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DRAFT

TECHNICAL GUIDE RELATED TO THE STRATEGIC ASSESSMENT OF CLIMATE CHANGE:

Guidance on quantification of net GHG emissions, impact on carbon sinks, mitigation measures, net-zero plan and upstream GHG assessment

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Canada

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EXECUTIVE SUMMARY

In August 2019, the Impact Assessment Act (IAA) came into force. The IAA establishes a new process for considering environmental, health, social and economic effects of projects that will undergo a federal impact assessment. One of the factors to be considered in the impact assessment process of a designated project is the extent to which the effects of the designated project hinder or contribute to the Government of Canada's ability to meet its commitments in respect to climate change such as the Paris Agreement, Canada's 2030 target and the goal of Canada achieving net-zero emissions by 2050.

In 2020, the Strategic Assessment of Climate Change was published to enable consistent, predictable, efficient and transparent consideration of climate change throughout the federal impact assessments.

This *Guidance on Quantification of Net GHG Emissions, Impact on Carbon Sinks, Mitigation Measures, Net-Zero Plan and Upstream GHG Assessment* complements the Strategic Assessment of Climate Change (SACC)[1] and provides proponents a consistent and coherent approach to assessing a designated project's greenhouse gas (GHG) emissions and impact on carbon sinks, and encourages optimized project design and implementation. Information in this guide may also be used to inform the review for projects on federal lands and outside Canada under the IAA, projects regulated by the Canada Energy Regulator, and regional assessments[2].

More specifically, this technical guide provides:

- A description of how a project's GHG emissions are to be estimated throughout the Impact Assessment process, including upstream emissions and impact on carbon sinks, where applicable;
- A description of the Best Available Technologies / Best Environmental Practices (BAT/BEP) Determination process that all projects are required to complete in the Impact Assessment process; and
- A description of the information required in the net-zero plan for projects with a lifetime beyond 2050.

With the publication of this draft, Environment and Climate Change Canada (ECCC) is providing opportunity for the public to comment on the technical guide until October 25, 2021. Environment and Climate Change Canada expects to publish a final version in early 2022.

1 Strategic Assessment of Climate Change - Canada.ca

2 See SACC section 1.2 Application for more information

GLOSSARY

Acquired Energy GHG emissions - GHG emissions associated with the generation of electricity, heat, steam or cooling, purchased or acquired from a third party for the project.

Afforestation - involves planting trees to create new forest on land that was previously agricultural, urban or some other non-forested land use.

Agricultural Land – comprises both Cropland and agricultural Grassland.

Avoided domestic GHG emissions - GHG emissions that are reduced or eliminated in Canada as a result of the project.

Biogenic Carbon - carbon derived from biogenic (plant or animal) sources excluding fossil carbon.

Best Available Technologies / Best Environmental Practices (BAT/BEP) – the most effective technologies, techniques, or practices, including emerging technologies that can be technically and economically feasible for reducing GHG emissions during the lifetime of the project.

Carbon sink – the ability of a forest, ocean or other natural environment to absorb carbon dioxide from the atmosphere.

CO_2 captured and stored (CCS) - CO_2 emissions that are generated by the project and permanently stored in a storage project that meets the criteria listed in Section 2.1.4.

Cropland – includes all lands in annual crops, summer fallow and perennial crops (mostly forage, but also including berries, grapes, nursery crops, vegetables, fruit trees and orchards as well as woody biomass in the form of shelter belts, shrubs and standing trees that do not comply with the definition of Forest Land), as defined by the 2006 *Intergovernmental Panel on Climate Change Guidelines for National Greenhouse Gas Inventories* (IPCC 2006, Volume 4, Chapter 3).

Designated project – one or more physical activities that (a) are carried out in Canada or on federal lands; and (b) are designated by regulations made under paragraph 109(b) of the IAA or designated in an order made by the Minister under subsection 9(1) of the IAA. It includes any physical activity that is incidental to those physical activities, but it does not include a physical activity designated by regulations made under paragraph 112(1)(a.2) of the IAA. For the purposes of this guide, the term "designated project" has been shortened to "project".

Direct GHG emissions - GHG emissions generated by activities that are within the defined scope of the project.

Downstream GHG emissions – the emissions that may occur after the project, including emissions resulting from the end use of products made by a project.

Energy products – those related to the exploitation or potential exploitation of non-renewable resources to produce energy, or the storage or transmission of energy products produced from non-renewable resources.

Forest Land – includes all areas of trees of 1 ha or more, with a minimum tree crown cover of 25% and trees of 5 m in height— or having the potential to reach this height, as defined by the 2006 *Intergovernmental Panel on Climate Change Guidelines for National Greenhouse Gas Inventories* (IPCC 2006, Volume 4, Chapter 3).

Grassland – "unimproved" pasture or rangeland that is used only for grazing domestic livestock, as is consistent with the 2006 *Intergovernmental Panel on Climate Change Guidelines for National Greenhouse Gas Inventories* (IPCC 2006, Volume 4, Chapter 3). It occurs only in geographical areas where the grassland would not naturally regrow to forest if abandoned, i.e. the natural shortgrass prairie in southern Saskatchewan and Alberta and the dry, interior mountain valleys of British Columbia. All agricultural land that is not grassland is de facto classified as Cropland, including unimproved pastures where natural vegetation would be forest (Eastern Canada and most of British Columbia). Vegetated areas that do not meet the definition of Forest Land or Cropland are generally classified as Grassland. Extensive areas of tundra in the Canadian North are considered unmanaged grassland.

Greenhouse gases (GHG) – Gases that possess global warming potential, as identified in Schedule 3 of the *Greenhouse Gas Pollution Pricing Act* (GGPPA).

Gross-tonne kilometre (GTK) - Unit of measure representing the total weight of the trailing tonnage (both loaded and empty railcars) and the distance the freight train travelled (excludes the weight of locomotives pulling the trains).

Incrementality - the increase in upstream production (and resulting emissions) that would only occur if the project were built.

Industrial processes - processes that involve a chemical or physical reaction, the primary purpose of which is to produce a product.

Lifecycle regulators – agencies that regulate a project from planning through to project abandonment. These agencies include the Canada Energy Regulator (CER), the Canadian Nuclear Safety Commission (CNSC) and the Offshore Petroleum Boards.

Main sources – groups of equipment (or bundle of technologies and practices) or activities that contribute 1% or more of the total direct GHG emissions of the project.

Net GHG emissions – The total GHG emissions attributable to the project undergoing federal impact assessment, including direct GHG emissions, acquired energy GHG emissions, avoided domestic GHG emissions and offset measures (offset credits, CO_2 captured and stored and corporate-level initiatives) (see Section 2 for additional details).

Offset credits – Credits that are issued by an offset system or program and that represent GHG emission reductions or removals generated from activities that are additional to what would have occurred in the absence of the offset project (i.e., generated from activities that go beyond legal requirements and a business-as-usual standard). Each offset credit generated by an offset project represents one tonne of carbon dioxide equivalent (CO_2 eq) reduced or removed from the atmosphere.

Project lifetime – the period encompassing all phases of the project, including construction, operation and decommissioning phases.

Projects undergoing a federal impact assessment – projects under the IAA, as well as projects under review by lifecycle regulators (for more information see section 1.2 of the Strategic Assessment of Climate Change).

Settlements – refers to all developed land, including transportation infrastructure and human settlements of any size, unless they are already included under other categories, as defined by the 2006 *Intergovernmental Panel on Climate Change Guidelines for National Greenhouse Gas Inventories* (IPCC 2006, Volume 4, Chapter 3).

Upstream GHG emissions – emissions from all stages of production, from the point of resource extraction or utilization to the project under review.

Wetlands – includes areas of peat extraction and land that is covered or saturated by water for all or part of the year (e.g., peatlands) and that does not fall into the Forest Land, Cropland, Grassland or Settlements categories as defined by the 2006 *Intergovernmental Panel on Climate Change Guidelines for National Greenhouse Gas Inventories* (IPCC 2006, Volume 4, Chapter 3). It includes areas of peat extraction and hydroelectric reservoirs.

ACRONYMS

BAT/BEP: Best Available Technologies / Best Environmental Practices

CCS: CO^2 captured and stored

CER: Canada Energy Regulator

CH_4: Methane

CNSC: Canadian Nuclear Safety Commission

CO_2: Carbon dioxide

CO_2 eq: Carbon dioxide equivalent

CSI: carbon sink impact

DOM: dead organic matter

EI: Emission intensity

EF: Emission factor

E3MC: Energy, Emissions and Economy Model for Canada

ECCC: Environment and Climate Change Canada

GHG: Greenhouse gas

GGPPA: *Greenhouse Gas Pollution Pricing Act*

GJ: Gigajoule (10^9 joules)

GTK: Gross tonne-kilometers

GWh: Gigawatt-hours (10^9 watt-hours)

IAA: *Impact Assessment Act*

IAAC: Impact Assessment Agency of Canada

IPCC: Intergovernmental Panel on Climate Change

LNG: Liquefied natural gas

MCC: Maximum carrying capacity

MMcf: Million cubic feet

Mt: Megatonne (1 million tonnes)

N_2O: Nitrous oxide

NIR : National Inventory Report: Greenhouse Gas Sources and Sinks in Canada

SACC: Strategic Assessment of Climate Change

SAGD: Steam-Assisted Gravity Drainage

t: Tonne (1,000 kg)

TISG: Tailored Impact Statement Guidelines

TRL: Technology Readiness Level

TW: Terawatt (10^{12} watts)

CONTENTS

1. INTRODUCTION

1.1. Objective

The purpose of this draft technical guide is to provide proponents of projects that may require a federal impact assessment pursuant to the *Impact Assessment Act* (IAA) with technical guidance on quantification of greenhouse gas (GHG) emissions (net and upstream), impact on carbon sinks, mitigation measures and plans to achieve net-zero emissions by 2050. This document supplements the Strategic Assessment of Climate Change[3] (SACC).

The information provided throughout the impact assessment process by proponents and others will inform the Minister's Public Interest Determination under the IAA, specifically subsection 63(1)(e), the extent to which the effects of the designated project hinder or contribute to the Government of Canada's ability to meet its environmental obligations and its commitments in respect of climate change.

Information in this guide may be adapted for projects on federal lands and outside Canada under the IAA, projects regulated by the Canada Energy Regulator, and regional assessments.

1.2. Context

The GHG emissions and impact on carbon sinks associated with a project are key to the Government of Canada's understanding of the extent to which a project hinders or contributes to Canada's ability to meet its climate change commitments, and in turn to decide whether the extent to which the project's adverse effects within federal jurisdiction are in the public interest.

The SACC enables consistent, predictable, efficient and transparent consideration of climate change throughout the impact assessment process. It describes the climate change-related information requirements throughout the federal impact assessment process, and requires proponents of projects with a lifetime beyond 2050 to provide a credible net-zero plan that describes how the project will achieve net-zero emissions by 2050. It also explains how the Impact Assessment Agency of Canada (IAAC) or lifecycle regulators, with support from expert federal authorities, will review, comment on and complement this information.

The *Information and Management of Time Limits Regulations*[4] outlines the information requirements for the initial and detailed Project Description. Section 4.1 of the SACC further clarifies the information related to GHG emissions and climate change that are to be included in the initial and detailed Project Description.

If an Impact Statement is required, project proponents will be required to refine the estimate of their project's annual net GHG emissions and emissions intensity (if applicable) provided during the Planning Phase, with additional detail and precision, including an uncertainty assessment. The scope of information related to GHG emissions and climate change will be tailored to the project in the Tailored Impact Statement Guidelines (TISG) provided to the proponent at the end of the Planning Phase. The TISG will also confirm if the proponent will need to conduct an assessment of upstream GHG emissions (see Section 5). An assessment of downstream emissions is not required.

3 Strategic Assessment of Climate Change - Canada.ca

4 *Information and Management of Time Limits Regulations* *https://laws.justice.gc.ca/eng/regulations/SOR-2019-283/index.html*

To help Canada meet its climate change commitments, mitigation measures are needed to minimize GHG emissions throughout all phases of the project. The BAT/BEP Determination process undertaken by the proponent will identify the mitigation measures that are technically and economically feasible to implement during the lifetime of the project in order to minimize the project's GHG emissions.

Proponents of projects with a lifetime beyond 2050 will be required to provide a credible net-zero plan that describes how the project will achieve net-zero emissions by 2050.

1.3. Using This Document

The technical guide complements other policy and guidance documents that support the impact assessment process.[5] It is assumed that readers of this document have a good understanding of the impact assessment process.[6]

The technical guide differentiates between the level of information required in the Planning Phase and the Impact Statement Phase. In general, it is expected that a more high-level analysis will be completed by the proponent in the Planning Phase, as it is recognized that all applicable information and data related to the project may not be available at the time of preparing the Project Description. This Planning Phase analysis will then be built upon in response to project-specific requirements from the TISG, and the advancement of the project design and plans prior to submission of the Impact Statement. This technical guide does not replace project-specific information requirements in the TISG, but rather complements those guidelines.

[5] For Canada Energy Regulator (CER)-regulated projects, proponents should also refer to the guidance provided in the CER Filing Manual for specific requirements. (https://www.cer-rec.gc.ca/en/applications-hearings/submit-applications-documents/filing-manuals/filing-manual/)

[6] For more information on the impact assessment process, please consult the IAAC website at: https://www.canada.ca/en/impact-assessment-agency.html

2. NET GHG EMISSIONS

2.1. Methodology

Proponents of projects undergoing a federal impact assessment are required to provide an estimate of the project's GHG emissions. This must be calculated as the net GHG emissions using Equation 1[7] below. Each term of this equation is described in further detail in the following sections.

Equation 1: Net GHG emissions

NET GHG EMISSIONS =		Direct GHG emissions
	+	Acquired energy GHG emissions
	-	Avoided domestic GHG emissions
	-	Offset measures

The net GHG emissions for new projects and expansion projects[8] are assessed differently:

- For new projects: the GHG emissions must reflect the maximum design throughput or capacity of the project.
- For expansion projects: GHG emissions are assessed based on the additional maximum throughput or capacity the project creates in comparison to the original design capacity.

If the project is expected to operate at a significantly different capacity from the maximum design capacity, the proponent can also provide the net GHG emissions for the expected operation capacity. The proponent can then use the net GHG emissions associated with the expected operation capacity when developing their plan for achieving net-zero emissions by 2050, if required.

The emissions of all GHGs outlined in the Schedule 3 of the Greenhouse Gas Pollution Pricing Act (GGPPA)[9] must be quantified and the net GHG emissions must be provided in CO_2 eq using the global warming potentials provided in the GGPPA. The net GHG emissions must be quantified for all phases of a project (construction, operation and decommissioning) and for each year of the lifetime of the project.

The following sections provide additional details for the quantification of each term of Equation 1. Quantification approaches and emission factors alternative to those presented in sections 2.1.1 to 2.1.4 can be used provided that the methodology, data sources, assumptions and justification for the approach are documented, and that the methodology aligns with the principles of ISO 14064.

Specific requirements for the Planning Phase and Impact Statement Phase are provided in section 2.4 and 2.5.

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7 This equation includes the same concepts as Equation 1 from the SACC, but has been simplified for clarity and ease of use. The offset measures term encompasses CO_2 captured and stored, offset credits and corporate-level initiatives, which were previously included under different terms of the equation in the SACC.

8 Expansion projects are defined by the Physical Activities Regulations, available at: Physical Activities Regulations (justice.gc.ca)

9 *Greenhouse Gas Pollution Pricing Act*

2.1.1. Direct GHG Emissions

Direct GHG emissions are defined in Section 3.1.1 of the SACC as those generated by activities that are within the scope of the project. What might be within the scope of a project will depend on the nature of a particular project. The definition of a designated project in section 2 of the IAA sets out that a designated project consists of physical activities and those physical activities that are incidental to them. At the Planning Phase, the proponent provides a description of the project and if an impact assessment is required, the scope of the factors to be considered in an impact assessment is determined by IAAC and set out in the Tailored Impact Statement Guidelines. If transportation of equipment or products is considered to be a physical activity that is within the project as described, for example, then emissions generated by that transportation would be considered as direct GHG emissions.[10]

Section 5.1.1 of the SACC states that the proponents must provide a description of the project's main sources of GHG emissions and their estimated GHG emissions. For the purpose of quantification, main sources should be understood as groups of equipment (or bundles of technologies and practices) or activities that contribute 1% or more of the total direct GHG emissions of the project.

Direct GHG emissions must be quantified for the construction, operation and decommissioning phases of a project and for each year of the lifetime of the project. Examples of direct GHG emissions include GHG emissions from mobile or stationary combustion, land-use change, industrial processes, solid waste disposal, and flaring, venting and fugitive emissions as described in further detail below.

2.1.1.1. GHG Emissions from Stationary and Mobile Combustion

Stationary fuel combustion sources include devices that combust fuel for the purpose of producing useful heat or work. This includes boilers, electricity generating units, cogeneration units, combustion turbines, engines, incinerators and process heaters. Mobile combustion include devices that combust fuel that are not stationary (e.g.: transport activities - road, off-road, air, railways, and water-borne navigation).

The GHG emissions from stationary or mobile combustion can be quantified using Equation 2.

Equation 2: Emissions from stationary and mobile combustion

GHG EMISSIONS FROM FUEL COMBUSTION = Estimated quantity of fuel to be consumed * Emission Factor

The project's total GHG emissions from fuel combustion is the sum of Equation 2 for each fuel type and GHG considered.

If project-specific and equipment-specific fuel consumption data is not available, the proponent can refer to Annex A of this guide for resources to estimate fuel consumption by equipment.

Emissions factors associated with different fuels are available in Part 2, Annex 6 of the National Inventory Report: Greenhouse Gas Sources and Sinks in Canada (NIR). Table 1 below provides reference to the values published in the 2020 NIR, however proponents should use the most recent NIR emission factors.

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10 Under the federal lands provisions, the definition of project under section 81 of the IAA sets out that a project is a physical activity that is carried out on federal lands in relation to a physical work. The scope of the GHG assessment for these projects will be determined by the federal authority.

Table 1: Emission factors associated with the combustion of different fuels

FUEL	GHG	REFERENCE FOR EMISSION FACTORS ASSOCIATED WITH THE COMBUSTION OF COMMON FUELS
Natural Gas	CO_2	NIR 2020, Part 2, Annex 6, Table A6.1-1
	CH_4 and N_2O	NIR 2020, Part 2, Annex 6, Table A6.1-2
Natural Gas Liquids	CO_2, CH_4 and N_2O	NIR 2020, Part 2, Annex 6, Table A6.1-3
Refined Petroleum Products	CO_2, CH_4 and N_2O	NIR 2020, Part 2, Annex 6, Table A6.1-4
Petroleum Coke and Still Gas	CO_2	NIR 2020, Part 2, Annex 6, Table A6.1-5
	N_2O	NIR 2020, Part 2, Annex 6, Table A6.1-6
Still Gas (Refineries & Others)	CH_4	NIR 2020, Part 2, Annex 6, Table A6.1-7
Coal	CO_2	NIR 2020, Part 2, Annex 6, Table A6.1-8
Coal Products	CO_2	NIR 2020, Part 2, Annex 6, Table A6.1-9
Coal and coke products	CH_4 and N_2O	NIR 2020, Part 2, Annex 6, Table A6.1-10
Fuels for mobile combustion sources	CO_2, CH_4 and N_2O	NIR 2020, Part 2, Annex 6, , Table A6.1-13

Alternatively, the proponent may choose to use emission factors associated with similar equipment in operation in another facility if conditions are similar (same type of fuel).

GHG Emissions from Marine Shipping

Marine shipping GHG emissions include those generated from commercial vessels operating in waters within the scope of the project. The methodology used in Canada's Marine Emissions Inventory Tool[11] can be used for the quantification of GHG emissions from marine shipping. This methodology will be outlined in the National Marine Emissions Inventory for Canada Methodology Report, which is expected to be published in 2021 on the Marine Emissions Inventory Tool website[12]. This report will consider emissions from a vessel's main engine(s), auxiliary engines, and boilers[13].

GHG emissions from marine shipping can be quantified using the activity-based emissions, Equation 3.

Equation 3: Emissions from marine shipping

GHG EMISSIONS FROM MARINE SHIPPING $= \Sigma i \{(ME * LF_{ME} * \Delta T_{ME} * EF_{ME}) + (AE * LF_{AE} * \Delta T_{AE} * EF_{AE}) + (BO * \Delta T_{BO} * EF_{BO})\}$

[11] The Marine Emissions Inventory Tool is an online web application that filters and displays marine emissions from commercial vessels operating in Canadian waters.

[12] https://www.canada.ca/en/environment-climate-change/services/managing-pollution/marine-emissions-inventory-tool.html

[13] For tankers and tanker barges transporting petroleum, fugitive emissions of volatile organic compounds are also considered.

Where:

i is the data point
ME is the main engine capacity or maximum continuous rating (kW)
AE is the total auxiliary engine capacity (kW)
LF is the engine load factor
EF is the emission factor (g/kWh for engines, kg/t fuel for boilers)
BO is the boiler fuel consumption rate (t/h)
ΔT is the time spent in the relevant mode (underway, berth or anchor) (hr)

The National Marine Emissions Inventory for Canada Methodology report provides emission factors for CO_2, CH_4, and N_2O based on fuel type, engine type, and stroke type of the engine.

Proponents must describe all the assumptions associated with the number and type of vessels, fuel consumption, engine type, navigation distances, and trip frequency per year.

GHG Emissions from Rail Transport

Emissions from railway locomotives within a port or terminal area can be calculated using the Port Emissions Inventory Tool. The tool and user guide are available from Environment and Climate Change Canada by contacting: ec.oaiem-meit.ec@canada.ca.

For railway locomotives in other applications, proponents can use the methodology and emission factors outlined in the most recent Locomotive Emissions Monitoring Report, produced annually by the Railway Association of Canada[14].

The 2018 Locomotive Emissions Monitoring Report is the most recent published report. Within this report, GHG emissions are calculated based on annual fuel consumption and fuel consumption rates (L/1,000 GTK), and are reported for Class 1 freight (separately for mainline locomotives and yard switchers/work trains) and various passenger operations (such as intercity, commuter, and VIA Rail). Proponents can consult Section 5 of the report ("Locomotive Emissions") for information on the emission factors and methodology used to calculate GHG emissions. Please refer to Table 3, Canadian Rail Operations Fuel Consumption, 1990, 2006–2018 for a breakdown of reported fuel consumption, and Table 9, GHG Emissions and Emission Intensities by Railway Service in Canada 1990, 2006–2018 for an example of how GHG emissions are reported per sector (such as mainline freight or yard switcher).

GHG Emissions from Combustion of Biogenic Carbon

In line with the approach presented in the 2006 Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories[15] (IPCC 2006), it can be assumed that biogenic CO_2 emissions from combustion are balanced by carbon uptake prior to harvest. In such a situation, only CH_4 and N_2O from combustion of biomass need to be considered in the quantification of direct GHG emissions from biomass combustion in stationary and mobile equipment.

2.1.1.2. Emissions from Land-Use Change

The GHG emissions and removals from land-use conversions as a direct result of project construction are included in the direct GHG emissions. Note that this does not include forgone carbon sequestration from land-use change that is included in the 'Carbon Sinks' quantification (see Section 4).

The quantification method for land-use change is outlined in Annex B of this guide. It is a tiered approach, providing three options of increasing complexity depending on the project area and proportion of project area on carbon dense lands (refer to Annex B, Figure 6). This method follows the approaches of the latest NIR and IPCC guidelines.

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14 Locomotive Emissions Monitoring Reports are available at RAC (railcan.ca)

15 Publications - IPCC-TFI (iges.or.jp)

2.1.1.3. GHG Emissions from Industrial Processes

Industrial processes are defined as those involving a chemical or physical reaction, the primary purpose of which is to produce a product, as opposed to useful heat or work (GC 2020-4). The proponent can use the following methods to quantify GHG emissions from an industrial process (such as cement production, ammonia production or iron and steel):

- Technical Guidance on Reporting Greenhouse Gas Emissions[16], under Canada's Greenhouse Gas Reporting Program (GHGRP).
- Volume 3 of IPCC 2006; or
- The NIR

The proponent must ensure that industrial process emissions are identified and calculated separately from stationary combustion emissions. Refer to IPCC 2006, Volumes 2 and 3 for further guidance.

2.1.1.4. Flaring, Venting and Fugitive GHG Emissions

Flaring, venting and fugitive GHG emissions are comprised of intentional or unintentional releases of GHGs from the production, processing, transmission, storage and delivery of fossil fuels. Table 2 categorizes these emissions based on categories in the NIR.

Table 2: Emission sources categorized as flaring, venting and fugitive emissions

EMISSION SOURCE	CATEGORY
Flaring	Flaring
Exposed Mine Face (Oil Sands)	Fugitive
Fugitive Equipment Leaks	Fugitive
Loading/Unloading	Fugitive
Spills/Pipeline Ruptures	Fugitive
Storage Losses	Fugitive
Surface Casing Vent Flow/Gas Migration	Fugitive
Tailings Ponds (Oil Sands)	Fugitive
Formation CO_2	Venting
Glycol Dehydrator Off-Gas	Venting
Reported Venting	Venting
Unreported Venting - Compressor Seals	Venting
Unreported Venting - Pneumatic Instruments	Venting
Unreported Venting - Pneumatic Pumps	Venting
Unreported Venting - Start Gas	Venting
Unreported Venting - Sulphur Pouring	Venting
Unreported Venting - Undifferentiated	Venting
Unreported Venting - Well Drill-Stem Test	Venting

16 En81-29-2019-eng.pdf (publications.gc.ca)

Emission factors for flaring, venting and fugitives GHG emissions from the oil and gas industry sectors are provided in Table 3. These were developed by ECCC based on historical GHG emissions from the NIR and a range of resources including Statistics Canada publications.

Table 3: Emission factors for flaring, venting and fugitives GHG emissions by oil and gas sector

OIL AND GAS SECTOR	BASIS FOR EMISSION FACTOR	EMISSION FACTOR UNIT	EMISSION FACTOR		
			Flaring	Venting	Fugitives
Natural Gas Production	Non-associated gas production	g CO_2eq / m^3	3.27	37.52	56.83
Natural Gas Processing	Gross natural gas production	g CO_2eq / m^3	3.10	19.56	2.24
Light/Medium Crude Oil Production	Light/medium crude oil production	kg CO_2eq / m^3	57.32	164.74	42.83
Heavy Crude Oil Production + Primary Oil Sands	Heavy crude oil production + primary oil sands production	kg CO_2eq / m^3	20.63	163.55	35.21
Oil Sands Mining and Extraction	Mined Bitumen Production	kg CO_2eq / m^3	1.88	0.15	21.67
Upgrading	Synthetic Crude Oil Production	kg CO_2eq / m^3	19.82	66.25	1.59
Thermal Oil Sands Production (CSS + SAGD)	CSS + Steam-Assisted Gravity Drainage Production	kg CO_2eq / m^3	2.08	0.96	3.57
Natural Gas Transmission and Storage	Length of transmission pipeline	t CO_2eq / km	0.08	9.77	14.63
Petroleum Refining	Crude oil charged to refineries	kg CO_2eq / GJ	0.05	0.25	0.03
Petroleum Refining	Refined petroleum products (RPP) production	kg CO_2eq / GJ	0.04	0.22	0.02

For fugitive emissions associated with coal mining, emission factors are provided in Part 2 Annex 6 of the NIR. Proponents will select the appropriate emission factor based on the project location, coal type and mine type.

