e-buses from commercial sources (confidential) and for e-trucks from Smith Electric and NREL reports for e-delivery truck vehicles as follows:
  - http://insideevs.com/smith-electric-vehicles-distance-energy-consumption/
  - http://www.nrel.gov/docs/fy17osti/66382.pdf
- Average MPG ratings for the corresponding class of MDV/HDV, as sourced from independent academic sources, specifically: https://www.nap.edu/read/12845/chapter/4#18
- Diesel fuel was the dominant baseline bus and truck fuel

The simple weighted average is calculated for each applicable fleet (e-bus and e-truck) based upon the number of EV models of each type on the road by beginning of 2017 multiplied by its corresponding kwh/100 mile value (AFEC) and equivalent GWV class of fossil fuel vehicle's average MPG value (MPG), which are listed in the table below.

Table A2: HDV Project Default Value Table

Applicable fleet	$AFEC_{iy}$	MPG_{jy}	EF_{jy}
e-buses	300	4.34	22.4 lbs CO2/gal = 0.0102 tCO2/gal or 0.0102 tCO_2e/gal
e-trucks	140	8.60	22.4 lbs CO2/gal = 0.0102 tCO2e/gal or 0.0102 tCO_2e/gal

LDV Weighted Averages in Canada

These weighted averages are based upon:

- The total number of each BEV and PHEV model on the road by end of 2016, based upon cumulative Canada data; kwh/100 mile and MPG ratings, all sourced from Natural Resources Canada
- Gasoline was the fuel which the comparable fossil fuel cars consumed

The simple weighted average has been calculated for each applicable fleet (BEV+PHEV and BEV) based upon the number of EV models of each type on the road by beginning of 2017 multiplied by its corresponding kwh/100 mile value (AFEC) and equivalent fossil fuel vehicle's MPG value (MPG), which are listed in the table below.

Table A3: LDV Project Default Value Table for Canada

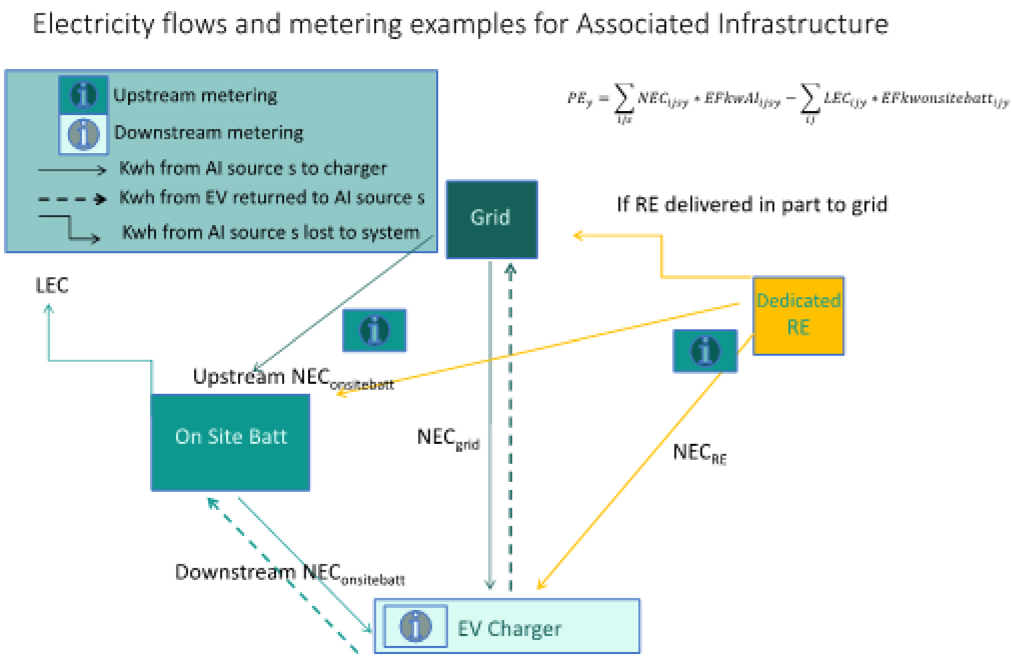
Applicable fleet	$AFEC_{iy}$	MPG_{jy}	EF_{jy}
L1/L2 (BEV and PHEV average)	35.44	29.65	19.56 lbs CO_2/gal = 0.0088 tCO_2/gal or 0.0088 tCO_2e/gal

DCFC (BEV average)	33.00	27.71	19.56 lbs CO_2/ga = 0.0088 tCO_2/gall or 0.0088 tCO_2e/gal

APPENDIX 2: GUIDANCE FOR DESIGN OF ADEQUATE METERING SYSTEMS FOR AI PROJECTS

This appendix outlines guidance for the design and application of metering systems of charging systems to adequately measure electricity exchanges when associated infrastructure (AI) is incorporated into projects when they apply to the determination of project emissions, as shown in Figure A1. If associated infrastructure is incorporated into the project boundary, PE equations 7, 8, or 9 are applicable.

Figure A1: Examples of Associated Infrastructure and Electricity Flows



When incorporating associated infrastructure, the charging system's metering system must adequately and accurately measure and trace the net electricity kwh provided to the charging system (i.e., deliveries minus receipts) from all electricity sourced from and returned to the grid, and the dedicated renewables. This may include dedicated renewable energy (e.g., on site) delivered to the EV directly and/or via on-site batteries, and net of kwh returned back to such sources from the EV batteries.

Note that metering systems for associated infrastructure can include "downstream" meters close to the EV, such as those provided by DCFC onboard meters (and referenced specifically in the ED parameter for kwh *delivered* by a charger to the EV which applies to the BE calculations), and "upstream" meters, located grid-side such as meters monitoring electricity (in kwh) delivered to the on-site batteries (which could be designed/applied to measure the kwh which a charger *consumes* in the EC parameter measurements which applies to the PE calculations).

Where the system's meters are located further "upstream", in order to not include any electricity lost to the EV charging system, any electricity sourced from associated infrastructure sources (notably from solar and the on-site battery) but delivered outside the EV charging system (e.g. delivered to the grid or the local building when the on-site battery is used as a back up generator source), must be sensibly taken into account for quantification. This includes the following examples:

1) Where the metered kwh to the on-site battery is located "upstream" on the grid side (rather than downstream of the on-site battery in the charger where electricity delivered to the EV is measured), any electricity that the on-site battery provides back to the grid, or its building in a given year must be measured and subtracted -- as LEC_{ijy} -- since these kwh represent losses to the overall charging system and do not result in EV miles driven.

2) Where the on-site battery is not connected to the grid or building (i.e., it does not serve as a power back up system), then the on-site battery does not need to be accounted for as a separate source, since it merely acts as a flow through for the grid and renewables sources. Any electricity received from the EV would also be returned to the EV. Therefore, the on-site battery would supply electricity consistent with the change in stored power between the year's starting and end points which, compared to the kwh supplied by the grid and/or dedicated renewables, would be *de minimis*.

3) Any transfer of electricity from the EV to the onsite battery represent internal flows within the system and can be set aside since the electricity must either be returned downstream to the EV at a later date or tracked via LEC if subsequently delivered back to the grid via the on-site battery. Therefore, transfers of electricity from the EV to the onsite battery can be set aside.

4) Projects must be able to measure or sensibly estimate the electricity supplied from the grid and/or from dedicated renewable sources to the charger system and this may be a subset of the total electricity from this source. For example, the electricity delivered to the charging system may be less than the total electricity generated by the onsite renewables if these renewables also provide power back to the grid within a particular associated infrastructure system[43]. Similarly, the total grid electricity delivered to the system may be shared across both the EV charger if delivered directly while also supplying in parallel electricity to the on-site battery – the former contributing to NEC from the grid source and latter to NEC for the on-site battery.

Where the systems meters are located "downstream", in order to not include any electricity lost to the EV charging system, any electricity sourced from associated infrastructure sources must be sensibly taken into account for quantification. This includes the following examples:

1) Although upstream-metering, (the measurement of kwh consumed by the chargers for parameter EC), typically applies for the PE calculations, the calculation of PE values can be made using downstream meters located in the chargers' internal systems provided appropriate efficiency factors are applied to take account of chargers' own electricity consumption. Where downstream measurement of PE is applied:

    - For PE calculations using downstream metering, consistent with the guidance in the parameter boxes for EC, ECTOD, NEC and NECT, efficiency factors must be applied to

[43] At a future date, projects may wish to consider issuing GHG credits for the subset of kwh delivered from the dedicated renewables to the grid (but not to the EV charger) using methodologies such as AMS-I.F https://cdm.unfccc.int/methodologies/DB/9KJWQ1G0WEG6LKHX21MLPS8BQR7242

account for potential efficiency losses due to the chargers' own kwh consumption. For L2s, such efficiency losses are de minimis[44] and so no efficiency factor is applied in the L2 EC, ECTOD, NEC and NECT parameter applications (since "downstream" meters would have de minimis variances with upstream meters). For DCFCs, if kwh data is sourced from "downstream" meters located within their own DCFCs internal smart meter systems (assuming as needed across these parameters that these smart meters are capable of differentiating inter alia the net kwh delivered to the EV's from each source s during time period t), then to establish the PE equation electricity *consumed* by the DCFC charger a DCFC default efficiency factor of 92.3% is applied to these internal smart DCFC metered kwh readings (i.e., using approach A in the parameter boxes)).

- Alternatively, DCFCs can use approach B applying "upstream" meter kwh measurements which are on the grid-side of the DCFC units/AI (e.g., for each source s and time period t).
- However, often relative to time-of-day periods *t* for NECT and ECTOD measurements, it is a DCFC's own "downstream" internal "smart" meters which have the most sophisticated metering capabilities for such time-of-day applications (whereupon approach A would be followed and the DCFC default efficiency factor applied).
- For DCFC using approach A, the default efficiency value applied would be the "downstream" smart meter's reading divided by the efficiency factor of 0.923 in order to estimate the kwh consumed by the DCFC fast charger on an "upstream kwh consumed" basis (as needed for the PE equations).
- If a project can demonstrate a more accurate efficiency factor for their particular DCFC systems (for example due to improvements in DCFC technology efficiencies over time), this updated accurate efficiency factor may be substituted for the 92.3% default efficiency value.

2) Where meters are located downstream for the measurement of NEC pertaining to the on-site battery, then the electricity measured must already be net of any LEC losses from the on-site battery to the grid – and thus LEC must be set at zero. This basis for such on-site battery net electricity measurements would be consistent with DCFC's measurement systems which track the electricity exchanges close the point of delivery to the EV. Additionally, for downstream metering, the electricity provided by the EV to the onsite battery must be measured for the calculation of NEC for the on-site battery (that is, it cannot be set aside for downstream metering).
3) Where the EV is delivering vehicle-to-grid (V2G) services where electricity from the car's on-board battery is returned directly to the grid, these EV-sourced electricity are netted out in the grid-sourced net-kwh (that is, in the calculation of NEC for the grid source *s*).
4) Where charging systems include simple associated infrastructure settings, such as residences using L1/L2 systems where "upstream" metering systems apply and where the associated infrastructure system elements can be limited (e.g. no on-site battery).

Note that the quantification of emissions from project associated infrastructure systems can be simplified using sensible estimates. For example, where a household residence has a solar panel

[44] Per INL: https://avt.inl.gov/evse-type/ac-level-2

that is grid-connected – which, while its total solar kwh production and grid-sales are metered, does not have a separate sub-meter to establish the solar kwh supplied to the EV charging system specifically -- it is acceptable to assume that the kwh delivered to the EV charger is the same weighted average as the solar/grid kwh mix the household itself consumed (i.e., sources whose electricity would have been separately metered). Utility-style modeling is also acceptable for settings where only the net electricity consumption/generation is measured for a household in order to establish the electricity delivered by both the grid and the on-site renewables and thus the required weighted average.

A.3.4 Energy Efficiency and Solid Waste Diversion

VCS | VERIFIED CARBON STANDARD
A Global Benchmark for Carbon

Approved VCS Methodology

VM0018

Version 1.0

Sectoral Scopes 3, 13

Energy Efficiency and Solid Waste Diversion Activities within a Sustainable Community

Scope

This methodology provides a procedure to determine the net CO_2, N_2O and CH_4 emissions reductions associated with grouped projects that focus on energy efficiency and solid waste diversion activities for an assortment of facilities within a set territory.

Methodology Developer

The methodology was developed by Will Solutions, Inc. (formerly Gedden Inc.), in collaboration with ICF Marbek and CertiConseil Inc.

