DRAFT
Local Government Operations Protocol
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California Air Resources Board
California Climate Action Registry
ICLEI - Local Governments for Sustainability
The Climate Registry

List of Tables

List of Figures

Abbreviations and Acronyms

AB 32	Assembly Bill 32, California State
ASTM	American Society for Testing and Materials
Btu	British thermal unit(s)
CARB	California Air Resources Board
CCAR	California Climate Action Registry
CEMS	Continuous Emissions Monitoring System
CFC	chlorofluorocarbon
CH_4	methane
CHP	combined heat and power
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
COP	coefficient of performance
CWCCG	California Wastewater Climate Change Group
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
EU ETS	European Union Emission Trading Scheme
g	gram(s)
GHG	greenhouse gas
GWP	global warming potential
HCFC	hydrochlorofluorocarbon
HFC	hydrofluorocarbon
HHV	higher heating value
HSE	health, safety, and environment
HV/AC	heating, ventilating, and air conditioning
IAPWS	International Association for the Properties of Water and Steam
IPCC	Intergovernmental Panel on Climate Change
ISO	International Organization for Standardization
J	joule
JPA	Joint Powers Authority
kg	kilogram(s)
kWh	kilowatt-hour(s)
lb(s)	pound(s)

LHV	lower heating value
LPG	liquefied petroleum gas
MMBtu	one million British thermal units
mpg	miles per gallon
MSW	municipal solid waste
mt	metric ton(s)
MWh	megawatt-hour(s)
N_2O	nitrous oxide
NMVOC	non-methane volatile organic compound(s)
NO_x	oxides of nitrogen
ODS	ozone depleting substances
PFC	perfluorocarbon
SF_6	sulfur hexafluoride
T&D	transmission and distribution
TCR	The Climate Registry
UNFCCC	United Nations Framework Convention on Climate Change
WBCSD	World Business Council for Sustainable Development
WERF	Water and Environment Research Foundation
WRI	World Resources Institute
WWTP	wastewater treatment plant

PART I Introduction

Background

In response to a scientific consensus linking greenhouse gas (GHG) emissions from human activities to global climate change[1], many local governments are looking inwards to identify opportunities to reduce GHG emissions not only from their communities, but also within their own operations. Local governments can inventory the emissions from their operations in order to track their performance and ensure that their actions do reduce GHG emissions. This GHG inventory, also referred to as a “carbon footprint”, is the foundation of any actions to address climate change. Complete, consistent and accurate measurement enables local governments to assess their risks and opportunities, track their progress, and create a strategy to reduce emissions in a quantifiable and transparent way.

The Local Government Operations Protocol (Protocol) is designed to provide a standardized set of guidelines to assist local governments in quantifying and reporting greenhouse gas (GHG) emissions associated with their government operations.

The Protocol was developed in partnership by the California Air Resources Board (CARB), California Climate Action Registry (CCAR), and ICLEI – Local Governments for Sustainability (ICLEI), in collaboration with The Climate Registry and dozens of stakeholders. Through this Protocol, the partners have sought to enable local governments to measure and report greenhouse gas emissions associated with government operations in a harmonized fashion. The Protocol facilitates the standardized and rigorous inventorying of GHG emissions, which can help track emissions reduction progress over time and in comparison to GHG reduction targets.

The Protocol provides the principles, approach, methodology, and procedures needed to develop a local government operations greenhouse gas emissions inventory. It is designed to support the complete, transparent, and accurate reporting of a local government’s GHG emissions. The Protocol guides participants through emissions calculation methodologies and reporting guidance applicable to all U.S. local governments.

The Protocol is meant to be a “program neutral” guidance document available for use by any local government engaging in a GHG inventory exercise. It brings together GHG inventory guidance from a number of existing programs, namely the guidance provided by ICLEI to its Cities for Climate Protection Campaign members over the last 15 years, the guidance provided by the California Registry through its General Reporting Protocol, and the guidance from ARB’s mandatory GHG reporting regulation under AB 32.If a local government is a member of either ICLEI or CCAR, they are subject to program-specific requirements in addition to the general guidance embodied in the Protocol. ICLEI and California Registry members should refer to Chapter 14 and Chapter 16 of this Protocol to ensure their inventories are being prepared in accordance with program-specific requirements. This structure allows all U.S. local governments, regardless of program affiliation, to utilize a single guidance document when developing GHG emissions inventories.

Guidance on the development of community-scale GHG emissions inventories will be provided in a subsequent document.

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[1] See Intergovernmental Panel on Climate Change, *The Physical Science Basis*, Fourth Assessment, Working Group I Report, 2007.

Purpose

The purpose of the Local Government Operations Protocol is to:

- Enable local governments to develop emissions inventories following internationally recognized GHG accounting and reporting principles defined below with attention to the unique context of local government operations;
- Advance the consistent, comparable and relevant quantification of emissions and appropriate, transparent, and policy-relevant reporting of emissions;
- Enable measurement towards climate goals;
- Promote understanding of the role of local governments in combating climate change; and
- Help to create harmonization between GHG inventories developed and reported to multiple programs.

The Protocol is a tool for accounting and reporting GHG emissions across a local government's operations. Reductions in emissions are calculated by comparing changes in a local government's emissions over time. By tracking emissions over time, local governments should be able to measure the GHG reduction benefits from policies and programs put in place to reduce emissions within their operations.

The Protocol is not designed for quantifying the reductions from GHG mitigation projects that will be used as offsets. Offsets are discrete GHG reductions used to compensate for (i.e., offset) GHG emissions elsewhere. Offsets are calculated relative to a baseline that represents a hypothetical scenario for what emissions would have been in the absence of the project.[2]

Project based GHG reductions that are to be used as offsets should be quantified using a project quantification method that addresses issues like baseline scenario, additionality, permanence and ownership. This Protocol does not address such issues and is not suitable for calculating reductions to be used as offsets in a voluntary or mandatory GHG reduction system.

Background on the Partners

The California Air Resources Board

The California Air Resources Board is the State agency responsible for protecting public health and the environment from the harmful effects of air pollution. The ARB is also the lead agency implementing the State of California's pioneering efforts to reduce greenhouse gas emissions. The landmark legislation known as AB32, The Global Warming Solutions Act of 2006, requires reducing greenhouse gas emissions to 1990 levels by 2020.

Development of local government greenhouse gas emissions inventory protocols are an integral tool in ARB's implementation of AB 32. ARB staff is partnering with the California Climate Action Registry, The Climate Registry, and ICLEI to develop local government protocols for GHG assessment.

More information is available at www.arb.ca.gov/cc/protocols/localgov/localgov.htm.

The California Climate Action Registry

The California Climate Action Registry is a private non-profit organization originally formed by the State of California in 2000. The California Registry serves as a voluntary greenhouse gas registry to protect and promote early actions to reduce GHG emissions by organizations. The California Registry provides leadership on climate change by developing and promoting credible, accurate, and consistent GHG

[2] WRI/WBCSD *GHG Protocol Corporate Standard*, March 2004.

reporting standards and tools for organizations to measure, monitor, third-party verify and reduce their GHG emissions consistently across industry sectors and geographical borders.

California Registry members voluntarily measure, verify, and publicly report their GHG emissions, are leaders in their respective industry sectors, and are actively participating in solving the challenge of climate change. In turn, the State of California offers its best efforts to ensure that California Registry members receive appropriate consideration for early actions in light of future state, federal or international GHG regulatory programs. Registry members are well prepared to participate in market based solutions and upcoming regulatory requirements.

The California Registry is regarded as a leading international thought center on climate change issues and an intersection where business, government and environmental organizations meet to work together to implement practical and effective solutions.

More information is available at www.climateregistry.org.

ICLEI – Local Governments for Sustainability

Founded in 1990, ICLEI – Local Governments for Sustainability is an association of city and county governments dedicated to improving global environmental conditions through cumulative local action. Through its campaigns, ICLEI generates political awareness of key environmental issues, provides technical assistance and training to build capacity in local governments to address these issues and evaluates their progress toward sustainable development.

ICLEI assists local governments in their efforts to reduce the greenhouse gas emissions that contribute to both global climate change and declining air quality. To this end, ICLEI provides local governments with analytical tools and methods to measure emissions so that they can set and achieve their emission reduction goals. ICLEI encourages action by focusing on improvement to the quality of life for the entire community by reducing greenhouse gas emissions (i.e. improving air quality, reducing traffic congestion and achieving financial savings for residents and businesses).

More information is available at www.iclei-usa.org.