2.1.1.5. GHG Emissions from Waste

Methodologies for estimating GHG emissions for several waste categories are available in the NIR, Part 2 Annex 3.6. The approaches outlined in the NIR are consistent with methodology presented in Volume 5 of IPCC 2006. Table 4 outlines the applicable sections for the NIR and IPCC 2006 for each waste category considered.

Table 4: Sources of methodologies to estimate GHG emissions from management of project wastes

WASTE CATEGORY	METHODOLOGY SOURCE	GHG AND ACTIVITIES CONSIDERED
Solid Waste Disposal (Landfill)	NIR 2020, Part 2, Section A3.6.1. or IPCC 2006, Volume 5, Chapter 3	Estimates CH_4 emissions from municipal solid waste landfills and wood waste landfills using first-order decay method
Biological Treatment of Solid Waste	NIR 2020, Part 2, Section A3.6.2. or IPCC 2006, Volume 5, Chapter 4	Estimates CH_4 and N_2O emissions from composting and anaerobic digestion
Incineration and Open Burning of Waste	NIR 2020, Part 2, Section A.3.6.3. or IPCC 2006, Volume 5, Chapter 5	Estimates CH_4, N_2O and CO_2 emissions for municipal solid waste, hazardous waste, clinical waste, and sewage sludge incineration (excludes CO_2)
Wastewater Treatment and Discharge	NIR 2020, Part 2, Section A.3.6.4. or IPCC 2006, Volume 5, Chapter 6	Estimates CH_4 and N_2O emissions for treated and untreated wastewater

ECCC developed a tool to support analysis of GHG emissions from organic waste management practices, called the Greenhouse Gas Calculator for Organic Waste Management. This tool is currently available upon request. Please contact ec.ges-dechets-ghg-waste.ec@canada.ca to obtain a copy.

2.1.2. Acquired Energy GHG Emissions

Acquired Energy GHG emissions are those associated with the generation of electricity, heat, steam or cooling, purchased or acquired from a third party for the project (see Section 3.1.1 of the SACC). Hydrogen use as fuel is also considered as an acquired energy if generated off site by a third party.

The following sections provide guidance to quantify acquired energy GHG emissions for the main sources of acquired energy.

2.1.2.1. Electricity

To quantify annual GHG emissions from acquired electricity, the proponent can use projected provincial emission intensities for electrical utilities, developed by ECCC. Emission intensity (EI) projections developed in 2020 are provided in Annex C of this guide. The annual update to EI projections are expected to be available in the open data tables of Canada's Greenhouse Gas Emissions Projections webpage[17] but are not available at the time of publication of this document.

The projections include time series of EIs that reflect emission reductions expected from policies and measures over time. These projections were developed using ECCC's Energy, Emissions and Economy Model for Canada (E3MC) built off NIR 2020, and were calculated as the total projected GHG emissions associated with electricity generated by electric utilities and net industrial generation sold to the grid divided by electricity consumption from the grid for each province (e.g. t CO_2 eq/GWh per year).

For the portion of the project that extends beyond the current projections, the proponent can use provincial policies to establish trends in the vicinity of the project location. The resulting EI estimates should be conservative, and the

[17] Open data table. Refer to folder: Current-Projections-Actuelles/Energy-Energie/Grid-O&G-intensities-Intensites-Reseau-Delectricite-P&G/

methodology, data sources, assumptions and justification must be documented.

2.1.2.2. Hydrogen Used as Fuel

To quantify GHG emissions from acquired hydrogen used as fuel in their project, proponents can use the EIs provided in Table 5.

Table 5: Emission intensities for hydrogen production processes

HYDROGEN PRODUCTION PROCESS	EMISSION INTENSITY[18] ($t\ CO_2\ eq\ /\ t\ H_2$)
Steam Methane Reforming (SMR) or Partial Oxidation of Hydrocarbons	10.0[19]
Autothermal Reforming (ATR)	8.98[20]
SMR with carbon capture and storage (CCS)	5.0
ATR with CCS	0.45

If hydrogen used for the project is not acquired but instead produced within the scope of the project, the proponent should use the quantification approach described in section 2.1.1.

The EI for the production of hydrogen via SMR with CCS assumes a capture rate of 50%[21] while the EI for the production of hydrogen via ATR with CCS assumes a capture rate of 95%[22].

The GHG emissions for hydrogen acquired via electrolysis can be quantified using a default electricity consumption rate23 of 50.0 kWh/kg of H_2 and the provincial grid electricity EI projection in Annex C for the province in which the hydrogen is produced.

2.1.2.3. Steam

To quantify GHG emissions from acquired steam, the proponent can use an emission factor of 223 t CO_2 eq/GWh thermal (or 0.062 t CO_2 eq/GJ thermal). This assumes a boiler fed with natural gas with an 80% efficiency.

2.1.2.4. Waste-Derived Energy

Energy that is derived from waste, co-products or biogas can be assumed to have an emission factor of 0 if the energy can be produced directly without first undergoing waste conversion processes that would emit GHGs. Examples could include use of landfill biogas for heat and steam, use of steam produced from incineration or combustion of waste, or waste-derived fuels. If this energy is not acquired but produced and used within the scope of the project, the proponent can consider this under the avoided domestic GHG emissions term of Equation 1 (see Section 2.1.3 below).

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18 Emission intensities presented include applicable capture rates

19 Value based on literature review conducted by ECCC

20 Clean Hydrogen. Part 1: Hydrogen from Natural Gas Through Cost Effective CO2 Capture - Features - The Chemical Engineer

21 The stated carbon capture rate of 50% includes the capture of process emissions only, based on a report to the Alberta Industrial Heartland Hydrogen Task Force Advisory Committee. It is possible to also capture flue gas and therefore lower the emission intensity of the hydrogen production overall. However this has not been considered in the table due to economic challenges in capturing flue gas. Alternate EI values will be considered from proponents who can demonstrate that they can achieve higher project-specific CCS rates.

22 Carbon capture rate based on multiple reports, including CE Delft's Feasibility Study into Blue Hydrogen, 2018 [Feasibility study into blue hydrogen - CE Delft]

23 EI value based on parameters within ECCC's Fuel Life Cycle Analysis model and the National Renewable Energy Laboratory, 2013 [Hydrogen Pathways: Updated Cost, Well-to-Wheels Energy Use, and Emissions for the Current Technology Status of Ten Hydrogen Production, Delivery, and Distribution Scenarios (Technical Report) | OSTI.GOV]

2.1.3. Avoided Domestic GHG Emissions

Avoided domestic GHG emissions are defined in Section 3.1.1 of the SACC as GHG emissions that are reduced or eliminated in Canada as a result of the project. The SACC states that avoided domestic GHG emissions can also include GHG emissions removed as a result of mitigation measures separate from the project and not reflected in the project's direct GHG emissions. This type of emission removals or reductions are now captured under corporate-level initiatives (see section 2.1.4.3). Not all projects will have avoided domestic GHG emissions. Considering avoided domestic GHG emissions in the net GHG emissions is optional.

Avoided domestic GHG emissions could be considered in the net GHG emissions of a project to reflect that a project may enable emission reductions that could benefit Canada at a national level. For example:

- In the case of an expansion, the emissions reduction resulting from the replacement of existing equipment with more energy-efficient equipment on the project site.
- In the case of a new project, the emissions reduction resulting from the replacement of a high-emitting facility with a lower-emitting facility.
- In the case of any facility that generates and sells surplus energy, the amount of emissions saved from producing that energy from the previous, higher-emitting source.

The general requirements for avoided domestic GHG emissions are outlined below:

Avoided domestic GHG emissions **must:**

- Only apply to the project's net GHG emissions (not to upstream or downstream GHG emissions);
- Represent reductions or removals that are real, additional, quantified, verifiable, unique, and permanent that can be assigned to the project (the same avoided emissions cannot be claimed more than once);
- Be from existing sources or sinks in Canada (not from a hypothetical scenario).

Avoided domestic GHG emissions **cannot be:**

- Emission reductions required by law and regulations;
- Emission reductions or removals that are used to generate offset measures (see Section 2.1.4 below);
- Emission reductions or removals funded or subsidised through other government programs and initiatives;
- Arising from impact on carbon sinks on the land affected by the project (as these are quantified separately from the net GHG emissions, see Section 4);
- Avoided foreign GHG emissions (proponents have the possibility to describe how the project would impact global GHG emissions, see Section 5.1.3 of the SACC);
- Emissions avoided from another hypothetical new project that might be built if this project does not proceed or from alternative technology that could be used for the project;
- Emission reductions that occur after the end of the project lifetime.

As more stringent policies come into force, avoided domestic GHG emissions that continue to meet the above requirements are expected to decrease with time. Therefore, in 2050 and thereafter, there will be no avoided domestic GHG emissions.

The quantification approach for avoided domestic GHG emissions involves the four steps outlined below.

Step 1: Establish Assessment Scope

Proponents must establish the scope for assessing the avoided domestic GHG emissions and describe it. The avoided domestic GHG emissions must be associated with the direct GHG emissions or acquired energy GHG emissions of the project (not to upstream or downstream GHG emissions).

Step 2: Establish Baseline Emissions Scenario (Without the Project)

Proponents must establish the Baseline Emissions Scenario (without the project) representing an equal throughput or capacity to the project emissions scenario. The Baseline Emissions Scenario must exist and cannot be hypothetical.

For example, if a pipeline project would replace product transport by railway, the scenario with rail transport must exist. Proponents must describe the existing scenario and provide details on the rail transportation mode, transportation capacity, distance travelled and frequency, and emissions that could become avoided in the project emission scenario in Step 3.

The Baseline Emissions Scenario must be developed for a time series until the end of the project, or the end of 2049, whichever is earlier. It is assumed that by 2050, the measures (policies, regulations, programs) and market conditions in place will render avoided domestic GHG emissions irrelevant, therefore they can no longer be considered part of a project's net GHG emissions in 2050 and thereafter. The time series must take into account announced measures (policies, regulations, programs) and market conditions. It must also account for replacement of technologies or equipment at the end of life, where applicable. It is possible that the measures (policies, regulations, programs) and market conditions in place will render avoided domestic GHG emissions irrelevant before 2049.

The quantification for the Baseline Emissions Scenario can be done using the approach for direct GHG emissions and acquired energy GHG emissions described in Sections 2.1.1 and 2.1.2, respectively. Proponents must describe the methodology as well as provide data, emission factors and assumptions used for quantification of the Baseline Emissions Scenario.

Step 3: Establish Project Emissions Scenario (With the Project)

Proponents must establish the Project Emissions Scenario for a time series until the end of the project, or the end of 2049, whichever is earlier. As in Step 2, the project emissions scenario must take into account announced measures and market conditions.

The quantification for the Project Emissions Scenario can be done using the approach for direct GHG emissions and acquired energy GHG emissions described in Sections 2.1.1 and 2.1.2, respectively. Proponents must describe the methodology as well as provide data, emission factors and assumptions used for quantification of the Project Emissions Scenario.

Note that direct GHG emissions and acquired energy GHG emissions of the Project Emissions Scenario may not be the same as those from the project's net GHG emissions calculation. This is because some avoided domestic GHG emissions may occur in the Project Emissions Scenario that are outside the scope of the project. This must be taken into account in the establishment of the scenarios. For example, a hypothetical new rail project uses a Baseline Emissions Scenario where goods are currently transported by trucks. In the Project Emissions Scenario, some of the goods transported by trucks are transported by rail (with appropriate documentation). Both the rail cars and trucks need to be considered for the avoided domestic GHG emissions evaluation, whereas those goods transported by trucks may not be within the scope of the rail project.

Step 4: Calculate Avoided Domestic GHG Emissions

The total avoided domestic GHG emissions is the absolute value of the difference between Step 3 and 2. To report avoided domestic GHG emissions, those from the Project Emissions Scenario must be less than those from the Baseline Emissions Scenario.

Avoided domestic GHG emissions must be presented for each year of the operation phase of the project up to 2049, if applicable.

A checklist for the avoided domestic GHG emissions is provided in Table 6.

Table 6: Checklist for avoided domestic GHG emissions

√	Is the project expected to generate avoided domestic GHG emissions?
√	Does the Baseline Emissions Scenario currently exist (real vs hypothetical)?
√	Do the scenarios consider announced measures (regulations, plans and programs) and market conditions and are the assumptions reasonable?
√	Are the avoided domestic GHG emissions real, additional, quantified, verifiable, unique, and permanent?
√	Are avoided domestic GHG emissions quantified for each year of the operation phase of the project (up to 2049 maximum)?
√	Are the avoided domestic emissions declining over time as measures become more stringent and electrification rate increases? Are avoided emissions still relevant considering announced measures (regulations, plans and programs) and market conditions?
√	Do the avoided domestic GHG emissions represent reductions in Canada?
√	Are the methodology description, data, emission factors and assumptions provided, and are they appropriate?

2.1.4. Offset Measures

The offset measures term of Equation 1 encompasses the sum of offset credits, CO_2 captured and stored, and corporate-level initiatives. These are described in further detail in sections 2.1.4.1 to 2.1.4.3 below. Offset measures can also include other mitigation measures such as land-use changes to mitigate carbon sink disturbance through restoration, afforestation, compensation and conservation (see Sections 3.4.3 and 3.5.3).

2.1.4.1. Offset Credits

Offset credits are defined in Section 3.1.1 of the SACC as GHG emission reductions or removals generated from activities that are additional to what would have occurred in the absence of the offset project (i.e., generated from activities that go beyond legal requirements and a business-as-usual standard). Each offset credit generated by an offset project represents one tonne of carbon dioxide equivalent (CO_2 eq) reduced or removed from the atmosphere.

Offset credits can apply to the project’s net GHG emissions (not to upstream or downstream GHG emissions).

With the exception of offsets that satisfy the requirements of foreign offset credits, offset credits applied against the new emissions of a project under the SACC must be sourced from a project registered in a Canadian federal, provincial or territorial regulatory offset program that aligns with the best practices outlined in the Canadian Council of Ministers of the Environment Pan-Canadian Offsets Framework.

At the time of releasing this technical guide, the federal GHG offset system was under development. Information regarding the federal system is available at Federal Greenhouse Gas Offset System - Canada.ca.

Offset credits will be purchased by the project proponent and retired or voluntarily cancelled in the associated offset system registries. To purchase offset credits, contracts would need to be negotiated between project proponents and interested sellers. Transfers of offset credits from one party to another would be tracked in the offset system's registry or credit tracking system. Third parties, such as carbon trade exchanges or brokerage services, may play a role in facilitating transactions. Proponents should ensure that they are aware of the terms, conditions and requirements of the offset program from which they are purchasing and using credits before pursuing this option.

Offset credits used toward the Impact Statement's net emissions calculation must not have been already retired or canceled for any other purpose, including compliance with any regulatory requirement, voluntary claim by the proponent (e.g. for purposes unrelated to the impact assessment), or compliance or voluntary purposes by any other entity. This will ensure that the offsets identified represent incremental emission reductions and are offsetting emissions that cannot be mitigated any other way (e.g. emissions from the construction phase of the project).

Offset credits used to compensate for project emissions in a given year must have been issued no more than five years prior to their use for the SACC, and represent emission reductions or removals of one or more of the GHGs reported in Canada's most recent NIR.

Foreign Offset Credits:

Foreign Offset Credits or Internationally Transferred Mitigation Outcomes (ITMO)s are not acceptable as an offset credit at the time of publication of this draft technical guide.

When the rules for the transfer of mitigation outcomes between Canada and foreign countries are established, it is anticipated that foreign offset credits will be acceptable if they fully comply with the rules for Internationally Transferred Mitigation Outcomes (ITMOs) established in Article 6 of the Paris Agreement, all applicable decisions adopted by the Conference of the Parties and any further criteria for international offset credits to be developed by ECCC.[24]

2.1.4.2. CO_2 Captured and Stored

CO_2 captured and stored (CCS) is defined in Section 3.1.1 of the SACC as CO_2 emissions that are generated by the project and permanently stored in a storage project that meets the following criteria:

- the geological site into which the CO_2 is injected is a deep saline aquifer for the sole purpose of storage of CO_2, or a depleted oil reservoir for the purpose of enhanced oil recovery; and
- the quantity of CO_2 stored for the purposes of the project is captured, transported and stored in accordance with federal, provincial, U.S., or state laws.

Proponents can store CO_2 in a storage project or product that does not align with the criteria above if supporting documentation that the CO_2 will be sequestered permanently (i.e. for a minimum of 100 years) is provided, and is to the satisfaction of federal authorities.

[24] The international community could not agree to finalize the rules for Article 6 at the Madrid Climate Conference (COP25/CMA2) in December 2019. The Government of Canada will continue to work closely with other Parties, with a view to finalizing robust international rules for Article 6 at the Glasgow Climate Conference (COP26/CMA1) in November 2021.

Article 6 is clear that the use of ITMOs must be authorized by the participating Parties, which would include Canada and the applicable host country. The Government of Canada is still considering whether and how it might use ITMOs as a complement to domestic emission reduction efforts toward its national climate targets. Further analysis and discussion with international and domestic stakeholders will be needed to inform any future decision on Canada's use of ITMOs, including the establishment of criteria for international offset credits.

Until such a decision is made, only domestic offset credits may be counted in the net GHG emissions calculation, given that no ITMOs currently meet all of the requirements set out in the SACC. However, in describing the process they will follow to make the decisions and investments needed to achieve net-zero emissions by 2050, project proponents may include plans or commitments to purchase international offset credits once the relevant rules and criteria for ITMOs are in place and these will be considered as actions towards achieving net-zero in the credible net-zero plan to be provided by the proponent.

Proponents incorporating CO_2 capture and storage in their project must provide a description of the capture and storage system, including capture and storage locations (with anticipated storage capacity) or end uses (for storage in products), and the associated technologies and transportation infrastructure. Proponents must also indicate the targeted efficiency of CO_2 capture and storage for the project.

For each year of the project lifetime in which the CO_2 capture and storage system will be operational, the proponent must provide an estimate of the annual amount of CO_2 captured, and the annual amount of CO_2 stored. These values are to be represented separately. The direct GHG emissions associated with capture and storage that occur within the scope of the project must be included in the direct GHG emissions estimate (Section 2.1.1).

2.1.4.3. Corporate-Level Initiatives

Actions and initiatives taken at the corporate level include GHG emissions removed as a result of mitigation measures separate from the project and not reflected in the project's direct GHG emissions. Although these GHG emissions are outside of the scope of the project, they must be assigned exclusively to the project (i.e. the same GHG emission removals cannot be counted toward multiple projects). The GHG emissions removed must also represent real, additional, quantifiable, verifiable, unique and permanent removals in Canada.

Similar to avoided domestic GHG emissions, corporate-level GHG removals **cannot be:**

- Emission reductions required by law and regulations
- Emission reductions or removals funded or subsidised through other government programs and initiatives
- Impact on carbon sinks on the land affected by the project (as these are quantified separately from the net GHG emissions, see Section 4)
- Emission reductions that occur after the end of the project lifetime.

The proponent must provide information on the corporate initiatives that will count toward offset measures. This includes a description of the specific actions and initiatives and relevant technologies, intended schedule of implementation, and the time series of the quantity of offset measures. Any data, emission factors and assumptions used in determining the amount of GHG emissions removed must be provided.

2.1.5. Project Emission Intensity

When applicable, proponents will calculate the project EI, using the following equation:

Equation 4: Project emission intensity

$$\text{PROJECT EMISSION INTENSITY} = \frac{\text{Net GHG Emissions}}{\text{Units Produced}}$$

The Units Produced term in Equation 4 must correspond with production at the maximum design capacity of the project or additional maximum capacity the project creates, as described for Equation 1.

The project EI units will be specified in the TISG. Examples of possible EI units by project type are provided in Table 7.

Table 7: Examples of emission intensity units by project type

PROJECT TYPE	EMISSION INTENSITY UNIT
Natural gas electricity generation	t CO_2eq / GWh generated
Hydro electricity generation	t CO_2eq / GWh generated
Liquefied natural gas (LNG)	t CO_2eq / t LNG produced
Oil pipeline	t CO_2eq / barrel (bbl) transported
Gas pipeline	t CO_2eq / million cubic feet (MMcf) transported
Metal mines	t CO_2eq / t metal produced
Industrial facility	t CO_2eq / t output produced

For some project types, the project EI estimate may not be possible nor relevant, and will not be requested in the TISG.

The project EI estimate will be calculated in the Impact Statement for each year of the project's operation phase. Projects that provide both the maximum and net GHG emissions associated with the expected operation capacity as described in Section 2.1 can provide both corresponding project EIs.

2.2. Possible Accident or Malfunction

In the Impact Statement Phase, project proponents will provide a description of large sources of GHG emissions that may be the consequence of possible accidents or malfunctions.

2.3. Discussion on the Development of Emission Estimates and Uncertainty Assessment

In the Impact Statement Phase, project proponents will describe the uncertainty associated with their project's net GHG emissions estimates. This description should be both qualitative and quantitative, where possible.

There are two types of uncertainty to be considered:

1. uncertainty related to data; and
2. uncertainty related to methods and models.

The discussion of uncertainty related to data will identify any assumptions made in selecting the data, its applicability to the project, its representativeness, and its completeness. The discussion will explain how the data may be improved with more certainty on the project design and variables (type and volume of fuel used for example) as the design progresses toward finalization. A comparison of the data to comparable data sets may inform the uncertainty discussion. The discussion of uncertainty will acknowledge that the uncertainty of GHG emissions estimates generally increases for years further out into the future. The discussion will also include a description of possible circumstances under which accidents or malfunctions as described in Section 2.2 may occur.

The discussion on uncertainty of the methods and models, if applicable, will list the assumptions related to the method or model used and their rationale. Where possible, the uncertainty could be quantitatively represented using different methods and models, or by developing scenarios with varying data inputs to generate a range of reasonable emissions. There could be scenarios related to changes in project design and/or external considerations that may affect a project's GHG emissions over time. Examples include a qualitative discussion on how the economics surrounding the project could influence the project's emissions, such as the price of commodities and/or utilization of the project, uncertainties related to the EI of acquired energy GHG emissions, and how the emissions could change depending on the type of equipment, fuel or other source of energy used.

Finally, the discussion on uncertainty will describe how the uncertainty of the emissions estimates was reduced.

2.4. Planning Phase

The *Information and Management of Time Limits Regulations* require project proponents to provide an estimate of any GHG emissions associated with the project in the Initial Project Description and Detailed Project Description. This should be calculated as the maximum annual net GHG emissions for each phase of the project, including a breakdown of each term of Equation 1. The proponent must also provide the methodology, data, emission factors and assumptions used.

During the Planning Phase, proponents may not have sufficient information to determine precise net GHG emissions for each year of the project lifetime. Project proponents are to provide the information in Part 1 of Table 8 in the Initial and Detailed Project Descriptions. The proponent is also encouraged to provide information in Part 2 of Table 8 to help IAAC, or relevant lifecycle regulators, understand potential GHG emissions associated with the project.

Table 8: Information to provide in the Initial and Detailed Project Descriptions

PART 1: MANDATORY INFORMATION	
Net GHG emissions	• An estimate of the maximum annual net GHG emissions for each phase of the project, including a breakdown of each term of Equation 1, based on the information available in the Planning Phase. • A description of the methodology, data, emission factors and assumptions used.
PART 2: SUPPORTING INFORMATION FOR THE NET GHG EMISSIONS ESTIMATE	
Direct GHG Emissions	• An indication of the anticipated main sources of GHG emissions • An estimate of the maximum annual direct GHG emissions for each phase of the project (construction, operation, decommissioning), with a description of the methodology, emission factors and assumptions used for the quantification. • An estimate of the expected area of impacted land in each IPCC land-use category: Forest Land, Wetlands, Cropland, Grassland.
Acquired Energy GHG Emissions	A confirmation of whether the project will acquire energy, and if applicable and available: • A description of the acquired energy to be used for each phase of the project. • The expected annual quantity of acquired energy and the annual acquired energy GHG emissions for each phase of the project. • The identification of the years during which the project is expected to use each acquired energy.

Avoided Domestic GHG Emissions	A confirmation of whether the project will generate avoided domestic GHG emissions, and if applicable and available: • A description of the avoided domestic GHG emissions including a description of the proposed Baseline Emissions Scenarios. • A list of new measures, such as policies, regulations, programs as well as other considerations (such as market condition and electrification rate) that will be taken into account when developing the Baseline Emissions Scenario and the Project Emissions Scenario time series. • The years for which avoided domestic GHG emissions could be generated.
Offset Measures	An indication of whether the proponent intends to use offset measures for the project, and if applicable and available: • For offset credits: ○ Indication of offset programs providing credits. ○ The estimated annual amount of offset credits to be purchased for each phase of the project. • For CO_2 captured and stored: ○ A description of CO_2 capture, transportation and storage system, including whether partial or complete capture of CO_2 will be targeted (efficiency) and whether the CO_2 storage project is within the scope of the project or outside of the scope. ○ An indication of the expected annual amount of CO_2 that would be captured by the system. ○ For storage projects: - A description of the CO_2 storage project including the location and expected total storage capacity. ○ For storage in products: - A description of the end use of the CO_2 (i.e. products produced). - An indication of the expected annual amount of CO_2 stored (in a project or product). • For corporate-level initiatives: ○ A description of the corporate initiatives or actions, the location and area covered if applicable. • An identification of the years of the project lifetime for which offset measures will be used

2.5. Impact Statement Phase

In the Impact Statement, project proponents will quantify the project's net GHG emissions for each year of the lifetime of the project, and the project EI, for each year of the operation phase of the project. Quantification must reflect the final design including the mitigation measures identified in Section 3 (the BAT/BEPs, additional mitigation measures, and offset measures).

In the Impact Statement, each term of Equation 1 must be provided along with methodologies, a description of any models used, data, EIs and any assumption used. The impact statement should contain a greater level of detail and accuracy that reflects the new information gathered and decisions made subsequent to the Planning Phase Project Description. At a minimum, the proponent must provide the information requested in Table 9:

Table 9: Checklist of minimum information that will be required from the proponent in the Impact Statement

TOPIC	MINIMUM INFORMATION REQUIRED
Direct GHG Emissions	• A description of the main sources of GHG emissions, including details on equipment types and activities. • An estimate of the annual direct GHG emissions from each main source for the lifetime of the project. • An estimate of the annual direct GHG emissions for each year of the lifetime of the project. • A description of the methodology, data, emission factors and assumptions used to quantify the direct GHG emissions.
Acquired Energy GHG Emissions	A confirmation of whether the project will acquire energy, and if applicable: • A description of the types of acquired energy, including sources of the energy and supporting information. • The quantity of acquired energy for each year of the lifetime of the project. • An estimate of the annual acquired energy GHG emissions for each year of the lifetime of the project for each type of acquired energy. • A description of the methodology, data, emission factors and assumptions used for the quantification of acquired energy GHG emissions.
Avoided Domestic GHG Emissions	A confirmation of whether the project will generate avoided domestic GHG emissions, and if applicable: • A description of the avoided domestic GHG emissions including a description of the Baseline Emissions Scenario. • A list of new measures, such as policies, regulations, programs as well as other considerations (such as market conditions and electrification rate) that are taken into account in the Baseline Emissions Scenario and the Project Emissions Scenario time series. • An estimate of the annual avoided domestic GHG emissions for each year of the operation life of the project. • A description of the methodology, data, EIs and assumptions used for the quantification the Baseline Emissions Scenario and the Project Emissions Scenario, including a demonstration of reasonableness and conservativeness.