Authors

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- Christophe Kaestli LEED AP, DBA - CertiConseil Inc.
- Duncan Rotherham, Chad Hamre, Braydon Boulanger – ICF Marbek

Relationship to Approved or Pending Methodologies

No approved or pending methodology under the VCS Program or an approved GHG program can reasonably be revised to meet the objective of this proposed methodology. All existing and pending VCS, CDM and CAR methodologies under sectoral scopes 3 and 13 have been reviewed. All corresponding methodologies have been grouped and listed below. None of the similar methodologies listed below could be revised without the addition of new procedures or scenarios to more than half of its sections.

Program	Sectoral Scope	Title	Similarity
CDM	3	*AM0025 - Avoided emissions from organic waste through alternative waste treatment processes*	Similar
CDM	3	*AM0041 - Mitigation of Methane Emissions in the Wood Carbonization Activity for Charcoal Production*	Not Similar
CDM	3	*AM0049 - Methodology for gas based energy generation in an industrial facility*	Not Similar
CDM	3	*AM0046 - Distribution of efficient light bulbs to households*	Not Similar
CDM	3	*AM0055 - Baseline and Monitoring Methodology for the recovery and utilization of waste gas in refinery facilities*	Not Similar
CDM	3	*AM0086- Installation of zero energy water purifier for safe drinking water application*	Not Similar
CDM	3	*AM0091- Energy efficiency technologies and fuel switching in new buildings*	Similar
CDM	3	*AM065 - Replacement of SF6 with alternate cover gas in the magnesium industry*	Not Similar
CDM	3	*AM0070 - Manufacturing of energy efficient domestic refrigerators*	Not Similar
CDM	3	*ACM003 - Emissions reduction through partial substitution of fossil fuels with alternative fuels or less carbon intensive fuels in cement manufacture*	Not Similar
CDM	3	*AM0007 - Analysis of the least-cost fuel option for seasonally-operating biomass cogeneration plants*	Not Similar
CDM	3	*AM0014 - Natural gas-based package cogeneration*	Not Similar
CDM	3	*ACM0012 - Consolidated baseline methodology for GHG emission reductions from waste energy recovery projects*	Not Similar
CDM	3	*AM0024 - Methodology for greenhouse gas reductions through waste heat recovery and utilization for power generation at cement plants*	Not Similar

Program	Sectoral Scope	Title	Similarity
CDM	4	*ACM0015 - Consolidated baseline and monitoring methodology for project activities using alternative raw materials that do not contain carbonates for clinker production in cement kilns*	Not Similar
CDM	3	*AM0020 - Baseline methodology for water pumping efficiency improvements --- Version 2.0*	Not Similar
CDM	3	*AM0044 - Energy efficiency improvement projects: boiler rehabilitation or replacement in industrial and district heating sectors --- Version 1.0*	Similar
CDM	3	*AM0060 - Power saving through replacement by energy efficient chillers --- Version 1.1*	Similar
CDM	3	*AM0068 - Methodology for improved energy efficiency by modifying ferroalloy production facility --- Version 1.0*	Not Similar
CDM	3	*AM0088 - Air separation using cryogenic energy recovered from the vaporization of LNG --- Version 1.0*	Not Similar
CDM	3	*AM0017 - Steam system efficiency improvements by replacing thermal energy traps and returning condensate --- Version 2.0*	Similar
CDM	3	*AM0018 - Baseline methodology for thermal energy optimization systems --- Version 2.2*	Similar
CDM	3	*AMS-I.I. - Biogas/biomass thermal applications for households/small users --- Version 1.0*	Not Similar
CDM	3	*AMS-II.C.- Demand-side energy efficiency activities for specific technologies --- Version 13.0*	Similar
CDM	3	*AMS-II.F. - Energy efficiency and fuel switching measures for agricultural facilities and activities --- Version 9.0*	Similar
CDM	3	*AMS-II.G. - Energy Efficiency Measures in Thermal Applications of Non-Renewable Biomass --- Version 2.0*	Not Similar
CDM	3	*ACM0005 - Consolidated Baseline Methodology for Increasing the Blend in Cement Production --- Version 5.0*	Not Similar
CDM	3	*AMS-III.B. - Switching fossil fuels --- Version 15.0*	Similar
CDM	3	*AMS-II.E. - Energy efficiency and fuel switching measures for buildings*	Similar
CDM	*3*	*AMS-II.J. - Demand-side activities for efficient lighting technologies*	Similar
CDM	*3*	*AMS-II.K. - Installation of co-generation or tri-generation systems supplying energy to commercial building*	Not Similar

Program	**Sectoral Scope**	**Title**	**Similarity**
CDM	3	*AMS-II.L. - Demand-side activities for efficient outdoor and street lighting technologies*	Similar
CDM	*3*	*AMS-II.M. - Demand-side energy efficiency activities for installation of low-flow hot water savings devices*	Similar
CDM	3	*AMS-III.AE. - Energy efficiency and renewable energy measures in new residential buildings*	Similar
CDM	3	*AMS-III.AL. - Conversion from single cycle to combined cycle power generation*	Similar
CDM	3	*AMS-III.AV. - Low greenhouse gas emitting water purification systems*	Similar
CDM	3	*AMS-III.X. - Energy Efficiency and HFC-134a Recovery in Residential Refrigerators*	Not Similar
CDM	13	*AM0039 - Methane emissions reduction from organic waste water and bioorganic solid waste using co-composting*	Similar
CDM	13	*AM0057 - Avoided emissions from biomass wastes through use as feed stock in pulp and paper production or in bio-oil production*	Similar
CAR	13	*CAR - Organic Waste Composting Project Protocol*	Similar
CDM	13	*AM0073 - GHG emission reductions through multi-site manure collection and treatment in a central plant*	Not Similar
CDM	13	*AM0083 - Avoidance of landfill gas emissions by in-situ aeration of landfills*	Not Similar
CDM	13	*ACM0014 - Mitigation of greenhouse gas emissions from treatment of industrial wastewater*	Not Similar
CAR	13	*CAR - Landfill Project Protocol*	Not Similar
CDM	13	*AMS-III.AJ. - Recovery and recycling of materials from solid wastes*	Similar
CDM	13	*AM0025 - Avoided emissions from organic waste through alternative waste treatment processes*	Similar
CDM	13	*AM0073 - GHG emission reductions through multi-site manure collection and treatment in a central plant*	Not Similar
CDM	13	*ACM0001 - Consolidated baseline and monitoring methodology for landfill gas project activities*	Similar
CDM	13	*ACM0010 - Consolidated baseline methodology for GHG emission reductions from manure management systems*	Not Similar

Program	Sectoral Scope	Title	Similarity
CDM	13	*ACM0014 - Mitigation of greenhouse gas emissions from treatment of industrial wastewater*	Not Similar
CDM	13	*AMS-III.G. - Landfill methane recovery*	Similar
CDM	13	*AMS-III.H. - Methane recovery in wastewater treatment*	Not Similar
CDM	13	*AMS-III.AF. - Avoidance of methane emissions through excavating and composting of partially decayed municipal solid waste (MSW)*	Not Similar
CDM	13	*AMS-III.L. - Avoidance of methane production from biomass decay through controlled pyrolysis*	Not Similar
CDM	13	*AMS-III.AO. - Methane recovery through controlled anaerobic digestion*	Not Similar
CDM	13	*AM0039 - Methane emissions reduction from organic waste water and bioorganic solid waste using co-composting*	Not Similar
CDM	13	*AM0057 - Avoided emissions from biomass wastes through use as feed stock in pulp and paper, cardboard, fiberboard or bio-oil production*	Not Similar
CDM	13	*AM0080 - Mitigation of greenhouse gases emissions with treatment of wastewater in aerobic wastewater treatment plants*	Not Similar
CDM	13	*AM0083 - Avoidance of landfill gas emissions by in-situ aeration of landfills*	Not Similar
CDM	13	*AM0093 - Avoidance of landfill gas emissions by passive aeration of landfills*	Not Similar
CDM	13	*AMS-III.E. - Avoidance of methane production from decay of biomass through controlled combustion, gasification or mechanical/ thermal treatment*	Similar
CDM	13	*AMS-III.F. - Avoidance of methane emissions through controlled biological treatment of biomass*	Not Similar
CDM	13	*AMS-III.I. - Avoidance of methane production in wastewater treatment through replacement of anaerobic systems by aerobic systems*	Not Similar
CDM	13	*AMS-III.Y. - Methane avoidance through separation of solids from wastewater or manure treatment systems*	Not Similar
CDM	13	*ACM0001 - Consolidated baseline and monitoring methodology for landfill gas project activities*	Similar
CDM	13	*ACM0010 - Consolidated baseline methodology for GHG emission reductions from manure management systems*	Not Similar

Program	**Sectoral Scope**	**Title**	**Similarity**
CDM	13	*ACM0014 - Mitigation of greenhouse gas emissions from treatment of industrial wastewater*	Not Similar
VCS	3	*Methodology for Weatherization of Single Family and Multi-family Buildings*	Similar

Table of Contents

1 SOURCES

These documents have been drawn upon heavily in the development of this methodology. Throughout the text the short form reference (PUBLISHER, YEAR) will be used to indicate areas where the sources were drawn upon most heavily.

This methodology complies with the principles of:

- *ISO 14064*: Part 2, "Specification with guidance at the project level for the quantification, monitoring and reporting of greenhouse gas emission reductions and removal enhancements*"* (ISO, 2006).
- VCS, *VCS Standard*, Version 3 (VCS, Version 3)

This methodology also draws ideas from the latest approved version of the following CDM tools:

- CDM, *Tool to Calculate the Emission Factor for an Electricity System* (Version 2.2.0) (CDM, 2011) and
- CDM, *Combined Tool to Identify the Baseline Scenario and Demonstrate Additionality* (Version 3.0.1) (CDM, 2011).

The energy efficiency approach within has been based on elements of the following methodologies:

- Direct Energy's, *GHG Quantification Protocol for Energy Efficiency in Commercial and Institutional Buildings* (Direct Energy, 2009);
- Alberta Offset System, Protocol, *GHG Quantification Protocol for Energy Efficiency in Commercial and Institutional Buildings* (AENV, 2010);
- Alberta Offset System, Protocol, *Quantification Protocol For Energy Efficiency Projects* (Version 01) (AENV, 2007);
- IPMVP - Efficiency Valuation Organization (EVO-1000-1, 2010) in its International Performance Measurement and Verification Protocol (IPMVP) (www.evo-world.org) for guidance on methods determining energy savings.[1]

This waste diversion approach within has been based on elements of the following methodologies:

- CDM, AM0039, *Methane Emissions Reduction from Organic Waste Water and Bioorganic Solid Waste using Co-composting* (Version 02) (CDM, 2007).
- CDM, *Tool to Determine Methane Emissions Avoided from Disposal of Waste at a Solid Waste Disposal Site* (Version 6.0) (CDM, 2011)
- CCX "Avoided Emissions from Organic Waste Disposal Offset Project Protocol" (CCX, 2009);

[1] IPMVP is a recognized international standard for measuring, monitoring, and verifying energy savings.

2 SUMMARY DESCRIPTION OF THE METHODOLOGY

This methodology provides a framework for the quantification of emission reductions for grouped projects[2], where energy efficiency and solid waste diversion activities have been initiated by a Sustainable Community Service Promoter for an assortment of Client Facilities grouped in a Territory. This methodology requires that the SCSP uses a consolidated, Information and Communication Technology-enabled data monitoring and collection system to track project activity data. Even though the activities of Client Facilities vary, energy consumption and waste management are similar across many businesses and organizations. This methodology is meant to work with and support the provision of single window reporting and measurement provided by a third party to capture the information required to quantify emissions reductions.

3 DEFINITIONS

This sub-section introduces important terminology to ensure the project proponent and validation/verification bodies (VVBs) share common understandings of the various roles, parties and grouping systems involved in this methodology.

Client Facility	A large range of small companies or business units that contract the Sustainable Community Service Promoter to manage their GHG emitting services. Client Facilities may include commercial, institutional, residential and industrial buildings/facilities including but not limited to warehouses, apartment buildings, hotels, restaurants, educational buildings, shopping malls, food manufacturing plants, chemical manufacturing facilities, and light industrial plants. Client Facilities are typically located in regional or state clusters.
Sustainable Community (SC)	A Sustainable Community is as a collection of Client Facilities that have undertaken common actions (usually initiated by the SCSP) to reduce their overall GHG emissions.

[2] See *VCS Standard* for grouped project requirements.