The Climate Registry

Established in 2007, The Registry is a non-profit organization that supports both voluntary and mandatory reporting programs, provides meaningful information to reduce greenhouse gas emissions, and embodies the highest levels of environmental integrity. The Climate Registry sets consistent and transparent standards for the measurement, verification, and public reporting of greenhouse gas emissions throughout North America in a single unified registry.

More information is available at www.theclimateregistry.org.

Partner Objectives

In addition to achieving the general purpose of the Protocol described above, each of the partners to the development of this Protocol has additional objectives:

The California Air Resources Board intends to provide this Protocol to help enable local governments in California to develop and report consistent and accurate GHG inventories that can track reductions in overall GHG emissions to support the State's AB 32 program and goals.

The California Climate Action Registry intends for this Protocol to provide "industry-specific" guidance for CCAR's local government members to enable more policy-relevant quantification and reporting of GHG emission inventories.

ICLEI seeks to offer standardized guidance to all local governments in the U.S. (including but not limited to ICLEI members) on the development of greenhouse gas emissions inventories. This Protocol effectively serves as the translation of ICLEI's International Local Government Greenhouse Gas Protocol for use in developing local government operations emissions inventories in the U.S.

The Climate Registry plans to look to this Protocol in the future as it strives to develop guidance for TCR local government reporters that will be applicable across the U.S., in Canada, and in Mexico.

California Local Governments and AB 32

The State of California believes that local governments have an important role to play in the State's efforts to meet its GHG reduction goals under AB 32. ARB is dedicated to providing California's local governments with the tools and guidance they need to help California meet its reduction goals.

ARB is partnering in this process in order to give California's local governments a powerful tool that will allow them to take a critical first step in addressing their GHG emissions - developing a comprehensive, rigorous GHG emissions inventory.

ARB encourages California's local governments to use this Protocol to annually inventory and report their GHG emissions so that reductions made by local governments are tracked in a transparent, consistent and accurate manner.

Protocol Audience

This Protocol has been developed for use by local governments throughout the United States, with potential application by local governments in Canada and Mexico. Components of this Protocol may also be applicable to state and provincial agencies, quasi-governmental agencies, service districts, special districts and other local agencies in the act of developing similar greenhouse gas emissions inventories. For those elements of the Protocol applicable to special districts, they are encouraged to use this Protocol.

Given the wide diversity of local and state agency activities, these agencies may in some cases need to supplement guidance contained in this Protocol with additional guidance from other sources to ensure measurement and reporting in alignment with the guiding principles outlined above. Accounting for all possible variations and special circumstances that might occur within these other agencies and districts falls outside the scope of this Protocol.

Protocol Origin

This Protocol is based on the *Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard*, developed by the World Business Council for Sustainable Development and the World Resources Institute (WBCSD/WRI) through a multi-stakeholder effort to develop a standardized approach to the voluntary reporting of GHG emissions. Perceiving a need for additional guidance to local governments on applying the Greenhouse Gas Protocol within the context of local government operations inventory efforts, the partners chose to collaborate in developing this Local Government Operations Protocol. The partners have drawn upon their combined experience in greenhouse gas protocol development and assistance to local governments in measuring and reporting greenhouse gas emissions, as well as the experience of a wide variety of stakeholders that have participated in the development of this Protocol via participation in a Technical Workgroup or Advisory Group to the development process. This resulting Protocol will serve as a shared standard enabling consistency and harmonized reporting by all local governments.

The partners have also drawn from the following existing GHG programs and protocols in the development of this Protocol:

- California Air Resources Board, *Regulation for the Mandatory Reporting of Greenhouse Gas Emissions* and *California Greenhouse Gas Inventory (1990-2004)*.
- California Climate Action Registry, *General Reporting Protocol* and various industry-specific protocols.
- ICLEI - Local Governments for Sustainability, *International Local Government GHG Emissions Analysis Protocol.*
- International Organization for Standardization (ISO) 14064-1, *Specification with guidance at the organization level for quantification and reporting of greenhouse gas emissions and removals.*
- The Climate Registry, *General Reporting Protocol.*
- U.S. Environmental Protection Agency Climate Leaders *Greenhouse Gas Inventory Guidance*.

Evolution and Availability of the Protocol

This Protocol is intended to reflect best practices associated with GHG accounting and will continue to evolve periodically as new science or technical knowledge becomes available. Version 1.0 was released in 2008 - a new version is not expected for at least 12 months. The current version of this Protocol will be maintained on the websites of each of the partner organizations.

Technical Assistance

The partners can assist local governments in a number of ways related to use of this Protocol for the development of government operations GHG emissions inventories. See the program-specific chapters of this Protocol for further information on the technical assistance offered by each of the partners.

PART II IDENTIFYING YOUR EMISSIONS

Chapter 1 Introduction

The Protocol is divided into several parts. These parts mirror the chronology of the reporting process:

- Identifying the emissions to be included in your inventory;
- Quantifying your emissions; and
- Reporting your emissions.

Part I provides background on the origin and development of the Protocol, and an overview of its purpose and audience.

Part II provides guidance on determining the specific emissions sources you should include in your inventory and how your emissions data should be categorized and consolidated for reporting purposes. It is recommended that you read Part II in its entirety to ensure that you have identified all appropriate emission sources.

Part III provides the methodologies for quantifying your emissions from various emission sources. You should read those chapters of Part III that provide quantification guidance for emission sources owned or operated by your local government, but you may skip over those chapters and/or sections that do not pertain to your operations and activities.

Part IV provides guidance on how to report your emissions in a standardized and consistent manner once they have been quantified using the methodologies explained in Part III.

Chapters 14-16 provide program-specific requirements that must be taken into account if you are participating in either CCAR or the ICLEI Cities for Climate Protection program. In the future, when TCR adopts the Protocol for use by its reporters, TCR's program-specific requirements will be incorporated into the Protocol, as well.

1.1 GHG Accounting and Reporting Principles

This Protocol has adopted five overarching accounting and reporting principles, which are intended to help you ensure that your GHG data represent a faithful, true, and fair account of your local government's GHG emissions. These principles, adapted from the WRI/WBCSD GHG Protocol Initiative (March 2004), serve to guide the measurement and reporting of emissions.

Relevance: The greenhouse gas inventory should appropriately reflect the greenhouse gas emissions of the local government and should be organized to reflect the areas over which local governments exert control and hold responsibility in order to serve the decision-making needs of users.

Completeness: All greenhouse gas emission sources and emissions-causing activities within the chosen inventory boundary should be accounted for. Any specific exclusion should be justified and disclosed.

Consistency: Consistent methodologies should be used in the identification of boundaries, analysis of data and quantification of emissions to enable meaningful trend analysis over time, demonstration of reductions, and comparisons of emissions. Any changes to the data, inventory boundary, methods, or any relevant factors in subsequent inventories should be disclosed.

Transparency: All relevant issues should be addressed and documented in a factual and coherent manner to provide a trail for future review and replication. All relevant data sources and assumptions should be disclosed, along with specific descriptions of methodologies and data sources used.

Accuracy: The quantification of greenhouse gas emissions should not be systematically over or under the actual emissions. Accuracy should be sufficient to enable users to make decisions with reasonable assurance as to the integrity of the reported information.

Chapter 2 Inventory Guidelines

2.1 GHGs to be Assessed

Local governments should assess emissions of all six internationally-recognized greenhouse gases regulated under the Kyoto Protocol:

- Carbon dioxide (CO_2);
- Methane (CH_4);
- Nitrous oxide (N_2O);
- Hydrofluorocarbons (HFCs);
- Perfluorocarbons (PFCs); and
- Sulfur hexafluoride (SF_6).

You should account for emissions of each gas separately and report emissions in metric tons of each gas and metric tons of CO_2 equivalent (CO_2e). A complete list of the internationally-recognized GHGs, including individual HFC and PFC compounds, is provided in Appendix A Global Warming Potentials. This list also includes the Global Warming Potential (GWP) of each GHG, which is used to calculate CO_2e of the non-CO_2 gases.

Converting emissions of non-CO_2 gases to units of CO_2e allows GHGs to be compared on a common basis (i.e. on the ability of each GHG to trap heat in the atmosphere). Non-CO_2 gases are converted to CO_2e using internationally recognized Global Warming Potential (GWP) factors. GWPs were developed by the Intergovernmental Panel on Climate Change (IPCC) to represent the heat-trapping ability of each GHG relative to that of CO_2. For example, the GWP of methane is 21 because one metric ton of methane has 21 times more ability to trap heat in the atmosphere than one metric ton of carbon dioxide. Refer to Appendix A Global Warming Potentials for more information on converting non-CO_2 gases to CO_2e.