<table>
<tr><th>TOPIC</th><th>MINIMUM INFORMATION REQUIRED</th></tr>
<tr><td>Offset Measures</td><td>A confirmation of whether the proponent intends to use offset measures for the project, and if applicable:

For offset credits:

Whether the proponent intends to purchase offset credits, and if applicable:

The number of GHG offset credits intended to be used, for each year of the project life.
The GHG offset programs from which each offset credit will be sourced.
Confirmation that any offset credits are sourced from a project registered in a Canadian federal, provincial or territorial regulatory offset program.

For CO_2 captured and stored:

A confirmation of whether the project will capture or store CO_2, and if applicable:
A description of the CO_2 capture and storage systems, and locations (i.e. capture site, storage project site or product manufacturing site).
The expected annual amount of CO_2 captured for each year or the operation phase of the project.
For storage projects:

Geological characteristics of the storage site, including total capacity.
Annual amount of CO_2 expected to be stored for each year of the operation phase of the project.

For storage in products:

A description of the end use of the CO_2 (i.e. product) and the associated life cycle.
The annual amount of CO_2 expected to be stored in products (i.e. amount per product unit and total number of product units produced) for each year of the operation phase of the project.

Technologies used for capture, transportation, injection and monitoring, including any project-specific considerations and whether the technology has been demonstrated elsewhere (location and capture rate).
Identify any specific protocols used or adhered to for the quantification.
An explanation, and supporting documentation, of how the project will ensure that the CO_2 is stored permanently, and a discussion of the feasibility and risk of transportation of CO_2 captured to the storage location.
Identify any contracts that are in place or being negotiated between the proponent, storage project, and/or government(s) as applicable.

For corporate-level initiatives:

An estimate of the annual GHG emissions removed as a result of corporate initiatives for each year of the lifetime of the project.
A description of the corporate initiatives that will be assigned to the project, and supporting documentation, if applicable.
The proposed schedule of implementation.
Confirmation of how the proponent will ensure that corporate initiatives will not be double counted by other projects that are submitted for impact assessment.

A description of the methodology, data, EIs and assumptions used for the quantification of offset measures, if applicable.
</td></tr>
</table>

TOPIC	MINIMUM INFORMATION REQUIRED
Net GHG emissions	• Net GHG emissions by year for each phase of the project based on the project's maximum throughput or capacity (new project) or additional throughput or capacity (expansion project). • Optionally, if the project is expected to operate at a significantly different capacity from the maximum design capacity, the proponent can also provide the net GHG emissions for the expected operation capacity. The proponent can then use the net GHG emissions associated with the expected operation capacity if a plan for achieving net-zero emissions by 2050 is required.
Project Emission Intensity	• An estimate of the project's EI by year for the operation phase, based on the net GHG emissions calculated above. • A description and quantity of the "unit produced" from Equation 2 for each year of the operation phase.
Possible accident or malfunction	• A description of large sources of GHG emissions that may be the consequence of accidents or malfunctions.
Uncertainty	• Discussion on the development of emissions estimates and uncertainty assessment (Section 2.3).

3. MITIGATION MEASURES AND NET-ZERO PLAN

Proponents of projects undergoing a federal impact assessment will be required to provide information regarding mitigation measures. Mitigation measures are measures that eliminate, reduce, control or offset the adverse effects of a project. In the context of GHGs, mitigation measures are technologies, techniques and practices that are developed in the project design phase and implemented during the construction, operation, and decommissioning phases that help reduce the project's net GHG emissions, as described in Sections 4.1.3 and 5.1.4 of the SACC.

The development and implementation of mitigation measures must follow the principles discussed in Section 3.1 to minimize a project's GHG emissions. The BAT/BEP Determination process described in Section 3.2 is a tool based on these principles that is used to identify effective mitigation measures that are technically and economically feasible. Section 3.3 provides a description of the information required for the Planning Phase. A description of the information required during the Impact Statement Phase for projects with a lifetime ending before 2050 and projects with a lifetime beyond 2050 is provided in Sections 3.4 and 3.5, respectively.

3.1. Principles

The development and implementation of mitigation measures that will reduce GHG emissions must follow the principles outlined below:

- Put the emphasis on reducing the net GHG emissions of the project as early as possible during the project's lifetime;
- Based on the concept of energy efficiency, the BAT/BEP Determination process reduces energy and resource consumption at the source, thus prioritizing the reduction of direct GHG emissions and acquired energy GHG emissions;
- Reducing GHG emissions through the use of mitigation measures and the BAT/BEP Determination is an ongoing process that should be performed iteratively over the lifetime of the project to include any emerging technologies and practices that may become technically and/or economically feasible during the lifetime of the project.

3.2. BAT/BEP Determination Process

For all projects proceeding to the Impact Assessment Phase, proponents will be asked to conduct a BAT/BEP Determination process. The BAT/BEP Determination process is a tool that helps proponents identify GHG mitigation measures and minimize GHG emissions based on the principles outlined previously.

The BAT/BEP Determination process is outlined in Figure 1 and involves a structured analysis developed into six steps to identify and select the most effective technologies, techniques and practices that are technically and economically feasible to minimize GHG emissions associated with the project.

The scope of the BAT/BEP analysis considers all main sources of emissions of the project, from construction, operation, and decommissioning phases, within the scope of the project. This provides the flexibility to proponents to create project-wide scenarios which would include technologies and practices that would minimize GHG emissions from the main emission sources of the project. Figure 2 below illustrates how the project-wide scenarios is developed during each step of the BAT/BEP Determination process.

Additional details are provided in the following sections to help proponents determine the required information for each step. For some of those steps (2, 4A and 4B), guiding questions are proposed to support proponents during the BAT/BEP Determination process. These guiding questions encourage transparency and clarity, and they allow proponents to assess each technology and practice without bias.

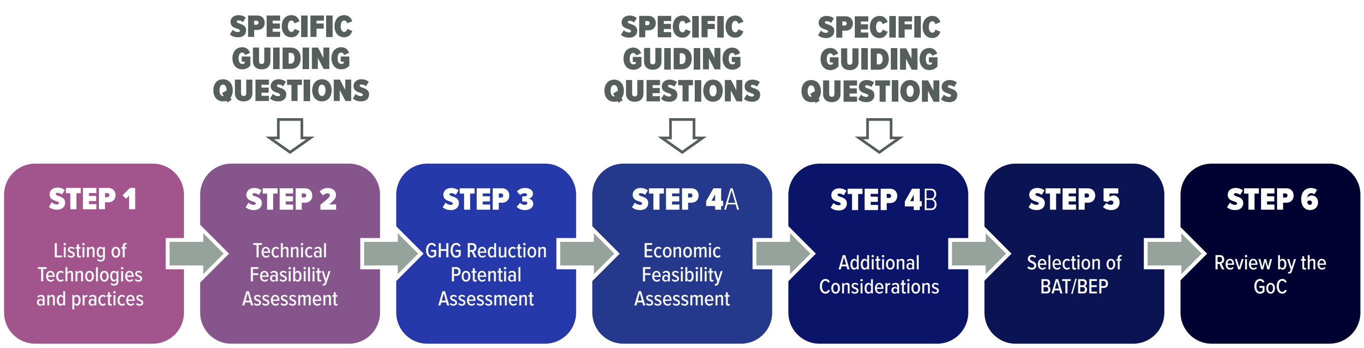

Figure 1: Steps of the BAT/BEP Determination Process

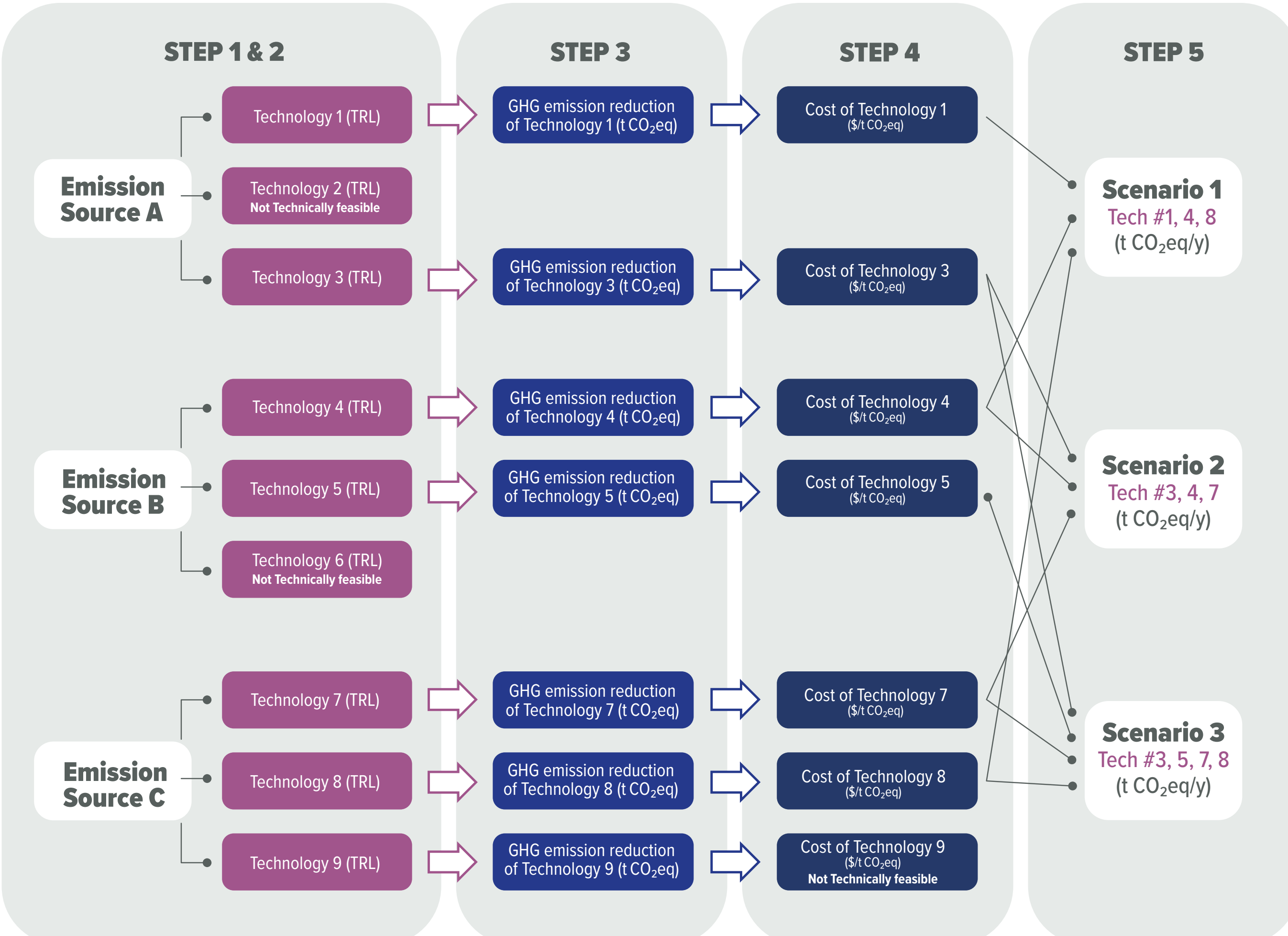

Figure 2: Illustration of the progression and potential metric for each step of the BAT/BEP Determination process.

Step 1: Listing of Technologies and Practices

Project proponents begin the BAT/BEP Determination by identifying all available and emerging technologies and practices based on the identified main sources of emissions for each project phase. The main sources of emissions, as described in Section 2.1.1, could include bundles of technologies or practices that contribute 1% or more of the total direct GHG emissions of the project. These bundles of technologies and practices (hereafter referred to as “bundles”) have the same operating purposes but may have different designs, specifications and characteristics. Examples include different processes and technologies such as steam generation, ore processing or transportation, with associated auxiliary equipment.

The list can be informed and improved by considering emerging technologies and practices of similar domestic and international high-performing energy-efficient projects. At this stage, all available and emerging options should be considered, including technologies and practices in application or in development outside Canada and beyond the project’s sector. Proponents must also identify any technology gaps, where no technologies are commercially available, highlighting where emerging technologies may fill this gap.

The following are examples of technologies and practices that proponents can explore in developing their list of specific BAT/BEP:

- Low-emitting technologies such as the use of carbon capture and storage;
- Low-carbon or renewable fuel technologies;
- Electrification technologies;
- Energy efficiency measures (such as energy integration through waste heat recovery, process optimization, artificial intelligence);
- Anti-idling practices for mobile equipment;
- Leak detection and repair systems;
- Continuous monitoring systems;
- Fleet optimization;
- Measures taken in the design to provide flexibility and potential for future upgrades; and
- Limiting the speed of mobile equipment.

Step 2: Technical Feasibility Assessment

The technical feasibility of all listed technologies and practices (or bundles) for each main emission source listed in Step 1 will be assessed. A technology or practice that is technically feasible can be successfully implemented under the specific circumstances of the project and is generally accepted, documented, and/or tested. Developing technical criteria is a useful method for determining the technical feasibility, and some have been captured in the guiding questions presented below.

For emerging technologies, proponents may use metrics, such as the Technology Readiness Level (TRL), to evaluate when those technologies may become technically feasible. Figure 2 presented above illustrates how proponents must identify the main emissions sources and their respective technical feasibility during Steps 1 and 2 of the BAT/BEP Determination process.

In instances where proponents conclude that a technology or practice is not technically feasible within the lifetime of the project, a detailed justification must be provided, including data, calculations, assumptions, and other analyses supporting the exclusion of a technology or practice due to technical considerations. Proponents are invited to discuss the timing and circumstances in which the eliminated technologies and practices could become technically feasible. Consideration of additional factors such as economic, environmental, and social considerations, will be addressed later in Steps 4A and 4B of the process.

Table 10 provides a non-exhaustive list of guiding questions to assist proponents in assessing whether each technology or practice is technically feasible.

Table 10: Guiding Questions – Technical Feasibility

- How does the technology/practice compare with the conventional technologies and practices in terms of performance metrics and efficiency (e.g. product quality or product purity, or another metric that fits the project needs)?
- Can the technology/practice reasonably be integrated with existing infrastructure and spacing availability?
- Can the technology/practice reasonably be integrated with the proposed mode of operation?
- Are there specific regional conditions or limitations (such as climate considerations) that impact the feasibility of this technology/practice?
- Is there sufficient availability of energy sources (in terms of infrastructure and supply) to support the use of the technology/practice?
- Is the technology/practice commercially available? If not, when is it expected to be commercially available?
- Has the technology/practice been demonstrated on an industrial scale in this sector? Proponents can reference the TRL, if applicable for use in the justification.
- What are the technical restrictions/limitations of this technology/practice, if any?
- What are the technical risks associated with this technology/practice, if any?
- Are the technologies/practices aligned with climate resilience practices?

Step 3: GHG Reduction Potential Assessment

Step 3 considers the GHG impact of each technology and practice (or bundles) on each main emission source. Proponents must complete this exercise for all technologies, including emerging technologies, and practices that have not been eliminated.

When assessing the GHG emission reduction potential associated with the technology, proponents must consider the additional GHGs related to the use or integration of the technology, if any. For example, the emission reduction potential (in tonnes CO_2 eq/year) of a CCS technology will consider both the direct rate of capture and the energy consumed by the technology. Figure 2 presented above illustrates moving from Step 2 to Step 3 of the BAT/BEP Determination process.

Some technologies and practices are mutually exclusive, wherein the implementation of one prevents the implementation of another (e.g., if electrification of processes is explored, then CCS technologies are eliminated because there is no stationary combustion on site). In other cases, some technologies and practices are complementary, wherein the implementation of one positively impacts or requires another (e.g. waste heat recovery used in combination with cogeneration). To allow for flexibility in the assessment, proponents may assess each mitigation measure individually or in combination with other mitigation measures.

Some mitigation measures might result in high GHG reduction potential but generate significant upstream GHG emissions or consume a significant amount of resources. Shifts in GHG emissions between emission sources, including upstream emissions, as a result of implementing technologies and practices should be considered and discussed by proponents. The objective is to reduce overall GHG emissions.

It is possible that the combination of mitigation measures, such as the use of CCS with a biomass power boiler, will result in zero or negative net GHG emissions from the project.

Step 4A: Economic Feasibility Assessment

In Step 4A, the project proponent will assess the economic feasibility of each technology and practice (or bundles) from Step 3.

Proponents must provide a detailed justification for technologies and practices not deemed economically feasible, including data, calculations, assumptions, and other analyses to support their exclusion.[25]

Examples of economic criteria that proponents could use to evaluate the economic feasibility of a technology or practice could include its estimated costs (capital and operating, including energy cost), revenue, profit, and production forecasts. The cost of carbon may also be considered, if available.

The total expected project costs will be considered for competing technologies and practices. One method used to express these projected costs is an average annual total cost (in which the capital and operating costs are annualized) in \$/t of CO_2 eq abated or reduced over the lifetime of the technology or project, but other methods are acceptable. During this phase, proponents can justify the economic feasibility of the selected technology by justifying the criteria being used for the assessment. The economic risks associated with the project and how these will affect the overall economic impact of the project should be indicated.

Proponents must discuss any relevant trade-off between competing technologies and discuss how investments are placed in areas that show early and high net GHG emission reductions.

Proponents must discuss the timing and circumstances in which the technologies and practices eliminated in this step could become economically feasible.

Table 11 provides a non-exhaustive list of guiding questions to assist proponents in assessing whether or not the technique or practice is economically feasible. Proponents may also refer to relevant questions from previous sections, if applicable.

Table 11: Guiding Questions - Economic Feasibility

- How are the economic outcomes of the project (including items such as projected revenue, return on investment (ROI), net profit, or other criteria deemed relevant) expected to change from one technology/practice to another over the lifetime of the project?
- What are the annual total costs in \$/t CO_2 eq abated or reduced associated with the different technologies considered?

Step 4B: Additional Considerations

In Step 4B, the project proponent will assess any additional considerations of the technologies or practices (or bundles) that have not been excluded due to technical or economic feasibility. These considerations can include social, health and any additional environmental aspects, such as increases in air pollutant emissions or significant adverse impacts on demographics, employment, quality of life, impacts on Indigenous rights, etc.

Project proponents must provide a detailed justification, including data, calculations, assumptions, and other analyses supporting the exclusion of a technology or practice due to social, health, and any additional environmental aspects.

[25] Information received during the Impact Assessment process is usually posted on the Impact Assessment Registry; however, if it can be demonstrated that disclosure of evidence, records or other things would cause specific, direct, and substantial harm to a person or Indigenous group, the evidence, records, or things are privileged, won't be disclosed without authorization from the person that provided them. See section 30 of the *Impact Assessment Act*.

Table 12 provides a non-exhaustive list of guiding questions to assist proponents in assessing additional considerations.

Table 12: Guiding Questions - Additional Considerations

- Are there environmental aspects that could impact the feasibility of this technology/practice, including significant adverse environmental or health impacts? This could also include impacts on design considerations such as energy use and fuel usage.
- Are there any Indigenous aspects, including an impact on indigenous rights, that could affect the feasibility of this technology/practice?
- Are there any social aspects, such as proximity to recreational or residential areas, which could impact the feasibility of this technology/practice?
- Do the technologies/practices have an impact on carbon sinks?

Step 5: Selection of BAT/BEPs

In Step 5, project proponents must combine the technologies and practices (or bundles) not eliminated in previous steps, and develop scenarios at the project level by considering all emission sources and potential interactions between mitigation measures. Proponents should prioritize early emission reductions and minimize the GHG emissions of the largest sources of emissions first, as this often results in the largest absolute reduction in the net GHG emissions over the project's lifetime.

Proponents must develop and compare various scenarios by considering when it is feasible to implement the mitigation measures, including emerging technologies that may become technically and economically feasible during the lifetime of the project. This would avoid any stranded investments. Figure 2 presented earlier illustrates the progression and potential metric for each step of the BAT/BEP Determination process.

Assessing different scenarios often leads to trade-offs and challenging decisions. For example, proponents can face a decision-making challenge between choosing technologies that provide early emission reductions and those that instead minimize emissions over the project lifetime. Proponents should discuss any relevant implications of the trade-offs between GHG emission reductions, economics and other considerations, such as upstream emissions and resource consumption.

At the end of this step, proponents must select the best scenario based on the principles discussed in Section 3.1 and any specific considerations relevant for the project. Proponents must provide, at a minimum, the following:

- A discussion on the interaction between technologies and practices in the selected scenario. This includes a discussion of the project level emission reduction potential for the selected BAT/BEPs, and why these measures were selected over others;
- The project's direct GHG emissions and acquired energy GHG emissions expressed in t CO_2 eq/year at key stages in the project lifetime with the associated EI, if relevant;
- Any actions or incentives that would aid in implementing these BAT/BEPs and emerging technologies, if relevant; and
- A list of the technologies and practices that were eliminated in Steps 2, 4A and 4B. While they are deemed to be technically and/or economically unfeasible when the BAT/BEP Determination is developed, they may become feasible during the lifetime of the project. The list will allow for their reconsideration for implementation throughout the project lifetime, such as periods of maintenance and facility upgrades.

Comparison with similar high-performing energy-efficient projects

With the selected BAT/BEPs, proponents must compare the project's GHG EI with similar high-performing energy-efficient project types in Canada and internationally, if the information is publically available.

For some types of projects, an EI comparison might not be possible or relevant. For these cases, proponents are required to explain why a GHG EI comparison is not possible or relevant. Proponents must then compare its project with similar high-performing energy-efficient projects based on direct GHG emissions and acquired energy GHG emissions, or another appropriate metric.

The comparison must include the following information for each project under comparison, if available:

- A project overview including the following:
  - Proponent;
  - Project location; and
  - Project description.
- The project's GHG emissions based on direct GHG emissions and acquired energy GHG emissions in t CO_2 eq/year with its associated EI (if relevant); and
- A summary description of the following information:
  - Why the project was considered to be high-performing, energy-efficient and suitable for comparison to the proponent's project;
  - The comparison of GHG emissions with its associated EI (if relevant) to the proponent's project values; and
  - Why the GHG emissions and EI (if relevant) may be different, highlighting any project-specific conditions that should be taken into account, and revise the BAT/BEP Determination accordingly.

Step 6: Review

Step 6 of the BAT/BEP Determination process refers to the review process which will be completed by IAAC or lifecycle regulators, with the support of expert federal authorities, during the Impact Assessment Phase. All information related to the BAT/BEP Determination process (Steps 1 to 5), including any conclusions drawn from the guiding questions, will be reviewed, commented and complemented, as needed, by the federal authorities. IAAC or lifecycle regulators may request additional rationale or justification.

The review and analysis of the Impact Statement by the IAAC or lifecycle regulators, with the support of expert federal authorities, will be made available to the public and decision-makers.

3.3. Planning Phase

3.3.1. Alternative Means of Carrying Out the Project

Proponents are required to provide information regarding the potential alternative means of carrying out the project, as described in the *Information and Management of Time Limits Regulations. The Regulations require proponents to list (for the Initial Project Description) and describe (for the Detailed Project Description) the potential alternative means of carrying out the project that are technically and economically feasible, including through the use of best available technologies.*

When evaluating the potential alternative means of carrying out the project, proponents should discuss the potential impacts of the alternatives on GHG emissions and how GHG emissions were considered as a criterion in the alternatives selection. This could include providing a qualitative discussion on the GHG emissions for each alternative, or describe the available mitigation measures specific to each alternative. Table 13 below provides a non-exhaustive list of guiding questions to assist proponents in assessing these alternative means.

Table 13: Guiding Questions – Alternative Means

• What are other similar high-performing, energy-efficient projects doing? • What mitigation measures are restricted by this alternative? • Is there any development or research being conducted on this alternative? • How feasible would it be to add mitigation measures throughout the project lifetime? • What are the risks associated with the alternative? • Are there any other considerations for this alternative? • How would the effectiveness of this alternative be monitored and measured?

3.3.2. Mitigation Measures and Credible Net-Zero Plan

Project proponents will be encouraged to integrate the principles in Section 3.1 early on during the design phase of the project and to provide information on mitigation measures in the Planning Phase. As proponents will be required to complete a BAT/BEP Determination during the Impact Statement Phase, considering potential mitigation measures early in the design and Planning Phase offers a greater opportunity for proponents to identify and plan GHG reductions. Proponents are encouraged to provide information on potential GHG mitigation measures, including a description of measures, the level of emission reductions, and how the measures compare to other options.

For projects with a lifetime beyond 2050, proponents are encouraged to provide information in the Planning Phase regarding their credible net-zero plan, which can include a corporate or project plan to achieve net-zero emissions by 2050. Information regarding the credible net-zero plan in the Impact Statement Phase can be found in Section 3.5.

3.4. Impact Statement Phase for Projects with a Lifetime Ending Before 2050

During the Impact Statement Phase, for projects with a lifetime ending before 2050, proponents must describe the mitigation measures they will take to minimize GHG emissions throughout all phases of the project. In keeping with the principles in Section 3.1, emphasis must be placed on reducing net GHG emissions as early as possible in the project's lifetime.

The following sub-sections present information requirements proponents of projects with a lifetime ending before 2050 must provide. The information requirements will also be reflected in the publication of the TISG for each project where it has been determined that an impact assessment is required. The level of depth of analysis and information required from the proponent will be proportional to the emissions of the project.

3.4.1. BAT/BEP Determination Process Conclusions

Proponents must complete a BAT/BEP Determination process as described in Section 3.2 and provide their conclusions. This must include all information and rationale developed by proponents that support the conclusions of the BAT/BEP Determination process.

The BAT/BEP Determination process conclusions must contain, at a minimum, the following:

- The list of all potential GHG mitigation measures that were considered in the BAT/BEP Determination process;
- The list of potential GHG mitigation measures selected at the end of the BAT/BEP Determination process that are to be implemented in all phases of the project (BAT/BEP and emerging technologies), including the following information;
    - The potential percentage reduction in GHG emissions associated with each measure;
    - The level of technology maturity (when the technology could be implemented); and
    - The barriers to implementing the selected mitigation measures.

- A rationale for eliminating each technology or practice that has not been selected for implementation;
- Subject to the public availability of information, a comparison of the project's projected EI to similar high-performing energy-efficient project types in Canada and internationally;
- The implementation schedule of the mitigation measures, considering equipment replacements. The implementation schedule must include;
    - The relevant data sources, assumptions, and information to support it; and
    - A discussion on factors associated with the schedule such as schedule dependencies, constraints, and risk.
- As described in Section 2.5, a quantitative description of the project's estimated annual net GHG emissions over the lifetime of the project and the associated EI, when relevant. This must be aligned with the implementation schedule of the different mitigation measures over time but also with the project's maximum design capacity, or expected operation capacity (if the project is operating at a significantly different capacity from the maximum design capacity);
- A set of EI targets (and/or emission targets if EI is not relevant) at specified time intervals for the lifetime of the project.

3.4.2. Additional Mitigation Measures

Proponents must consider implementing additional mitigation measures (i.e. offset measures) to further reduce GHG emissions, including CO_2 captured and stored, corporate-level initiatives and offset credits, if applicable. Examples of possible initiatives at the corporate level in Canada include direct air capture technology and afforestation provided that action is not required by law or attributed to any other project. More information on the quantification of offset measures can be found in Section 2.1.4.