Sustainable Community Service Promoter (SCSP)	An independent entity, which acts as the project proponent, providing essential consultation services in the fields of energy and waste to Client Facilities to stimulate greenhouse gas (GHG) reduction activities. SCSPs add value to Client Facilities by implementing Information and Communication Technology-enabled electronic tracking platforms, monitoring technologies, and emission reduction activities. In providing services to Client Facilities, SCSPs contractually maintain ownership of the environmental attributes associated with actions that reduce the Client Facilities overall GHG emissions.
Territory	A grouping of Client Facilities which belong to a common industrial or geographic cluster, where the regional conditions (i.e. electricity source, climate, waste processing schemes, etc.) and regulations (i.e. waste and emission regulations, etc.) are similar for the different facilities; where homogeneous emission factors for fossil combustibles and identifiable emission factor for the electricity grid can be applied; and where common energy efficiency activities and waste processing activities are possible. The Territory concept has been applied to facilitate VVB sampling procedures, though sampling resolutions are ultimately to be determined by the VVB based on a risk assessment of the project and project controls.

This sub-section introduces data, sampling, and conceptual terminologies that are important to how emission reductions are quantified and monitored under this methodology.

Baseline Adjustments	The non-routine adjustments arising during the monitoring period from changes in: 1) any energy governing characteristic of the facility within the measurement boundary, except the named independent variables used for routine adjustments (EVO 10000-1, 2010); or 2) any waste governing characteristic of the facility within the measurement boundary (for example, total production).
Baseline Period	The period of time chosen to represent operation of the facility or system before implementation of an Energy Conservation Measure or waste reduction/diversion activities. This period may be as short as the time required for an instantaneous measurement of a constant quantity, or long enough to reflect one full operating cycle of a system or facility with variable operations.

Confidence Interval	A confidence interval (CI) is a particular kind of interval estimate of a population parameter and is used to indicate the reliability of an estimate. It is an observed interval (i.e. it is calculated from the observations), in principle different from sample to sample, that frequently includes the parameter of interest, if the experiment is repeated. How frequently the observed interval contains the parameter is determined by the confidence interval or confidence coefficient.
Estimate	A process of determining a parameter used in a savings calculation through methods other than measuring it in the baseline and monitoring periods. These methods may be based on secondary data or engineering assumptions and estimates derived from manufacturer's rating of equipment performance. Equipment performance tests that are not made in the place where they are used during the monitoring period shall be considered as estimates.
Facility	The collection of units, excluding the Project Unit. As such, the greenhouse emissions from the facility are defined to remain constant as only the Project Unit is impacted by the project. Where the Project Unit encompasses the entire site, there may be no components defined as the Facility at the site.
Functional Equivalence	The project and the baseline shall provide the same function and quality of products or services. This type of comparison requires a common metric or unit of measurement (such as the mass of cardboard diverted from landfill for mass of finished furniture, energy use/per unit of product) for comparison between the project and baseline activity.
Information and Communication Technology (ICT)	Information and Communication Technology that is applied through an electronic tracking platform for each Client Facility. An electronic account and the effective electronic link between all Client Facilities inside a Territory to stimulate, to support and measure their GHG related activities. SCSPs employ an ICT-enabled GHG monitoring system.

Measurement Boundary	A notional boundary drawn around equipment and/or systems to segregate those which are relevant to savings determination from those which are not. All energy uses of equipment or systems within the measurement boundary must be measured or estimated, whether the energy uses are within the boundary or not (EVO 10000-1, 2010)
Non-Routine Adjustments	Calculations that account for changes in Static Factors within the measurement boundary since the baseline period. Examples of changes in Static Factors that require non-routine adjustments include the facility size, product types, building envelope characteristics, indoor environment and occupancy characteristics. Non-routine adjustments applied to the baseline are sometimes referenced as "baseline adjustments" (EVO 10000-11, 2010). For this quantification protocol, non-routine adjustments also account for changes in the "surplus" characteristics of the project.
Primary Data	Observed data from specific facilities linked to the SCSP tracking system.
Project Unit	A project activity instance wherein the equipment, processes and facilities are being serviced and impacted by the energy efficiency and waste diversion processing project. The Project Unit must be clearly defined and justified by the project proponent. All non-Project Unit items are covered under the heading of facility operation.
Routine Adjustments	The calculations made by a formula, as shown in the energy efficiency and waste diversion monitoring plans, to account for changes in selected independent variables within the measurement boundary since the baseline period (EVO 10000-11, 2010), not including any changes to Static Factors.
Secondary Data	Generic- or industry-average data from published sources that are representative of Project unit Activities and Client Facility products.
Static Factors	Those characteristics of a Client Facility which affect energy use and waste volume produced, within the chosen measurement boundary. These characteristics include fixed, environmental, operational and maintenance characteristics. They may be constant or varying (EVO 10000-11, 2010).

Standard Deviation	The standard deviation, denoted by *s* and is defined as follows: $$s = \sqrt{\frac{1}{n-1}\sum_{i=1}^{n}(x_i - \overline{x})^2},$$ where $\{x_1, x_2, \ldots, x_N\}$ are the observed values of the sample items and $\overline{x}$ is the mean value of these observations.
Suggested Sample Size	While the ultimate level of sampling must be determined by the VVB, the project proponent may provide a suggested number of Sustainable Community Project Units to be physically verified.
Unit of Productivity	The unit of productivity is to be defined by the project proponent as a basis for incorporating Functional Equivalence within the calculation methodology. Examples of units of productivity could be: energy requirements for residential buildings, per square foot of front of house commercial space, per kg/L/m2/m3 of output from manufacturing facilities, etc. The unit of productivity shall be defined to account for any non-production sensitive components. In all cases the project proponent must thoroughly justify their assessment of the appropriate unit of productivity.
Verified Data Feedback Loop	After each verification cycle, verified SCSP Client Facility data may be used to increase the confidence interval on any estimated values included in the baseline or project scenarios. Examples of such situations could include replacing regional factors for a specific facility with a more accurate waste or energy profile of the specific Client Facility based on measured data, providing it can still be related to the baseline period. This verified data feedback loop could ultimately result in adjustments that both increase or decrease emission reduction assertions in future years. The adjustments would not be retroactive to previously serialized offsets.

These definitions apply to the energy efficiency components of GHG quantification described herein.

Adjusted-baseline energy	The energy use of the baseline period, adjusted to a different set of operating conditions (EVO 10000-11, 2010).
Baseline Energy	The energy use occurring during the baseline period without adjustments (EVO 10000-11, 2010).

Cycle	The period of time between the start of successive similar operating modes of a facility or piece of equipment whose energy use varies in response to operating procedures or independent variables. For example, the cycle of most buildings is 12 months, since their energy use responds to outdoor weather which varies on an annual basis. Another example is the weekly cycle of an industrial process which operates differently on Sundays than during the rest of the week (EVO 10000-11, 2010).
Energy Conservation Measure (ECM)	An activity or set of instances designed to increase the energy efficiency of a facility, system or piece of equipment. ECMs may also conserve energy without changing efficiency. Several ECMs may be carried out in a facility at one time, each with a different thrust. An ECM may involve one or more of: physical changes to facility equipment, revisions to operating and maintenance procedures, software changes, or new means of training or managing users of the space or operations and maintenance staff. An ECM may be applied as a retrofit to an existing system or facility, or as a modification to a design before construction of a new system or facility.

These definitions apply to the waste diversion components of GHG quantification described herein.

Alternative Processing	Refers to recycling, reusing, reduction and re-processing activities which are applied as part of the project to divert waste from reaching a landfill.
Biodegradability	Biodegradability is the capability of a substance to break down into simpler substances, especially into innocuous products, by the actions of living organisms (that is, microorganisms).
Composting	The process of collecting, grinding, mixing, piling, and supplying sufficient moisture and air to organic materials to speed natural decay. The finished product of a composting operation is compost, a soil amendment suitable for incorporating into topsoil and for growing plants. Compost is different than mulch, which is a shredded or chipped organic product placed on top of soil as a protective layer.
Destinations	The ultimate destination for waste being shipped by the project. This is the location where the waste would be unloaded from a truck after having been shipped from project Origins.

Disposal	Final stage in the management of waste, which includes: treatment of waste prior to disposal, incineration of waste, with or without energy recovery, deposit of waste to land or water, discharge of liquid waste to sewer, and permanent, indefinite or long term storage of waste.
Diversion	For waste measurement purposes, diversion is any combination of waste prevention (source reduction), recycling, reuse and composting instances that reduces waste disposed at authorized landfills and transformation facilities.
Landfill Gas (LFG)	Gas generated by biological decomposition of waste material in a landfill. The gas is typically comprised of methane, carbon dioxide, other trace gases and water vapor.
Origins	Starting points for waste being shipped by the project. This is the location where the waste would be loaded onto a truck or train for ultimate delivery to Destinations.
Producer	Refers to the Client Facility that produces the waste to be disposed of.
Process Emissions	Process emissions are direct emissions from sources directly associated with production that involve chemical or physical reactions, other than combustion, and where the primary purpose of the process is not energy production.
Recycling	The process of collecting, sorting, cleansing, treating, and reconstituting materials that would otherwise become solid waste, and returning them to the economic mainstream in the form of raw material for new, reused, or reconstituted products that meet the quality standards necessary to be used in the marketplace.

Waste	All type of wastes, regulated or not regulated, hazardous or non-hazardous and generated by citizens under the municipal umbrella (Municipal Solid Waste (MSW)) or by others sources such as an Industrial, Commercial and Institutional (ICI) business unit. This definition of the wastes defined by the Basel Convention http://www.basel.int/ in the Basel Convention on the Control of Transboundary Movements of Hazardous Wastes and Their Disposal in the article 2 and referred to Annex I and II, shall apply for all types of wastes. Notice this UN international convention respect the full right of country to define their wastes (article 2 item 1).
Waste Transformation	Incineration, pyrolysis, distillation, gasification, or biological conversion other than composting.
Waste Management	All types of waste management operations, disposal and recycling applied for all types of wastes shall refer to the definition used by the Basel Convention http://www.basel.int/ in the Basel Convention on the Control of Transboundary Movements of Hazardous Wastes and Their Disposal in article 2 and referred to Annex IV. Notice this UN international convention respect the full right of country to define their management wastes operations (article 2).

4 APPLICABILITY CONDITIONS

This methodology is applicable for grouped projects for the quantification of direct and indirect reductions of GHG emissions arising from energy efficiency and waste management project activity instances at client facilities (project units).

The requirements of this methodology have been designed to meet micro energy efficiency and/or waste diversion project units where the maximum emission reductions from an individual project unit is 5,000 tCO_2e/year. Therefore, through a combination of energy efficiency and waste management activities, project units within a grouped project could have a maximum combined abatement threshold of 10,000 tCO_2e/year. While each client facility, or project unit, may only contribute a modest abatement (10,000 tCO_2e/year or less), the total sum of abatement from all project units within this entire grouped project may exceed the combined threshold of 10,000 tCO_2e/year.

This methodology is applicable for grouped projects for the quantification of direct and indirect reductions of GHG emissions arising from energy-efficiency and waste-diversion projects at client facilities. Projects can be located in residential, commercial, institutional, or industrial buildings/facilities. The project proponent must demonstrate right of use in respect of the project’s GHG emission reductions, which may, for example, entail securing right of use from client facilities.

Energy Efficiency

This methodology is applicable to ECMs where the project activity is the construction of new facilities, the retrofit of existing facilities, or process/management changes of existing facilities that result in a reduction of energy use per unit of productivity. The ECMs must occur in conjunction with the following:

- Building envelope modifications
- Heating, ventilation and air conditioning (HVAC)
- Heat generation (including industrial thermal energy systems)
- Chilling/cooling systems
- Lighting and lighting control
- Building mechanical infrastructure
- Appliances and industrial processes (including heating and cooling requirements and process modification)
- Electric motors
- Equipment optimization

The following guidance provides further clarification on energy efficiency activities, approach and applicability:

a. The project proponent must document the useful life of the ECMs and the remaining useful life of the existing baseline equipment and ensure that the project unit(s) is not credited beyond the useful life of the ECM or remaining useful life of the existing technology in the baseline scenario. If capital stock equipment that was originally measured in the baseline for a given project crediting period is replaced during a project crediting period, it can only be considered additional, and in turn be able to generate GHG credits, if it was retired prior to its natural capital stock rotation as indicated in the initial documentation of useful life. If capital stock enters the end of its useful life prior to the end of a project crediting period and is replaced, any emission reduction attributable to this replacement technology must not be considered towards generating credits, and shall lower the facility baseline by a sum equal to the difference in emissions between the previous capital stock equipment and the replacement capital stock equipment.

b. By reducing energy consumption, applicable projects will reduce GHG emissions associated with the conversion of primary energy sources to secondary forms of energy (e.g., electricity, heat, mechanical energy, etc.).

c. This methodology is also applicable to activities generating GHG emission reductions related to improvements in combustion efficiency[3]. This applies to projects involving switching from one energy generation method to a less GHG-intensive energy generation method. In this case, this methodology only quantifies emissions reductions from fuel switching that occur within the project boundary. Fuel switching associated with large energy suppliers, which

[3] There must not be double counting between activities related to improvements in combustion efficiency and any energy efficiency activities within the project.

have emission reductions that exceed the established threshold of this methodology, are not intended to be quantified using this protocol. Only small on-site power sources, with emission reductions within the threshold limit of this methodology, are applicable for inclusion within the methodology. This separation of large offsite generation and the project removes risk of double counting. A net emission reduction and efficiency improvement would be achieved by such activities so long as a net reduction in overall greenhouse gas emissions per unit of productivity is achieved. The production of energy, particularly from fossil energy sources, has significant associated GHG emissions (typically combustion-related), including both direct and indirect sources.

d. Biological or chemical components of the operation must not yield any increase in non-biogenic greenhouse gas emissions compared to the baseline scenario, unless these are accounted for under the applicable flexibility mechanisms as indicated by an affirmation from the project proponent.