Tracking each gas separately will allow your local government to see the relative impact from different sources of GHG emissions, and may help you prioritize the most efficient and effective way to reduce your overall GHG emissions. It will also make your inventory more transparent, and may simplify updates to your inventory, as the internationally recognized GWP values are expected to change over time as science improves.

2.2 Inventory Frequency and Base Year

A local government's emissions inventory should comprise all GHG emissions occurring during a selected calendar year. Reporting GHG inventories on a calendar year basis is considered standard internationally; UNFCCC, the Kyoto Protocol, EU ETS, The Climate Registry, the California Climate Action Registry, and the state of California's mandatory reporting regulation under AB 32 all require GHG inventories to be tracked and reported on a calendar year basis. In cases where local government records are available only on a fiscal year basis, efforts should be made to reorganize these records and report according to the calendar year, not the fiscal year.

A meaningful and consistent comparison of emissions over time requires that local governments set a performance datum with which to compare current emissions. This performance datum is referred to as a base year. Prior to beginning data collection, local governments should examine the range of data sources available and select a year for which accurate records of all key emission sources exist in sufficient detail to conduct an accurate inventory. Simultaneously it is often preferable to establish a base year several years in the past so as to be able to account for the emissions benefits of recent actions.

It is good practice to compile an emissions inventory for the earliest year for which complete and accurate data can be gathered. The base year for the UNFCCC and subsequent Kyoto Protocol is calendar year 1990. However, required data from 1990 is often prohibitively difficult or impossible to collect. Given that the priority for a greenhouse gas management program should be on practical results, it is more important that the base year be documented with enough detail to provide a good basis for local action planning than it is that all local governments produce an inventory with the same, stipulated base year.

Moreover, it is good practice to aim for a base year that is likely to be representative of the general level of emissions over the surrounding period. Energy use in a year that was particularly hot or particularly cold would usually differ to energy use in an average year, due to the greater level of use of air conditioning or heating respectively. Similarly, local governments that have an electricity supply comprising a high proportion of hydroelectricity should avoid abnormally dry years during which the amount of hydroelectricity generation is lower than usual.

When choosing a base year, it is important to remember that this is the emissions level against which changes in emissions are measured. Therefore, any emission reduction activities put in place before the base year are considered to be part of the status quo and do not provide the local government with credit towards reaching an emission reduction target that may be adopted.

In addition to conducting an inventory of base year emissions, you should complete a comprehensive inventory of emissions at regular intervals following the base year. Standard practice for entity-level GHG accounting is to inventory your emissions on an annual basis.

Note that there are program-specific requirements for setting a base year, adjusting a base year due to structural changes, and calendar year reporting. Refer to Chapters 14-16 for details on these program specific requirements.

2.3 Scope of Sources

Under this Protocol, local governments should quantify and report all sources of GHG emissions within their operations. The Protocol does not include guidance on nor expect local governments to quantify biological stocks (or “sinks”) of carbon that local governments may control. Furthermore, the Protocol does not provide guidance on quantifying emissions from GHG mitigation projects for use as offsets of greenhouse gas credits.

Biological stocks of carbon and estimations of project-specific GHG reductions may be reported optionally. Note that biological stocks and project-specific reductions should be reported separately from your inventory emissions, and no line item adjustments should be made to your inventory based on these activities.

Local governments can explore the following resources for more information on how to quantify biological stocks and project-specific GHG reductions:

- California Climate Action Registry, Forest Sector Protocol, September 2007.
- California Climate Action Registry Project Protocols, various. (www.climateregistry.org/tools/protocols/project-protocols.html)
- IPCC Guidelines for National Greenhouse Gas Inventories, 2006.

- World Business Council for Sustainable Development and World Resources Institute, The GHG Protocol for Project Accounting, November 2005.

- U.S. EPA Climate Leaders Offset Project Methodologies, various. (www.epa.gov/stateply/resources/optional-module.html)

Chapter 3 Organizational Boundaries

Local governments vary in their legal and organizational structures, and may contain a diverse number of departments, boards, facilities, joint ventures, etc. For the purposes of financial accounting, entities are treated to established rules that depend on the structure of the organization and the relationships among parties involved. Setting your local government's organizational boundary for GHG accounting and reporting will follow a similar process - you will select an approach for consolidating GHG emissions and then consistently apply the selected approach to define the departments, activities and operations that constitute your local government for the purpose of reporting GHG emissions.

Local governments utilizing this Protocol should account for and report their emissions according to one of two control approaches - operational control or financial control.

Under both control approaches, a local government accounts for 100 percent of the GHG emissions from operations over which it has control. It does not account for GHG emissions from operations in which it owns an interest but has no control. In most cases, whether an operation is controlled by the local government or not does not vary based on whether the financial control or operational control criterion is used. However, there are situations where your control approach choice will determine whether a source falls within or outside of your organizational boundary. You must choose one control approach and apply it consistently across all of your operations. How to assess your local government's boundaries based on each control approach is provided below. Table 3.1 also provides an illustration of the reporting responsibility under the two different control approach options.

3.1.1 Control Approach Recommendation

The Protocol strongly encourages local governments to utilize operational control when defining their organizational boundary. The stakeholders involved in the development of this Protocol believe that operational control most accurately represents the emission sources that local government's can influence. Operational control is also the consolidation approach required under AB 32's mandatory reporting program and is consistent with the requirements of many other types of environmental and air quality reporting.

3.2 Operational Control

A local government has operational control over an operation if the local government has the full authority to introduce and implement its operating policies at the operation. This approach is consistent with the current accounting and reporting practice of many organizations that report on emissions from facilities, which they operate (i.e., for which they hold the operating license). It is expected that except in very rare circumstances, if the local government is the operator of a facility, it will have the full authority to introduce and implement its operating policies and thus has operational control. One or more of the following conditions establishes operational control:

- Wholly owning an operation, facility, or source

- Having the full authority to introduce and implement operational and health, safety and environmental policies (including both GHG- and non-GHG related policies). In many instances, the authority to introduce and implement operational and health, safety, and environmental (HSE) policies is explicitly conveyed in the contractual or legal structure of the partnership or joint venture. In most cases, holding an operator's license is an indication of your organization's authority to implement operational and HSE policies. However, this may not always be so. If your organization holds an operating license and you believe you do not have operational control, you will need to explicitly demonstrate that your authority to introduce operational and HSE policies is significantly limited or vested with a separate entity.

- Under the operational control approach, a local government accounts for 100 percent of emissions from operations over which it has operational control. It should be emphasized that having operational control does not mean that a local government necessarily has authority to make all decisions concerning an operation. For example, big capital investments will likely require the approval of all the partners that have joint financial control.

3.3 Financial Control

The local government has financial control over the operation if the former has the ability to direct the financial and operating policies of the latter with a view to gaining economic benefits from its activities.3 One or more of the following conditions establishes financial control:

- Wholly owning an operation, facility, or source
- Considering an operation to be, for the purposes of financial accounting, a group company or subsidiary, and consolidating its financial accounts in your organization's financial statements
- Governing the financial policies of a joint venture under a statute, agreement or contract
- Retaining the rights to the majority of the economic benefits and/or financial risks from an operation or facility that is part of a joint venture or partnership (incorporated or unincorporated), however these rights are conveyed. These rights may be evident through the traditional conveyance of equity interest or working/participating interest or through nontraditional arrangements. The latter could include your organization casting the majority of votes at a meeting of the board of directors or having the right to appoint/remove a majority of the members of the board in the case of an incorporated joint venture.

For example, financial control usually exists if the local government has the right to the majority of benefits of the operation, however these rights are conveyed. Similarly, a local government is considered to financially control an operation if it retains the majority risks and rewards of ownership of the operation's assets.

Under this control approach, the economic substance of the relationship between the local government and the operation takes precedence over the legal ownership status, so that the local government may have financial control over the operation even if it has less than a 50 percent interest in that operation. In assessing the economic substance of the relationship, the impact of potential voting rights, including both those held by the local government and those held by other parties, is also taken into account.

This approach is consistent with international financial accounting standards; therefore, a local government has financial control over an operation for GHG accounting purposes if the operation is fully consolidated in financial accounts. If this approach is chosen to determine control, emissions from joint ventures where partners have joint financial control are accounted for proportionally based on the each partner's interest of the joint venture's income, expenses, assets and liabilities.