3.4.3. Carbon Sinks

If the project has an impact on carbon sinks, the proponent is required to consider implementing mitigation measures to restore disturbed carbon sinks. Examples of mitigation measures could be as follows:

- Restoration at project site (full recovery);
- Remediation and reclamation at the project site (reducing impacts through preventive actions/ecosystem modification);
- Carbon sink compensation or conservation activities outside the project site.

In the case that a site, or portion of a site, is to be restored to its natural state after the project completion, the loss of carbon sinks should consider the restoration area and the time required to restore the natural sink capacity.

Land-use change resulting from restoration, afforestation, compensation and conservation on other land owned, managed or controlled by the proponent may be calculated as offset measures.

More information on how to quantify the impact on carbon sinks is presented under Section 4 of the document.

3.4.4. GHG Legislation, Policies and Regulations

Proponents must include a list of the federal, provincial or territorial GHG legislation, policies or regulations that will apply to their project, explaining any implications for the project.

3.5. Impact Statement Phase for Projects with a Lifetime Beyond 2050

During the Impact Statement Phase, for projects with a lifetime beyond 2050, proponents must submit their credible net-zero plan that will describe how the project will achieve net-zero emissions by 2050 and thereafter for the remainder of its lifetime.

The BAT/BEP Determination process in Section 3.2 will play a central role in developing the credible net-zero plan of the mitigation measures to achieve net-zero by 2050. It is possible that some projects will require additional mitigation measures to achieve net-zero emissions.

The following sub-sections present the information proponents of projects with a lifetime beyond 2050 must provide. The information requirements will be reflected in the TISG for each project where it has been determined that an impact assessment is required. The level of depth of analysis and information required will be proportional to the emissions of the project.

3.5.1. Principles of the Net-Zero Plan

The net-zero plan must demonstrate how the net GHG emissions of Equation 1 outlined in Section 2.1 will equal 0 t CO_2 eq by 2050 and thereafter for the remainder of the project lifetime. The plan will be evaluated against the following principles:

- The plan must be based on the BAT/BEP Determination process which aims at minimizing direct GHG emissions and GHG emissions from acquired energy and demonstrate how offset measures are used to mitigate residual GHG emissions.
- The plan must include a schedule of the actions taken to achieve net-zero emissions by 2050. The plan should include, as much as possible, the mitigation measures that will be implemented over the lifetime of the project. Alternatively, it can describe the process proponents will follow in order to make the decisions and investments needed. This could include, for example, partnerships or investments with the providers of technologies considered for implementation in the future.
- The net-zero plan must estimate the projected net GHG emissions over the project's lifetime. It must seek to minimize GHG emissions of the project as early as possible for the project lifetime. The plan must also include proposed emission reductions at specified intervals up to 2050 and must be aligned with the schedule of the mitigation measures that will be implemented.
- The plan must be coherent with the proponent's corporate commitments, if any, and long-term business strategies.
- All methodology, justification and assumptions must be provided to support the steps taken to achieve net-zero emissions.
- The plan must be clearly presented and easily understood.

The project's net-zero plan can refer to the proponent's corporate net-zero plan, if any. Proponents should describe how the corporate net-zero plan will assist in reducing the project's net GHG emissions, if applicable. In particular, if actions being undertaken by the company at a facility separate from the project are included in the project's net zero plan, the proponent must explain how those actions and related GHG reductions will be assigned exclusively to the project as offset measures (see Section 2.1.4.3).

The plan to achieve net-zero emissions does not apply to upstream GHG emissions, even if an upstream GHG emissions assessment was conducted.

3.5.2. Information Required in the Credible Net-Zero Plan

The information presented in the credible net-zero plan must use and build off the BAT/BEP Determination and analysis outlined in Section 3.2. The plan must include at a minimum:

- The conclusions related to the BAT/BEP Determination process (see Section 3.4.1), with a net-zero emission perspective, including:
  - A list of all potential GHG mitigation measures that were considered in the BAT/BEP Determination process;
  - A list of potential GHG mitigation measures selected at the end of the process that are to be implemented in all phases of the project (BAT/BEP and emerging technologies), including the following;
    - The potential percentage reduction in GHG emissions associated with each measure;
    - The level of technology maturity (when the technology could be implemented); and
    - The barriers to implementing the selected mitigation measures.
  - A rationale for eliminating each technology or practice that was not selected for implementation; and
  - Subject to public availability of information, a comparison of the project's projected EI to similar high-performing energy-efficient project types in Canada and internationally.
- A description of any additional mitigation measures (i.e. offset measures) that will be implemented for the project to achieve net-zero emissions by 2050, if applicable. As described in Section 2.1.4, the additional mitigation measures can include:
  - Implementation of CCS technologies.
  - Description of the proponent's corporate-level GHG commitments and/or net-zero plan and an explanation on how it aligns with the project's credible net-zero plan, if relevant; and
  - Acquisition of offset credits.
- The implementation schedule of the mitigation measures must align with the BAT/BEP Determination, consider the TRL of the mitigation measures and describe when the mitigation measures will be implemented (including equipment replacement). The implementation schedule does not need to describe every technology or practice the project will implement over time to achieve net-zero emissions. The plan may describe the process the proponent will follow in order to make the decisions and investments needed to achieve net-zero emissions by 2050. The implementation schedule must include;
  - The relevant data sources, assumptions, and information to support it; and
  - A discussion on factors associated with the schedule such as schedule dependencies, constraints, and risk.
- As described in Section 2.5, a quantitative description of the project's estimated annual net GHG emissions over the lifetime of the project and the associated EI, when relevant. This must be aligned with the implementation schedule of the different mitigation measures over time but also with the project's maximum design capacity, or expected operation capacity (if the project is operating at a significantly different capacity from the maximum design capacity);
- A set of EI targets (and/or emission targets if EI is not relevant) at specified time intervals until the project achieves net-zero emissions.

Additional information that may support the net-zero plan are as follows:

- Additional discussions of each mitigation measure, including factors such as associated costs, technical challenges, risks, infrastructure requirements and any other relevant considerations.
- Any supportive actions needed in order to be able to achieve net-zero emissions. This could include, for example, identifying the need for the construction of a grid intertie to enable access to clean electricity.

3.5.3. Carbon Sinks

If the project has an impact on carbon sinks, the proponent is required to consider implementing mitigation measures to restore disturbed carbon sinks. Examples of mitigation measures could be as follows:

- Restoration at project site (full recovery);
- Remediation and reclamation at the project site (reducing impacts through preventive actions/ ecosystem modification);
- Carbon sink compensation or conservation activities outside the project site.

In the case that a site, or portion of a site, is to be restored to its natural state after the project completion, the loss of carbon sinks should consider the restoration area and the time required to restore the natural sink capacity.

Land-use change resulting from restoration, afforestation, or compensation and conservation on other land owned, managed or controlled by the proponent may be calculated as offset measures.

More information on how to quantify the impact on carbon sinks is presented under Section 4 of the document.

3.5.4. GHG Legislation, Policies and Regulations

Proponents must include a list of the federal, provincial or territorial GHG legislation, policies or regulations that will apply to their project, explaining any implications for the project.

3.6. Summary of Required Information in the Impact Statement Phase

Table 14 contains a summary of information required for the Impact Statement Phase for projects with a lifetime ending before and beyond 2050.

Table 14: Summary of relevant sections associated with the required information in the Impact Statement

INFORMATION REQUIRED	PROJECTS WITH A LIFETIME ENDING BEFORE 2050	PROJECTS WITH A LIFETIME BEYOND 2050
BAT/BEP Determination process	3.2	3.2
BAT/BEP Conclusions	3.4.1	Included within 3.5.2
Additional Mitigation Measures	3.4.2	Included within 3.5.2
Net-Zero Plan	Not applicable	3.5.2
Carbon Sinks	3.4.3	3.5.3
GHG Legislation, Policies and Regulations	3.4.4	3.5.4

4. CARBON SINKS

Proponents are required to provide a quantitative assessment of the impact to carbon sinks resulting from land-use change, in addition to the qualitative assessment already described in the SACC. An impact to a carbon sink implies the interruption of the land's natural process that results in the net absorption of carbon from the atmosphere.

4.1. Methodology

In order to determine a project's impact to carbon sinks, proponents are required to calculate the natural carbon sink capacity of a site if undisturbed for a pre-determined time interval, and calculate the sum of this lost carbon sink capacity, measured as carbon emissions or removals (i.e., carbon exchanged or carbon flux) as a result of the project. To calculate this, proponents should use Equation 5:

Equation 5: Estimated carbon sink impact

$$\mathbf{CSI} = \sum_{i,j}((NatFlux - PostDFlux)_{i,j} \bullet T_{i,j} \bullet A_{i,j})$$

Where:

CSI is the estimated carbon sink impact (t C)
NatFlux is the natural annual carbon accumulation rate of the land being impacted (t C ha^{-1} y^{-1})
PostDFlux is the post-disturbance (i.e. post conversion) flux rate impacted by the project (t C ha^{-1} y^{-1})
T is the time interval (years)
A is the land area (ha)
i is the land-use class
j is the disturbance activity for each phase of the project (construction, operation, decommission including, for instance, site restoration or reclamation).

A detailed methodology for obtaining the values required for Equation 5 and an example of application are provided in Annex D: Further guidance on the methodology used to quantify the impact to carbon sinks.

4.2. Planning Phase

The Information and Management of Time Limits Regulations require project proponents to provide information on the land that will be impacted by the project in the Initial Project Description and Detailed Project Description.

Project proponents should provide the following information to help IAAC, or relevant lifecycle regulators, with the support of expert federal authorities, to understand the potential impact on carbon sinks:

- A description of the activities that would result in an impact on carbon sinks. A carbon sink represents a land that absorbs CO_2 and the storage of that carbon in either living biomass or in soil organic carbon. Activities that result in a removal of a sink are those that remove actively growing biomass (deforestation), or disrupt a process in which carbon is being integrated into soil organic carbon, such as peat accumulation (wetland disturbance); and
- The land areas expected to be directly impacted by the project over the course of the project lifetime, classified by IPCC land-use category (IPCC 2006): Forest Land, Cropland, Grassland, Wetlands.

4.3. Impact Statement Phase

In the Impact Statement, proponents are required to provide a qualitative and quantitative assessment of the project's impact on carbon sinks. Proponents should refer to Section 5.1.2 of the SACC for information on the qualitative information to be included in the Impact Statement.

For estimating the project's positive or negative impacts to carbon sinks, project proponents should refer to the carbon sinks methodology in Annex D. For some projects, simple default values provided in this document may be adequate. However, when projects result in important losses of carbon sink potential, proponents need to use an approach based on site- and/or region-specific values, as per Figure 3. Project area refers to the land area converted to land classified as Settlements (refer to glossary for definition of Settlements).

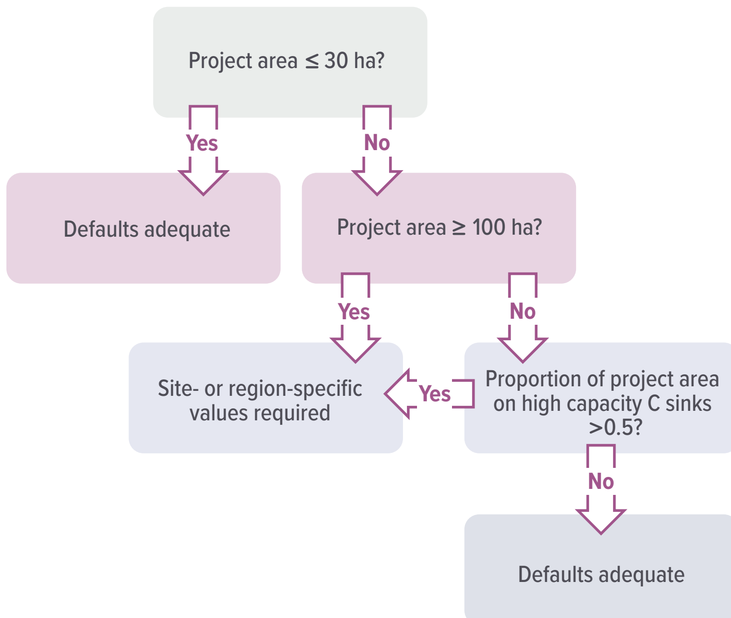

Figure 3: Decision tree used to determine if the provided defaults are adequate for the methodology used to quantify the impact to carbon sinks, or if project proponents are required to take a more detailed approach by determining site- or region-specific values. "Project area" refers to the land area converted to land classified as Settlements. Areas with high carbon sink capacity include wetlands classified as bogs, young- to medium-aged forests, and forested wetlands.

Documentation

Proponents are required to justify and document the methodology used in determining the project's carbon sink impact, as well as relevant information pertaining to how values were obtained, such as:

- If field measurements are included in calculations, a detailed report on sampling methodologies is required. This report should be comparable in detail to a methodology section of a peer-reviewed published journal study, providing information on the number of samples taken per site area, the equipment and methods used to extract and analyze the samples, and relevant information on how the data were compiled. Sample statistics (such as standard deviation) should also be reported.
- If values are derived from scientific literature, proponents are responsible for demonstrating that values chosen are appropriate for the project region and site.

- If a site-specific approach or a country-specific model using data from the site is applied, then proponents are required to provide a description of the model, data, emission factors and any assumptions that were required, or applied in order to derive values used in the modelling. Proponents should justify their choice of model in citing examples of studies in which the model was used in a comparative manner.

4.4. Uncertainty

It is recognized that there is uncertainty when estimating the natural carbon sink capacity of lands.

The project proponents should provide a qualitative discussion on the uncertainties and sources of uncertainties associated with the quantification of the impact on carbon sinks, and what was done to reduce or mitigate the uncertainties. Uncertainties may arise from several sources. The uncertainties discussion should include, but not necessarily be limited to, the following:

- Data sources: Describe the data sources used and how they have an impact on the uncertainties;
- Assumptions: The uncertainties associated with assumptions due to lack of site- or regionally-specific carbon accumulation data; and
- Scenarios/models: The uncertainties associated with the models used to calculate the natural or post-disturbance carbon accumulation rates. Statistical random sampling error should be included if possible.

5. UPSTREAM GHG ASSESSMENT

5.1. Methodology

The upstream GHG emissions are defined in Section 3.2 of the SACC as the domestic and non-domestic emissions associated with all stages of production, from the point of extracting the resources up to, but not including, the activities within the scope of the project under review.

The requirement for completing an upstream GHG emissions assessment will be confirmed in the TISG based on preliminary calculations conducted by expert federal authorities. Projects likely to exceed the upstream GHG emissions thresholds outlined in Table 15 will be required to complete an upstream GHG emissions assessment in the Impact Statement Phase.

Table 15: Upstream GHG emissions thresholds for conducting an upstream GHG assessment

PUBLICATION YEAR OF TAILORED IMPACT STATEMENT GUIDELINES	UPSTREAM GHG THRESHOLD (kt CO_2 eq/year)
2020-2029	500
2030-2039	300
2040-2049	200
2050 and beyond	100

In the past 5 years, upstream GHG emissions assessments were required for some energy projects that had the potential for high upstream GHG emissions. Energy projects are those related to the exploitation or potential exploitation of non-renewable resources to produce energy, or to the storage or transmission of energy products produced from non-renewable resources. As the thresholds decline over time, upstream GHG assessments are more likely to be requested for other project types.

Transparency of data is a key element in an upstream GHG emissions assessment. The data sources, EIs, methodology and assumptions used to estimate the upstream GHG emissions must be provided.

It may be possible that certain projects are dependent on other project(s) proceeding, which are undergoing or have undergone their own separate impact assessment (and possibly separate upstream GHG assessments). Examples include an LNG marine jetty project or natural gas pipeline project that would not be built without an LNG facility project proceeding, and vice versa.

If an upstream GHG emission assessment already exists for the other dependent projects, it could be referenced in the Impact Statement. In this case, the proponent should provide justification of how the existing upstream GHG emissions assessment applies to the project under review, or how it can be adapted to form the basis of the new assessment. For example, both projects would need to be of equal capacity, amongst other factors, to justify the direct application of the existing upstream assessment.

The following sections provide an approach specific to the preparation of the upstream GHG emissions assessment. The upstream GHG emissions assessment should be a separate, standalone section of the Impact Statement and is distinct from the project's net GHG emissions estimates. The upstream GHG emissions assessment is divided in two parts:

- Part A Quantitative estimate of upstream GHG emissions
- Part B Qualitative discussion on the incrementality of upstream GHG emissions

5.1.1. Part A – Quantitative Estimate of Upstream GHG Emissions

Part A of the upstream assessment is a quantitative estimate of the range of GHG emissions released from the upstream activities of the operation phase[26] of the project. It includes GHG emissions generated from activities including production, processing and transportation (via pipeline, vehicle, rail and ship) of energy products such as oil[27], natural gas[28], coal and methanol.

Upstream GHG emissions should also include the fugitive, venting and flaring emissions associated with the activities above, and GHG emissions associated with the diluents used.

Upstream GHG emissions must be based on **maximum annual capacity** of the project at any given time during the **operation phase**. In the case of expansion projects, the upstream GHG emissions estimates must be based on the maximum annual additional capacity of the project.

The GHG emissions from the following upstream activities are exclusions and they are **not** required to be quantified in Part A of the upstream GHG emissions assessment because they are either outside of the assessment of the upstream emissions scope, there are methodology and/or data limitations, or high uncertainty:

- Generation of purchased (third party) electricity, hydrogen, or steam used for the project as these are considered in the net GHG emissions (as acquired energy GHG emissions);
- Generation of hydrogen or steam used for the upstream activities to the project, if data is not available;
- Land-use changes;
- Exploratory drilling;
- Manufacturing of equipment and material; and,
- Construction of infrastructure on-site.

The proposed methodology and EIs to quantify the upstream GHG emissions are presented in Annex F. Proponents may use their own methodology and EIs if more appropriate or accurate for the project, but must provide justification for this, as well as the methodology, data, EIs and assumptions used to quantify the upstream GHG emissions.

5.1.2. Part B – Qualitative Discussion on the Incrementality of Upstream Emissions

Part B of the upstream GHG emissions assessment assesses the conditions under which the Canadian upstream emissions estimated in Part A could be expected to occur, regardless of whether the project proceeds. *Incrementality* refers to the upstream production (and resulting emissions) that would only occur if the project were built. Incrementality can be illustrated by comparing the differences between scenarios where the project does not proceed (the "No Project Case") and at least one scenario where the project is built, (the "Project Case"), all else equal.

If a project represents either a new source of demand or an alternative source of demand for upstream production, it is likely to result in incremental upstream production and GHG emissions.

The GHG upstream assessment Part B discussion must:

- Include a scenario analysis of project alternatives, including a comparison of a scenario in which the project does not proceed to at least one scenario where the project is built, all else equal. See below for requirements for developing legitimate counterfactual scenarios.

[26] Quantification of upstream emissions for the construction and decommissioning phases are not required.

[27] Oil includes heavy oil, light oil, frontier oil, oil sands, in-situ oil sands (Cyclic Steam Stimulation (CSS), Steam Assisted Gravity Drainage (SAGD) and primary oil sands), synthetic crude oil and refined petroleum products.

[28] Natural gas includes unconventional and conventional natural gas.

- Use sourced and verifiable technical and economic information to discuss various market and infrastructure assumptions that could result in incremental emissions and support assumptions being made in the scenario analysis with credible references.
- Discuss the potential impact of upstream GHG emissions associated with the project on Canada's overall GHG emissions.
- Assess the relationship between production and emissions in Canada, including how proposed and existing GHG policies could affect upstream emissions intensity over time.
- Discuss the potential impact of incremental upstream production on global emissions:
  - Highlight the degree to which upstream production in Canada results in a combination of i) shifting production and emissions to other jurisdictions and ii) increasing the total amount of global production and emissions;
  - For upstream production in Canada expected to displace existing global production, compare upstream emissions intensity of the project to upstream emissions intensity of global competitors. Proponents should justify the global competitors chosen using market data and credible references;
  - Discuss the total lifecycle emissions of the project's upstream production expected to add to total global supply.

Consideration must be given to whether the alternatives represent legitimate counterfactual scenarios. For a scenario to be considered a legitimate counterfactual scenario compared to the Project Case scenario it must:

- Be economically viable.
- Be based only on relevant information and circumstances related to the project.
- Not assume a comparable project to the one under review, which would require its own upstream GHG assessment, is built. For example, the proponent for a pipeline project cannot merely assume that another unapproved pipeline would be constructed if the project is not built.

Proponents should clearly define assumptions made and provide sources and/or verifiable evidence such as expected costs and prices, target markets, and other relevant factors.

5.2. Addressing Uncertainty

There is inherent uncertainty when estimating upstream GHG assessments, as discussed in Section 3.3 of the SACC.

The project proponents should provide a qualitative discussion on the uncertainties and sources of uncertainties associated with its GHG upstream emissions estimates and what was done to reduce or mitigate the uncertainties. Uncertainties may arise from several sources. The uncertainties discussion should include, but not be limited to the following:

- Data sources: Describe the data sources used and how they have an impact on the uncertainties.
- Assumptions: The uncertainties associated with assumptions due to lack of data, lack of information on upstream input resources, throughput product(s), product mixes, etc.
- Scenarios/models: The uncertainties associated with the models used in developing the different scenarios to estimate the upstream GHG emissions. Statistical random sampling error if possible.

5.3. Planning Phase

To ensure that federal authorities have sufficient information to determine if an upstream GHG emission assessment is required, the proponent can provide the following information in the Initial Project Description and Detailed Project Description:

- An indication of the amount of energy products and diluents that will be produced, processed or transported by the project.
- Potential sources of these energy products and diluents, including whether those sources are domestic or international.
- An indication of how upstream GHG emissions could be expected to change over the project lifetime.

As indicated in section 3.2.2 of the SACC, the TISG will confirm if an upstream GHG assessment is required in the Impact Statement based on preliminary calculations conducted by IAAC with the support of expert federal authorities.

5.4. Impact Statement Phase

Proponents should provide information described in Sections 5.1 and 5.2.

Table 16 presents a checklist that proponents may use to confirm that the necessary information has been provided in their assessment.

Table 16: Checklist for Upstream GHG Emissions Assessment

PART A – QUANTITATIVE ESTIMATE		
√	Project	Is it a new project or an expansion project?
√	Throughput/ Capacity	What is the maximum capacity of the project?
√	Products	What are the energy products? Are diluents used? What is the proportion of recycled diluent?
√	Scenarios	What are the scenarios in Part A? Are they appropriate?
√	Quantification	What are the EIs used? What are the assumptions? Are they appropriate?
√	Time Series	Are upstream emissions provided for each year of the operation phase of the project?
√	EIs	Are the upstream emissions intensity comparable to other similar projects?
√	Uncertainty	Does the upstream GHG emission assessment include a qualitative discussion on the uncertainties and sources of uncertainties associated with its GHG upstream emissions estimates and what were done to reduce or mitigate the uncertainties
PART B – QUALITATIVE DISCUSSION		
√	Scenarios	Does Part B include scenarios that discuss the potential for the upstream emissions from a project occurring in the absence of the proposed project? Is there a comparison of a scenario where the project proceeds to one in which it does not proceed, all else equal? Are the assumptions of the "No Project Case" scenario justifiable or do they assume other, unapproved, comparable projects would proceed?

√	Technical and Economic Data to Justify Assumptions	Does the discussion include sourced and/or verifiable technical and economic data to justify the assumptions of the scenarios?
√	Domestic Emissions	Does the discussion include domestic GHG emission impacts? Does the discussion include how proposed and existing GHG policies could affect upstream emissions intensity over time?
√	Global Emissions	Does the discussion include global GHG impacts including how much upstream production would displace other sources of production and how much would add to total global supply?

6. NEXT STEPS

Stakeholders and Indigenous peoples are encouraged to submit comments on this draft technical guide by October 25, 2021. Comments are to be submitted by email to:

Environment and Climate Change Canada
Strategic Assessment of Climate Change – Draft Technical Guide

351 St. Joseph Boulevard, 12th Floor
Gatineau, QC K1A 0H3
Email: ec.escc-sacc.ec@canada.ca

Following the publication of this draft technical guide and a review of comments received, the final technical guide is expected to be published in early 2022.

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8. ANNEXES

Annex A: Fuel Consumption by Equipment

Where the amount of fuel consumed is not available, the proponent can refer to Table 17 for resources can be used to estimate the quantity of fuel for different type of emission sources.

Table 17: Fuel Consumption Resources

SOURCE TYPE	METHOD	DESCRIPTION	SOURCE
Stationary/ portable combustion devices	Based on maximum rated power output	Fuel consumption can be calculated based on maximum rated power output, using the methodology found in the Newfoundland GHG Guidance Document, Equation 6-15a.	NFLD Guidance Document for Reporting GHG Emissions for Large Industry in NFLD and Labrador, equation 6-15a, section 6.5.2
Vehicles	Fuel consumption documentation	Fuel consumption can be determined by the distance travelled by the vehicle, as described in IPCC Volume 2 Chapter 3.	IPCC Volume 2 Chapter 3, section 3.2.1.1
Marine vessels		Average fuel consumption factors for marine transport can be found in Table 3.5.6 in IPCC Volume 2 Chapter 3.	IPCC Volume 2 Chapter 3, section 3.5.1.3 table 3.5.6
Rail		The Railway Association of Canada (RAC) published yearly trends. The most recent document (for 2019) contains information on fuel consumption based on revenue-tonne-kilometres. Average fuel consumption factors for some trains can be found in Box 3.4.1in IPCC Volume 2 Chapter 3, section 3.4.1.2.	Railway Association of Canada 2019 Trends – Page 13 IPCC Volume 2 Chapter 3, section 3.4.1.2 Box 3.4.1
Aircraft		Average fuel consumption per flight hour for military aircraft can be found in Tables 3.6.7 and 3.6.8 in IPCC Volume 2 Chapter 3. Fuel consumption of commercial aircraft on lift-off and landing are in Table 3.6.9.	IPCC Volume 2 Chapter 3, section 3.6.1.4 tables 3.5.7, 3.6.8, and section 3.6.3 table 3.6.9
Vehicles	Models	Emission models such as the USEPA MOVES, MOBILE, or EEA's COPERT model can be used to estimate fuel consumption of vehicles.	US EPA MOVES US EPA MOBILE COPERT

Annex B: Quantification of Direct GHG Emissions from Land-Use Change

Proponents must track the conversion of lands to the Settlements land-use category from the following land-use categories defined in the 2006 IPCC Guidelines for National GHG Inventories (IPCC 2006)[29]: Forest Land, Cropland, Grassland, Wetlands, and Other Lands (see Volume 4, Chapter 3, Section 3.2 for detailed definitions). Further, proponents are responsible for identifying projects that involve long-term flooding of a land area (e.g. construction of a hydroelectric reservoir), falling under the land-change category of Land to Wetlands. On each Land conversion to Settlements and Land to Wetlands conversion proponents must quantify the impact, and subsequent emissions from project construction on the following carbon pools: living biomass (aboveground and belowground), dead organic matter (dead wood and litter), and soils (soil organic matter) defined in Table 1.1 of the IPCC guidelines (IPCC 2006; Volume 4, Chapter 1, Section 1.3) and harvested wood products (IPCC 2006; Volume 4, Chapter 12, Section 12.1). The change in carbon stocks from a project's construction is first calculated as an emission to the atmosphere as CO_2 gas (Table 18). Proponents must then quantify and sum any additional emission of CO_2 from flooded lands for the construction of a reservoir, as well as any non-CO_2 gas from flooded lands (reservoir and non-reservoir), drainage of organic soils, or burning of organic soils, biomass or dead organic matter (DOM; Table 19).