Waste Diversion

This methodology is applicable where the project activity is the diversion of waste for other productive uses and alternative disposal options. This methodology is only applicable to quantify emission reductions associated with methane avoidance. This methodology is not approved for quantifying emission reductions associated with landfill gas flaring or electricity/energy production. This methodology is applicable to the following activities:

- Card board recycling
- Organic composting
- Aerobic decomposition

5 PROJECT BOUNDARY

5.1 Project

The project proponent shall identify all GHG sources and sinks (SS) relevant to the project such as:

- Production of electricity
- Maintenance, construction and decommissioning
- Decomposition of solid waste in landfills.

The process set out in Diagram 1 identifies, illustrates and organizes SS for a typical project applicable under this methodology. Table 1 describes each SS identified in Diagram 1, discusses the SS relevance and characterizes the SS as controlled, related or affected by the project activity.

Since this methodology has been written to work for various types of project activities, one single project boundary cannot be provided. The project proponent shall use the requirements set out in this section to clearly define the most appropriate boundary for each grouping of client facilities with appropriate justifications for the inclusion or exclusion of SS. This shall include unique geo-coordinates if the projects are implemented across several dispersed locations.

For energy efficiency activities, it is important to note that the site boundaries are determined by whether the project proponent elects to quantify using “Option A – Isolation Parameter Measurement” or “Option B – Whole Facility Measurement.”

If Option A, Isolation Parameter Measurement, is selected, savings are determined by measuring the energy use of the ECM affected system, rather than the entire building. As such the boundary chosen is the ECM affected system. In this case, clear justification must be provided at the Territory level by the project proponent that the ECM affected system would have no material impact on the operation and emissions of the whole or remaining facility. Functional equivalence and unit of productivity adjustments for the ECM affected system must be made to the baseline of the system.

If Option B, Whole Facility Measurement, is selected, energy use for the entire facility is measured and any savings are calculated accordingly and therefore the boundary chosen is the entire facility. In this case, clear justification must be provided at the Territory level by the project proponent that the entire building’s baseline meets functional equivalence and has been adjusted by units of productivity.

Regardless of which option is selected, the project energy use calculations shall be done according to the methodology documents in IPMVP’s “Concepts and Options for Determining Energy and Water Savings (Volume 1)” (EVO, 2010). For waste diversion activities, the project proponent must use “Whole Facility Measurement” to determine the site boundaries. This means that if the project proponent is including waste diversion activities, then an isolated component of the facility cannot be used, the entire facility’s facility and waste stream must be included in the boundary. The project and baseline element life cycle charts are shown in Diagrams 1 and 2, respectively. Project documentation shall include diagrams that disclose the locations and processes of metering equipment used in determining the mass energy flows.

Diagram1: Project Element Life Cycle Chart

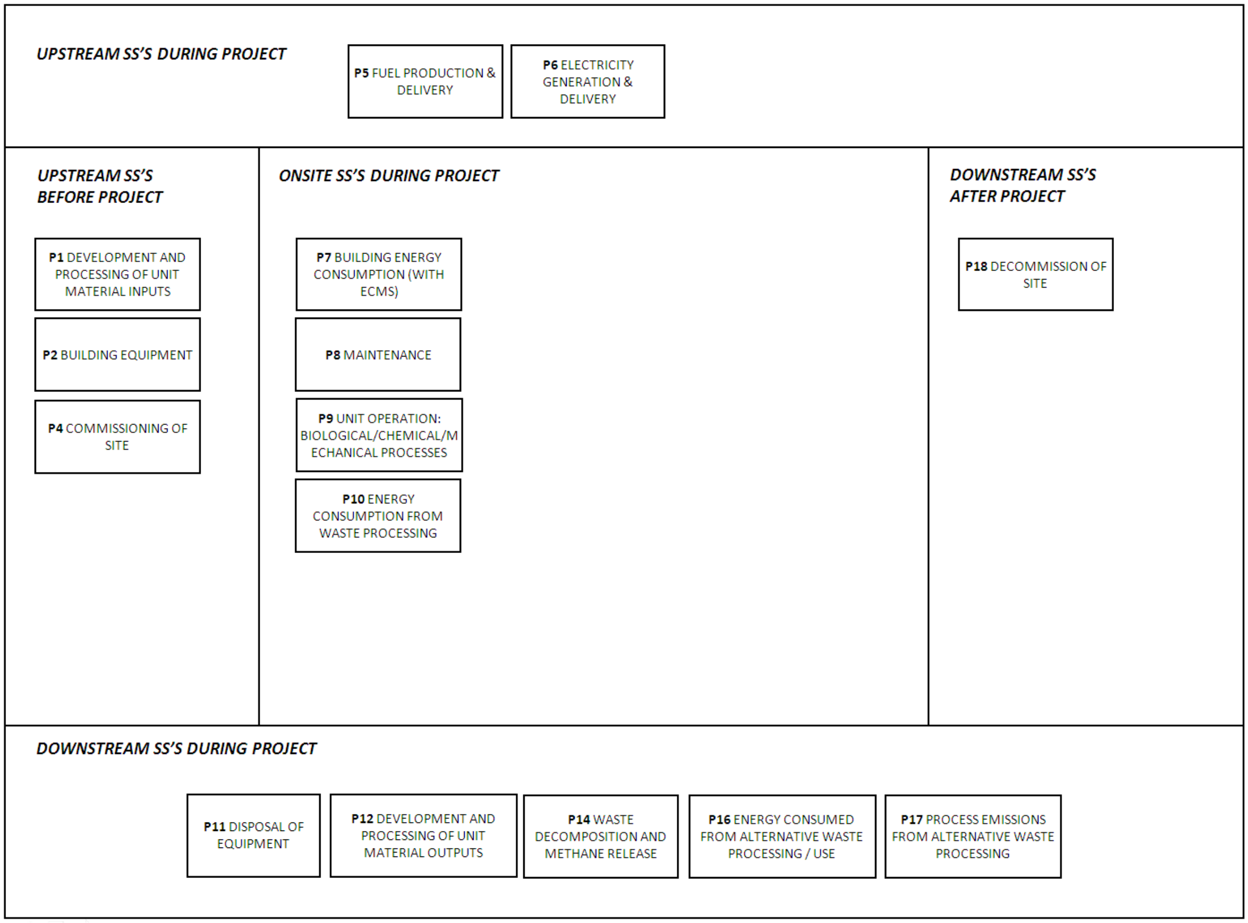

Table 1: Project Life Cycle SS Descriptions

SS	Description	Controlled, Related or Affected
Upstream Before Project		
P1 Development and Processing of Unit Material Inputs	The material inputs to the unit process need to be transported, developed and/or processed prior to the unit process. This may require any number of mechanical, chemical or biological processes. All relevant characteristics of the material inputs would need to be tracked to prove functional equivalence with the baseline scenario.	Related
P2 Building Equipment	GHG emissions arise from the manufacturing process of the equipment to implement the ECMs and conventional building/facility operation in the project. Such emissions are likely associated with the fossil fuels and electricity consumed during the manufacturing process.	Related

P4 Commissioning of Site	The development of the site (technically onsite before project) and installation of equipment result in GHG emissions, primarily from the use of fossil fuels and electricity during this process.	Related
Upstream During Project		
P5 Fuel Production & Delivery	The production and distribution of fuel used during building/facility operations result in GHG emissions. The volume and type of fuel shall be required for GHG emission calculations, as is the distribution distance.	Related
P6 Electricity Generation & Delivery	Building/facility operations could require significant amounts of electricity. The generation and distribution of electricity results in GHG emissions.	Related
Onsite During Project		
P7 Building/System Energy Consumption (with ECMs)	Energy (including fossil fuel and electricity) is likely required on-site to operate the building/facility. Equipment utilizing this energy could include boilers, lighting systems, HVAC Systems, ventilation systems, equipment, etc.	Controlled
P8 Maintenance	The facility and systems within the facility likely requires maintenance. GHG emissions arise from the use of fuels and electricity in maintenance procedures.	Controlled
P9 Unit Operation: Biological/Chemical /Mechanical Processes	Greenhouse gas emissions may occur that are associated with the operation and maintenance of the biological processes (biological, chemical, and mechanical) within the unit at the project site. All relevant characteristics of the biological processes would need to be identified.	Controlled
P10 Energy Consumption from Waste Processing	Energy may be required to power waste processing or handling equipment (i.e. compacters, etc.)	Controlled
Downstream During Project		
P11 Disposal of Equipment	The disposal of some materials/equipment which compose all or a component of the ECM or waste diversion systems may result in GHG emissions.	Related
P12 Development and Processing of Unit Material Outputs	The material outputs from the unit process need to be transported, developed, and/or processed subsequent to the unit process. This may require any number of mechanical, chemical or biological processes. All relevant characteristics of the material outputs would need to be identified to prove functional equivalence with the baseline scenario.	Related

P14 Waste Decomposition and Methane Release	Waste may decompose in the disposal facility (typically a landfill site) resulting in the production of methane. A methane collection and destruction system may be in place at the disposal site. If such a system is active in the landfill or the area of the landfill where this material is being disposed, then its characteristics must be identified and the efficiency (ie, percent of total methane generation that is capture and destroyed) must be accounted for in a reasonable manner. Disposal site characteristics, mass disposed at each site, and methane collection and destruction system characteristics may need to be identified.	Related
P16 Energy Consumed from alternative processing of waste/use	Energy may be consumed by the alternative processing waste diversion activity. The related energy inputs for fueling this equipment are identified under this SS, for the purpose of calculating the resulting GHG emissions.	Related
P17 Process Emissions from Alternative Processing of Waste	This SS encompasses any process emissions associated with the new method of handling waste. Any process emissions related to the alternative use or disposal of the solid waste must be measured or estimated. All relevant characteristics of these processes would need to be identified.	Related
Downstream After Project		
P12 Decommission of Site	Once the facility is no longer operational, the site may need to be decommissioned. This may involve the disassembly of the equipment, demolition of on-site structures, disposal of some materials, environmental restoration, re-grading, planting or seeding, and transportation of materials off-site. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment required to decommission the site.	Related

5.2 Baseline

All SS relevant to the baseline, including on-site, upstream and downstream SS shall be identified.

The process set out in Diagram 2 identifies, illustrates and organizes SS for a typical baseline applicable under this methodology. Table 2 describes each SS identified in Diagram 2, discusses the SS relevance and characterizes the SS as controlled, related, or affected by the project activity.