3.4 Joint Control

Sometimes a local government can have joint financial control over an operation, but not operational control. In such cases, the local government would need to look at the contractual arrangements to determine whether any one of the partners has the authority to introduce and implement its operating policies at the operation and thus has the responsibility to report emissions under operational control. If

[3] Financial accounting standards use the generic term "control" for what is denoted as "financial control" in this chapter.

the operation itself will introduce and implement its own operating policies, the partners with joint financial control over the operation will not report any emissions under operational control.

Table 3.1 Reporting Based on Financial Versus Operational Control

Level of Control of Facility	% of Emissions to Report Under Financial Control	% of Emissions to Report Under Operational Control
Wholly owned	100%	100%
Partially owned with financial and operational control	100%	100%
Partially owned with financial control; no operational control	100%	0%
Partially owned with operational control; no financial control	0%	100%
Joint financial control with operational control	Based on % ownership	100%
Joint financial control; no operational control	Based on % ownership	0%
Associated entity (not consolidated in financial accounts) with operational control	0%	100%
Associated entity (not consolidated in financial accounts); no operational control	0%	0%
Fixed asset investments	0%	0%
Not owned but have a capital or financial lease	100%	100%
Not owned but have an operating lease	0%	100%

3.5 Autonomous Departments, Municipal Utilities and Joint Powers Authorities

Local governments' organizational structures can vary greatly from jurisdiction to jurisdiction. One of the goals of this Protocol is to promote consistency in the activities and emission sources reported by all local governments. Large local governments may be divided into a number of departments with a wide variety of autonomy, including autonomous, self-supporting departments that control a municipal utility, a port, an airport, a water or wastewater system/facility, or other large industrial or non-industrial facilities. To ensure consistency, this Protocol provides clarifying guidance on how to apply operational and financial control criterion to these departments specifically.

Operational Control. It is often the case that autonomous departments like municipal utilities, ports and airports are managed by their own board of commissioners or executives. If this board is appointed by local government officials (e.g. appointed by the Mayor and confirmed by the City Council) and the local government officials have some level of oversight of the board (e.g. the local government can help guide policy decisions of the department, the actions of the Board must have City Council approval, etc.), then the local government is considered to have operational control over the department and should report all emissions associated with the municipal utility/port/airport as part of the local government's GHG inventory.

Financial Control. It is possible that even if the local government maintains operational control of an autonomous department, it may not maintain financial control of the department. Because municipal utilities, ports and airports often have large assets, the autonomous department may maintain ownership of its assets separate from the local government. If the assets of the utility/port/airport/etc. do not appear as part of or are not consolidated under the financial report of the local government, then it is assumed that the local government does not have financial control over the autonomous department.

Using the guidance above, it is possible that a local government would include the emissions from a municipal utility/port/airport in its inventory if using operational control to define its organizational boundaries, but would exclude the emissions from a municipal utility/port/airport from its inventory if using financial control to define its organizational boundaries. As discussed in Section 3.1.1, the Protocol recommends local governments to define their organizational boundary according to operational control.

Joint Powers Authorities
A Joint Powers Authority (JPA) is an institution permitted under the laws of some states, whereby two or more public authorities (e.g. local governments, utility districts or transport districts) can operate collectively[4]. While JPAs are found throughout the country, they are particularly widely used in California. JPAs have separate operating boards of directors, and these boards can be given any of the powers inherent in all of the participating agencies. The joint authority can employ staff and establish policies independently of the constituent authorities.

As a JPA is considered a distinct entity from its member authorities, emissions from JPAs should not be reported as part of a local government's inventory, regardless of control approach being used by the local government.

3.6 Leased Facilities/Vehicles and Landlord/Tenant Arrangements

You should account for and report emissions from leased facilities and vehicles according to the type of lease associated with the facility or source and the organizational boundary approach selected. This guidance applies to rented office space, vehicles, and other facilities or sources (e.g., industrial equipment).

There are two types of leases:

Finance or capital lease. This type of lease enables the lessee to operate an asset and also gives the lessee all the risks and rewards of owning the asset. Assets leased under a capital or finance lease are considered wholly owned assets in financial accounting and are recorded as such on the balance sheet. If you have an asset under a finance or capital lease, this asset is considered to be wholly owned by you.

Operating lease. This type of lease enables the lessee to operate an asset, like a building or vehicle, but does not give the lessee any of the risks or rewards of owning the asset. Any lease that is not a finance or capital lease is considered an operating lease. In most cases, operating leases cover rented office space and leased vehicles, whereas finance or capital leases are for large industrial equipment.

3.6.1 Emissions from Leased Assets

You should account for and report emissions from a facility or source under a finance or capital lease as if it is an asset wholly owned and controlled by your local government, regardless of the organizational boundary approach selected. Therefore, you should account for and report these emissions under both financial control and operational control.

With respect to facilities or sources under an operating lease (e.g., most office space rentals and vehicle leases), the organizational boundary approach selected (operational control or financial control) will determine whether reporting the asset's associated emissions is required or optional.

When consolidating using the operational control approach, you should report emissions from assets for which you have an operating lease and these will be counted as Scope 1 or Scope 2 emissions (see Chapter 4 for a discussion of scopes). This follows from the fact that a lessee has operational control over

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[4] http://en.wikipedia.org/wiki/Joint_Powers_Authority.

an asset it leases under an operating lease. For example, the renter of office space has control over the office's lights, as well as the various office equipment (computers, copy machines, etc.) located in the office. Under the operational control approach, it is the lessee's control of these emission sources that makes the lessee responsible for reporting the emissions from these sources.

If you use the financial control approach, then reporting the emissions from a facility or source with an operating lease is optional. If you choose to report these emissions, they are counted as Scope 3 emissions (see the following chapter for a detailed discussion of the various scopes, including Scope 3).

Lessees of office space should report emissions from electricity use, heating and cooling of the space whenever possible. If you cannot report emissions from heating and cooling because it is not possible to obtain the necessary data, then you are only required to report emissions from electricity use.

Figure 3.1 is a decision tree designed to help lessees determine what sources from leased assets are within the organizational boundaries of a lessee.

3.6.2 Assessing Emissions for a Lessor

In general, the guidance for a lessor is the opposite of the lessee's. For example, the lessor should not report emissions for assets leased under a capital or finance lease regardless of the consolidation method applied by the lessor (although the lessor may opt to report these emissions as Scope 3 emissions). Similarly, the lessor should not report emissions for assets leased under an operating lease if the lessor is using the operational control consolidation method. However, the lessor should report such emissions if it is using the financial control approach.

Figure 3.2 is a decision tree providing guidance in determining what sources are within the organizational boundaries of a lessor.