Proponents should prioritize the methodology used in the latest National Inventory Report (NIR): Greenhouse Gas Sources and Sinks in Canada which is the preferred methodology because it implements Canada-specific implementation of the IPCC guidance for the calculation of emissions and removals from land-use conversion. Where methods provided within the NIR do not specifically apply to land conversions applicable to impact assessment then proponents should follow the generic IPCC guidelines.

Determining the Appropriate Tier for the Project

The IPCC guidelines follow a tiered approach, in which Tier 1 is a generic approach using very general, non-specific parameters to estimate emissions and removals of GHGs, Tier 2 is an intermediate approach and Tier 3 is the most demanding in terms of complexity and data requirements. IPCC higher tiers integrate data and information that are more specific to country or region-specific circumstances and in doing so reduce uncertainty in estimates (See Box 1.1, Section 1.3.3., Chapter 1; IPCC 2006). Here, the use of a tiered approach is also suggested but the scale is adapted to a project or site level, where the Tier 1 approach uses IPCC framework and default parameters; Tier 2 approach uses IPCC framework and site- or region-specific data, and Tier 3 approach uses a country-specific Tier 3 model as defined by IPCC (IPCC 2006):

- Tier 1 approach is a generic approach and uses a clearly defined framework for calculations as well as default international parameters provided in the IPCC guidelines (IPCC 2006), or national parameters drawn from the NIR, but not specifically applicable to the precise location.
- Tier 2 approach uses the same methodological framework for calculations as in Tier 1 above but replaces the IPCC Tier 1 default values or derives default factors using standardized functions with site- or regionally-specific data.
- Tier 3 approach is a site-specific approach and involves tracking the relevant carbon stocks, as well as the transfers between them and to the atmosphere, through time. This can be done through comprehensive field surveys repeated regularly over time, or through a country-specific Tier 3 model, using data from the site as model input.

The requirement to use a Tier 1 approach versus a higher tiered approach (Tier 2 or 3) is based on the area of the project converted to land classified as Settlements (refer to glossary for definition of Settlements) (referred to as project area) in Figure 4 (see also Figure 5) and the proportion of that land that is considered to be a carbon dense ecosystem. Carbon dense ecosystems are defined as being mature forests (defined here as having an age of at least 50% of the age of the forest when it reaches its maximum carrying capacity (refer to Annex E for a list of forest types and their corresponding ages at maximum carrying capacity (A_{mcc}))), wetlands, or forested wetlands.

[29] https://www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html

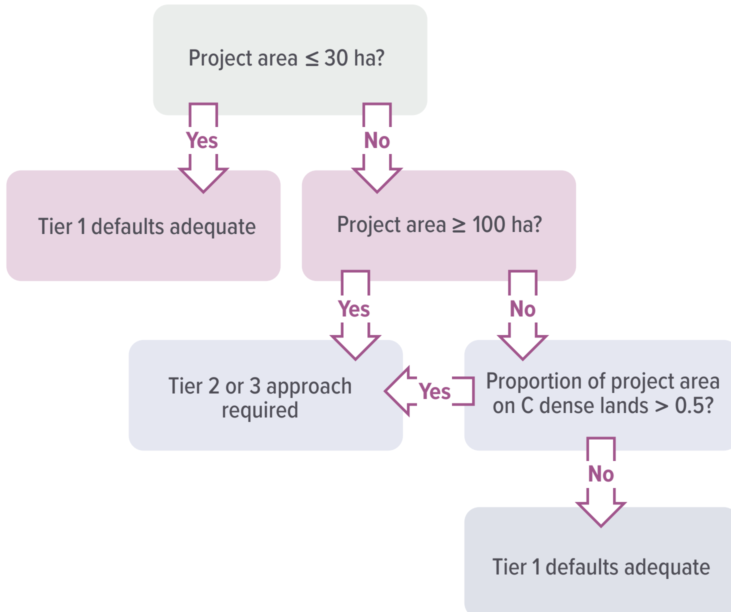


Figure 4: Decision tree to determine if Tier 1 defaults are adequate for the quantification of direct GHG emissions from land-use change, or if Tier 2 or 3 approach is required. Carbon dense lands are defined as mature forests **(defined here as having an age of at least 50% of the age of the forest when it reaches its maximum carrying capacity (refer to Annex E for a list of forest types and their corresponding ages at maximum carrying capacity (A_{mcc})))**, wetlands, or forested wetlands.

Tier 1 Approach

If a Tier 1 approach is determined to be adequate based on Figure 4, the proponent can calculate the change in carbon stocks from the project's construction as an emission to the atmosphere as CO_2 gas using equations and defaults outlined in Table 18.

Table 18: Guidance on using the IPCC Tier 1 framework for calculating carbon stock change resulting in direct GHG emissions or removals from land-use conversion

STOCK	RELEVANT IPCC SECTION AND EQUATION*	TIER 1 DEFAULTS AND ADDITIONAL NOTES
Living Biomass	Section 2.3.1, equation 2.15 (IPCC 2006)	For ΔC_G use equation 2.9 and 2.10 in Section 2.3.1.1 (IPCC 2006), but can assume 0 change in most cases. For ΔC_L use equation 2.11 to 2.13 in Section 2.3.1.1 (IPCC 2006), if any biomass is removed from the site (e.g. harvested for wood products), if not assume 0 change.
	Section 2.3.1, equation 2.16 (IPCC 2006)	Set $B_{AFTERi} = 0$ For default values of $B_{BEFOREi}$, see Table 8.4 (IPCC 2006) for Forest Land. See Table 20 in this document for default living biomass values for Cropland.

Dead Organic Matter (DOM)	Section 2.3.2.2, equation 2.23 (IPCC 2006)	$T_{on} = 1$ $C_n = 0$ Default initial values for litter for Forest Land provided in Table 2.2 (IPCC 2006). Deadwood for Forest Land is not included for Tier 1. DOM is assumed to be 0 for all non-forest land-use categories.
Soil Organic Carbon (SOC)	Section 2.3.3.1, equation 2.24 (IPCC 2006)	Defaults provided based on depth of 30 cm $\Delta C_{Inorganic} = 0$
	Section 2.3.3.1, equation 2.25 (IPCC 2006)	Default D = 20 years. Use Table 2.3 (IPCC 2006) for default SOC_{REF} See Section 8.3.3.2 for stock change factor assumptions for conversion to Settlements (e.g. for most Land to Settlements conversion a 0.20 factor can apply, i.e. 20% of mineral soil SOC is lost over 20 years and assumed emitted to the atmosphere). For details on how to move to Tier 2 approach see Section 2.3.3.1 (IPCC 2006)
	Section 2.3.3.1, equation 2.26 (IPCC 2006)	Default stock change emission factors (EF): • Forest Land see Table 4.6 (Section 4.5; IPCC 2006) • Cropland see Table 5.6 (Section 5.2.3.2; IPCC 2006) • Grassland stock change factors see Table 6.3 (Section 6.2.3.2) (IPCC 2006) For organic soils (Wetlands or Forest Land on organic soils) the Tier 1 default is to assume any C from excavated soil is instantly oxidized and emitted to the atmosphere. For a Tier 2 approach proponents can choose to reference the literature to derive peat decay after oxidation (example Schurr et al. 2015). Additional guidance in Section 8.2.3.1 (IPCC 2006). For details on how to move to Tier 2 approach see Section 2.3.3.1 (IPCC 2006). In the case of drainage of organic soils $L_{organic}$ is replaced by CO_2-$C_{organicdrained}$ and solved using equation 2.2 (IPCC 2014): • To determine CO_2-$C_{on\text{-}site}$ use equation 2.23 with Tier 1 default EF provided in Table 2.1 (IPCC 2014) • To determine CO_2-C_{DOC} use equations 2.24 and 2.25 with Tier 1 default EF provided in Table 2.2 (IPCC 2014) • L_{fire}-CO_2-C is applied if peat is burned after drainage. Use the generic equation 2.8 (IPCC 2014) to solve for L_{Fire} for CO_2, and use the Tier 1 default CO_2-C EF in Table 2.7 (IPCC 2014) combined with the Tier 1 default fuel consumption values in Table 2.6 (IPCC 2014). Note that Non-CO_2 emission from peat burning is also calculated separately and added to the total (See Table 19).

* Document sections, tables or equations here are not contained in this document but are instead referring the reader to the IPCC 2006 and IPCC 2014 (only for drainage of organic soils and drainage and rewetting of wetlands):

IPCC 2006. 2006 IPCC Guidelines for National GHG Inventories, Chapter 2

IPCC 2014[30]. 2013 Supplement to the 2006 IPCC guidelines for National GHG Inventories, Chapter 2

Note that CO_2 emissions from these equations solve for carbon stock changes (in units of carbon) and need to be multiplied by 44/12 in order to solve for units of CO_2 gas emitted (See Section 2.2.3; IPCC 2006). Non-CO_2 emissions need to be multiplied by the Global Warming Potential[31] to convert into units of CO_2 equivalent. See additional guidance and an example calculations below.

Proponents can then calculate the post-disturbance GHG emissions from land-use change using the equations in Table 19.

Table 19: Post-disturbance GHG emissions included in direct GHG emissions from land-use change

DISTURBANCE TYPE	GHG GAS TO BE ACCOUNTED FOR	RELEVANT SECTION AND EQUATION FROM THE NATIONAL GHG INVENTORY REPORT (NIR)* OR IPCC**	CONSIDERATIONS
Flooded lands –reservoir	CO_2	Equations A3.5-20 and A3.5-21 (NIR 2020; Part 2; A3.5.6.2)	In this case, the methods used in Table 18 to determine the fate of C stocks are not used unless carbon stocks are removed from the site prior to flooding. CO_2 emissions from carbon stocks left in place and flooded are calculated using this method.
	CH_4	Equation 7.15 and 7.10 (IPCC 2019)	In this case, proponents calculate CH_4 emissions for the life of the reservoir up to 100 years. Use equation 7.15 to calculate CH_4 emissions for the first 20 years, and equation 7.10 to calculate emissions for years prior to 20 years (IPCC 2019).
Flooded lands –that are not reservoirs. Example: ditches, canals, or ponds	CH_4	Equation 7.12 (IPCC 2019)	Proponents can use Tier 1 default EFs provided in Table 7.15 (IPCC 2019), or they can develop Tier 2 emission factors.

30 http://www.ipcc-nggip.iges.or.jp/public/wetlands/

31 *Greenhouse Gas Pollution Pricing Act*

Drained inland organic soils	CH_4	Equation 2.6 (IPCC 2014)	Proponents can use Tier 1 default EFs provided in Table 2.3 and 2.4 (IPCC 2014), or they can chose to develop Tier 2 EFs(not required).
	N_2O	Equation 2.7 (IPCC 2014)	Proponents can use Tier 1 default EFs provided in Table 2.5 (IPCC 2014), or they can develop Tier 2 EFs (not required).
Burning of peat after drainage (non-CO_2 emissions from fires on drained inland organic soils)	CH_4	Equation 2.8 (IPCC 2014)	Proponents can multiply the amount of peat carbon scheduled to burn by the CH_4 EF 0.01285 for flaming, or 0.149 for smouldering fire (Bona et al. 2020)[32] (Note that CO is not considered a direct GHG emission from land-use change and does not need to be considered in this case)
Burning of biomass and/or dead organic matter (DOM)	CH_4	Section A3.5.2.1 (NIR 2020; Part 2)	If biomass and/or DOM is scheduled to be burned then the amount of fuel consumed must be estimated by proponents and then an emission ratio of 1% for CH_4 can be applied.
	CO_2	Section A3.5.2.1 (NIR 2020; Part 2)	If biomass and/or DOM is scheduled to be burned then the amount of fuel consumed must be estimated by proponents and then an emission ratio of 90% for CO_2 can be applied. (Note that CO is not considered a direct GHG emission from land-use change and does not need to be considered in this case)
	N_2O	NA	If biomass is burned then proponents must also calculate the amount of N_2O emitted by multiplying the amount of CO_2 gas (t CO_2) emitted by a factor of 0.00017 (Kurz et al. 2009)[33]

32 https://doi.org/10.1016/j.ecolmodel.2020.109164

33 https://doi.org/10.1016/j.ecolmodel.2008.10.018

*Document sections, tables or equations here are not contained in this document but are instead referring the reader to either the NIR 2020, or the IPCC 2014 or 2019.
(NIR 2020) National Inventory Report 1990-2018: GHG sources and sinks in Canada, Part 2
(IPCC 2019)[34] 2019 Refinement of the 2006 IPCC guidelines for National GHG Inventories, Vol.4, Chapter 7
(IPCC 2014) 2013 Supplement to the 2006 IPCC guidelines for National GHG Inventories, Chapter 2

Tier 2 Approach

If project proponents are required to follow a Tier 2 or 3 approach, and they choose a Tier 2 approach, they should refer to Table 18 and Table 19 and information below to determine which Tier 1 defaults are required to be replaced and which are optional to replace.

The use of the IPCC methodological framework for calculations (equations summarized in Table 18 and Table 19) is an acceptable approach if Tier 1 defaults are substituted with Tier 2 site- or regionally-specific data whenever possible. This substitution can be done by way of field sampling or appropriate values cited in the scientific literature.

If carbon stocks are estimated through field sampling, a detailed report on sampling methodologies needs to be included in the impact statement. This report should be comparable in detail to a methodology section of a peer-reviewed published journal study and should provide a scientifically robust sampling protocol, including the equipment and methods used to extract and analyze the samples, sample statistics (such as standard deviation), and other relevant information on how the data was compiled. An example of a sampling protocol is Canada's National Forest Inventory Ground Sampling Guidelines[35].

Appropriate Tier 2 values from peer-reviewed studies of carbon stocks, stock change factors or emission factors can also be used by proponents for calculations. However, literature values should only be considered if they are sampled or modelled for the same climatic region and in a comparable ecosystem. Proponents are required to demonstrate that the studies chosen are comparable based on standard Canadian ecozone classification (Ecological Stratification Working Group, 1995[36]) and have similar site characteristics as the project site. For instance, forest stands should have the same leading tree species, wetlands should be of the same wetland class as defined by the Wetland Classification System (National Wetland Working Group, 1997[37]), and croplands should be on a similar soil texture and/or soil great group (Soil Classification Working Group, 1998[38]).

Tier 3 Approach

In many cases, it may be more appropriate to use a Tier 3 approach, and in some cases, it may be the least time-consuming approach for proponents. For instance, there are a variety of Tier 3 models that can be used to calculate the GHG emissions from land-use conversion (reviews of forest carbon dynamics models are available; Kim et al. 2015[39]). The operational-scale Carbon Budget Model of the Canadian Forest Sector (CBM-CFS3; Kurz et al. 2009[40]; Kull et al. 2019; Canada 2020[41]), for example, is used in the NIR for calculations related to the Forest Land category and its spatially explicit version, the Generic Carbon Budget Model, has been applied to assess cumulative effects of disturbances on forest carbon in the oil sands region of Alberta (Shaw et al. 2021[42]). Proponents should choose a model built or validated for use in Canada and are required to provide a description of the model, data, emission factors and

[34] https://www.ipcc.ch/report/2019-refinement-to-the-2006-ipcc-guidelines-for-national-greenhouse-gas-inventories/

[35] https://nfi.nfis.org/resources/groundplot/Gp_guidelines_v5.0.pdf

[36] https://sis.agr.gc.ca/cansis/publications/manuals/1996/A42-65-1996-national-ecological-framework.pdf

[37] http://www.wetlandpolicy.ca/canadian-wetland-classification-system

[38] https://sis.agr.gc.ca/cansis/publications/manuals/1998-cssc-ed3/cssc3_manual.pdf

[39] https://doi.org/10.1080/21580103.2014.987325

[40] //doi.org/10.1016/j.ecolmodel.2008.10.018

[41] https://unfccc.int/sites/default/files/resource/can-2020-nir-14apr20_0.zip

[42] //doi.org/10.1186/s13021-020-00164-1

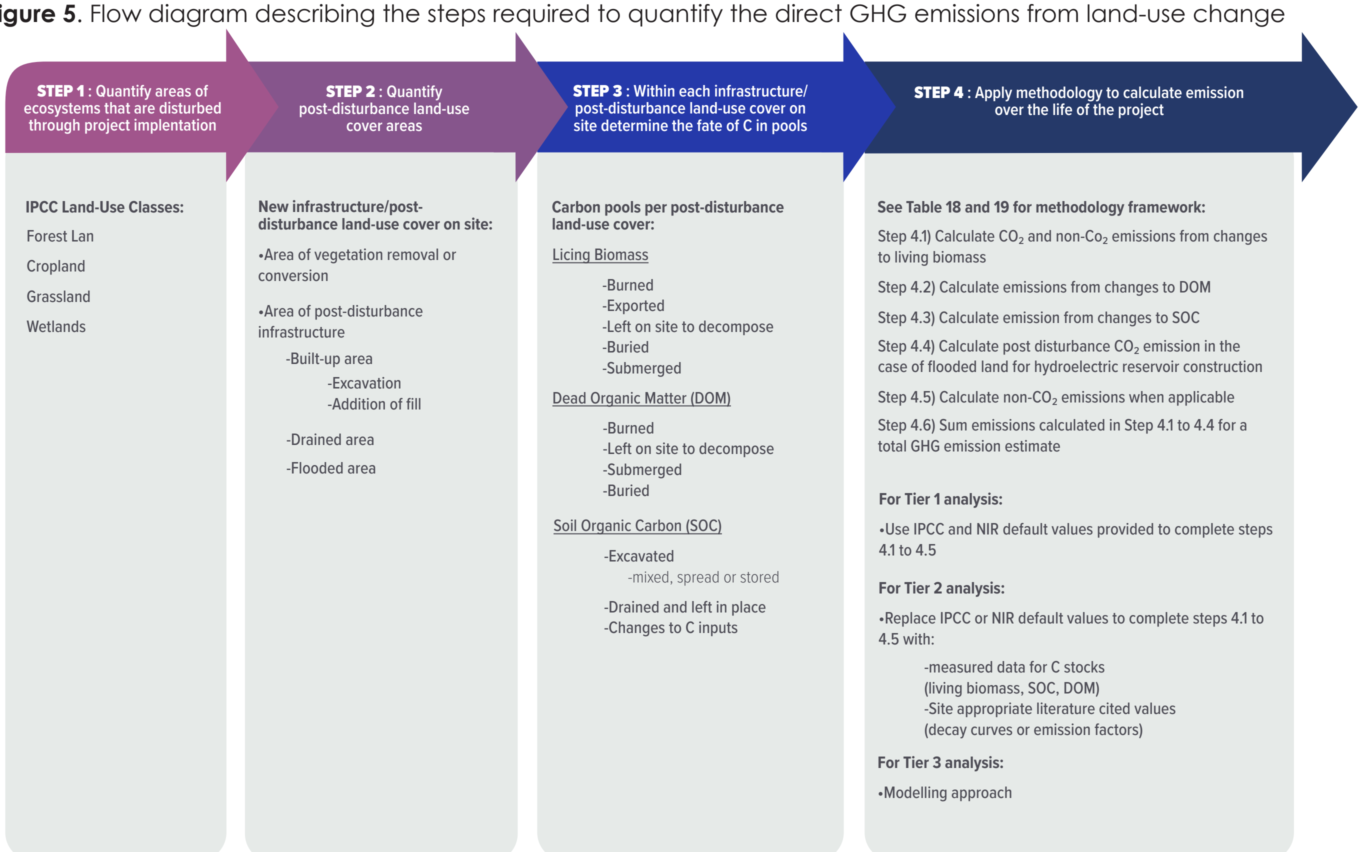
any assumptions or calibration of parameters that was required, or applied in order to derive parameters used in the modelling. Choice of the model should be justified through a demonstration of the model's ability to reproduce measured data on sites similar to site in question, or through reference to scientific publications that demonstrate the model's ability to simulate similar sites.

Land Conversions Where IPCC is not Applicable

Table 18 and Table 19 provide relevant equations and sections from the IPCC Guidelines for National GHG Inventories (IPCC 2006) or default values derived from the Canada's National GHG Inventory Report (NIR 2020) required for calculating emissions from land conversions during a project's development and over the life of the project. These IPCC equations and guidelines provide a generic framework that can be applied to multiple land-use and land management changes. However some of the IPCC methods will not specifically apply in the case of all land conversions applicable to impact assessment, and portions of the guidance are irrelevant in the case of project development. Therefore, this Annex serves to guide proponents through the relevant steps (Figure 5) and calculations (Table 21 to Table 29), while outlining the factors that need to be accounted for in calculating direct GHG emissions from land-use change.

In order to quantify the loss of carbon stocks to the atmosphere, proponents need to determine the areas of ecosystems that are disturbed by the project (Step 1), the areas of infrastructure/post-disturbance land-use cover within each ecosystem (Step 2), the fate of carbon stocks on the site, considering the type of disturbance (Step 3) and the emissions associated with the disturbance of these carbon stocks over the life of the project (Step 4) (Figure 5).

Figure 5. Flow diagram describing the steps required to quantify the direct GHG emissions from land-use change



(Section 2.1.1.2). The light blue arrow describes the first step required in the Planning Phase (Section 2.4); dark blue arrows are required for the Impact Statement Phase (Section 2.5).

Step 1: Quantify areas of ecosystems that are disturbed through project implementation

Projects may span multiple ecosystems and therefore, areas that are disturbed (i.e. converted) through project implementation must be quantified for each individual land use. Proponents must quantify the area of land in each land-use category defined in the IPCC guidelines (IPCC 2006; Chapter 3, Section 3.2): Forest Land, Cropland, Grassland and Wetlands. This information must be provided in the Planning Phase (Section 2.4).

Proponents may wish to collect additional land information at this stage that is not needed in the Planning Phase but will be required for future steps. This additional information will be used to further split the IPCC land categories into more site-specific land classifiers and will help determine appropriate values in equations later in the process. The area of each land classifier will be required on a per hectare basis. Useful land classifiers include:

For Forest Land:

- Forest stands should be identified. A forest stand is defined by forested areas that are homogeneous in relation to the following:
    - Leading tree species
    - Age-class
    - Site productivity class (or appropriate merchantable yield curves)

For Cropland:

- Type of vegetation on the land, mainly includes living biomass (see Table 20)
- Soil texture (fine, course, medium)

For Wetlands:

- Wetland class (e.g. open bog or fen)

Step 2: Quantify post-disturbance land-use cover areas

Within each land-use category identified, proponents must determine what area of land is directly impacted by the project's activities.

When lands are disturbed for the building of infrastructure, or other activities, proponents need to consider the area of land where:

- Vegetation will be removed
- Excavation will occur
- Fill will be required
- Drainage will be required
- Flooding will be required

Step 3: Within each infrastructure/post-disturbance land-use cover on site, determine the fate of carbon in pools

Within each infrastructure/post-disturbance land-use cover identified, proponents need to determine the fate of carbon pools. The carbon pools that should be considered separately are living biomass, dead organic matter (DOM), and soil organic carbon (SOC).

1. For living biomass removals, what proportion will be burned, exported as harvested wood products, left on site to decompose, buried or submerged?
2. For DOM removals, what proportion will be burned, left on site to decompose, submerged or buried?
3. For SOC, what proportion is excavated (mixed, spread or stored), drained and left in place, flooded, or fertilized (in the case of remediation, for example)?

Step 4: Apply the methodology to calculate emissions over the life of the project

Proponents calculate the emissions and removals associated with the land-use change required in the impact statement document. Proponents must decide if they are using a Tier 1, Tier 2, or Tier 3 approach to these calculations. An approach is:

- Tier 1 when IPCC defaults or default values derived from the NIR or IPCC guidance are used in the equations;
- Tier 2 when IPCC defaults are replaced with site-specific data either by measuring carbon stocks, or by using appropriate literature-cited values for decay curve or emission factors;
- Tier 3 when using a modelling approach not described in this annex. This is the most efficient approach if an appropriate Tier 3 model can be applicable (see Section 2.1.1.2 for details on requirements).

Refer to the text (Annex B; Figure 4) to determine if a Tier 1 approach will be considered sufficient, or if a higher tiered approach will be required. In the case of a Tier 2 approach, some Tier 1 defaults (when appropriate) may be used but equations must also include site- or regional-specific data (non-defaults). Throughout this section (Steps 4.1 to 4.5 below), defaults that are required to be replaced in a Tier 2 approach will be indicated, as well as those that can be optionally replaced but are not required. Regardless of the methodology used, proponents should consult the default values that are cited in these methodological reports in order to provide them with an understanding of the range of values of carbon that can be expected in different ecosystems and assure that values that are used in calculations are within expected ranges.

Step 4.1: Calculate the emissions from a change in living biomass by using the generic equation 2.15 (IPCC 2006)

To solve for equation 2.15 (IPCC 2006), sum the changes in biomass including biomass growth, biomass losses, as well as the difference between the quantity of living biomass on the site pre-disturbance and post-disturbance. While in Tier 3 modelling non-living biomass stocks may be included, in a Tier 1 or 2 approach proponents are only required to consider changes to the living biomass carbon stocks.

- For biomass growth (equations 2.9 to 2.10; IPCC 2006), proponents can assume that this is equal to zero in the case of any Land to Settlements conversions.
- For biomass losses from the removal of wood or firewood, proponents must apply the appropriate equations 2.11 to 2.13 (IPCC 2006).
    - If wood is being removed for harvested wood products ($L_{wood\text{-}removals}$) then proponents can use a Tier 1 assumption that wood products are a complete loss of carbon to the atmosphere here (100% is oxidized and emitted in the year of removal), or they can also use the harvested wood products model used in the NIR (NIR 2020; Part 2, A3.5.3) (Tier 2; optional).
    - Losses from disturbances ($L_{Disturbanace}$) (equation 2.14; IPCC 2006) represent the removal of carbon by a disturbance on lands that are not being converted (Forest Land remaining Forest Land) unrelated to a conversion to Settlements, and therefore proponents can assume that this is zero.

  - The equation 2.15 uses the Tier 1 assumption that any biomass being cleared will be instantly oxidized (if it is not removed for forest products) and included as immediate direct GHG emissions, regardless if biomass is left on-site, piled, or spread into adjacent areas. If the proponent wishes, they can instead opt to calculate a residual (i.e. over time) decomposition trajectory for biomass that is removed and treated (e.g. pilled), as long as their chosen decay curve is justified and cited.
- In a project construction the main component of the calculation of the change in biomass (equation 2.15; IPCC 2006) is the initial biomass changes from the land conversion ($\Delta C_{CONVERSION}$; equation 2.16; IPCC 2006). For this equation (2.16; IPCC 2006) the proponents will need an estimate of living biomass pre- and post-disturbance.
  - The Tier 1 default assumption is that living biomass will be equal to zero post disturbance (B_{AFTER} = 0). However, if living biomass is maintained or replanted on the project site then proponents should quantify the proportion of living biomass remaining (site-specific estimate of B_{AFTER} optional for Tier 1 and 2).
  - Baseline Tier 1 defaults for living biomass before construction (B_{BEFORE}) are supplied in Table 8.4 (IPCC 2006) for Forest Land. See Table 20 in this document for default living biomass values for Cropland. Proponents should refine these values through field surveys, inventories, or appropriate literature cited values when possible, or if Tier 2 approach is required (site-specific estimate of B_{BEFORE} required for Tier 2).