Diagram 2: Baseline Life Cycle Chart

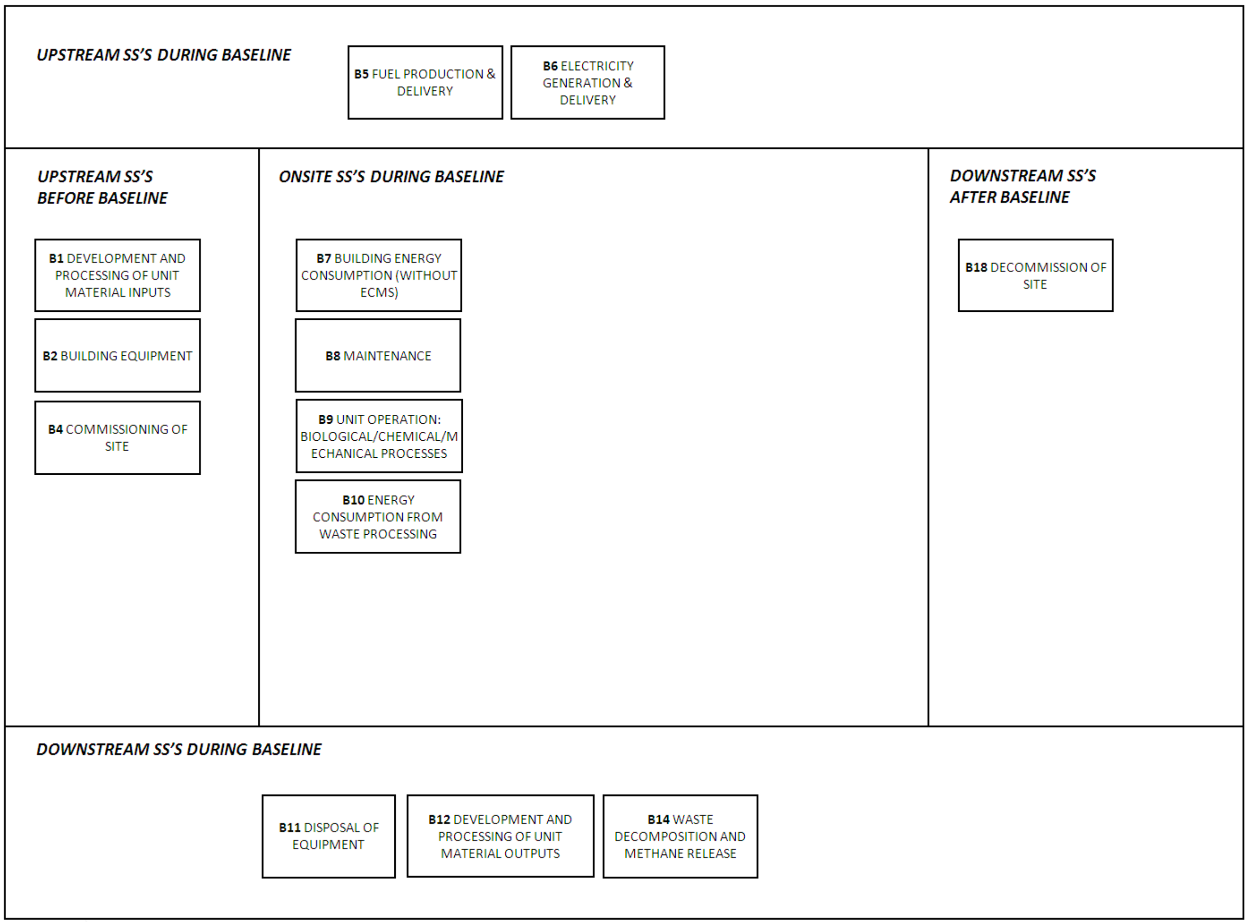

Table 2: Baseline Element Life Cycle SS Descriptions

SS	Description	Controlled, Related or Affected
Upstream During Baseline		
B1 Development and Processing of Unit Material Inputs	The material inputs to the unit process need to be transported, developed and/or processed prior to the unit process. This may require any number of mechanical, chemical or biological processes. All relevant characteristics of the material inputs would need to be identified to prove functional equivalence with the baseline scenario.	Related
B2 Building Equipment	GHG emissions arise from the manufacturing process of the equipment to implement the ECMs and conventional building/facility operation in the project. Such emissions are likely associated with the fossil fuels and electricity consumed during the manufacturing process.	Related
B4 Commissioning of Site	The development of the site (before project) and installation of equipment results in GHG emissions, primarily from the use of fossil fuels and electricity during this process.	Related
Upstream Before Baseline		
B5 Fuel Production & Delivery	The production and distribution of fuel used during building/facility operations results in GHG emissions. The volume and type of fuel shall be required for GHG emission calculations, as is the distribution distance.	Related
B6 Electricity Generation & Delivery	Building/facility operations could require significant amounts of electricity. The generation and distribution of electricity results in GHG emissions.	Related
Onsite During Baseline		
B7 Building/System Energy Consumption (without ECMs)	Energy (including fossil fuel and electricity) is likely required on-site to operate the building/facility. Equipment utilizing this energy could include boilers, lighting systems, HVAC Systems, ventilation systems, equipment, etc.	Controlled
B8 Maintenance	The facility and systems within the facility likely requires maintenance. GHG emissions arise from the use of fuels and electricity in maintenance procedures.	Controlled
B9 Unit Operation: Biological/Chemical/ Mechanical Processes	GHG emissions may occur that are associated with the operation and maintenance of the biological processes (biological, chemical, and mechanical) within the unit at the project site. All relevant characteristics of the biological processes would need to be identified.	Controlled

B10 Energy Consumption from Waste Processing	Energy may be required to power waste processing or handling equipment (i.e. compacters, etc.)	Controlled
Downstream During Baseline		
B11 Disposal of Equipment	The disposal of some materials/equipment which compose all or a component of the ECM or waste diversion systems may result in GHG emissions.	Related
B12 Development and Processing of Unit Material Outputs	The material outputs from the unit process need to be transported, developed, and/or processed subsequent to the unit process. This may require any number of mechanical, chemical or biological processes. All relevant characteristics of the material outputs would need to be identified to prove functional equivalence with the baseline scenario.	Related
B14 Waste Decomposition and Methane Release	Waste may decompose in the disposal facility (typically a landfill site) resulting in the production of methane. A methane collection and destruction system may be in place at the disposal site. If such a system is active in the landfill or the area of the landfill where this material is being disposed, then its characteristics must be identified and the efficiency (ie, percent of total methane generation that is capture and destroyed) must be accounted for in a reasonable manner. Disposal site characteristics and mass disposed of at each site may need to be identified.	Related
Downstream After Baseline		
B15 Decommission of Site	Once the facility is no longer operational, the site may need to be decommissioned. This may involve the disassembly of the equipment, demolition of on-site structures, disposal of some materials, environmental restoration, re-grading, planting or seeding, and transportation of materials off-site. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment required to decommission the site.	Related

5.3 SS Selection

Each of the SS from the project and baseline scenario shall be compared and evaluated as to their relevancy. The justification for the potential exclusion or conditions upon which the SS may be excluded is provided in Table 3. Negligible emissions have been defined as being less than 1% of the project's lifetime emissions (calculated on an annual basis). Where the SS are to be excluded, they must fall below this threshold. Table 3 includes a generalized assessment that is expected to be accurate for most facilities. However, the project proponent must make an assessment for their specific project and may only exclude emissions that do not exceed the 1% threshold.

Table 3: Process for Selection of SS

Source		Gas	Included?	Justification/Explanation
Baseline	B1 Development and Processing of Unit Material Inputs	CO_2	[Excluded]	Expected to be excluded as they must be functionally equivalent to allow for the application of the methodology.
		CH_4	[Excluded]	
		N_2O	[Excluded]	
	B2 Building Equipment	CO_2	[Excluded]	Expected to be excluded since emissions from manufacturing of building equipment are expected to be negligible over the lifetime of the project.
		CH_4	[Excluded]	
		N_2O	[Excluded]	
	B4 Commissioning of Site	CO_2	[Excluded]	Expected to be excluded since emissions from site development are expected to be negligible given the minimal site development typically required.
		CH_4	[Excluded]	
		N_2O	[Excluded]	
	B5 Fuel Production & Delivery	CO_2	[Excluded]	Expected to be excluded since emissions from fuel production and delivery are expected to be greater under the baseline scenario.
		CH_4	[Excluded]	
		N_2O	[Excluded]	
	B6 Electricity Generation & Delivery	CO_2	[Excluded]	Expected to be excluded since emissions from electricity generation and delivery are expected to be greater under the baseline scenario.
		CH_4	[Excluded]	
		N_2O	[Excluded]	
	B7 Building/System Energy Consumption (without ECMs)	CO_2	Included	Must be included as part of baseline if energy efficiency actions are included in the project activity since this SS is fundamental to quantifying the baseline for EE emission reductions under this methodology.
		CH_4	Included	
		N_2O	Included	

Source		Gas	Included?	Justification/Explanation
	B8 Maintenance	CO_2	Included	Must be included, though can be excluded if the baseline and project scenarios would involve immaterial difference in energy consumed for maintenance activities.
		CH_4	Included	
		N_2O	Included	
	B9 Unit Operation: Biological/Chemical/ Mechanical Processes	CO_2	Included	Must be included, though can be excluded if prescribed to be functionally equivalent.
		CH_4	Included	
		N_2O	Included	
	B10 Energy Consumption from Waste Processing	CO_2	Included	Must be included, though can be excluded if the facility or group of facilities is not quantifying emission reductions associated with waste diversion activities and if the ECM activities would not affect the energy consumed for waste processing at the Territory level.
		CH_4	Included	
		N_2O	Included	
	B11 Disposal of Equipment	CO_2	[Excluded]	Expected to be excluded since emissions from disposal of equipment are expected to be negligible.
		CH_4	[Excluded]	
		N_2O	[Excluded]	
	B12 Development and Processing of Unit Material Outputs	CO_2	[Excluded]	Expected to be excluded as they must be functionally equivalent to allow for the application of the methodology.
		CH_4	[Excluded]	
		N_2O	[Excluded]	
	B14 Waste Decomposition and Methane Release	CO_2	Included	Must be included, though can be excluded if the facility or group of facilities is not quantifying emission reductions associated with waste diversion activities and if the ECM activities would not affect the amount methane emitted
		CH_4	Included	
		N_2O	Included	

Source		Gas	Included?	Justification/Explanation
				from decomposition.
	B15 Decommission of Site	CO_2	[Excluded]	Expected to be excluded since emissions from equipment disposal are expected to be negligible.
		CH_4	[Excluded]	
		N_2O	[Excluded]	
Project	P1 Development and Processing of Unit Material Inputs	CO_2	[Excluded]	Expected to be excluded as they must be functionally equivalent to allow for the application of the methodology.
		CH_4	[Excluded]	
		N_2O	[Excluded]	
	P2 Building Equipment	CO_2	[Excluded]	Expected to be excluded since emissions from the manufacture of building equipment are expected to be negligible over the lifetime of the project.
		CH_4	[Excluded]	
		N_2O	[Excluded]	
	P4 Commissioning of Site	CO_2	[Excluded]	Expected to be excluded since emissions from site development are expected to be negligible given the minimal site development typically required.
		CH_4	[Excluded]	
		N_2O	[Excluded]	
	P5 Fuel Production & Delivery	CO_2	[Excluded]	Expected to be excluded since emissions from fuel production and delivery are expected to be greater under the baseline scenario.
		CH_4	[Excluded]	
		N_2O	[Excluded]	
	P6 Electricity Generation & Delivery	CO_2	[Excluded]	Expected to be excluded since emissions from fuel production and delivery are expected to be
		CH_4	[Excluded]	

Source		Gas	Included?	Justification/Explanation
		N_2O	[Excluded]	greater under the baseline scenario.
	P7 Building/System Energy Consumption (with ECMs)	CO_2	Included	Must be included as part of baseline if energy efficiency actions are included in the project activity.
		CH_4	Included	
		N_2O	Included	
	P8 Maintenance	CO_2	Included	Must be included, though can be excluded if the baseline and project scenario operations would involve immaterial difference in energy consumed for maintenance activities. If however maintenance activities included major overhauls that would not have been included in the baseline scenario, evidence must be provided by the project proponent to show the SS is below the negligible emissions threshold.
		CH_4	Included	
		N_2O	Included	
	P9 Unit Operation: Biological/Chemical/Mechanical Processes	CO_2	Included	Must be included, though can be excluded if prescribed to be functionally equivalent.
		CH_4	Included	
		N_2O	Included	
	P10 Energy Consumption from Waste Processing	CO_2	Included	Must be included, though can be excluded if the facility or group of facilities is not quantifying emission reductions associated with waste diversion activities and if the ECM activities would not affect the energy consumed for waste processing.
		CH_4	Included	
		N_2O	Included	
	P11 Disposal of Equipment	CO_2	[Excluded]	Expected to be excluded since emissions from disposal of equipment are expected to be negligible
		CH_4	[Excluded]	
		N_2O	[Excluded]	

Source		Gas	Included?	Justification/Explanation
	P12 Development and Processing of Unit Material Outputs	CO_2	[Excluded]	Expected to be excluded as they must be functionally equivalent to allow for the application of the methodology.
		CH_4	[Excluded]	
		N_2O	[Excluded]	
	P14 Waste Decomposition and Methane Release	CO_2	Included	Must be included, though can be excluded if the facility or group of facilities is not quantifying emission reductions associated with waste diversion activities and if the ECM activities would not affect the amount methane emitted from decomposition.
		CH_4	Included	
		N_2O	Included	
	P16 Energy Consumed from Alternative Processing of Waste / Use	CO_2	Included	Must be included, though can only be excluded if the facility or group of facilities is not quantifying emission reductions associated with alternative processing of waste / use in the project scenario at the Territory level.
		CH_4	Included	
		N_2O	Included	
	P17 Process Emissions from Alternative Processing of Waste	CO_2	Included	Must be included, though can be excluded if the facility or group of facilities is not quantifying emission reductions associated with the alternative processing of waste at the Territory level.
		CH_4	Included	
		N_2O	Included	
	P18 Decommission of Site	CO_2	[Excluded]	Expected to be excluded since emissions from decommissioning are not expected to differ highly between the baseline and project scenarios.
		CH_4	[Excluded]	
		N_2O	[Excluded]	

6 PROCEDURE FOR DETERMINING THE BASELINE SCENARIO AND DEMONSTRATING ADDITIONALITY

Regardless of the specific project type being proposed, the project proponent must follow the step-wise approach specified in the CDM *Combined Tool to Identify the Baseline Scenario and Demonstrate Additionality* to identify the baseline scenario and demonstrate additionality. The tool shall be applied with baseline alternatives and project scenarios categorized by project units. The cost savings associated with energy efficiency shall be included in the investment analysis.