Figure 3.1 Organizational Boundary Decision Tree from a Lessee's Perspective

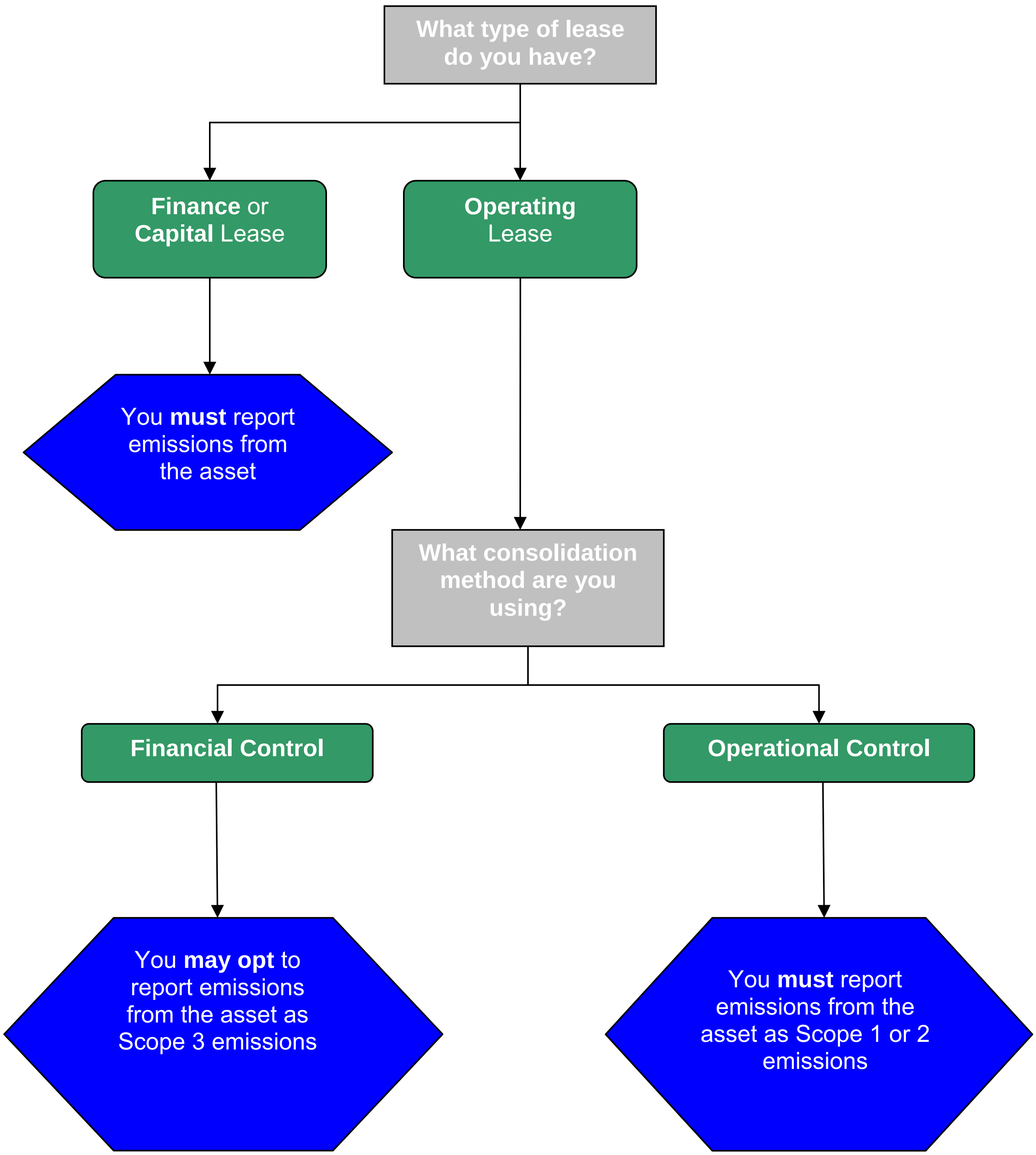
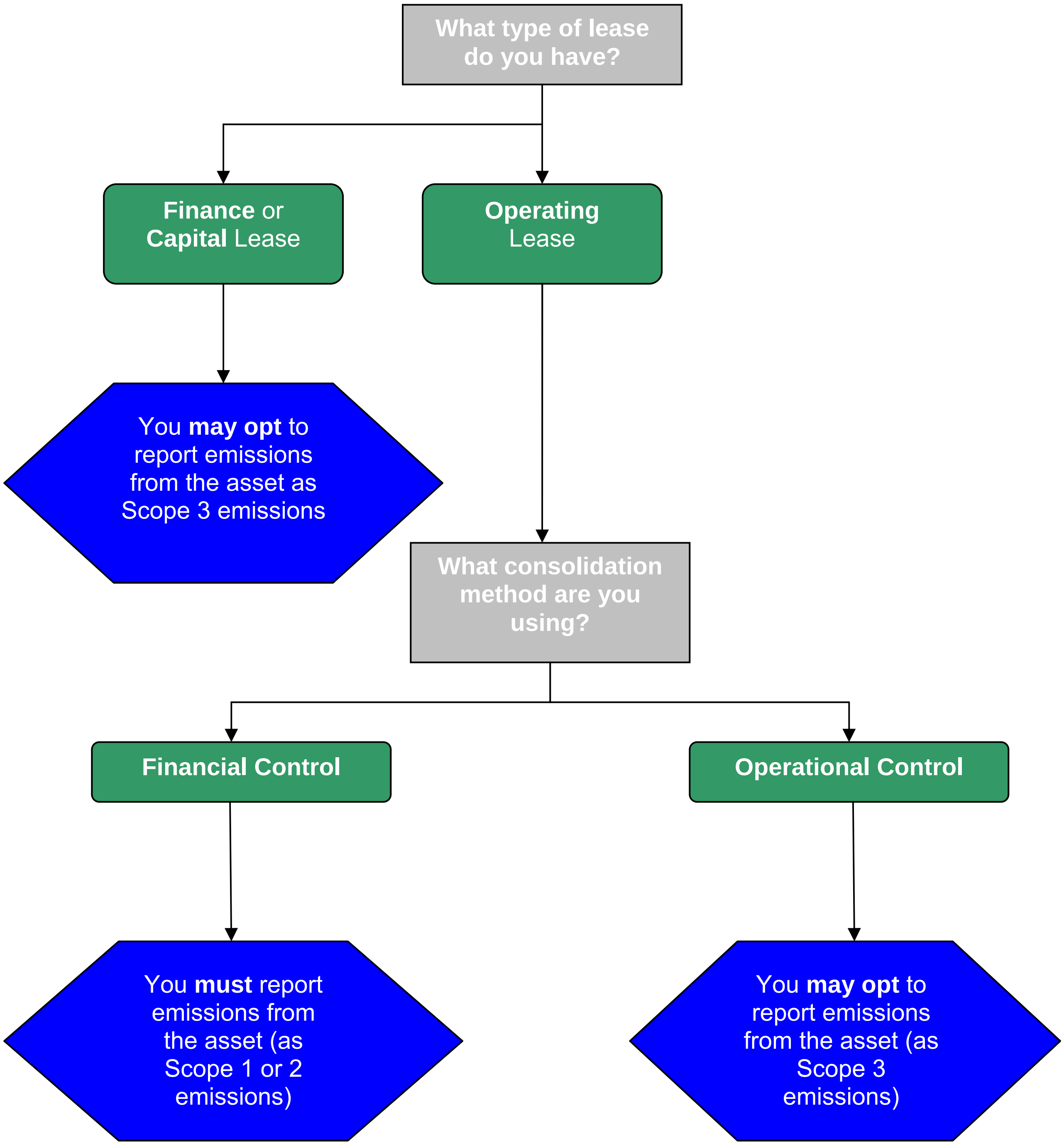


Figure 3.2 Organizational Boundary Decision Tree from a Lessor's Perspective



Chapter 4 Operational Boundaries

After your local government has determined its organizational boundaries in terms of the operations that it owns or controls, you then need to set your operational boundaries. This involves identifying emissions associated with your operations, categorizing them as direct and indirect emissions[5], and choosing the scope of accounting and reporting for optional emissions.

4.1 GHG Emission Scopes

To separately account for direct and indirect emissions, to improve transparency, and to provide utility for different types of climate policies and goals, this Protocol follows the WRI/WBCSD GHG Protocol *Corporate Standard* in categorizing direct and indirect emissions into "scopes" as follows:

Scope 1: All direct GHG emissions (with the exception of direct CO_2 emissions from biomass combustion).

Scope 2: Indirect GHG emissions associated with the consumption of purchased or acquired electricity, steam, heating, or cooling.

Scope 3: All other indirect emissions not covered in Scope 2, such as upstream and downstream emissions, emissions resulting from the extraction and production of purchased materials and fuels, transport-related activities in vehicles not owned or controlled by the reporting entity (e.g., employee commuting and business travel), outsourced activities, waste disposal, etc.

Together the three scopes provide a comprehensive accounting framework for managing and reducing direct and indirect emissions.

Figure 4.1 provides an overview of the relationship between the scopes and the activities that generate direct and indirect emissions along an entity's value chain. Scopes 1 and 2 are carefully defined in this Protocol to ensure that two or more entities will not account for the same emissions in the same scope.

Local governments should, at a minimum, quantify and report all Scope 1 and Scope 2 emissions. Reporting of Scope 3 emissions is *optional* - see Sections 4.7 and Chapter 12 for more information on Scope 3 emissions. Direct CO_2 emissions from the combustion of biomass (biogenic emissions) should also be quantified and reported, but should not be included in Scope 1 emissions. Biogenic emissions should instead be reported separately from the scopes (see Section 4.6).

4.2 Local Government Sectors

Along with scopes, emissions are also categorized into local government sectors under this Protocol. The local government sectors are:

- Buildings and other facilities
- Streetlights and traffic signals
- Water supply facilities
- Vehicle fleet
- Power generation facilities
- Solid waste facilities
- Wastewater facilities

[5] The terms "direct" and "indirect" as used in this document should not be confused with their use in national GHG inventories where 'direct' refers to the six Kyoto gases and 'indirect' refers to the precursors NOx, NMVOC, and CO.

- Other process and fugitive emissions

The local government sectors are meant to create a framework that is based on internationally recognized GHG accounting terms (i.e., Scope 1, Scope 2, stationary combustion, mobile combustion, etc.), but that is more policy relevant to local governments. By categorizing your GHG inventory according to these sectors, you may be able to more easily communicate your inventory results to the public, and identify opportunities for reductions.