Table 20: Defaults provided for living biomass on Cropland

PROVINCE	ECOZONE	ABOVEGROUND WOODY BIOMASS (t C ha^{-1})			
		Tree	Shrubs	Orchard	Vineyard
Newfoundland	Boreal shield east	39	0.12	29	24
Nova Scotia	Atlantic maritime	38	4.6	29	24
Prince Edward Island	Atlantic maritime	37	13	29	24
New Brunswick	Atlantic maritime	37	13	29	24
Québec	Atlantic maritime	37	13	29	24
Québec	Mixedwood plains	34	0.53	29	24
Québec	Boreal shield east	39	0.12	29	24
Ontario	Mixedwood plains	30	0.35	29	24
Ontario	Boreal shield east	39	0.12	29	24
Manitoba	Boreal plains	32	1.5	29	24
Manitoba	Subhumid prairies	42	11	29	24
Saskatchewan	Boreal plains	32	1.5	29	24
Saskatchewan	Subhumid prairies	42	11	29	24
Saskatchewan	Semi arid prairies	42	14	29	24
Alberta	Boreal plains	32	1.5	29	24
Alberta	Subhumid prairies	42	11	29	24
Alberta	Montane cordillera	28	3.9	29	24
Alberta	Semi arid prairies	42	14	29	24
British Columbia	Pacific maritime	28	9.9	29	24
British Columbia	Montane cordillera	25	3.1	29	24

All values derived from Huffman et al. 2015

Total living biomass loss on cropland is calculated as the biomass per biomass type (tree, shrub, etc.) multiplied by the fraction of woody biomass on cropland in the project area.

Step 4.2: Calculate the emissions from changes in DOM by using the generic equation 2.23 (IPCC 2006)

To solve for equation 2.23 (IPCC 2006), the carbon in DOM pre-disturbance per unit area is subtracted from the DOM left in the post-disturbance land-use category per unit area (in this case Settlements), then multiplied by the area of land converted and divided by the time period for the land-use conversion.

- The Tier 1 default assumption is that all the carbon in DOM is lost due to the conversion; therefore, proponents can set the DOM carbon from the post conversion (referred to as "new" in the IPCC guidelines) land-use category (C_n) to zero. If a proportion of the DOM litter or woody debris will remain untouched on site then the default value of zero can be replaced with a more appropriate estimate (site-specific estimate of Cn optional for Tier 1 and 2).
- For the DOM carbon in the pre-disturbance land-use category (referred to as "old" in the IPCC guidelines") (C_o), proponents should determine appropriate estimates from field inventory or surveys (site-specific estimate of C_o required for Tier 2). Default Tier 1 values are provided in Table 2.2 (IPCC 2006) for carbon in litter pools for the Forest Land category but not for dead wood and will therefore still need to be determined for a Tier 1 approach on Forest Land.
- For the purpose of SACC calculations, when dealing with non-forest land use, the Tier 1 and 2 default assumption that the change in DOM is zero can be made given that the average rate of transfer to the DOM is equal to the average rate of transfer out of the DOM. Note that in this case forested wetlands should be treated as forest land (included in the Forest Land category) and changes in DOM stocks should be considered in calculations.

Step 4.3: Calculate the emissions from a change in SOC by using the generic equation 2.24 (IPCC 2006)

To solve for equation 2.24, sum the change in SOC in mineral soils, with the change in inorganic carbon from soils, and subtract the loss of SOC from organic soils. Changes in SOC are generally assumed not to be instantaneous, as in changes to biomass and DOM stocks, but they are instead calculated as emissions from soil stocks for a certain time-period (for the NIR a 20-year time-period is usually considered and can be used as a default here). For example, if a site is excavated and the soil profile is disturbed (e.g. mixed, spread or stored), then a SOC decay curve can be applied for a 20-year duration to determine how much carbon is emitted from the soil's accelerated decomposition for that period.

- Tier 1 default assumptions consider the change in inorganic carbon is equal to zero ($\Delta C_{Inorganic} = 0$). Proponents can conduct a more in-depth analysis here if they wish (site-specific estimate of $\Delta C_{Inorganic}$ optional for Tier 1 and 2; only applicable in very specific circumstances).
- Default values for SOC in the IPCC guidelines, when provided, are given up to a 30-cm depth of soil that may be inadequate for some sites and disturbances. Proponents should, in those cases, determine their own SOC stock estimates through field surveys.

Step 4.3.1: Calculate the SOC change in mineral soils by solving equation 2.25 (IPCC 2006)

Equation 2.25 (IPCC 2006) solves for the change in mineral soils for a time series which describes the annual change in SOC from time 0 to time T for a duration of time that is set to 20 years by default (T = D = 20).

- To determine the initial SOC values for time 0 (T = 0; pre-disturbance) Table 2.3 (IPCC 2006) can be used for baseline Tier 1 default calculations, but proponents should determine initial SOC values for their sites when appropriate, or if Tier 2 approach is required (site-specific estimate of SOC required for Tier 2).
- To determine SOC at time T, after 20 years, a simple linear decay can be applied through the application of a stock change factor (F_{LU}) which differs by land-use category (Figure 3), but in general, for many cases, a 20% loss of carbon from soils (and emitted to the atmosphere) can be assumed for a 20-year period. Where evidence is available proponents may modify the total fraction of carbon loss. Further, proponents should apply more appropriate non-linear decay curves from scientific literature when default stock change factors provided in the IPCC guidelines are inadequate, or when Tier 2 approach is required (site-specific decay curves required for Tier 2). Non-linear decay curves are available in the Cropland and Grassland sections of the NIR.

- F_{MG} and F_I are only applicable in cases of land reclamation or remediation where land management practices or organic matter inputs (from fertilization) are employed (site-specific F_{MG} and F_I optional for Tier 2).

Step 4.3.2: Calculate the loss of SOC from organic soils (Forest Land on organic soils (i.e. forested wetlands) and Wetlands) using equation 2.26 (IPCC 2006)

Equation 2.26 (IPCC 2006) solves for loss of SOC from organic soils. The method used to solve for $L_{organic}$ will depend on the project activity.

- If losses from organic soils are anticipated from excavation, then proponents are responsible for developing appropriate factors from field data collection, modelling, or literature cited values. Tier 1 defaults assume instant oxidation of all peats on excavation.
    - Determine the amount of peat carbon at the site through field sampling (see Vleeschouwer et al. 2010, Chambers et al. 2010[43]).
    - For a Tier 1 approach proponents can assume 100% of the peat is lost from the disturbance or excavation activity, but they can choose to determine the proportion of the peat profile that will be disturbed or excavated and provide justification for this decision. For a Tier 1 approach assume instant oxidation of the entire peat profile (complete emission to the atmosphere in the year of construction), or for Tier 2 approach proponents may choose to apply an appropriate decomposition curve (e.g. Schurr et al. 2015[44]) for a 20-year duration (corresponds to the default time frame most often used in the IPCC guidelines for residual decay of soil C) (site-specific decay curve optional for Tier 2).
- If drainage is planned on organic soils than $L_{organic}$ is be replaced with $CO_2\text{-}C_{organicdrained}$ and solved using equation 2.2 in Chapter 2 of the 2013 Wetland Supplement to the 2006 IPCC 2006 Guidelines (IPCC 2014):
    - To determine $CO_2\text{-}C_{on\text{-}site}$ use equation 2.23 with Tier 1 default emission factors provided in Table 2.1 (IPCC 2014). Proponents may choose to develop Tier 2 emission factors (site-specific Tier 2 emission factors optional)
    - $Lfire\text{-}CO_2\text{-}C$ is applied if peat is burned after drainage. Proponents can multiply the amount of peat carbon scheduled to burn by the CH_4 emissions factor 0.01285 for flaming, or 0.149 for smouldering fire (Bona et al. 2020). Proponents may choose to develop Tier 2 emission factors (site-specific Tier 2 emission factors optional). Note that non-CO_2 emission from peat burning is also calculated separately and added to the total (See Step 4.5 and Table 19).
    - To determine $CO_2\text{-}C_{DOC}$ use equations 2.24 and 2.25 with Tier 1 default emission factors provided in Table 2.2 (IPCC 2014). Proponents may choose to develop Tier 2 emission factors (site-specific Tier 2 emission factors optional).

Step 4.4: Calculate post-disturbance CO_2 emissions associated with flooded land (e.g., Hydroelectric reservoir creation)

When a project includes lands that will be flooded, for the creation of a reservoir, then post-disturbance emissions should be included in the estimate of direct GHG emissions from land-use change, as in the methodology used in the NIR (Table 19). In this case, the NIR's latest methodology is prioritized over IPCC methods. According to the NIR (NIR 2020; Part 2, A3.5.6.2), the CO_2 that is emitted from a newly flooded reservoir must be reported for the first 10 years post flooding (Blain et al. 2014). According to this method the fate of carbon stocks described in steps 4.1 to 4.3 above is only calculated if carbon stocks are removed from the reservoir site prior to flooding, and all emissions coming from carbon stocks that are left in situ when flooded are assumed to be captured in emissions from the reservoir surface. Proponents should use equation A3.5-20 and A3.5-21 (NIR 2020, Part 2) to calculate their annual emissions for the 10 years post flooding and then sum all 10 years for a total estimate of CO_2 emission.

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[43] http://www.mires-and-peat.net/pages/volumes/map07/map0707.php

[44] https://doi.org/10.1038/nature14338

Step 4.5: Calculate non-CO_2 emissions when applicable (Table 19)

There are five cases in which non-CO_2 emissions should be considered and included in the estimate of the direct GHG emission and removal from land-use change. Guidance is provided for each of these five scenarios here:

1. Non-CO_2 emission from land converted to flooded lands in the case of hydroelectric reservoirs.

Proponents are required to report on CH_4 emissions for the life of the reservoir (up to a maximum of 100 years). To obtain the CH_4 emitted in the first 20 years of the life of the reservoir, proponents must first use equation 7.15 in the 2019 refinement to the 2006 IPCC guidelines (IPCC 2019) to calculate the annual CH_4 emission rate for the first 20 years of the reservoir's life and multiply this by 20 years. Proponents must then use equation 7.10 (IPCC 2019) to calculate the annual CH_4 emission rate for a reservoir greater than 20 years old, and multiply this by 80 years (or less, if the life of the project is planned to be less than 100 years) to solve for the CH_4 emissions in the second phase of the reservoir's life. Proponents can use Tier 1 default emission factors provided by the IPCC guidelines, or they can develop site-specific emission factors[45] (site-specific emission factors are optional for Tier 1 and 2). Proponents should then add up both estimates (>20 years and ≤ 20 years) for a total CH_4 emissions for the life of the reservoir (up to 100 years).

2. Non-CO_2 emission from land converted to flooded lands that are not reservoirs such as freshwater ponds, saline ponds, canals and ditches.

Proponents are required to report on CH_4 emissions from areas of land that are flooded that are excluded from reservoir construction. Refer to equation 7.12 (IPCC 2019). Proponents can use the Tier 1 default emission factors that are provided in Table 7.15 (IPCC 2019), or develop their own site-specific Tier 2 emissions factors (site-specific emission factors optional for Tier 2).

3. Drained inland organic soils

Proponents are required to report on CH_4 emissions from areas of organic soils that are drained. Refer to equation 2.6 (IPCC 2014), and calculate the amount of CH_4 emitted for a default time period of 20 years. Proponents can use Tier 1 default emission factors that are provided in Table 2.3 and 2.4 (IPCC 2014), or they can choose to develop Tier 2 emission factors (site-specific emission factors optional for Tier 2).

Proponents must also report on N_2O emission from areas of organic soils that are drained. Refer to equation 2.7 (IPCC 2014). Proponents can use Tier 1 default emission factors that are provided in Table 2.5 (IPCC 2014), or they can choose to develop Tier 2 emission factors (site-specific emission factors optional for Tier 2).

4. Burning of peat after drainage (non-CO_2 emissions from fires on drained inland organic soils)

Proponents are required to report on CH_4 emissions from peat after drainage of organic soils. Refer to equation 2.8 (IPCC 2014). Proponents can use Tier 1 default emission factors that are provided in Table 2.7 (IPCC 2014), along with organic fuel consumption defaults provided in Table 2.6 (IPCC 2014), or they can choose to develop Tier 2 emission factors and fuel consumption values (site-specific emission factors optional for Tier 2).

While CO will also be emitted in the burning of peat, CO gas is considered an indirect GHG, and is not included in the calculation of the direct GHG emission and removals from land-use change.

[45] The development of site specific or Tier 2 emission factors requires measurements either on-site, or on ecologically similar sites using accepted, published methodologies and should be based on multiple measurement years.

5. Burning of biomass (and/or DOM)

If any proportion of carbon stocks identified in Step 3 are scheduled to be burned, then the amount of direct GHG emissions from fire (which includes CO_2, N_2O, and CH_4) must be calculated, and included in the direct GHG emissions from land-use change. Refer to Section A3.5.2.1 in the NIR (NIR 2020) that includes emission ratios for burning of biomass and DOM. First, proponents must determine the amount of carbon in biomass or DOM that will be scheduled to be burned (defaults not provided), and then the amount of CH_4, CO_2 emission can be determined through emission ratios of 1% and 90%, respectively (NIR 2020). Note that although CO will also be emitted from fire, CO is considered an indirect gas, and is not included in the calculation of the direct GHG emission and removals from land-use change.

Proponents must also include an estimate of N_2O emitted from biomass (and/or DOM) burning. To determine the amount of N_2O emitted, multiply the amount of CO_2 emitted (in units of CO_2 gas) from burning by a factor of 0.00017 (Kurz et al. 2009).

Step 4.6: Convert all carbon stock changes in each category to units of CO_2 emissions to the atmosphere and sum them to solve for the total amount of CO_2 emitted to the atmosphere from land-use change

All equations discussed above estimate a change in carbon stocks in units of carbon. Proponents need to then convert this into units of CO_2 eq being emitted to the atmosphere from each stock calculated in steps 4.1 to 4.5 above, and then sum to the total amount of CO_2 eq emitted to the atmosphere.

- All CO_2 emissions from carbon stock changes in units of carbon are multiplied by 44/12 to solve for units of CO_2 gas emitted to the atmosphere (Refer to Section 2.2.3; IPCC 2006).
- Any non-CO_2 emissions are multiplied by the Global Warming Potential[46] to convert into units of CO_2 eq. These values should be reported separately, but also added to the total units of CO_2, for a total of emissions in units of CO_2 eq.
- The IPCC methods reviewed in steps 4.1 to 4.3 are calculated based on the perspective of a stock change such that a positive value indicates an addition to the stock (and removal from the atmosphere), and a negative value indicates a removal from the stock (and an emittance to the atmosphere). However, the SACC and this technical guide takes the 'atmosphere perspective', where values should be positive when being emitted (i.e. added) to the atmosphere, and negative when being removed from the atmosphere. Therefore, all estimates of direct carbon emissions to the atmosphere from land-use change reported from this section should be calculated as positive.

Example Calculations

This section provides proponents with a step-by-step example of how to apply the methodology described above.

In this scenario, a proponent is proposing a project that includes a 40 km stretch of highway in the Boreal Plains ecozone.

[46] *Greenhouse Gas Pollution Pricing Act*

Step 1: Quantify areas of ecosystems that are disturbed through project implementation

In this scenario the project will require 80 ha of land in total. For the Planning Phase the proponent conducts a field survey to determine the amount of land area designated to each land-use category described in the IPCC guidelines:

- Area on Wetlands = 20 ha
- Area on Forest Land = 20 ha
- Area on Cropland = 40 ha
- Area on Grassland = 0 ha

Furthermore, additional information was obtained to facilitate calculations needed in future steps.

- Wetlands area is split into 10 ha of open bog and 10 ha of rich fen
- Forest Land area is split into 10 ha of young (aged 20 years) black spruce forest, and 10 ha of mature (170-year old jack pine)
- Cropland area contains annual crops with hedgerows that include tree and shrub biomass

Step 2: Within each land class, quantify post-disturbance land-use cover areas

In this scenario, for simplicity we will assume that all of the 80 ha of land will be excavated and paved, therefore vegetation will be removed for all land classes. In wetland areas a culvert is scheduled to be built to avoid impacts to wetland hydrology.

Step 3: Within each infrastructure/post-disturbance land-use cover on site determine the fate of carbon in pools

In this scenario, all living biomass and DOM will be removed from the site and piled. No harvested wood products will be removed from the site. A portion of the SOC stock will be excavated and the remainder will be paved over.

Step 4: Apply methodology to calculate emissions over the life of the project

In this step, emissions are calculated for each sub-step (4.1 to 4.6) separately for each land-use class. Before proceeding to calculations, proponents must first determine if a Tier 1 approach is adequate or if a Tier 2 or 3 approach is required. According to the decision tree (Figure 4), because the project area is 80 ha, and the proportion of the project that will impact carbon dense land (which in this scenario includes the 20 ha of wetlands, and 10 ha of mature jack pine forest) is 0.375 ((20+10)/80 = 0.375), the proponent can take a Tier 1 approach (Figure 4).

Step 4.1: Calculate the emission from a change in living biomass by using the generic equation 2.15

$$\Delta C_B = \Delta C_G + \Delta C_{CONVERSION} - \Delta C_L$$

Table 21: Calculating change in living biomass from land-use change (eq. 2.15; IPCC 2006) for Forest Land area

VARIABLE	VALUE (T C)	ASSUMPTIONS AND CALCULATIONS
ΔC_G	0	Assume zero growth
$\Delta C_{CONVERSION}$	517 t C	$\Delta C_{CONVERSION} = \sum_i \left\{ \left(B_{AFTER_i} + B_{BEFORE_i} \right) \cdot \Delta A_{TO\_OTHERS_i} \right\} \cdot CF;$ where i = jack pine and black spruce $B_{AFTERpine} = B_{AFTERspruce} = 0$; assume all living biomass will be removed and instantly oxidized from road construction $B_{BEFOREpine} = B_{BEFOREspruce} = 55$ t d.m. ha^{-1}; range of default values given in Table 4.8 (IPCC 2006) for natural forests in a boreal coniferous forest. For simplicity a median number of 55 is taken here from the range of 10 to 90 t d.m. ha^{-1}. $\Delta A_{TO_OTHERSFir} = 10$ha ; $\Delta A_{TO\_OTHERSPine} = 10$ ha $CF = 0.47$ $\Delta C_{CONVERSION} = \{((0 + 55) \cdot 10) + ((0 + 55) \cdot 10)\} \bullet 0.47 = 517$ t C
- ΔC_L	0 t C	No living biomass is removed from the site as wood products in this scenario
ΔC_B	**517 t C**	$\Delta C_B = \Delta C_G + \Delta C_{CONVERSION} - \Delta C_L$ $= 0 + 517 - 0 = 517$ t C

Table 22: Calculating change in living biomass from land-use change (eq. 2.15; IPCC 2006) for Cropland area

VARIABLE	VALUE	ASSUMPTIONS AND CALCULATIONS
ΔC_G	0	Assume zero growth
$\Delta C_{CONVERSION}$	78 t C	$\Delta C_{CONVERSION} = \sum_i \left\{ \left(B_{AFTER_i} + B_{BEFORE_i} \right) * F_{WB} \cdot \Delta A_{TO_{OTHERS_i}} \right\} \cdot CF;$ where i = cropland $B_{AFTERcropland} = 0$; assume all living biomass will be removed from road construction $B_{BEFOREpine} = 39.12$ t C ha^{-1}; from the defaults provided in Table 20 for Alberta Boreal Plains for trees plus shrub biomass. $\Delta A_{TO\_OTHERScropland} = 40$ ha $CF = 1$ (in this case 1 because defaults are provided in units of C) F_{WB}= Fraction of cropland on which living woody biomass is present, equals 5% in this case $\Delta C_{CONVERSION} = \{((0 + 39.12) \cdot 0.05)\} \cdot 40 = 78$ t C
- ΔC_L	0	No wood or firewood will be removed from the cropland area

AC_B	**78 t C**	$= \Delta C_G + \Delta C_{CONVERSION} - \Delta C_L$ $= 0 + 78 - 0 = 78$ t C

Table 23: Calculating change in living biomass from land-use change (eq. 2.15; IPCC 2006) for Wetlands area

VARIABLE	VALUE (T C)	ASSUMPTIONS AND CALCULATIONS
AC_G	0	Assume zero growth
$AC_{CONVERSION}$	17.1 t C	$\Delta C_{CONVERSION} = \sum_i \left\{ \left(B_{AFTER_i} + B_{BEFORE_i} \right) \cdot \Delta A_{TO\_OTHERS_i} \right\} \cdot CF$; where i = Bog, Fen $B_{AFTERBog} = 0$; $B_{AFTERFen} = 0$, assume all living biomass will be removed and instantly oxidized from road construction $B_{BEFOREBog} =$ 2.3 t d.m. ha^{-1} ; $B_{BEFOREFen} =$ 1.34 t d.m. ha^{-1} NOTE: no IPCC Tier 1 defaults are provided for initial biomass in Wetlands therefore a literature search was performed for comparable sites. These values came from an open bog and a shrubby rich fen in the Boreal Plains (Szumigalski et al. 1995) $\Delta A_{TO\_OTHERSBog} =$ 10ha ; $\Delta A_{TO\_OTHERSFEN} =$ 10 ha CF = 0.47 $\Delta C_{CONVERSION} = \{((0 + 2.3) \cdot 10) + ((0 + 1.34) \cdot 10)\} \bullet 0.47 = 17.1$ t C
$-AC_L$	0	No living biomass will be removed from the wetland area
AC_B	**17.1 t C**	$= \Delta C_G + \Delta C_{CONVERSION} - \Delta C_L$ $= 0 + 17.1 - 0 = 17.1$ t C

Step 4.2: Calculate the emission from changes in DOM by using the generic equation 2.23 (IPCC 2006)

$$\Delta DOM = \frac{(C_n - C_o) \bullet A_{on}}{T_{on}}$$

Table 24: Calculating change in dead organic matter from land-use change (eq. 2.23; IPCC 2006) for Forest Land

VARIABLE	VALUE	ASSUMPTIONS AND CALCULATIONS
C_n	0	Assume zero; all DOM is lost
C_o	JP: 0.57 t C ha^{-1} BS: 0.51 t C ha^{-1}	Table 2.2 only supplies litter stock for needleleaf evergreen forests but dead wood is not included, therefore a literature search was performed: From Preston et al. 2006: Stands in the same ecoregion and lead species were found to have the following values for foliar litter + woody litter: Jack pine (JP) cited as having 112.6 g d.m. m^{-2} = 0.57 t C ha^{-1} Black spruce (BS) cited as having 102.8 g d.m. m^{-2} = 0.51 t C ha^{-1}
A_{on}	JP: 10 ha BS: 10 ha	Area of land in this scenario in jack pine and black spruce
T_{on}	1 y	Default of 1 year duration assume for carbon losses
ΔDOM	**10.8 t C**	$=\frac{(C_n - C_o) \bullet A_{on}}{T_{on}}$ JP : = ((0-0.57) · 10)/1 = -5.7 t C BS: = ((0-0.51) · 10)/1 = - 5.1 t C Total = -10.8 t C Note: Numbers are negative here because they are losses to the carbon DOM stock, but here we convert to a positive number by convention in order to take the atmosphere perspective (i.e. addition to the atmosphere).

Table 25: Calculating change in dead organic matter from land-use change (eq. 2.23; IPCC 2006) for Cropland

VARIABLE	VALUE	ASSUMPTIONS AND CALCULATIONS
C_n	0	Assume zero; all DOM is lost
C_o	0	Assume zero for non-forested categories
A_{on}	40	Area of total Cropland
T_{on}	1 y	1 year duration assume for carbon losses
ΔDOM	**0 t C**	$=\frac{(C_n - C_o) \bullet A_{on}}{T_{on}}$ = ((0-0)·40)/1 = 0 t C

Table 26: Calculating change in dead organic matter from land-use change (eq. 2.23; IPCC 2006) for Wetlands

VARIABLE	VALUE	ASSUMPTIONS AND CALCULATIONS
C_n	0	Assume zero; all DOM is lost
C_o	0	Assume zero for non-forested categories. In this scenario, we are assuming an open bog or fen, therefore there will be little to no tree litter at the site and therefore this is a valid assumption for this case. If wetlands are forested then efforts should be made to determine a reasonable DOM pool value here and treated as in the Forest Land category.
A_{on}	1000 ha	Area of land in this scenario in Wetlands land-use category
T_{on}	1y	Default of 1 year duration assumed for carbon losses
ΔDOM	**0 t C**	$=\frac{(C_n - C_o) \bullet A_{on}}{T_{on}}$ = ((0-0)·1000)/1 = 0 t C

Step 4.3: Calculate the direct GHG emissions from land-use conversions is to calculate the emissions from a change in SOC by solving for the generic equation 2.24 (IPCC 2006)

$$\Delta C_{soils} = \Delta C_{Mineral} - L_{organic} + \Delta C_{Inorganic}$$

Table 27: Calculating change in soil organic carbon from land-use change (eq. 2.24; IPCC 2006) for Forest Land

VARIABLE	VALUE (T C)	ASSUMPTIONS AND CALCULATIONS
$\Delta C_{Mineral}$	234 t C	Jack pine forest is on mineral soil, which we assume to be on a sandy soil. $\Delta C_{Mineral} = \frac{(SOC_0 - SOC_{(0-T)})}{D}$ $SOC = \sum(SOC_{REF} \bullet F_{LU} \bullet F_I \bullet F_{MG} \cdot A)$ SOC_{REF}= 117 t C ha-1 (using table 2.3; Sandy soil in boreal) F_{LU} = 0.8 (default given for paving Section 8.3.3.2; IPCC 2006) $F_I = F_{MG}$ = 1 (not applicable here) A = 10 ha Solve for SOC at end of conversion (i.e. apply stock change factor): SOC_0 = (117 · 0.8 · 1 · 10) = 936 t C Solve for SOC before conversion (i.e. no change, only initial reference soil value needed) $SOC_{(0-T)}$ = (117 · 10) = 1170 t C D = 20 years (assume 20 year duration by default) $\Delta C_{Mineral} = \frac{(SOC_0 - SOC_{(0-T)})}{D}$ $\Delta C_{Mineral}$ = (936 – 1170)/20 = -11.7 t C y^{-1}

		IMPORTANT: this equation solves for the amount of carbon lost per year (annual rate of loss). In this case we need to solve for the total amount of C lost within the 20 year period therefore we then multiply by the duration (20 years): Total C lost = 11.7 t C y-1 · 20 = -234 t C
$-L_{organic}$	13,060 t C	Black spruce Forest Land is on organic soils. In this scenario, a culvert will be built to avoid impacts to wetland hydrology, however some organic soil in the form of peat will be removed during construction. There are no IPCC defaults for the initial SOC stocks therefore a published database was used (Zoltai et al. 2000): Forested site on organic soil (forested bog): 1,306 t C ha^{-1} Multiply with area: 1306 t C ha^{-1} · 10 ha = 13,060 t C We use the Tier 1 IPCC default of 100% loss from paving and assume instant oxidation
$\Delta C_{Inorganic}$	0	Assume zero
ΔC_{soils}	**13,294 t C**	$= \Delta C_{Mineral} - L_{organic} + \Delta C_{Inorganic}$ = -234 – 13,060 + 0 = -13,294 t C Note: Numbers are negative here because they are losses to the carbon DOM stock, but here we convert to a positive number by convention in order to take the atmosphere perspective (i.e. addition to the atmosphere).