When selecting the baseline period for waste diversion and energy efficiency activities, the appropriateness of baseline period shall be analyzed for the two activities separately. While one baseline period for both may be deemed appropriate, it is also possible that different baseline periods and approaches are required for the different activities. As one example, the best unit of productivity for the waste diversion baseline period may be different from that for the energy efficiency baseline period depending on the selected unit of productivity and the quality of data available for each.

The baseline scenario shall be determined by analyzing, at minimum, the following potential alternatives:

a. Each business owner proactively exceeds the current regulations and decreases their per unit energy consumption. Additionally, each business owner could also purchase new capital equipment prior to the natural turnover rate of their existing stock, for the purposes of energy efficiency savings, without installing the added monitoring equipment as required to quantify GHG emission reductions. This step is essentially the implementation of the energy efficiency project activity without carbon financing.

b. Each business owner proactively puts into place a system to treat waste in a manner other than anaerobic decomposition in a landfill. This step is essentially the implementation of the waste diversion project activity without carbon financing.

c. The government or industrial sector enforces minimum building codes, not only for new facilities but for the current stock of buildings. These codes could mandate certain levels of efficiency or waste handling that could achieve the anticipated results of this protocol without the use of VCUs.

d. The continuation of the current situation (ie, no project activity or other alternatives undertaken). Comparable outputs of the project – constant energy intensity per production unit and anaerobic decomposition of waste in landfill – will continue. Currently, technologies/ practices that provide outputs/services of comparable qualities, properties and application areas as the proposed project activity, are not incentivized and are not introduced to the market for dispersed client facilities. These facilities do not have the economies of scale necessary to develop and operate the necessary monitoring systems to achieve affordable gains similar to the goals of this protocol.

7 QUANTIFICATION OF GHG EMISSION REDUCTIONS AND REMOVALS

Quantification of the reductions, removals and reversals of relevant SS for each of the greenhouses gases must be completed by using the baseline and project emissions equations specified for energy efficiency and waste diversion activities.

If the project proponent chooses to exclude any of the sources from the SS selection (Table 3: Process for Selection of SS

), a detailed justification must be provided for each exclusion.

7.1 Baseline Emissions

Emissions $_{\text{Adjusted Baseline EE}}$	= the energy efficiency activities related baseline emissions plus any adjustments needed to adjust it to the conditions of the monitoring period
Emissions $_{\text{Adjusted Baseline EE}}$	= Emissions $_{\text{Adjusted Building/System Energy Consumption w/o ECM}}$ + Emissions $_{\text{Adjusted Maintenance}}$ + Emissions $_{\text{Adjusted Unit Operation}}$

Emissions $_{\text{Adjusted Building Energy Consumption w/o ECM}}$ = Emissions under SS **B7** Adjusted Building/System Energy Consumption (w/o ECMs)

Emissions $_{\text{Adjusted Maintenance}}$ = Emissions under SS **B8** Adjusted Maintenance

Emissions $_{\text{Adjusted Unit Operation}}$ = Emissions under SS **B9** Adjusted Unit Operation: Biological/Chemical/Mechanical Processes

Emissions $_{\text{Adjusted Baseline WASTE}}$	= the waste related baseline emissions plus any adjustments needed to adjust it to the conditions of the monitoring period
Emissions $_{\text{Adjusted Baseline WASTE}}$	= Emissions $_{\text{Adjusted Energy Consumption from Waste Processing}}$ + Emissions $_{\text{Adjusted Waste Decomposition and Methane Release}}$

Emissions $_{\text{Adjusted Energy Consumption from Waste Processing}}$ = Emissions under SS **B10** Adjusted Energy Consumption from Waste Processing

Emissions $_{\text{Adjusted Waste Decomposition and Methane Release}}$ = Emissions under SS **B14** Adjusted Waste Decomposition and Methane Release

7.2 Adjustments

The project proponent may conduct emission adjustments for measuring functional equivalence as well as unit of productivity. The baseline scenario identified for the projects using this methodology may require adjustments to ensure functional equivalence with the project.

In order for this comparison between the project scenario and baseline scenario to be meaningful, the project and the baseline must provide the same function and quality of products or services. This consistency in metrics and units of production provides an ability to quantify actual emissions reductions achieved in the project scenario.

Table 4 provides SS-specific equations for the baseline component of the comparison. Table 5 provides project SS emission adjustment quantification.

In some cases, the project scenario cannot have the same units as the baseline. An example of this would be where the project seeks to displace conventional natural gas with landfill gas. In this case, the common metric would be the energy content of each fuel, reported as energy content/liter of fuel[4].

The project proponent is strongly encouraged to review IPMVP volumes for examples of how to make adjustments for functional equivalence and productivity.

The unit of productivity must be used by the project proponent as a basis for incorporating functional equivalence within the calculation methodology. Examples of units of productivity could be: energy requirements for residential buildings, per square foot of front of house commercial space, per kg/L/m^2/m^3 of output from manufacturing facilities, etc. The unit of productivity shall be defined to account for any non-production sensitive components. In all cases the project proponent must thoroughly justify their assessment of the appropriate unit of productivity.

The project proponent must also justify the selection of data used for deriving the unit of productivity.

Functional equivalence adjustments are usually performed when the energy savings are quantified. In many cases, the quantification and claims of GHG emission reductions shall occur on a yearly basis; therefore, these adjustments need to be performed according to that same schedule. Typical adjustment includes routine adjustments and non-routine adjustments as explained below:

Routine Adjustments of the Baseline

IPMVP provides the following guidance on performing routine adjustments: “For any energy governing factors expected to change routinely during the monitoring period such as weather… a variety of techniques can be used to perform the adjustments. Techniques may be as simple as a constant value (no adjustment) or as complex as a several multiple parameter non-linear equations, each correlating energy with one or more independent variables. Valid mathematical techniques must be used to derive

[4] Ibid.

the adjustment method." The quantification of routine baseline adjustments should reflect best practice set out in the latest IPMVP volume[5].

Non-Routine Adjustments of the Baseline

IPMVP provides examples of non-routine adjustments. The quantification of non-routine baseline adjustments should reflect best practice set out in the latest IPMVP volume.

Table 4: Baseline SS Emission Adjustment Quantification

5 IPMVP contains examples of routine and non-routine adjustments.

SS	Units	Baseline SS Formula
B7 Building/System Energy Consumption (without ECMs)	kgCO2e	Emissions $_{\text{Building/System Energy Consumption w/o ECM}}$ = ∑ [(Vol. Fuel $_i$ * EF Fuel $_{i\ CO2}$) ; (GWP$_{CH4}$ * Vol. Fuel $_i$ * EF Fuel $_{i\ CH4}$) ; (GWP$_{N2O}$ * Vol. Fuel $_i$ * EF Fuel $_{i\ N20}$)] + [Electricity * EF Grid$_{CO2e}$] + [Thermal Energy * EF Thermal Energy$_{CO2e}$]
B8 Maintenance	kgCO2e	Emissions $_{\text{Maintenance}}$ = ∑ [(Vol. Fuel $_i$ * EF Fuel $_{i\ CO2}$) ; (GWP$_{CH4}$ * Vol. Fuel $_i$ * EF Fuel $_{i\ CH4}$) ; (GWP$_{N2O}$ * Vol. Fuel $_i$ * EF Fuel $_{i\ N20}$)] + [Electricity * EF Grid$_{CO2e}$] + [Thermal Energy * EF Thermal Energy$_{CO2e}$]
B9 Unit Operation: Biological / Chemical / Mechanical Processes	kgCO2e	Emissions $_{\text{Unit Operation}}$ = ∑ [(Vol. Fuel $_i$ * EF Fuel $_{i\ CO2}$) ; (GWP$_{CH4}$ * Vol. Fuel $_i$ * EF Fuel $_{i\ CH4}$) ; (GWP$_{N2O}$ * Vol. Fuel $_i$ * EF Fuel $_{i\ N20}$)] + [Electricity * EF Grid$_{CO2e}$] + [Thermal Energy * EF Thermal Energy$_{CO2e}$]
B10 Energy Consumption from Waste Processing	kgCO2e	Emissions $_{\text{Energy Consumption from Waste Processing}}$ = ∑ [(Vol. Fuel $_i$ * EF Fuel $_{i\ CO2}$) ; (GWP$_{CH4}$ * Vol. Fuel $_i$ * EF Fuel $_{i\ CH4}$) ; (GWP$_{N2O}$ * Vol. Fuel $_i$ * EF Fuel $_{i\ N20}$)] + [Electricity * EF Grid$_{CO2e}$] + [Thermal Energy * EF Thermal Energy$_{CO2e}$]
B13 Energy Consumption from Waste Processing	kgCO2e	Emissions $_{\text{Energy Consumption from Waste Processing}}$ = ∑ [(Vol. Fuel $_i$ * EF Fuel $_{i\ CO2}$) ; (GWP$_{CH4}$ * Vol. Fuel $_i$ * EF Fuel $_{i\ CH4}$) ; (GWP$_{N2O}$ * Vol. Fuel $_i$ * EF Fuel $_{i\ N20}$)] + [Electricity * EF Grid$_{CO2e}$] + [Thermal Energy * EF Thermal Energy$_{CO2e}$]

B14 Waste Decomposition and Methane Release	kgCO2e	Emissions $_{\text{Waste Decomposition and Methane Release}}$ $= 1000 * \phi * (1-f) * GWP_{CH4} * (1-OX) * \left(\frac{16}{12}\right) * F * DOC_f * MCF * \sum_{x=1}^{y} \sum_{j} W_{j,x} * DOC_j * e^{-k_j(y-x)} * \left(1-e^{-k_j}\right)$ aste Decomposition and Methane Release = Methane emissions avoided during the year y from preventing waste disposal at the solid waste disposal site during the period from the start of the project activity to the end of the year y Model correction factor to account for model uncertainties (0.9) Fraction of methane captured at the solid waste disposal sites (SWDS) and flared, combusted or used in another manner Global Warming Potential (GWP) of methane, valid for the relevant commitment period Oxidation factor (reflecting the amount of methane from SWDS that is oxidised in the soil or other material covering the waste) Fraction of methane in the SWDS gas (volume fraction) (0.5) Fraction of degradable organic carbon (DOC) that can decompose Methane correction factor Mass of Waste Material type j Sent to Landfill in the year x (tons) Fraction of degradable organic carbon (by weight) in the waste type j Decay rate for the waste type j Waste type category (index) Year during the crediting period: x runs from the first year of the first crediting period (x = 1) to the year y for which avoided emissions a re-calculated (x = y) Year for which methane emissions are calculated

7.3 Project Emissions

$Emissions_{\text{Project EE}}$	= sum of the energy efficiency related emissions under the project scenario
$Emissions_{\text{Project EE}}$	= $Emissions_{\text{Building/System Energy Consumption with ECM}}$ + $Emissions_{\text{Maintenance}}$ + $Emissions_{\text{Unit Operation}}$

$Emissions_{\text{Building Energy Consumption with ECM}}$	=	Emissions under SS **P7** Building/System Energy Consumption (with ECMs)
$Emissions_{\text{Maintenance}}$	=	Emissions under SS **P8** Maintenance
$Emissions_{\text{Unit Operation}}$	=	Emissions under SS **P9** Unit Operation: Biological/Chemical/Mechanical Processes

$Emissions_{\text{Project WASTE}}$	= sum of the waste related emissions under the project scenario
$Emissions_{\text{Project WASTE}}$	= $Emissions_{\text{Energy Consumption from Waste Processing}}$ + $Emissions_{\text{Waste Decomposition and Methane Release}}$ + $Emissions_{\text{Energy Consumed from Alternative Processing of Waste Use}}$ + $Emissions_{\text{Process Emissions from Alternative Processing of Waste}}$

$Emissions_{\text{Energy Consumption from Waste Processing}}$ =	Emissions under SS **P10** Energy Consumption from Waste Processing
$Emissions_{\text{Waste Decomposition and Methane Release}}$ =	Emissions under SS **P14** Waste Decomposition and Methane Release
$Emissions_{\text{Energy Consumed from alternative processing of waste / use}}$ =	Emissions under SS **P16** Energy Consumed from alternative processing of waste / use
$Emissions_{\text{Process Emissions from Alternative Processing of Waste}}$ =	Emissions under SS **P17** Process Emissions from Alternative Processing of Waste

Table 5 provides SS-specific equations for comparisons of the project SS.