Because these sectors are familiar to local governments, the quantification guidance in the Protocol is structured according to sector, as is the Standard Inventory Report (see Chapter 13).

4.3 Scope 1: Direct Emissions

Direct GHG emissions are emissions from sources within the local government's organizational boundaries (see previous chapter) that the local government owns or controls. These emissions should be further subdivided into emissions from four separate types of sources:

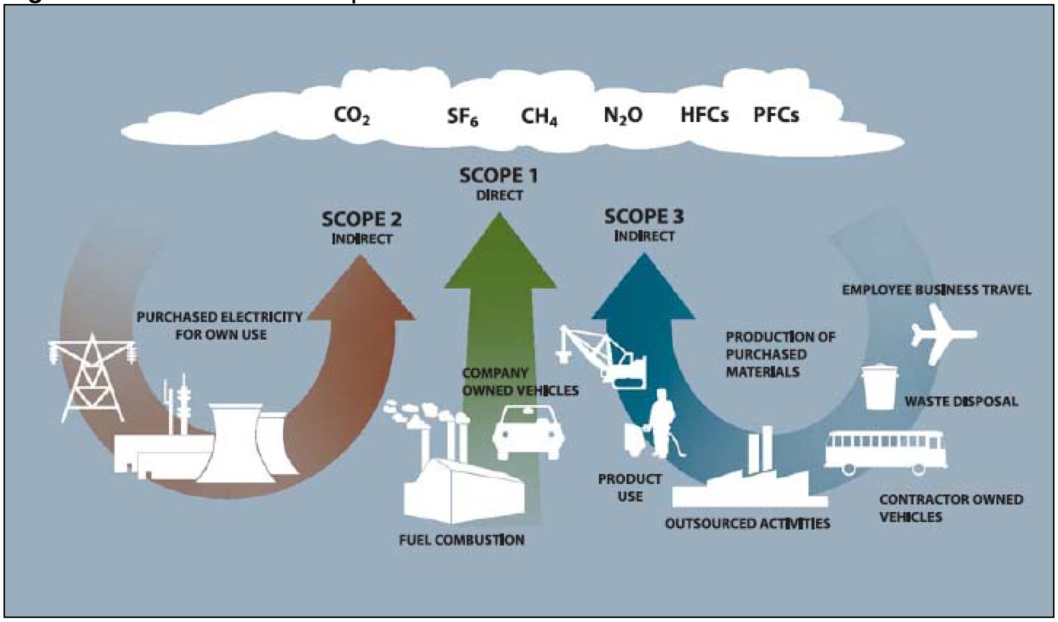
- *Stationary combustion* to produce electricity, steam, heat or power using equipment in a fixed location (found in most local government sectors);

- *Mobile combustion* of fuels in fleet transportation sources (e.g., cars, trucks, marine vessels and planes) and emissions from off-road equipment such as in construction, agriculture and forestry (found in the Vehicle Fleet sector - see Chapter 7);

- *Process emissions* from physical or chemical processing, other than fuel combustion (e.g., from the manufacturing of cement, aluminum, adipic acid, ammonia, etc.); and

- *Fugitive emissions* that are not physically controlled but result from intentional or unintentional releases, commonly arising from the production, processing, transmission, storage, and use of fuels and other substances, often through joints, seals, packing, gaskets, etc. (e.g., HFCs from refrigeration leaks, SF6 from electrical power distributors, and CH4 from solid waste landfills).

Figure 4.1 Overview of Scopes and Emission Sources



Source: WRI/WBCSD GHG Protocol *Corporate Accounting and Reporting Standard* (Revised Edition), Chapter 4.

4.4 Scope 2: Indirect Emissions

Scope 2 is a special category of indirect emissions and refers only to indirect emissions associated with the consumption of purchased or acquired electricity, steam, heating, or cooling. Indirect GHG emissions are emissions that are a consequence of activities that take place within the organizational boundaries of the reporting entity, but that occur at sources owned or controlled by another entity. Scope 2 emissions physically occur at the facility where electricity[6] is generated. For example, emissions that occur at a utility's power plant as a result of electricity used by a local government's administrative buildings represent the local government's indirect emissions.

Scope 2 emissions typically represent one of the largest sources of emissions for local governments; therefore, it embodies a significant opportunity for GHG management and reduction. Local governments can reduce their use of electricity by investing in energy efficient technologies and energy conservation. A local government could also install an efficient on site co-generation plant, particularly if it replaces the purchase of more GHG intensive electricity from the grid or electricity supplier. Reporting of Scope 2 emissions enables transparent accounting and reporting of emissions and reductions associated with such opportunities.

Scope 2 emissions are found throughout the local government sectors, but guidance on calculating these emissions is found in Chapter 6 .

4.5 Scopes and Double Counting

GHG accounting programs recognize that the indirect emissions reported by one entity may also be reported as direct emissions by another entity. For example, the indirect emissions from electricity use reported by a local government may also be reported as direct emissions by the regionally-serving utility that produced the electricity. This dual reporting does not constitute double counting of emissions as the entities report the emissions associated with the electricity production and use in different scopes (Scope 1 for the regionally-serving utility and Scope 2 for the local government). Emissions can only be aggregated meaningfully *within* a scope, not across scopes. By definition, Scope 2 emissions will always be accounted for by another entity as Scope 1 emissions. Therefore, Scope 1 and 2 emissions must be accounted for separately.

Reporting both Scope 1 and Scope 2 emissions helps ensure that local governments provide a comprehensive emissions profile reflecting the decisions and activities of their operations.

4.6 Biogenic Emissions

The combustion of biomass and biomass-based fuels (such as wood, wood waste, landfill gas, ethanol, etc.) emit CO_2 emissions, but these CO_2 emissions are distinct from Scope 1 emissions generated by combusting fossil fuels. The CO_2 emissions from biomass combustion are tracked separately because the carbon in biomass is of a biogenic origin—meaning that it was recently contained in living organic matter—while the carbon in fossil fuels has been trapped in geologic formations for millennia. Because of this biogenic origin, the IPCC *Guidelines for National Greenhouse Gas Inventories* requires that CO_2 emissions from biomass combustion be reported separately.

International consensus on the net climate impact from the combustion of these fuel sources has not yet been reached. But because of the distinction between biogenic and anthropogenic emissions, local governments should track the biogenic CO_2 emissions from biomass combustion separately from Scope 1 direct emissions.

[6] The term "electricity" is used in this chapter as shorthand for electricity, steam, and district heating/cooling.

Biogenic emissions related to forestry and land management need not be quantified under this Protocol, as the Protocol is designed to account primarily for the anthropogenic sources of GHG emissions, and is not designed to assess the carbon stocks of government-owned lands (see Section 2.3).

Because biofuels are often mixed with fossil fuels prior to combustion (e.g., wood waste with coal in a power plant, ethanol with gasoline in an automobile, or biomass with fossil-based materials in municipal solid waste), you must separately calculate your CO_2 emissions from biomass combustion from your CO_2 emissions from fossil fuel emissions. Chapter 6 and Chapter 7 in Part III of the Protocol provide methodologies you can use to calculate your biogenic CO_2 emissions separately from your anthropogenic CO_2 emissions.

Box 4.1 The Life Cycle Impact of Biofuels

In some cases, biofuels can be derived from sources that have significant embodied energy or other environmental consequences - for example, ethanol derived from a crop that requires significant petrochemical inputs such as fertilizers and pesticides. This can vary widely dependent upon the fuel crop, the region and the growing practices. While this is a distinct issue from the question of how to treat biogenic carbon sources, it is an important one, nonetheless. Like coal mining and oil refining, upstream emissions from these sources could be considered Scope 3 within the protocol. Guidance on lifecycle assessments is beyond the scope of this Protocol. However, local governments are encouraged to consider the upstream emissions from the specific source of biofuels in making decisions about the use of those fuels.

Note that the distinction of emissions from biomass combustion applies only to CO_2 and not to CH_4 and N_2O, which are also emitted from biomass combustion. Unlike CO_2 emissions, CH_4 and N_2O emitted from biomass combustion are not of a biogenic origin. This is because no CH_4 or N_2O would have been produced had the biomass naturally decomposed. It is only the combustion of the biomass that caused these emissions to be produced. Therefore, CH_4 and N_2O emissions from biomass combustion should be considered part of your Scope 1 emissions and should not be tracked separately from your other CH_4 and N_2O emissions.

4.7 Scope 3 Emissions

In addition to the Scope 1 and 2 emission sources, a number of additional emissions sources of potential policy relevance to local government operations can be measured and reported. These include emission sources related to local government operations, but for which local governments do not have financial or operational control.