Table 28: Calculating change in soil organic carbon from land-use change (eq. 2.24; IPCC 2006) for Cropland

VARIABLE	VALUE (T C)	ASSUMPTIONS AND CALCULATIONS
$\Delta C_{Mineral}$	400 t C	$\Delta C_{Mineral}=\frac{(SOC_0-SOC_{(0-T)})}{D}$ $SOC = \sum(SOC_{REF} \bullet F_{LU} \bullet F_I \bullet F_{MG} \cdot A)$ SOC_{REF}= 50 t C ha^{-1} (Tier 1 default taken from Table 2.3, Chapter 2, Volume 4 IPCC 2006 guidelines, value for HAC soils) F_{LU} = 0.2 (default given for excavation Section 8.3.3.2 IPCC 2006, 20% loss of soil stocks) $F_I = F_{MG}$ = 1 (not applicable here) *A* = 40 ha Solve for SOC at end of conversion (i.e. apply stock change factor): SOC_0 = 50 · 0.8 · 1 · 40) = 1,600 t C Solve for SOC before conversion (i.e. no change, only initial reference soil value needed) $SOC_{(0-T)}$ = (50 · 40) = 2,000 t C D = 20 years (assume 20 year duration by default) $\Delta C_{Mineral}=\frac{(SOC_0-SOC_{(0-T)})}{D}$ $\Delta C_{Mineral}$ = (1600- 2000)/20 = -20 t C y^{-1} IMPORTANT[47]: this equation solves for the amount of carbon lost per year (annual rate of loss). But in this case we need to solve for the total amount of C lost within the 20 year period therefore we then multiply by the duration (20 years): Total C lost = -20 t C y-1 · 20 = -400 t C
$-L_{organic}$	0	Assume zero
$\Delta C_{Inorganic}$	0	Assume zero
ΔC_{soils}	**400 t C**	$= \Delta C_{Mineral} - L_{organic} + \Delta C_{Inorganic}$ = 400 - 0 + 0 = 400 t C Note: Numbers are negative here because they are losses to the carbon DOM stock, but here we convert to a positive number by convention in order to take the atmosphere perspective (i.e. addition to the atmosphere).

[47] In this example, the assumption is that the project duration is greater than 20 years and therefore the total SOC loss over 20 years is included in the sum, so the annual emission conversion seems redundant. However, if emissions were occurring over a shorter period, total emissions should be calculated for the shorter period using the annual emission multiplied by the period over which emissions are occurring.

Table 29: Calculating change in soil organic carbon from land-use change (eq. 2.24; IPCC 2006) for Wetlands

VARIABLE	VALUE (T C)	ASSUMPTIONS AND CALCULATIONS
$\Delta C_{Mineral}$	0	The bog and fen wetlands in this scenario are on organic soils (i.e. not mineral wetlands).
$-L_{organic}$	23,610 t C	In this scenario, a culvert will be built to avoid impacts to wetland hydrology, however some organic soil in the form of peat will be removed during construction. IPCC Tier 1 defaults are not available for the initial SOC stocks therefore a published database was used (Zoltai et al. 2000): Mean value for open bogs in boreal plains = 1199 t C ha^{-1} Mean value for rich fens in boreal plains = 1162 t C ha^{-1} Multiply with area: Open bogs in boreal plains = 1199 t C ha^{-1} · 10ha = 11,990 t C Rich fens in boreal plains = 1162 t C ha^{-1} *· 10ha = 11,620 t C We use the Tier 1 IPCC default of 100% loss from excavation and assume instant oxidation. Total = 11,990 + 11,620 = 23,610 t C
$\Delta C_{Inorganic}$	0	Assume zero
ΔC_{soils}	**23,610 t C**	$= \Delta C_{Mineral} - L_{organic} + \Delta C_{Inorganic}$ = 0 – **23,610** + 0 = **-23,610** t C Note: Numbers are negative here because they are losses to the carbon DOM stock, but here we convert to a positive number by convention in order to take the atmosphere perspective (i.e. addition to the atmosphere).

Steps 4.4. Calculate post-disturbance emissions associated with flooded land (Hydroelectric reservoir creation)

No calculations are required in this scenario because lands will not be flooded and biomass residues will not be burned.

Step 4.5. Calculate non-CO_2 emissions

No calculations are required in this scenario because lands will not be flooded and biomass residues will not be burned.

Step 4.6. Convert all carbon stock changes in each category to units of CO_2 emissions to the atmosphere and sum them to solve for the total amount of CO_2 emitted to the atmosphere from land-use change.

Sum all changes to carbon stocks, for all land-use categories, calculated in steps 4.1 to 4.5:

Forest Land: $\Delta C_{FL} = \Delta C_{Biomass} + \Delta C_{DOM} + \Delta C_{SOC}$
$= 517 + 10.8 + 13{,}294 =$ **13,822 t C**

Cropland: $\Delta C_{CL} = \Delta C_{Biomass} + \Delta C_{DOM} + \Delta C_{SOC}$
$= 78.2 + 0 + 400 =$ **478 t C**

Wetlands: $\Delta C_{WT} = \Delta C_{Biomass} + \Delta C_{DOM} + \Delta C_{SOC}$
$= 17.1 + 0 + 23{,}610 =$ **23,627 t C**

Total Emissions: $\Delta C = \Delta C_{FL} + \Delta C_{WT} + \Delta C_{CL}$
$= 13{,}822 + 23{,}627 + 478 =$ **37,927 t C**

Convert to units of CO_2:

37,327 t C x 44/12 = **139,065 t CO_2**

Note: Because in this scenario there are zero non-CO_2 emissions estimated, we do not need to convert to CO_2 eq.

Conclusion to example:

In this scenario, it is estimated that the direct GHG emissions from land-use change will result in approximately **139,065** t CO_2 gas emitted to the atmosphere over the life of the project.

Annex C: Provincial Grid Electricity Emission Intensity Projections

Table 30: Grid electricity emission intensity by province

AREA	UNITS	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Alberta	t CO_2 eq/GWh	295.3	235.4	211.5	191.4	193.1	175.7	178.2	181.8	184.8	187.0	185.5
British Columbia	t CO_2 eq/GWh	1.5	1.4	1.4	1.4	1.3	1.3	1.2	1.2	1.2	1.1	1.1
Manitoba	t CO_2 eq/GWh	0.9	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
New Brunswick	t CO_2 eq/GWh	360.7	293.8	290.8	291.9	293.5	281.3	282.9	311.6	312.6	313.5	215.6
Newfoundland	t CO_2 eq/GWh	168.2	157.0	103.5	98.5	96.0	100.0	94.6	89.9	76.5	70.4	67.1
Northwest Territory	t CO_2 eq/GWh	242.6	245.6	237.1	215.1	166.1	48.8	55.7	63.1	61.9	56.4	52.8
Nova Scotia	t CO_2 eq/GWh	732.0	604.8	469.7	459.2	453.6	410.0	440.3	441.3	441.4	442.1	178.0
Nunavut	t CO_2 eq/GWh	898.8	903.5	876.7	843.3	766.4	632.1	625.7	617.2	631.1	625.8	617.2
Ontario	t CO_2 eq/GWh	16.3	24.2	31.9	52.5	39.9	56.9	39.8	39.1	28.8	23.0	16.4
Prince Edward Island	t CO_2 eq/GWh	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.6	4.6	4.6	4.6
Quebec	t CO_2 eq/GWh	1.9	1.8	1.8	1.8	1.9	1.9	2.1	2.2	2.5	2.7	2.9
Saskatchewan	t CO_2 eq/GWh	404.3	387.4	315.6	323.1	257.3	263.7	266.1	253.5	212.7	200.4	192.3
Yukon Territory	t CO_2 eq/GWh	56.9	66.4	58.8	62.2	70.8	76.0	40.0	42.8	48.9	55.0	61.3

Note:

1. Emission intensities do not include CO_2 emissions from combustion of biomass and renewable natural gas.
2. For information on how these emission intensities were developed see Section 2.1.2.1.

Annex D: Further guidance on the methodology used to quantify the impact to carbon sinks

To obtain the values needed to calculate the *CSI* for Equation 5, the following 4 steps are required:

- Step 1: Determine the project land area with carbon sink capacity for each land-use class and disturbance activity for each phase of the project
- Step 2: Determine the natural carbon sink capacity for the appropriate time interval
- Step 3: Determine the impact of the project on the carbon sink capacity of the site for the appropriate time interval
- Step 4: Calculate the sum of carbon sink lost during the project

Step 1: Determine the project land area with carbon sink capacity for each land-use class and disturbance activity for each phase of the project

Proponents should refer to IPCC Guidelines for National GHG Inventories (IPCC 2003[48]; IPCC 2006[49]; IPCC 2014[50]; IPCC 2019[51]) for definitions of land-use categories: Forest Land, Cropland, Grassland, Wetlands, and Other Lands (see Chapter 3, Section 3.2, IPCC 2006). For the purpose of quantifying a project's impact to carbon sinks under the SACC, only lands categorized by the IPCC guidelines (IPCC 2006) as being Forest Land or Wetlands are considered as carbon sinks. Therefore, proponents require an estimated area of lands impacted by the project within the Forest Land and Wetlands category.

IPCC land-use categories Wetlands and Forest Land should be split further into meaningful classes (*i* and *j* in Equation 5) to provide a refined estimate of the carbon stocks and rates of carbon sequestration. For instance, wetland areas should be split into relevant wetland classes such as bogs or fen, as defined by the Wetland Classification System (National Wetland Working Group, 1997), and Forest Land area can be split into leading tree species, age class, and productivity class. Post-disturbance land-use cover can also be used to define the type of impact that is occurring on the landscape and as a consequence split high impact areas, areas that will be left intact during a project's construction or operational phase, or areas that will be restored or remediated in a project's decommissioning phase. The post-disturbance land-use cover will determine the intensity of the impact to carbon sinks across the project's footprint.

Step 2: Determine the natural carbon sink capacity and the appropriate time interval for each land class and phase of the project

The methodology required to determine the natural carbon sink capacity of land for the appropriate time interval will differ depending on the ecosystem, whether Forest Land or Wetlands land-use category.

48 https://www.ipcc-nggip.iges.or.jp/public/gpglulucf/gpglulucf_files/GPG_LULUCF_FULL.pdf

49 https://www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html

50 http://www.ipcc-nggip.iges.or.jp/public/wetlands/

51 https://www.ipcc.ch/report/2019-refinement-to-the-2006-ipcc-guidelines-for-national-greenhouse-gas-inventories/

Step 2.1 Forest Land

The generic method for calculating the natural carbon sink capacity of Forest Land area is to determine an appropriate annual carbon accumulation rate and the corresponding time interval over which the forest would be accumulating carbon. The annual carbon accumulation rate can be determined by solving for the negative slope of the line between the current age ($Age_{current}$) and biomass ($BM_{current}$) of a forest stand, and the age and biomass at which maximum carrying capacity (MCC) of a forest stand is reached ($Age_{MCC,}$ and $BM_{MCC,}$ respectively), such that:

Equation 6: Natural annual carbon accumulation rate of a forest

$$NATFLUX_{FOREST} = \frac{BM_{MCC} - BM_{Current}}{Age_{MCC} - Age_{Current}}$$

Where:

$NatFlux_{forest}$ is the natural annual carbon accumulation rate of a forest (t C ha^{-1} y^{-1})
BM_{MCC} is the living tree biomass at MCC (t C ha^{-1})
$BM_{current}$ is the living tree biomass at the forest stand's current age (t C ha^{-1})
Age_{MCC} is the age at which MCC is reached (years)
$Age_{current}$ is the current age of the forest (years)

Maximum carrying capacity is defined as the point at which the above-ground biomass of the forest stand reaches a plateau in growth (or in some cases, a decline) as the stand matures. When trees are mature the rates of carbon uptake by growing trees decreases, and carbon uptake associated with tree growth tends to be balanced by carbon released by the decay of dead organic matter. For some mature forests, the MCC may have already been surpassed and the proponent may in that case calculate a positive *NatFlux* rate (C source instead of a sink). In that case *NatFlux* rate can be excluded from the calculation of the impact to carbon sinks. However justification of the omission of the land area should be provided. Note that, while the proponent may not be reporting a loss of a carbon sink in these cases, the removal of these mature stands will result in important direct GHG emissions that proponents are required to include (See Section 2.1.1.2).

Default values of tree biomass and corresponding stand ages at MCC classified by province or territory, ecozone, leading tree species, and site class are provided in Annex E.

When defaults are inadequate and additional information is required (see Section 4.3; Figure 3), proponents have three options:

1. Use site-specific biomass curves (BM_{MCC}) determined by field inventory.
2. Use measured annual carbon flux rates directly by taken from Eddie Covariance flux tower measurements. Due to the high inter-annual variability of Eddie Covariance flux measures, if proponents choose this approach then monitoring of the site would be required at a minimum of three years (or 3 growing seasons) of data are required and ideally a longer period . Alternatively, published Eddie Covariance CO_2 flux data from a comparable forest stand collected by qualified personnel, for at least three years or growing seasons, can also be used from sources such as FLUXNET Canada Research Network[52]. Proponents are required to demonstrate that the data chosen are in comparable forest stand based on standard Canadian ecozone classification (Ecological Stratification Working Group, 1995), and have similar site characteristics such as the same leading tree species, productivity class, soil type and landscape position. Also, to maintain consistency with the default method, if the forest is older than the age at which MCC is reached, the proponent can assume a zero rate of annual carbon accumulation. In addition, when choosing an appropriate flux estimate proponents must consider that fluxes will vary with age class. Therefore, a representative flux estimate that is appropriate for the age of the forest stand being considered needs to be determined. Given that this is the most complex option and requires significant

[52] https://daac.ornl.gov/FLUXNET/guides/FLUXNET_Canada.html

pre-project monitoring, this method should only be considered in very specific circumstances when the proponent has previous on-site measurements or comparable data as defined above.

3. Employ an appropriate Tier 3 model that tracks carbon fluxes to the atmosphere (i.e. net ecosystem exchange) on Forest Land. Proponents should choose a model built or validated for use in Canada and are required to provide a description of the model, data, emission factors and any assumption that were required, or applied in order to derive values used in modelling (see a review of models in Kim et al. 2015). The CBM-CFS3 (Kurz et al. 2009, Kull et al. 2019; Canada 2020), for example, is used for developing the Forest Land NIR estimates. The GCBM (Shaw et al. 2021) has been applied in a pilot study area of the oil sands region of Alberta that has experienced a large number of disturbances. Application of models should be carried out by qualified personnel who have a complete understanding of the procedures required to produce and validate model results.

Once the appropriate annual carbon accumulation rate is established proponents must determine the corresponding time interval. For Forest Land, the default time interval is determined first by calculating the difference between the age at MCC (Age_{MCC}) with the current age of the forest ($Age_{current}$) (i.e. the amount of time to reach MCC):

- If this difference is greater than the 100 year time-frame then proponents can use a default of 100 years as the time interval for calculations ($T = 100$).
- If this difference is less than or equal to 100 year time-frame then proponents should use the amount of time it will take to reach MCC ($T = Age_{MCC} – Age_{current}$).

Step 2.2 Wetlands

As in Forest Land, the carbon sink capacity of land area categorized as Wetlands is calculated as the site appropriate annual carbon accumulation rate ($NatFlux_{wetlands}$) and corresponding default time interval ($T_{wetlands}$). In the case of Wetlands, the default time interval will in all cases be set to 100 years ($T = 100$).

To determine an appropriate annual carbon accumulation rate proponents can choose between two approaches:

1. Annual total carbon flux method
2. Sum of annual CO_2 and CH_4 flux method

Developing accurate estimates of long-term trends using measurements of fluxes require multiple measurement years. If the proponent performs multiple measurement years on the site in question, or an ecologically similar site, the annual total carbon flux method is preferred.

Approach 1) Annual total carbon flux approach

If proponents choose to take the 'annual total carbon flux approach' then an appropriate annual rate of total carbon sequestered into organic soil (i.e. peat) stocks is required. The annual rate of carbon sequestration of a wetland area is determined through C-dating (C^{14} or Pb^{210}) of peat layers to solve for the long-term rate of carbon accumulation.

Default values of long-term carbon accumulation rates of peat are provided in Table 31.

Table 31: Defaults provided for natural C accumulation rate (NatFlux) for the 'total C approach'

ECOZONE	MEAN ANNUAL LONG-TERM C ACCUMULATION RATE (t C ha^{-1})		
	Bog	Rich Fen	Poor Fen
Atlantic Maritime	0.21 (0.06)	*0.33 (0.05)	*0.21 (0.06)
Boreal Plains	0.11 (0.03)	0.33 (0.05)	0.31 (0.06)
Boreal Shield	0.24 (0.03)	*0.33 (0.05)	*0.31 (0.06)
Hudson Plains	0.15 (0.02)	*0.33 (0.05)	*0.31 (0.06)
Mixedwood Plains	0.12 (na)	*0.33 (0.05)	*0.12 (na)
Taiga Plains	0.22 (0.02)	*0.33 (0.05)	*0.13 (0.01)
Taiga Shield	0.13 (0.01)	*0.33 (0.05)	0.13 (0.01)

From an unpublished data compilation from Michelle Garneau 2021. Long-term rates were calculated from 500 to 2000 years before present. Standard error is provided in parentheses. Asterisk (*) indicates a data gap in which a proxy was chosen based on the most similar peatland type or region. na: not available

For a site or regional specific calculation approach, when required (refer to Figure 3), proponents have two options:

1. Conduct a field survey that includes the collection of peat cores (see Vleeschouwer et al. 2010[53]) and perform C-dating analyses (see Piotrowska et al. 2011[54], LeRoux et al. 2010[55]) to solve for a long-term annual peat accumulation rate. If choosing this method proponents must omit the most recent layers of peat (first 400 to 500 years) unless an appropriate decay model is used to account for future decomposition of recent peat layers (see Young et al. 2019[56]).

2. Employ an appropriate Tier 3 model that estimates carbon fluxes to the atmosphere in Wetlands based on measured parameters of the site being disturbed used as input to the model. Proponents should choose a model built or validated for use in Canadian conditions. Choice of the model should be justified through a demonstration of the model's ability to reproduce measured data on sites similar to site in question, or through reference to scientific publications that demonstrate the model's ability to simulate similar sites.

In absence of a validated model, measurements are preferred. However, if a model is available and has been validated for similar ecological conditions to the site, the use of the modelling approach may be the preferred option for the proponent if they judge that the analytical burden is reduced through the application of the model. The proponent is nonetheless required to use site-specific data collected from the site (such as soil carbon stocks) for use in the modelling exercise as defined by the required model inputs.

Approach 2) Sum of annual CO_2 and CH_4 flux approach

If proponents choose to use this approach then separate annual rates of carbon flux for CO_2 and CH_4 gas are required and summed for a total carbon accumulation rate. Annual CO_2 or CH_4 flux rates can be determined through field data collected using Eddie Covariance flux towers or through flux chambers.

For preliminary calculations, default national values are provided in Table 32.

53 http://www.mires-and-peat.net/

54 http://www.mires-and-peat.net/pages/volumes/map07/map0710.php

55 http://www.mires-and-peat.net/pages/volumes/map07/map0708.php

56 https://doi.org/10.1038/s41598-019-53879-8

Table 32: National defaults provided for natural carbon accumulation rate (NatFlux) for the 'sum of annual CO_2 and CH_4 flux approach'

WETLAND CLASS	CO_2 (t CO_2-C ha^{-1} y^{-1})	CH_4 (t CH_4-C ha^{-1} y^{-1})
Bog	-0.7	0.059
Fen	0*	0.063
*Due to uncertainty associated with annually-scaled fen carbon accumulation rates, it is assumed here that their net carbon balance is neutral Data source: values in this table are calculated using unpublished raw data from the Canadian Forest Service (CFS, NRCan), that were compiled for publication in Webster et al. 2018.		

When a more detailed approach must be used as per Figure 5 of Section 4.3, proponents have two options:

1. Measure the annual carbon flux rate directly by taking Eddie Covariance flux tower or flux chamber measurements. Due to the high inter-annual variability of flux measures, if proponents choose this approach then a minimum of three years (or 3 growing seasons) of data are required. Alternatively, published flux data for a comparable wetland site can also be used from sources such as FLUXNET Canada. Proponents are required to demonstrate that published data chosen are in a comparable wetland site based on standard Canadian ecozone classification (Ecological Stratification Working Group, 1995), and wetland class as defined by the Wetland Classification System (National Wetland Working Group, 1997[57]). Comparability of the site should be based on a characterization of the wetland type, and such ecological considerations as vegetation, site productivity, soil characteristics and depth, and water table depth.

2. Employ an appropriate Tier 3 model that estimates carbon fluxes to the atmosphere in Wetlands based on measured site specific parameters. Proponents should choose a model built or validated for use in Canadian conditions (see a review of models in Yu et al. 2001[58] and Farmer et al. 2011[59]). Choice of the model should be justified through a demonstration of the model's ability to reproduce measured data on sites similar to site in question, or through reference to scientific publications that demonstrate the model's ability to simulate similar sites.

Once the natural annual flux of CO_2 and CH_4 of the wetland area is determined, proponents must convert these individual emission rates to units of carbon and then sum for a total carbon accumulation rate. To convert CO_2 gas flux (t CO_2 gas ha^{-1} y^{-1}) into units of carbon (t CO_2-C ha^{-1} y^{-1}) multiply by the molar ratio 12/44. To convert CH_4 gas flux (t CH_4 ha^{-1} y^{-1}) into units of carbon (t CH_4-C ha^{-1} y^{-1}) multiply by the molar ratio 12/16. Once CO_2 and CH_4 flux are converted to units of C, then they can be summed for a total carbon accumulation rate. Note that CO_2-C will be sequestered, while CH_4-C is emitted, therefore the net carbon change is CO_2-C sequestered minus CH_4-C emitted. Further, this calculation takes the 'stock perspective' (i.e. how much carbon is accumulated in carbon pools), rather than an 'atmosphere perspective', (i.e. what is the impact on atmospheric warming) therefore, the global warming potential of CH_4 does not need to be accounted in quantifying the impact to carbon sinks.

Step 3: Determine the impact of the project on the carbon sink capacity of the site

The methodology required to determine the post-disturbance carbon sink capacity of land for the appropriate time interval will differ depending on a project's planned activities.

- The default assumption is that the project will entirely interrupt the capacity of the land to act as a carbon sink for areas directly disturbed by project construction (e.g. infrastructure, excavation, highway construction). Therefore, in this case, the post-disturbance flux rate *(PostDFlux)* rate can be assumed zero, since the carbon sink capacity of the land is completely lost *(PostDFlux = 0)*.

[57] http://www.wetlandpolicy.ca/canadian-wetland-classification-system

[58] https://www.lehigh.edu/~ziy2/pubs/Yu2001EcoModl.pdf

[59] https://doi.org/10.1016/j.cosust.2011.08.010

- Proponents can choose to perform a more detailed analysis by calculating a partial loss of a carbon sink when deemed appropriate. In this case, proponents must justify that the carbon sink is not completely lost, and provide a comprehensive step-by-step report on their calculations of the *PostDFlux* including their assumptions and any peer-reviewed studies used.
- If site restoration is planned (see Section 3.4.3 and 3.5.3), where the project proponent anticipates that the natural ecosystem will be completely restored to its original state, then proponents can assume that the natural carbon sink capacity of land (*NatFlux*, determined in step 2) is re-established (*PostDflux* = *NatFlux*). In this scenario, it is important to note that restored wetland or forest stands will take time to re-establish their carbon sink capacity. Only then can proponents assume that the post-disturbance flux is back to the original natural carbon flux rate (Nugent et al. 2019[60]).
- If mitigation measures such as reclamation, remediation, or afforestation activities are planned (see Section 3.4.3 and 3.5.3), where the natural ecosystem has recovered some carbon sink capacity but is not fully restored to its original state, then proponents are responsible for determining appropriate post-disturbance flux rates (*PostDFlux*) either based on measured flux rates or literature-cited flux rates in comparable sites with similar treatments or through a validated Tier 3 modelling approach.

Section 4.1 describes the steps required to quantify the impact of a project on carbon sinks. This annex provides further guidance by demonstrating an example of such a calculation.

Example Calculations

In this example, a project involves the construction of a 40 km stretch of highway in the boreal plains.

Step 1: Determine the project land area with carbon sink capacity for each land-use class and disturbance activity for each phase of the project

In this scenario the project will require 80 ha of land in total. For the Planning Phase the proponent conducts a field survey to determine the amount of land area designated to each land-use category described in the IPCC guidelines:

- Area on Forest Land = 20 ha
- Area on Cropland = 40 ha
- Area on Grassland = 0 ha
- Area on Wetlands = 20 ha

Furthermore, additional land classifiers and disturbance activities are also obtained at this step, in order to facilitate calculations in future steps (Table 33).

Table 33: Land classifiers and disturbance activities for example scenario

IPCC LAND-USE CATEGORY	DISTURBANCE ACTIVITIES FOR EACH PHASE OF THE PROJECT (J)*	ADDITIONAL LAND CLASSIFIERS (I)	AREA (HA)
Wetland	Highway (paved)	Bog	10
Wetland	Highway (paved)	Fen	10
Forest Land	Highway (paved)	Black spruce leading species, age class = 20 years, tree biomass = 10 t C ha^{-1}	10
Forest Land	Highway (paved)	Jack pine leading species; age class = 150 years; tree biomass = 50 t C ha^{-1}	10

60 https://doi.org/10.1088/1748-9326/ab56e6

*Note that in this scenario there is only one phase of the project which is paving, once the highway is constructed the pavement will be permanent therefore there are no other phases of the project to consider

Before proceeding to the next step, the proponent must consult Figure 3, Section 4.3 in order to determine if using default values will be adequate for calculations, or if site- or regional-specific values will be required. In this scenario, the project area is 80 ha, and the proportion of land with high carbon sink capacity (which in this scenario includes the land classified as bog, as well as the young black spruce forested land) is 0.25 ((10 ha+10 ha)/80 ha) = 0.25), which means that provided defaults will be adequate[61] in this case (Figure 3).

Step 2: Determine the natural carbon sink capacity for the appropriate time interval

In this step proponents must calculate the natural carbon accumulation rate (*NatFlux)* and the corresponding time interval and area for each combination of land classifier (i) and disturbance type or project phase (j) classified above.

i = bog, j = paved

For this scenario we chose to apply the 'Sum of annual CO_2 and CH_4 flux approach' and consult Table 32 to determine the national default estimate of annual carbon accumulation rate for bogs. Note that Table 31 provides defaults for natural carbon accumulation rate if the 'Total carbon approach' is chosen.

$NatFlux_{bpg,\ paved\ CO2}$ = -0.7 t C-CO_2 ha^{-1} y^{-1}
$NatFlux_{bog,\ paved\ CH4}$ = 0.059 t C-CH_4 ha^{-1} y^{-1}
Total $NatFlux_{bog,paved}$ = -0.7 + 0.059 = -0.641 t C ha^{-1} y^{-1}

$NatFlux_{bog,\ paved}$ = -0.641 t C ha^{-1} y^{-1}
$T_{bog,\ paved}$ = 100 y
$A_{bog,\ paved}$ = 10 ha

i = fen, j = paved

For this scenario we chose to apply the 'Sum of annual CO_2 and CH_4 flux approach' and consult Table 32 to determine the national default estimate of annual carbon accumulation rate of fens.