Table 5: Project SS Emission Adjustment Quantification

SS	Units	Project SS Formula
P7 Building/System Energy Consumption (with ECMs)	kgCO2e	Emissions $_{\text{Building/System Energy Consumption with ECM}}$ = ∑ [(Vol. Fuel $_i$ * EF Fuel $_{i\ CO2}$) ; (GWP_{CH4} * Vol. Fuel $_i$ * EF Fuel $_{i\ CH4}$) ; (GWP_{N2O} * Vol. Fuel $_i$ * EF Fuel $_{i\ N20}$)]
P8 Maintenance	kgCO2e	Emissions $_{\text{Maintenance}}$ = ∑ [(Vol. Fuel $_i$ * EF Fuel $_{i\ CO2}$) ; (GWP_{CH4} * Vol. Fuel $_i$ * EF Fuel $_{i\ CH4}$) ; (GWP_{N2O} * Vol. Fuel $_i$ * EF Fuel $_{i\ N20}$)] + [Electricity * EF $Grid_{CO2e}$] + [Thermal Energy * EF Thermal $Energy_{CO2e}$]
P9 Unit Operation: Biological / Chemical / Mechanical Processes	kgCO2e	Emissions $_{\text{Unit Operation}}$ = ∑ [(Vol. Fuel $_i$ * EF Fuel $_{i\ CO2}$) ; (GWP_{CH4} * Vol. Fuel $_i$ * EF Fuel $_{i\ CH4}$) ; (GWP_{N2O} * Vol. Fuel $_i$ * EF Fuel $_{i\ N20}$)] + [Electricity * EF $Grid_{CO2e}$] + [Thermal Energy * EF Thermal $Energy_{CO2e}$]
P10 Energy Consumption from Waste Processing	kgCO2e	Emissions $_{\text{Energy Consumption from Waste Processing}}$ = ∑ [(Vol. Fuel $_i$ * EF Fuel $_{i\ CO2}$) ; (GWP_{CH4} * Vol. Fuel $_i$ * EF Fuel $_{i\ CH4}$) ; (GWP_{N2O} * Vol. Fuel $_i$ * EF Fuel $_{i\ N20}$)] + [Electricity * EF $Grid_{CO2e}$] + [Thermal Energy * EF Thermal $Energy_{CO2e}$]
P14 Waste Decomposition and Methane Release	kgCO2e	Emissions $_{\text{Waste Decomposition and Methane Release}}$ $= 1000 * \phi * (1-f) * GWP_{CH4} * (1-OX) * \left(\frac{16}{12}\right) * F * DOC_{f} * MCF * \sum_{x=1}^{y} \sum_{j} W_{j,x} * DOC_j * e^{-k_j(y-x)} * \left(1-e^{-k_j}\right)$
P16 Energy Consumed from alternative processing of waste / use	kgCO2e	Emissions $_{\text{Energy Consumed from alternative processing of waste / use}}$ = ∑ [(Vol. Fuel $_i$ * EF Fuel $_{i\ CO2}$) ; (GWP_{CH4} * Vol. Fuel $_i$ * EF Fuel $_{i\ CH4}$) ; (Vol. Fuel $_i$ * EF Fuel $_{i\ N20}$)] + [Electricity * EF $Grid_{CO2e}$] + [Thermal Energy * EF Thermal $Energy_{CO2e}$]
P17 Process Emissions from Alternative Processing of Waste	kgCO2e	Emissions $_{\text{Process Emissions from Alternative Processing of Waste}}$ = ∑ [(Mass $_{CO2}$) ; (Mass $_{N2O}$) ; (Mass $_{CH4}$)]

7.4 Leakage

The project proponent must assess the likelihood of leakage based on the specific project activities. If it cannot be shown that no plausible material leakage would occur based on the specific project activities, then this methodology shall not be applied.

The project proponent must quantify GHG emissions sources occurring outside the project boundary as a result of implementation of the project activities, which are expected to contribute more than 1% of the overall average emission reductions.

7.5 Summary of GHG Emission Reduction and/or Removals

Quantification of the net GHG reductions must be calculated using the equation set out below.

Emission Reductions = [Emission $_{\text{Adjusted Baseline EE}}$ – Emissions $_{\text{Project EE}}$] + [Emission $_{\text{Adjusted Baseline WASTE}}$ – Emissions $_{\text{Project WASTE}}$]

Where:

Emissions $_{\text{Adjusted Baseline EE}}$ = the energy efficiency related baseline emissions plus any adjustments needed to adjust it to the conditions of the monitoring period

Emissions $_{\text{Adjusted Baseline WASTE}}$ = the waste related baseline emissions plus any adjustments needed to adjust it to the conditions of the monitoring period

Emissions $_{\text{Project EE}}$ = sum of the energy efficiency related emissions under the project scenario

Emissions $_{\text{Project WASTE}}$ = sum of the waste related emissions under the project scenario

8 Monitoring

8.1 Parameters Available at Validation

The following data units/parameters are referred to numerous times in the formulas presented in Section 6. Actual measured or local data are to be used when available. If not available, regional data must be used. The data sources for each parameter are offered below, however; in their absence, IPCC defaults can be used from the most recent version of the IPCC Guidelines for National Greenhouse Gas Inventories.

Parameter:	EF Thermal Energy$_{CO2e}$
Data unit:	Kg CO_2e per GJ
Description:	CO_2e emissions factor for local generation of thermal energy
Source of data:	For the Territory of interest, the project proponent must identify the most appropriate CO2e emission factor for the source of thermal energy used under the project scenario. Regional data (for example: US Department of Energy's Form EIA-1605 Appendix N. Emission factors for Steam and Chilled/Hot Water) shall be used. In its absence, IPCC defaults must be used from the most recent version of *IPCC Guidelines for National Greenhouse Gas Inventories* providing they are deemed to reasonably represent local circumstances. The project proponent must choose the values in a conservative manner and justify the choice.
Justification of choice of data or description of measurement methods and procedures applied:	Thermal Energy generation characteristics are likely to remain relatively stable over a year's time.

Parameter:	EF Fuel $_{i\ N20}$
Data unit:	Kg N_2O per L, m^3, or other
Description:	N_2O emissions factor for combustion of each type of fuel (EF Fuel $_{i\ N2O}$)
Source of data:	For both mobile and stationary fuel combustion for the Territory of interest, the project proponent must identify the most appropriate emission factors for the source of thermal energy used under the project condition. Regional data (for example: EPA's AP 42, *Compilation of Air Pollutant Emission Factors*) shall be used. In its absence, IPCC defaults must be used from the most recent version of *IPCC Guidelines for National Greenhouse Gas Inventories* providing they are deemed to reasonably represent local circumstances. The project proponent must choose the values in a conservative manner and justify the choice.
Justification of choice of data or description of measurement methods and procedures applied:	This is one of the most comprehensive fuel emission factor databases available.

Parameter:	EF Fuel $_{i\ CH4}$
Data unit:	Kg CH_4 per L, m^3, or other
Description:	CH_4 emissions factor for combustion of each type of fuel (EF Fuel $_{i\ CH4}$)
Source of data:	For both mobile and stationary fuel combustion for the Territory of interest, the project proponent must identify the most appropriate emission factors for the source of thermal energy used under the project scenario. Regional data (for example: EPA's AP 42, *Compilation of Air Pollutant Emission Factors*) shall be used. In its absence, IPCC defaults can be used from the most recent version of *IPCC Guidelines for National Greenhouse Gas Inventories* providing they are deemed to reasonably represent local circumstances. The project proponent must choose the values in a conservative manner and justify the choice.
Justification of choice of data or description of measurement methods and procedures applied:	This is one of the most comprehensive fuel emission factor databases available.

Parameter:	EF Fuel $_{i\ CO2}$
Data unit:	Kg CO_2 per L, m^3, or other
Description:	CO_2 Emissions Factor for combustion of each type of fuel (EF Fuel $_{i\ CO2}$)
Source of data:	For both mobile and stationary fuel combustion for the Territory of interest, the project proponent must identify the most appropriate emission factors for the source of thermal energy used under the project scenario. Regional data (for example: EPA's AP 42, *Compilation of Air Pollutant Emission Factors*) shall be used. In its absence, IPCC defaults can be used from the most recent version of *IPCC Guidelines for National Greenhouse Gas Inventories* providing they are deemed to reasonably represent local circumstances. The project proponent must choose the values in a conservative manner and justify the choice.
Justification of choice of data or description of measurement methods and procedures applied:	This is one of the most comprehensive fuel emission factor databases available.

Parameter:	ϕ
Data unit:	-
Description:	Model correction factor to account for model uncertainties (0.9)
Source of data:	This factor is determined using the CDM's "Tool to determine methane emissions avoided from disposal of waste at a solid waste disposal site (Version 05.1.0)" (CDM, 2011).
Justification of choice of data or description of measurement methods and procedures applied:	The most used tool for calculation landfill gas emission reductions.

Parameter:	OX
Data unit:	-
Description:	Oxidation factor (reflecting the amount of soil or other material covering the waste)
Source of data:	This factor is determined using the CDM's "Tool to determine methane emissions avoided from disposal of waste at a solid waste disposal site (Version 05.1.0)" (CDM, 2011).
Justification of choice of data or description of measurement methods and procedures applied:	The most used tool for calculation landfill gas emission reductions.

Parameter:	DOC_f
Data unit:	-
Description:	Fraction of degradable organic carbon (DOC) that can decompose
Source of data:	This factor is determined using the CDM's "Tool to determine methane emissions avoided from disposal of waste at a solid waste disposal site (Version 05.1.0)" (CDM, 2011).
Justification of choice of data or description of measurement methods and procedures applied:	The most used tool for calculation landfill gas emission reductions.

Parameter:	DOC_j
Data unit:	-
Description:	Fraction of degradable organic carbon (by weight)
Source of data:	This factor is determined using the CDM's "Tool to determine methane emissions avoided from disposal of waste at a solid waste disposal site (Version 05.1.0)" (CDM, 2011).
Justification of choice of data or description of measurement methods and procedures applied:	The most used tool for calculation landfill gas emission reductions.

Parameter:	MCF
Data unit:	-
Description:	Methane correction factor
Source of data:	This factor is determined using the CDM's "Tool to determine methane emissions avoided from disposal of waste at a solid waste disposal site (Version 05.1.0)" (CDM, 2011).
Justification of choice of data or description of measurement methods and procedures applied:	The most used tool for calculation landfill gas emission reductions.

<table>
<tr><td>Parameter:</td><td>k_j</td></tr>
<tr><td>Data unit:</td><td>-</td></tr>
<tr><td>Description:</td><td>Decay rate for the waste type j</td></tr>
<tr><td>Source of data:</td><td>IPCC 2006 Guidelines for National Greenhouse Gas Inventories (adapted from Volume 5, Table 3.3)</td></tr>
<tr><td>Justification of choice of data or description of measurement methods and procedures applied:</td><td>Apply the following default values for the different waste types j

<table>
<tr><th rowspan="2" colspan="2">Waste type j</th><th colspan="2">Boreal and Temperate (MAT≤20°C)</th><th colspan="2">Tropical (MAT>20°C)</th></tr>
<tr><th>Dry (MAP/PET <1)</th><th>Wet (MAP/PET >1)</th><th>Dry (MAP< 1000mm)</th><th>Wet (MAP> 1000mm)</th></tr>
<tr><td rowspan="2">Slowly degrading</td><td>Pulp, paper, cardboard (other than sludge), textiles</td><td>0.04</td><td>0.06</td><td>0.045</td><td>0.07</td></tr>
<tr><td>Wood, wood products and straw</td><td>0.02</td><td>0.03</td><td>0.025</td><td>0.035</td></tr>
<tr><td>Moderately degrading</td><td>Other (non-food) organic putrescible garden and park waste</td><td>0.05</td><td>0.10</td><td>0.065</td><td>0.17</td></tr>
<tr><td>Rapidly degrading</td><td>Food, food waste, beverages and tobacco (other than sludge)</td><td>0.06</td><td>0.185</td><td>0.085</td><td>0.40</td></tr>
</table>

NB: MAT – mean annual temperature, MAP – Mean annual precipitation, PET – potential evapotranspiration. MAP/PET is the ratio between the mean annual precipitation and the potential evapotranspiration.