Scope 3 emissions include all other indirect emissions not covered in Scope 2, such as upstream and downstream emissions, emissions resulting from the extraction and production of purchased materials and fuels, transport-related activities in vehicles not owned or controlled by the local government (e.g., employee commuting and business travel), outsourced activities, waste disposal, etc.

Local governments are encouraged to identify and measure all Scope 3 emission sources to the extent possible. While reporting of Scope 3 emissions is considered optional, doing so provides an opportunity for innovation in GHG management. Local governments may want to focus on accounting for and reporting those activities that are relevant to their GHG programs and goals, and for which they have reliable information.

While data availability and reliability may influence which Scope 3 activities are included in the inventory, it is accepted that data accuracy may be lower than Scope 1 and Scope 2 data. It may be more important to understand the relative magnitude of and possible changes to Scope 3 activities. Emission estimates are acceptable as long as there is transparency with regard to the estimation approach, and the data used for the analysis are adequate to support the objectives of the inventory.

Note that it is possible that the same Scope 3 emissions may be reported as Scope 3 emissions by more than one entity. For example, both a local government and a landfill operator who outsources its waste hauling may choose to report the emissions associated with transporting waste from its point of generation to the landfill as Scope 3 emissions. For this reason, Scope 3 emissions should not be summed across entities or combined with Scope 1 or Scope 2 emissions.

Further guidance on identifying, calculating and reporting Scope 3 emissions is provided in Chapter 12 .

PART III QUANTIFYING YOUR EMISSIONS

Chapter 5 Choosing the Appropriate Calculation Methodology

After determining your local government's boundaries, you must next quantify your GHG emissions. Part III provides emissions quantification guidelines that provide step-by-step guidance on how to quantify GHG emissions for your various sources of emissions.

This Protocol is designed to allow local governments with different levels of resources and data availability to create a complete and consistent inventory of the GHG emissions occurring within their organizational boundary. In order to do this, the Protocol contains a variety of calculation methodologies with different levels of data requirements, rigor and accuracy.

5.1 Calculation-Based Methodologies

Local governments will use calculation-based methodologies to quantify most of their GHG emissions. Calculation-based methodologies involve the calculation of emissions based on "activity data" and "emission factors".

5.1.1 Activity Data

Activity data is the relevant measurement of energy use or other greenhouse gas generating processes. Examples of activity data referenced in this Protocol include fuel consumption by fuel type, metered annual energy consumption, and annual vehicle mileage by vehicle type. Activity data is used in conjunction with an emission factor (see below) to determine emissions using the following generalized equation:

Activity Data x Emission Factor = Emissions

5.1.2 Emission Factors

Emission factors are calculated ratios relating GHG emissions to a proxy measure of activity at an emissions source[7]. Emission factors are used to convert activity data, like energy usage, into the associated GHG emissions and thus are central to creating your emissions inventory. They are usually expressed in terms of emissions/energy used (i.e. lbs. of CO_2/kWh).

Emission factors are determined by means of direct measurement and laboratory analyses or by using generalized default factors. This Protocol provides default emission factors for all calculation methodologies included in the document.

5.1.3 Recommended vs. Alternate Activity Data and Emission Factors

The use of common quantification guidelines ensures that local governments creating GHG inventories based on this Protocol quantify their emissions consistently, such that a "tonne of CO_2 is a tonne of CO_2" across all participating local governments.

In theory, all local governments would use comparable activity data and consistent emission factors to calculate their GHG inventories. In practice, not all local governments have the same level of time, resources, and data availability to be able to do so. To address this, the Protocol uses a tiered

[7] WRI/WBCSD *GHG Protocol Corporate Standard*, March 2004.

quantification system to present activity data and emission factors according to their level of rigor and accuracy.

In this system, “recommended” designates the preferred, or most accurate, approach for a given emission source; “alternate” represents a less accurate approach that often requires less data.

Each chapter will identify *recommended* activity data, sources of emission factors, and calculation approaches, as well as *alternate* activity data and sources of emission factors that may be used if you are unable to use the *recommended* approach.

Note that in some cases there may be multiple approaches designated as *recommended* or *alternate*, while for other sources there may only be one or two available quantification approaches for a given source.

Local governments should strive to use the *recommended* activity data and emission factors when calculating their GHG emissions, and work to improve their management systems and data collection so that, if they must use an *alternate* approach, they can move towards the *recommended* calculation approaches over time.

Please keep in mind that individual GHG reporting programs, like the California Climate Action Registry, may require certain activity data and sources of emission factors to be used in order to meet their standards for third party verification. While these will usually be consistent with what is denoted as *recommended*, there are some exceptions. All activity data and emission factors accepted by the California Registry are denoted in the Protocol with the following icon:

☑

If you are a California Registry participant, please ensure that you have used acceptable activity data and emission factors when calculating your emissions.

Please refer to Chapters 14-16 for more program-specific requirements on activity data and emission factors.

5.2 Measurement-Based Methodologies

Measurement-based methodologies determine emissions by means of continuous measurement of the exhaust stream and the concentration of the relevant GHG(s) in the flue gas. Direct measurement will only be relevant to local governments with facilities using existing continuous emission monitoring systems (CEMS), such as power plants or industrial facilities with large stationary combustion units. Local governments without existing monitoring systems do not need to install new monitoring equipment to calculate emissions from these sources, but rather can use the calculation-based methodologies provided. Those with CEMS should follow the guidance provided in Chapter 8 , Section 8.1.

5.3 Calculation Methodology Disclosure

To increase transparency and comparability, all local governments should disclose the type of activity data and emission factors used in calculating their emissions inventory. The Protocol provides a standardized report template in Chapter 13 , with recommendations on how to provide this methodology disclosure.

California Local Governments and AB 32

The State of California has begun to develop rules and regulations to drive GHG reductions across sectors in order to meet the state's GHG reduction target. One of these regulations is a mandatory reporting regulation for the state's largest sources of GHG emissions, which requires facility-level reporting and third-party verification. These sources include: electricity generating facilities, electricity retail providers, electricity marketers, oil refineries, hydrogen plants, cement plants, co-generation facilities, and other industrial sources that emit over 25,000 metric tons of CO_2 per year.

While most local governments will not have facilities in the sectors mentioned above, some local government operations will include stationary combustion sources emitting over 25,000 metric tons of CO_2 per year, or co-generation/electric power facilities with a total generating capacity of at least 1 MW that emit 2,500 metric tons of CO_2 or more per year.

If your local government operates any facilities in California that may bring them under ARB's mandatory reporting regulation, you are expected to follow the quantification guidance provided in the mandatory reporting regulation. The regulation has additional reporting requirements beyond what is described in this Protocol.

For more information, see Chapter 14 and to download the mandatory reporting requirements, visit www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.htm.

Chapter 6 Facilities

Local governments own, operate and occupy a large variety of buildings and facilities, and these facilities contain a diverse array of GHG emission sources. This chapter identifies the Scope 1 and Scope 2 emission sources you may have within your buildings and facilities, and provides guidance on how to calculate the GHG emissions from those sources.

6.1 Stationary Combustion

Stationary combustion refers to the combustion of fuels to produce electricity, heat, or motive power using equipment in a fixed location. Stationary combustion is a Scope 1 emission source. Typical stationary sources you will find in your buildings and facilities include furnaces, boilers, burners and internal combustion engines that consume fossil fuels like natural gas, heating oil, coal, and diesel.

Below are the recommended and alternate activity data and emission factors for calculating your Scope 1 emissions from stationary combustion. The following sections detail how to calculate your emissions based on the activity data and emission factors you choose to utilize.

The default emission factors for stationary combustion are in Appendix C, Table C.1.

Local governments should report the Scope 1 emissions from stationary combustion at water and wastewater treatment and distribution facilities separately from those at other buildings and facilities.

Box 6.1 Common Local Government Buildings and Facilities

Owned and leased office space
Police and fire stations
Recreation centers and facilities, including:
Auditoriums
Museums
Zoos
Other cultural facilities
Warehouse, fleet and equipment yards, service facilities
Transportation facilities
Port and airport facilities
Hospitals and schools
Courts
Prisons
Housing
Water pump/lift stations
Water treatment plants
Wastewater treatment plants

Although the quantification methodologies for various types of stationary combustion sources are the same, there are generally different types of emissions reduction opportunities at water/wastewater systems than at other types of facilities. Additionally, reporting these sectors separately facilitates more accurate comparison between local governments that do and do not provide water/wastewater services.