$NatFlux_{fen,\ paved\ CO2}$ = 0 t C-CO_2 ha^{-1} y^{-1}
$NatFlux_{fen,\ paved\ CH4}$ = 0.063 t C-CH_4 ha^{-1} y^{-1}
Total $NatFlux_{fen,paved}$ = 0 + 0.063 = 0.063 t C ha^{-1} y^{-1}

In this scenario we have calculated fens as a source of C, and since proponents are only responsible for quantifying impacts to carbon sinks, we will omit the land area covered in fens in the calculation of *CSI* for this scenario.

i = black spruce, j = paved

Using default method for Forest Lands we apply Equation 6.

Consult Annex E for defaults for black spruce in boreal plains, Age_{MCC} = 100 and BM_{MCC} = 85 t C ha^{-t}, and Table 33 for data collected by the proponent in this scenario, $Age_{current}$ = 20 and $BM_{current}$ = 10 t C ha^{-t}.

[61] In the case that default values are not being used, the proponent should either measure the values that the default values represent using the methodologies outlined in Section 4.1, or estimate the lost sink through a Tier 3 approach using a validated model (e.g., Kim et al. 2015).

$NatFlux_{blackspruce,\ paved,}$= -(85-10)/(100-20) = -0.94 t C ha^{-1} y^{-1}
$Age_{MCC\ -\ Agecurrent}$ = 100 – 20 = 80 is less than 100[62], therefore Tblackspruce, paved = 80
$A_{blackspruce}$ = 10 ha

i = jack pine, j = paved

Using default method for Forest Land we apply Equation 6.

Consult Annex E for defaults on Age_{MCC} = 170 and BM_{MCC} = 55 t C ha^{-t}, and Table 33 for data collected by the proponent in this scenario, $Age_{current}$ = 150 and BM_{curren}t = 57 t C ha^{-t}.

$NatFlux_{jackpine,\ paved}$ = -(55-50)/(170-150) = -0.25 t C ha^{-1} y^{-1}
Age_{MCC} - $Age_{current}$ = 170 – 150 = 20 is less than 100, therefore $T_{jackpine,\ paved}$ = 20
$A_{jackpine,\ paved,}$ = 10 ha

Step 3: Determine the impact of the project on the carbon sink capacity of the site for the appropriate time interval

In this scenario there is only one disturbance type, a highway that will be paved. For this type of disturbance we will use the default assumption that all carbon sink capacity of the land is completely interrupted and assume that the post-disturbance rate will be reduced to zero:

$PostDFlux_{bog,\ paved}$ = 0
$PostDFlux_{blackspruce,\ paved}$ = 0
$PostDFlux_{jackpine,\ paved}$ = 0

Step 4: Calculate the carbon sink impact of the project

Apply Equation 5 (Section 4.1). Note that in this scenario there is only one disturbance type and phase of the project (j), therefore only land class (i) is considered:

Calculate CSI for i = bog, j = paved:
$CSI_{bog,\ paved}= (NatFlux - PostDFlux)_{bog,\ paved} \cdot T_{bog,\ paved} \cdot A_{bog,\ paved}$
$CSI_{bog,\ paved} = (-0.641 – 0) \cdot 100 \cdot 10 = -641\ t\ C$

Calculate CSI for i = blackspruce, j = paved:
$CSI_{blackspruce,\ paved}= (NatFlux - PostDFlux)_{blackspruce,\ paved} \cdot T_{blackspruce,\ paved} \cdot A_{blackspruce,\ paved}$
$CSI_{blackspruce,\ paved}= (-0.94 – 0)_{blackspruce,\ paved} \cdot 80 \cdot 10 = -750\ t\ C$

Calculate CSI for i = jackpine, j = paved:
$CSI_{jackpine,\ paved} = (NatFlux - PostDFlux)_{jackpine,\ paved} \cdot T_{jackpine,\ paved} \cdot A_{jackpine,\ paved}$
$CSI_{jackpine,\ paved}= (-0.25 – 0)_{jackpine,\ paved} \cdot 20 \cdot 10 = -50$

Calculate CSI total:
CSI = -641 – 750 - 50
CSI = -1,441 t C

The estimated carbon sink impact in this scenario is an estimated lost potential to sequester 1,441 t carbon from the atmosphere.

62 If the Age_{MCC} - $Age_{current}$ is greater than 100 than T is set at 100.

Annex E: Default Values of Tree Biomass and Age at Maximum Carrying Capacity

Table 34: Default values of age and living biomass at maximum carrying capacity (MCC), used in equation 6 to calculate the C sink impacts of development on Forest Land.

PROVINCE OR TERRITORY	ECOZONE	SPECIES	SITE INDEX (M)	AGE AT MCC (A_{mcc})	LIVE BIOMASS AT MCC (BM_{mcc}) (t C ha^{-1})
NL	BSE	balsam fir	na	58	85
LB	TSE	birch	5.0 to 9.9	104	61
LB	TSE	birch	na	98	61
LB	TSE	birch	10.0 to 14.9	49	89
LB	TSE	birch	15.0 to 19.9	64	82
LB	BSE	birch	5.0 to 9.9	104	62
LB	BSE	birch	na	100	66
LB	BSE	birch	10.0 to 14.9	49	89
LB	BSE	birch	15.0 to 19.9	63	94
NS	AM	red maple	17.06	88	85
NS	AM	red spruce	15.38	89	67
NS	AM	red spruce	13.6	63	35
NS	AM	red spruce	11.85	68	26
NB	AM	maple	15.0 to 19.9	48	73
NB	AM	hardwood species	5.0 to 9.9	57	68
NB	AM	hardwood species	10.0 to 14.9	66	68
NB	AM	hardwood species	20.0 to 24.9	63	81
NB	AM	hardwood species	na	55	71
QC	AM	sugar maple	na	197	149
QC	MP	red maple	na	196	95
QC	BSE	sugar maple	na	192	105
QC	BSE	birch	na	149	65
ON	BSW	poplar	25.0 to 29.9	194	94
ON	BSW	spruce	5.0 to 9.9	73	72
ON	BSW	balsam fir	20.0 to 24.9	238	121
ON	BSW	spruce	10.0 to 14.9	123	98
ON	BSW	pine	15.0 to 19.9	132	89
ON	MP	softwood species	20.0 to 24.9	236	139
ON	MP	poplar	25.0 to 29.9	116	81
ON	BSE	maple	10.0 to 14.9	123	87
ON	BSE	spruce	5.0 to 9.9	72	73
ON	BSE	maple	15.0 to 19.9	133	103
MB	BSW	poplar	15.0 to 19.9	94	55
MB	BSW	poplar	na	167	59
MB	BSW	poplar	5.0 to 9.9	56	33
MB	BSW	pine	10.0 to 14.9	59	38
MB	BP	poplar	15.0 to 19.9	187	65
MB	BP	pine	10.0 to 14.9	185	37
MB	BP	hardwood species	10.0 to 14.9	46	32

MB	SHP	poplar	5.0 to 9.9	63	39
MB	SHP	poplar	10.0 to 14.9	38	35
MB	SHP	poplar	15.0 to 19.9	168	63
SK	BSW	hardwood species	na	162	50
SK	BSW	poplar	15.0 to 19.9	178	63
SK	BSW	spruce	5.0 to 9.9	204	62
SK	BSW	pine	10.0 to 14.9	216	65
SK	BP	poplar	15.0 to 19.9	96	65
SK	BP	pine	10.0 to 14.9	170	55
SK	BP	spruce	5.0 to 9.9	116	52
SK	BP	red maple	17.06	199	49
SK	SHP	hardwood species	na	59	27
SK	SHP	poplar	15.0 to 19.9	67	49
SK	SHP	pine	10.0 to 14.9	231	45
AB	TP	black spruce	na	108	69
AB	TSW	black spruce	na	154	83
AB	BSW	black spruce	na	111	57
AB	BP	black spruce	na	100	85
AB	SHP	black spruce	na	119	111
AB	MC	poplar/aspen	na	150	111
AB	SAP	black spruce	na	114	121
BC	TP	lodgepole pine	5.0 to 14.9	151	108
BC	TP	lodgepole pine	15.0 to 24.9	130	127
BC	TP	lodgepole pine	25.0 to 34.9	128	175
BC	TP	black spruce	5.0 to 14.9	186	92
BC	TP	black spruce	15.0 to 24.9	160	16
BC	TP	black spruce	15.0 to 34.9	140	268
BC	BP	lodgepole pine	5.0 to 14.9	160	94
BC	BP	lodgepole pine	15.0 to 24.9	141	130
BC	BP	lodgepole pine	25.0 to 34.9	128	182
BC	BP	black spruce	5.0 to 14.9	185	101
BC	BP	black spruce	15.0 to 24.9	158	107
BC	BP	black spruce	25.0 to 34.9	139	261
BC	BC	lodgepole pine	5.0 to 14.9	160	103
BC	BC	lodgepole pine	15.0 to 24.9	142	145
BC	BC	lodgepole pine	25.0 to 34.9	126	195
BC	BC	black spruce	5.0 to 14.9	186	113
BC	BC	black spruce	15.0 to 24.9	158	195
BC	BC	pine	10.0 to 14.9	137	283
BC	PM	lodgepole pine	15.0 to 24.9	205	149
BC	PM	lodgepole pine	15.0 to 24.9	200	290
BC	PM	lodgepole pine	15.0 to 24.9	195	421
BC	PM	lodgepole pine	15.0 to 34.9	160	460
BC	MC	lodgepole pine	5.0 to 14.9	188	92
BC	MC	lodgepole pine	15.0 to 24.9	171	139
BC	MC	lodgepole pine	25.0 to 34.9	151	191
BC	MC	lodgepole pine	15 to 24.9	167	143

BC	MC	lodgepole pine	25.0 to 34.9	154	203
BC	MC	lodgepole pine	0 to 5	190	35
YT	TP	trembling aspen	15.0 to 19.9	208	171
YT	TC	lodgepole pine	5.0 to 14.9	215	109
YT	TC	trembling aspen	5.0 to 9.9	189	81
YT	BC	trembling aspen	20.0 to 24.9	128	107
YT	BC	trembling aspen	15.0 to 19.9	191	159
YT	BC	trembling aspen	na	214	88
YT	BC	lodgepole pine	10.0 to 14.9	215	109
YT	PM	trembling aspen	na	215	88
NT	TP	hardwood species	na	184	39
NT	TSW	black spruce	15.0 to 34.9	222	58
NT	BP	trembling aspen	15.0 to 19.9	115	61
NT	TC	poplar	5.0 to 9.9	114	58
NT	BC	hardwood species	na	206	93

Province/Territory	Province or territory of Canada. NL: Newfoundland, LB: Labrador, NS: Nova Scotia, NB: New Brunswick, QC: Quebec, ON: Ontario, MB: Manitoba, SK: Saskatchewan, AB: Alberta, BC: British Columbia, YT: Yukon Territory, NT: Northwest Territories
Ecozone	Terrestrial Ecozones of Canada. BSE: Boreal Shield East, TSE: Taiga Shield East, AM: Atlantic Maritimes, MP: Mixedwood Plains, BSW: Boreal Shield West, BP: Boreal Plains, SHP: Subhumid Praries, TP: Taiga Plains, TSW: Taiga Shield West, MC: Montane Cordillera, SAP: Semiarid Prairies, BC: Boreal Cordillera, PM: Pacific Maritimes, TC: Taiga Cordillera.
Species	Common name of leading (dominant) tree genus, species, or type (hardwood/softwood) if specified
Site Index	Stand height (m) at index age of 50 years (or 100 years for Yukon Territory). na: not available. Site index determined from CANFI2001 for most data (Available at : https://www.for.gov.bc.ca/hfd/library/documents/bib106168.pdf), or for Nova Scotia and British Columbia from provincial data.
Age at MCC (A_{mcc})	Age at which maximum carrying capacity of the forest stand is reached, defined as the point at which the above-ground biomass of the forest stand reaches a plateau in growth as the stand matures.
Live biomass at MCC (BM_{mcc}) (t C ha^{-1})	Live tree biomass at maximum carrying capacity, defined as the point at which the above-ground biomass of the forest stand reaches a plateau in growth as the stand matures.

Annex F: Methodology For Upstream GHG Assessment Part A

Step 1: Identify the Upstream Activities and Products

Using the upstream GHG emissions definitions and scopes defined in Section 5.1, identify the upstream activities associated with the project and the energy products and diluents that could generate upstream GHG emissions.

Step 2: Determine Possible Scenarios (Realistic and Conservative)

A project may evolve over its operation phase. Energy products may be sourced from different regions, and quantities and mixes may fluctuate with time. Proponents must prepare and report the upstream GHG emissions using scenarios that are realistic and conservative. The scenarios will represent the range of possible upstream emissions that may be experienced. Possible examples for scenarios include:

- changes in the mix of the received inputs (i.e. receiving more bitumen versus conventional oil);
- changes in the region where the energy products are sourced.

Data sources and assumptions used for the scenarios must be described and provided.

Step 3: Determine the Upstream GHG Emission Intensity(ies) Time Series for Each Activity

The proponent must determine the annual GHG emission intensity for each upstream activity for each scenario identified in Steps 1 and 2, from the expected start year of operations until 2050 or the end of the project's operation phase, whichever comes first. If the emission intensities are not available past certain years in the time series, the emission intensities can be assumed to remain constant or the proponent can make specific assumptions.

The time series emission intensities for each activity allows the emissions forecast to reflect the variation of a product's emission intensities over time. The emissions intensities can be derived by dividing the annual GHG emissions resulting from upstream activities of a given product by the annual production of that product.

Domestic and non-domestic emission intensities are presented below. Where the technical guide does not include specific emission intensities for a certain activity, proponents are encouraged to use emission intensities from publicly available data, providing data, assumptions, scopes (what is included and excluded) and an explanation on how the data is applicable in the context of an upstream GHG emissions assessment. The data should be relevant to the specific input sources (if the specific basins/sources are known), while accounting for the unique characteristics of the resource, such as including the emissions from the production, processing, and transmission equipment to supply the energy products to the project.

Emission intensities must be verifiable, recent and relevant to the region while reflecting sources of products that are expected to be used or transported by the project, with realistic scenarios representing various sources of energy products supply mixes.

Domestic Upstream GHG

To quantify annual upstream GHG emissions from Oil and Gas projects, the proponent can use projected emission intensities from Canada's Oil and Gas sector, developed by ECCC in Table 35 below. While these projections were developed in 2020, the annual update to emission intensity projections are expected to be available in the open data tables of Canada's Greenhouse Gas Emissions Projections webpage[63,] and the most recent data should be used.

The projections include time series of emission intensities that reflect emissions reductions expected from policies and

63 Open data tables Refer to folder: Current-Projections-Actuelles/Energy-Energie/ Grid-O&G-Intensities-Intensites-Reseau-Delectricite-P&G/

measures over time. These projections were developed using ECCC's Energy, Emissions and Economy Model for Canada (E3MC) built off NIR 2020, and were calculated as a ratio of total forecasted GHG emissions and the projected levels of production for each Oil and Gas sub-sector. Total GHG emissions included in this calculation are from sources such as combustion, fugitives, sequestration, and cogeneration. Moreover, ECCC's Oil and Gas production forecast is aligned to the Canada Energy Regulator's 2020 Energy Future report's Reference Scenario projections.

ECCC also developed transmission emission intensities for crude oil and natural gas. These emission intensities were calculated using the total forecasted GHG emissions associated with transmission divided by the national amount of product transported based on the Statistics Canada Table 25-10-0058-01 (natural gas, formerly CAMSIM 129-0006) and Table 25-10-0056-01 (oil, formerly CANSIM 133-0006). To develop projections for the national amount of product transported, the production projection trends were used. These emissions intensities are provided in Table 36.

Table 35: Oil & Gas Intensities (Includes indirect emissions from electricity purchased and sold to grid)

UPSTREAM ACTIVITY	UNITS	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
CSS Oil Sands	kg CO_2 eq / bbl eq	113.2	113.9	113.1	112.8	112.1	111.7	110.9	110.3	109.7	109.0	108.4
Frontier Oil Mining	kg CO_2 eq / bbl eq	31.8	31.5	30.6	31.4	31.9	30.5	30.7	27.4	29.3	26.5	31.8
Heavy Oil Mining	kg CO_2 eq / bbl eq	68.3	65.5	62.0	60.0	58.2	53.3	53.0	52.7	52.0	51.7	51.5
Light Oil Mining	kg CO_2 eq / bbl eq	72.9	69.7	67.9	62.0	61.0	58.6	58.3	57.5	57.0	56.7	56.2
Oil Sands Mining	kg CO_2 eq / bbl eq	32.0	31.9	30.8	30.7	30.6	30.8	30.7	30.5	30.4	30.2	30.1
Oil Sands Upgraders	kg CO_2 eq / bbl eq	55.2	54.9	54.5	54.3	54.1	53.8	53.6	53.4	53.2	53.0	52.8
Primary Oil Sands	kg CO_2 eq / bbl eq	28.0	27.6	27.3	27.1	27.0	26.7	26.5	26.4	26.3	26.2	26.1
SAGD Oil Sands	kg CO_2 eq / bbl eq	64.8	65.0	64.5	64.3	63.9	63.6	62.2	61.0	60.0	59.2	58.3
Petroleum Products	kg CO_2 eq / bbl eq	28.6	28.6	28.3	28.2	28.1	28.0	27.8	27.7	27.5	27.4	27.4
Natural Gas Production & Processing	kg CO_2 eq / bbl eq	39.0	38.6	36.8	33.8	33.3	32.4	31.7	30.7	30.7	30.5	30.3
LNG Production	kg CO_2 eq / bbl eq	-	-	-	-	10.6	10.5	10.5	10.4	10.4	10.3	10.3
Coal Mining	kg CO_2 eq / TJ	2 513	2 459	2 445	2 284	2 309	2 291	2 283	2 291	2 281	2 276	2 269

Notes:

- : no data.

Table 36: Transmission Emission Intensity

PRODUCT	UNITS	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Crude Oil Pipeline Transmission	kg CO_2 eq/bbl	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Natural Gas Transmission	kt CO_2 eq/bcf	1.63	1.57	1.56	1.52	1.49	1.46	1.44	1.42	1.41	1.40	1.38

For heavier crude oil projects that add diluents to facilitate movement through the pipeline, there will be upstream emissions associated with the total diluent volume transported. The type of and quantity of heavy crude oil being transported will impact the quantity of diluent required. The proportion of diluent needed for blending varies for different categories of heavy crude oil. Table 37 provides the volume proportion of diluent needed for various crude oil categories. The emission intensities for Light Oil Mining in Table 35 can be used as a proxy for the emission intensities for diluents. Proponents should also consider if recycled diluent will be used in the project and the expected proportion of recycled diluent over the lifetime of the project. Emission intensity of recycled diluent can be assumed to be 0. Diluent supply and disposition projections are available through CER's Canada's Energy Future series. Proponents are encouraged to refer to the most recent Canada's Energy Future report, and the corresponding data available at Pentanes Plus - Canada.ca (cer-rec.gc.ca)[64] to assist in determining the proportion of recycled diluent that the project may utilize. It should be noted that the net imports cited in the data also includes recycled diluent. If specific information on the proportion of net imports that is recycled is not available for the project, the proponent can assume a proportion of 50%.

Table 37: Volume Proportions for Diluent in Heavy Crude Oil

CRUDE OIL CATEGORY	DILUENT PROPORTION[65]
Conventional Heavy	8%
Cyclic Steam Stimulation (CSS) Heavy	30%
Steam-Assisted Gravity Drainage (SAGD) Heavy	30%
Mined Bitumen	20%

64 Ensure that the Pentanes Plus appendix is selected

65 Trans Mountain Pipeline ULC – Trans Mountain Expansion Project, Review of related Upstream Greenhouse Gas Emissions Estimates

Non-Domestic Upstream GHG

Upstream GHG emissions that occur internationally, outside of Canada, are required to be included in the assessment but reported separately from the domestic emissions. The emission intensities provided in this section for non-domestic upstream activities are developed using the lifecycle approach. Since a time series is not provided for the emission intensities for the non-domestic upstream activities, the proponent can either assume the emissions provided are the same until 2050, or make assumptions in developing the upstream emissions time series, but provide rationale for the proposed time series.

The sections below provide upstream emission intensities for crudes imported from different countries and emission intensities for natural gas imported from various basins in the United States. Recognizing that the emission intensities for non-domestic upstream activities may not have the same scope as the domestic upstream activities, the values are provided as a reference.

Crude Oil

Table 38 provides the upstream emission intensities for crudes imported from different countries. These emissions intensities represent emissions occurring from well to refinery gate located in Houston, Texas. These EIs can be used to represent emissions occurring from well to refinery gate located in Canada.

The provided EIs are calculated based on the Oil-Climate Index (OCI) study[66] (OCI, 2018). The Carnegie Endowment for International Peace has developed the OCI as a way to rank petroleum crude oils by their well-to-wheels life cycle GHG emissions. The OCI[67] uses the Oil Production GHG Emissions Estimator (OPGEE) to calculate GHG emissions for crude oil from extraction to transport to the refinery inlet. OPGEE includes emissions estimates for oil sands upgrading, better classified as a form of partial crude oil refining as opposed to being part of oil extraction. The activities included for each stage is provided in Table 39.

Table 38: Upstream emission intensities of imported crudes.

COUNTRY	UPSTREAM EMISSION INTENSITY (g CO_2 eq/MJ) ON HHV[68] BASIS
Algeria	21.05
Azerbaijan	6.91
Colombia	7.84
Denmark	7.69
Kazakhstan	6.94
Nigeria	18.16
Norway	9.76
Saudi Arabia	6.37
United Kingdom	10.91
United States	16.39

66 https://oci.carnegieendowment.org/

67 Updated emission intensities may be available through *OCI Review Report (Advisian, 2020), At the time of publication of this guide, the review of the report is incomplete. The report may be available upon request. Contact* ec.escc-sacc.ec@canada.ca for additional information.

68 Values in the OCI are provided on a lower heating value (LHV) basis. These values were therefore converted to a higher heating value basis (HHV) using a conversion factor of 1.064 HHV/LHV from OPGEE. As the OCI provides carbon intensity values for specific crudes or crude blends as opposed to carbon intensity values by country, an average was taken in the cases where a country produced several crudes. In the case of the U.S. where a large number of crudes are produced, the Canadian International Merchandise Trade Database was used to identify which crudes were likely imported into Canada in 2016.

Table 39: Activities included in non-domestic upstream operations to estimate GHG emissions of crude oil

STAGE	ACTIVITIES
Preproduction	• Well construction • Water withdrawal and discharge during well operations • Well completions
Production/ Extraction	• Crude production and extraction: venting, fugitives and flaring and combustion/ land use
Processing	• Surface processing: venting, fugitives and flaring and combustion/ land use
Transmission	• Crude transport
Other	• Maintenance: venting, fugitives and flaring and combustion/ land use • Other small sources (miscellaneous) • Offsite emissions credit/debit

Natural Gas

Canada trades natural gas mostly with the United States (Canada Energy Regulator, 2018).

The upstream EIs for natural gas imported from various basins in the United States are listed in Table 40. Values are sourced from the *Life Cycle Analysis of Natural Gas Extraction and Power Generation: National Energy Technology Laboratory (NETL) report (Skone et al., 2016). The EIs include GHG emissions from the preproduction (drilling and completion), production, processing and transmission*[69] of natural gas. The activities included for each stage is provided in Table 41.

Table 40: Upstream emission intensities (g CO_2 eq/MJ) of imported natural gas from various basins in the United States

NATURAL GAS BASIN IN THE UNITED STATES	EMISSION INTENSITY[70] (g CO_2 eq /MJ) ON HHV BASIS
Marcellus	12.7 (Preproduction: 3.5, Production: 2.5, Processing: 2.9, Transmission: 3.8)
Barnett	10.5 – 13.5
Eagleford	11.1
Fayetteville	15.6
Bakken	26.6
Haynesville	11.8

69 The total natural gas combustion and fugitive emissions is a function of pipeline distance, which was estimated at an average distance of 971 km. This distance is based on the characteristics of the entire transmission network and delivery rate for natural gas in the United States (Skone et al., 2016).

70 Based on the document Upstream, Natural Gas Emission Intensity Review of Existing Literature. 2018. Prepared by Greenpath Energy Ltd.

Table 41: Activities included in non-domestic upstream operations to estimate GHG emissions of natural gas

STAGE	ACTIVITIES
Preproduction	• Well construction • Water withdrawal and discharge during well operations • Well completions
Production/ Extraction	• Liquid unloading (with and without plunger) • Workovers • Fugitive emissions (connections, flanges, valves, open-ended lines) • Pneumatic device
Processing	• Pneumatic device for processing • Acid gas removals • Dehydration • Liquid separations • Compressors at the processing facilities
Transmission	• Pipeline construction and operation • Pipeline fugitives • Any other vent and fugitive sources in extraction and processing

Step 4: Calculate the Range of Annual Upstream GHG Emissions for Each Product

The annual upstream GHG emissions must be quantified for each product and scenario identified in Steps 1 and 2. The approach described in this guide consists of applying emission intensities to the maximum product throughput or capacity (for new projects), or the maximum additional throughput or capacity (for replacement or expansion projects).

Determining the product's annual upstream GHG emissions associated with each scenario is completed by aggregating the calculated GHG emissions from each product activity, as described in Equation 7 below.

Equation 7: Annual Product Upstream GHG Emissions

$$\text{ANNUAL PRODUCT UPSTREAM GHG EMISSIONS} = \sum_{j}^{n}\left[EI_j \times PROD_j\right]$$

Where

j is the distinct activity for the product
n is the total number of activities for the product
EI_j is the emission intensity of the activity identified, either developed by the proponent or provided in this guide (see Step 3)
$PROD_j$ is the annual upstream production associated with activity j.

Step 5: Calculate the Range of Annual Upstream GHG Emissions for the Project

Determining the project's annual upstream GHG emissions associated with each scenario is completed by aggregating the calculated GHG emissions from each energy product or diluent from Equation 7 above.

The resulting values from each scenario will be compared in Step 6.

Step 6: Present, Compare and Validate Results

The information that must be included in the Part A of the upstream GHG assessment are as follows:

- A description of the upstream activities associated with the project;
- A description of the identified scenarios, their assumptions and justifications;
- Annual domestic and non-domestic upstream emission intensities on a per-unit basis of each product and activity, until the end of the project's operation phase or until 2050, whichever comes first. For example, an LNG facility would report the emission intensity as t CO_2 eq per t of LNG, and an oil pipeline would report the emission intensity as kg CO_2 eq per bbl.
- Domestic and non-domestic upstream GHG emissions from the expected start year of operations until 2050 or the end of the project's operation phase, whichever comes first, for each scenario (domestic and non-domestic emission must be reported separately); and,
- Range of annual upstream emissions (based on the different scenarios) from the expected start year of operations until 2050 or the end of the project's operation phase, whichever comes first.

The upstream GHG assessment Part A must also include information on data sources, methodologies, justifications for scenario, assumptions and limitations, as well as an explanation of why the upstream GHG emissions may fluctuate year over year, as needed. When possible, the emission intensities and GHG estimates developed should be validated against estimates developed using other available emission and production projections (such as the GHGenius Model, the BC Shale Scenario Tool or other comparable project reviews).