If a waste type, prevented from disposal by the proposed CDM project activity, cannot clearly be attributed to one of the waste types in the table above, project participants choose among the waste types that have similar characteristics that waste type where the values of DOCj and kj result in a conservative estimate (lowest emissions), or request a revision of / deviation from this methodology.

Document in the CDM-PDD the climatic conditions at the SWDS site (temperature, precipitation and, where applicable, evapotranspiration). Use long-term averages based on statistical data, where available. Provide references.</td></tr>
</table>

8.2 Data and Parameters Monitored

The specific data and parameters associated with each SS are identified below.

Data Unit / Parameter:	Vol. Fuel $_i$
Data unit:	L, m^3, or other
Description:	Volume of each type of fuel combusted. This volume of fuel is adjusted for both functional equivalence and units of productivity.
Source of data:	The volume of fuel is determined by third party custody invoices, consolidated monthly. Un-calibrated internal meters cannot be used.
Description of measurement methods and procedures to be applied:	Monthly invoices filed for verification.
Frequency of monitoring/recording:	Monthly.
QA/QC procedures to be applied:	Manual transcription is avoided where possible.

Data Unit / Parameter:	Electricity
Data unit:	kWh
Description:	The amount of electricity consumed from the grid.
Source of data:	The amount of electricity consumed from the grid is determined by third party custody invoices, consolidated monthly. If internal meters are required for the Isolation Parameter Measurement option, calibration records is provided as per the manufacturer's schedule.
Description of measurement methods and procedures to be applied:	Monthly.
Frequency of monitoring/recording:	Manual transcription is avoided where possible.
QA/QC procedures to be applied:	Cross reference when possible.

Data Unit / Parameter:	EF $Grid_{CO2e}$
Data unit:	Kg CO2e per kWh
Description:	CO_2e Emissions Factor for electricity from the grid.
Source of data:	For the Territory of interest, the project proponent must calculate the emission factor for the appropriate emission factor using the CDM's "Tool to calculate the emission factor for an electricity system (Version 2.2.1)" (CDM, 2011).
Justification of choice of data or description of measurement methods and procedures applied:	Refer to the latest version of the CDM tool.

Data Unit / Parameter:	Thermal Energy
Data unit:	GJ
Description:	Thermal Energy consumed at the facility. This amount is adjusted for both functional equivalence and units of productivity.
Source of data:	Thermal energy crossing the boundary is measured with monthly invoices. If the thermal energy crosses the boundary without a custody caliber meter, only calibrated internal meters is relied upon. Calibration records must be made available during verification.
Description of measurement methods and procedures to be applied:	Continuous Metering or invoice reconciliation
Frequency of monitoring/recording:	Frequency of metering and reconciliation is most frequent as possible.
QA/QC procedures to be applied:	Cross-checked with the quantity of heat invoiced if relevant

Data Unit / Parameter:	$W_{j,x}$
Data unit:	kg
Description:	Mass of Waste Material Sent to Landfill
Source of data:	Direct measurement of mass of waste sent for disposal.
Description of measurement methods and procedures to be applied:	Continuous metering or invoice reconciliation. The mass of material diverted from conventional landfill disposal may be measured by invoice reconciliation from a sight appropriate for no anaerobic disposal of waste. The mass of organic material sent to landfill may be measured upon departure from the composting site or at the waste disposal site. Care must be taken to ensure no material is then diverted to landfill without being accounted for.
Frequency of monitoring/recording:	Both methods are standard practice. Frequency of metering is highest level possible.
QA/QC procedures to be applied:	As per the latest version of the “Tool to determine methane emissions avoided from disposal of waste at a solid waste disposal site (Version 05.1.0)” (CDM, 2011).

Data Unit / Parameter:	f
Data unit:	-
Description:	Fraction of methane captured in the SWDS gas
Source of data:	This factor is determined using the CDM’s “Tool to determine methane emissions avoided from disposal of waste at a solid waste disposal site (Version 05.1.0)” (CDM, 2011).
Justification of choice of data or description of measurement methods and procedures applied:	The most used tool for calculation landfill gas emission reductions.

Data Unit / Parameter:	Mass $_{CO2}$
Data unit:	Kg
Description:	Mass of CO_2 emitted as a process emissions
Source of data:	Measured or Estimated
Description of measurement methods and procedures to be applied:	This variable can be either measured or estimated. Measured process emissions would be conducted via a continuous monitoring system that records both the flow rate of the gas and the percent composition of CO_2. This would allow a mass to be accurately determined. If measurement is in place, calibration schedules and records must be provided in the project document. If estimation is used in absence of a continuous monitoring system, the details of the mass balance must be provided in the project document. The mass balance must include the justification around an average waste composition used in the mass balance.
Frequency of monitoring/recording:	Continuous measurement or hourly estimations
QA/QC procedures to be applied:	If the measurement results differ significantly from previous measurements or other relevant data sources, conduct additional measurements or cross checking with other reported values.

Data Unit / Parameter:	Mass $_{N2O}$
Data unit:	Kg
Description:	Mass of N_2O emitted as a process emissions
Source of data:	Measured or Estimated
Description of measurement methods and procedures to be applied:	This variable can be either measured or estimated. Measured process emissions would be conducted via a continuous monitoring system that records both the flow rate of the gas and the percent composition of N_2O. This would allow a mass to be accurately determined. If measurement is in place, calibration schedules and records must be provided in the project document. If estimation is used in absence of a continuous monitoring system, the details of the mass balance must be provided in the project document. The mass balance must include the justification around an average waste composition used in the mass balance.
Frequency of monitoring/recording:	Continuous measurement or hourly estimations
QA/QC procedures to be applied:	If the measurement results differ significantly from previous measurements or other relevant data sources, conduct additional measurements or cross checking with other reported values.

Data Unit / Parameter:	Mass $_{CH4}$
Data unit:	Kg
Description:	Mass of CH_4 emitted as a process emissions
Source of data:	Measured or Estimated
Description of measurement methods and procedures to be applied:	This variable can be either measured or estimated. Measured process emissions would be conducted via a continuous monitoring system that records both the flow rate of the gas and the percent composition of CH_4. This would allow a mass to be accurately determined. If measurement is in place, calibration schedules and records must be provided in the project document. If estimation is used in absence of a continuous monitoring system, the details of the mass balance must be provided in the project document. The mass balance must include the justification around an average waste composition used in the mass balance.
Frequency of monitoring/recording:	Continuous measurement or hourly estimations
QA/QC procedures to be applied:	If the measurement results differ significantly from previous measurements or other relevant data sources, conduct additional measurements or cross checking with other reported values.

8.3 Description of the Monitoring Plan

Data quality management must include sufficient data capture such that the mass and energy balances may be easily performed with the need for minimal assumptions and use of contingency procedures. The data shall be of sufficient quality to fulfill the quantification requirements and be substantiated by company records for the purpose of verification.

The project proponent shall establish and apply quality management procedures to manage data and information. Written procedures must be established for each measurement task outlining responsibility, timing and record location requirements. The greater the rigor of the management system for the data, the easier it will be to conduct an audit for the project.

In case of doubt regarding appropriateness of the proposed sample, the project proponent shall refer to the latest version of the CDM *General Guidelines for Sampling and Surveys for Small-Scale Project Activities and Programme of Activities (PoAs)*.

Record keeping practices shall include the following procedures:

- Electronic recording of values of logged primary parameters for each measurement interval;
- Offsite electronic back-up of all logged data;

- Written logs of operations and maintenance of the project system including notation of all shut-downs, start-ups and process adjustments; and
- Storage of all documents and records in a secure and retrievable manner for at least two years after the end of the project crediting period.

Quality assurance/Quality control (QA/QC) shall also be applied to add confidence that all measurements and calculations have been made correctly. These include, but are not limited to:

- Protecting monitoring equipment (sealed meters and data loggers);
- Protecting records of monitored data (hard copy and electronic storage);
- Checking data integrity on a regular and periodic basis (manual assessment, comparing redundant metered data, and detection of outstanding data/records);
- Comparing current estimates with previous estimates as a 'reality check';
- Provide sufficient training to operators to perform maintenance and calibration of monitoring devices;
- Establish minimum experience and requirements for operators in charge of project and monitoring; and
- Performing recalculations to make sure no mathematical errors have been made.

Requirements for sampling eligibility of a Territory within a Sustainable Community[6]:

- Project Units in the Territory, connected to the Sustainable Community and which apply all or part of the Sustainable Community activities (identified as ECM and/or waste diversion) are applicable for sampling as long the Sustainable Community data are collected and stored in the project proponent system.
- The project proponent's data collection and storage shall be centrally controlled and administered.
- The project proponent shall demonstrate its capacity to identify project units with data that inappropriately[7] affects the confidence interval of the Sustainable Community; these project units shall either be audited or excluded from the Sustainable Community.

Confidence Interval requirements:

- The Confidence Interval shall be set to 95%.

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[6] Sampling requirements follow guidance provided in *ANSI/ASQC Z1.4-2008* "Sampling Procedures and Tables for Inspection*" by Attributes* and *IAF MD 1:2007* "IAF Mandatory Document for the Certification of Multiple Sites Based on Sampling."

[7] Inappropriate in this context means data collected which, when compared to regional conditions, are outside the acceptable range (defect).

Sampling size requirements:

- The sample shall be partly selective based on factors, such as importance of activities and GHG reduction volume, range of activities being conducted, exceptional performance (beyond Territory and sectoral performance).
- The sample shall be partly nonselective, with at least 20% of the sample being selected at random.
- The project proponent shall have a documented procedure for determining the sample to be taken when verifying project sites and submit to the validation/verification body.
- When necessary, stratified random sampling shall be conducted on homogeneous sub-populations. The criteria for sub-population grouping are based on appropriate economic sectors. The criteria are based on an official territory authority classification or an internationally recognized equivalent (examples include the North American Industry Classification System (NAICS) or Statistical Classification of Economic Activities in the European Community (NACE[8]).

For a Territory, there are three different levels of sampling:

- Normal: the size of the sample shall be the square root of the number of project units connected to the project proponent, rounded to the upper whole number.
- Reduced: the size of the sample shall be the square root of the number of project units connected to the project proponent reduced by a coefficient (max. 0.6) when the overall confidence interval of the Sustainable Community data exceeds the target value[9].
- Reinforced: the size of the sample shall be the square root of the number of project units connected to the project proponent increased by a coefficient (max. 1.3) when the overall confidence interval of the Sustainable Community data is below the target value.

Sample Defect requirements:

- The sample size shall be enlarged to a maximum of 160% of the initial size if the reported values for one or more GHG reduction activities is beyond the acceptable range (defect) and the number of defects exceeds the acceptable quality level.
- The sample size shall be reduced to a maximum of 60% of the initial size if all client facility reported values are within the acceptable range (no defects) for five consecutive samplings.

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[8] The Statistical Classification of Economic Activities in the European Community (in French: *Nomenclature Statistique des Activités économiques dans la Communauté Européenne (NACE*)) is a pan-European classification system which groups organizations according to their business activities.

[9] The target value corresponds to a confidence interval of 95%.

REFERENCES AND OTHER INFORMATION

Acronyms

AENV	Alberta Environment
CCX	Chicago Climate Exchange
CDM	Clean Development Mechanism
CI	Confidence Interval
DOC	Degradable Organic Carbon
ECM	Energy Conservation Measure
EF	Emission Factor
EE	Energy Efficiency
EPA	Environmental Protection Agency
EVO	Efficiency Valuation Organization
f	Fraction
GHG	Greenhouse Gases
GJ	Gigajoule
GWP	Global Warming Potential
HVAC	Heating, Ventilation and Air Conditioning
ICI	Industrial, Commercial and Institutional Business Unit
IPCC	Intergovernmental Panel on Climate Change
IPMVP	International Performance Measurement and Verification Protocol
Kg	Kilograms
kWh	Kilowatt hour
/L	Per Litres
LFG	Landfill Gas
/m2	Per square metre
/m3	Per cubic metre
MAT	Mean Annual Temperature
M&V	Monitoring and Verification
MSW	Municipal Solid Waste
Mt	Metric tonnes
PET	Potential Evapotranspiration
QA/QC	Quality Assurance/ Quality Control
SC	Sustainable Community
SCSP	Sustainable Community Service Promoter
SS	Sources and Sinks

SWDS	Solid Waste Disposal Sites
UN	United Nations
VCS	Verified Carbon Standard
VCU	Verified Carbon Unit