See Chapter 13 for more information on how to report emissions according to these sectors.

	RECOMMENDED	ALTERNATE
ACTIVITY DATA	Known fuel use ☑[8] (meter readings/utility bills)	Proxy year data
		Fuel estimates based on comparable facilities and square footage

[8] This icon signifies that the activity and/or emission factor meets the standard of rigor required for third party verification under the California Climate Action Registry program.

EMISSION FACTOR	RECOMMENDED	ALTERNATE
	Default by fuel type ☑	N/A

California Local Governments and AB 32

Note: If your local government operates a stationary combustion source that emits over 25,000 metric tons of CO_2 per year, you will be subject to ARB's mandatory reporting regulation under AB 32. The regulation has additional reporting requirements beyond what is described in this Protocol.

For more information and to download the mandatory reporting requirements, visit www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.htm.

6.1.1 Recommended Approach

Calculating emissions from stationary combustion using fuel use activity data and default emission factors by fuel type involves the following six steps:

1. Determine annual consumption of each fuel combusted at your facilities;
2. Determine the appropriate CO2 emission factors for each fuel;
3. Determine the appropriate CH4 and N2O emission factors for each fuel;
4. Calculate each fuel's CO2 emissions;
5. Calculate each fuel's CH4 and N2O emissions; and
6. Convert CH4 and N2O emissions to CO2 equivalent and determine total emissions.

Step 1: Determine annual consumption of each fuel combusted at your facilities.

First identify all fuels combusted at your facilities. Examples of fuel types include bituminous coal, residual fuel oil, distillate fuel (diesel), liquefied petroleum gas (LPG), and natural gas.

Then determine your annual fuel use by fuel type, measured in terms of physical units (mass or volume).

For stationary combustion sources, the preferred method is to determine the amount of fuel combusted at each combustion unit by reading individual meters located at the fuel input point, if applicable. Alternatively, you may use fuel receipts or purchase records to calculate your total fuel usage. Convert fuel purchase and storage data to estimates of measured fuel use using Equation 6.1.

Equation 6.1	Accounting for Changes in Fuel Stocks
Total Annual Fuel Consumption = Annual Fuel Purchases - Annual Fuel Sales **+** Fuel Stock at Beginning of Year **-** Fuel Stock at End of Year	

Box 6.2 Potential Sources for Facility Fuel Use Activity Data

- Accounts payable
- Departmental records
- Engineering department
- Facility engineer
- Fuel vendors/suppliers
- Insurance company
- Real estate department
- Utility provider

Step 2: Select the appropriate CO_2 emission factor for each fuel.

The Protocol provides default emission factors for a wide variety of fuels in Appendix C, Table C.2.

Emission factors are provided in units of CO_2 per unit energy and CO_2 per unit mass or volume. If you combust a fuel that is not listed in the table, you should derive an emission factor based on the specific properties of the fuel.

Step 3: Determine the appropriate CH_4 and N_2O emission factors for each fuel.

Estimating CH_4 and N_2O emissions depend not only on fuel characteristics, but also on technology type and combustion characteristics; usage of pollution control equipment; and maintenance and operational practices. Due to this complexity, estimates of CH_4 and N_2O emissions from stationary sources are much more uncertain than estimates of CO_2 emissions. CH_4 and N_2O also account for much smaller quantities of emissions from stationary combustion than CO_2.

Use Table C.3 to obtain default emission factors by fuel type and sector. For most local government operations, you will use the "commercial/institutional" sector emission factors. However, because local government services are so diverse, the Protocol includes other sectors that may be more appropriate, depending on the facility in question.

Step 4: Calculate each fuel's CO_2 emissions and convert to metric tons.

To determine your CO_2 emissions from stationary combustion, multiply your fuel use from Step 1 by the CO_2 emission factor from Step 2, and then convert kilograms to metric tons. Repeat the calculation for each fuel type, then sum (see Equation 6.2).

Note that Equation 6.2 expresses fuel use in gallons. If fuel use is expressed in different units (such as short tons, cubic feet, MMBtu, etc.), replace "gallons" in the equation with the appropriate unit of measure. Be sure that your units of measure for fuel use are the same as those in your emission factor. Refer to Appendix B for a list of standard conversion factors.

Equation 6.2	**Calculating CO_2 Emissions From Stationary Combustion (Fuel use in gallons)**
Fuel A CO_2 Emissions (metric tons) = Fuel Consumed × Emission Factor ÷ 1,000 (gallons) (kg CO_2/gallon) (kg/metric ton)	
Fuel B CO_2 Emissions (metric tons) = Fuel Consumed × Emission Factor ÷ 1,000 (gallons) (kg CO_2/gallon) (kg/metric ton)	
Total CO_2 Emissions (metric tons) = CO_2 from Fuel A + CO_2 from Fuel B + … (metric tons) (metric tons) (metric tons)	

Step 5: Calculate each fuel's CH_4 and N_2O emissions and convert to metric tons.

To determine your CH_4 emissions from stationary combustion, multiply your fuel use from Step 1 by the CH_4 emission factor from Step 3, and then convert grams to metric tons. Repeat the calculation for each fuel and sector type, then sum (see Equation 6.3).

Note that Equation 6.3 expresses fuel use in MMBtu. If fuel use is expressed in different units (such as gallons, short tons, cubic feet, etc.) you must convert your fuel use data to units of MMBtu. Be sure that your units of measure for fuel use are the same as those in your emission factor. Refer to Appendix B for a list of standard conversion factors.

Follow the same procedure above, using Equation 6.4, to calculate total emissions of N_2O at your facility.

Equation 6.3	**Calculating CH_4 Emissions From Stationary Combustion**
Fuel/Sector Type A CH4 Emissions (metric tons) = Fuel Use (MMBtu) × Emission Factor (g CH4/MMBtu) ÷ 1,000,000 (g/metric ton)	
Fuel/Sector Type B CH4 Emissions (metric tons) = Fuel Use (MMBtu) × Emission Factor (g CH4/MMBtu) ÷ 1,000,000 (g/metric ton)	
Total CH4 Emissions (metric tons) = CH4 from Type A (metric tons) + CH4 from Type B (metric tons) + … (metric tons)	

Equation 6.4	**Calculating N_2O Emissions From Stationary Combustion**
Fuel/Sector Type A **N_2O Emissions** (metric tons) = Fuel Use (MMBtu) × Emission Factor (g N_2O/MMBtu) ÷ 1,000,000 (g/metric ton)	
Fuel/Sector Type B **N_2O Emissions** (metric tons) = Fuel Use (MMBtu) × Emission Factor (g N_2O/MMBtu) ÷ 1,000,000 (g/metric ton)	
Total N_2O Emissions (metric tons) = N_2O from Type A (metric tons) + N_2O from Type B (metric tons) + … (metric tons)	

Step 6: Convert CH_4 and N_2O emissions to units of CO_2 equivalent and determine total emissions from stationary combustion.

Use the IPCC global warming potential (GWP) factors provided in Equation 6.5 (and Appendix A) to convert CH_4 and N_2O emissions to units of CO_2 equivalent. Then sum your emissions of all three gases to determine your total emissions from stationary combustion at your facilities (see Equation 6.5).

Equation 6.5	**Converting to CO_2-Equivalent and Determining Total Emissions**
CO_2 Emissions (metric tons CO_2e) = CO_2 Emissions (metric tons) × 1 (GWP)	
CH_4 Emissions (metric tons CO_2e) = CH_4 Emissions (metric tons) × 21 (GWP)	
N_2O Emissions (metric tons CO_2e) = N_2O Emissions (metric tons) × 310 (GWP)	
Total Emissions (metric tons CO_2e) = CO_2 + CH_4 + N_2O (metric tons CO_2e)	

6.1.2 Activity Data Alternate Approaches

If you are unable to obtain fuel use data for your buildings or facilities, there are two alternate approaches for estimating your fuel use at facilities.

6.1.2.1 Fuel Use Estimates - Proxy Year Data

You can estimate fuel consumption for a facility based on the fuel consumed at the facility in another year.

Local governments should disclose the use of any proxy years in reporting as part of the calculation methodology disclosure.

Use the following steps to estimate fuel consumption at your facility:

1. Determine annual fuel consumption of fuel in the proxy year; and
2. Normalize for heating and cooling degree days;

Step 1: Determine the annual fuel consumption by fuel type in the proxy year.

The proxy year can be either another calendar year or else a fiscal year.

Step 2: Normalize for heating degree days and cooling degree days.

Estimate the proportion of fuel used in a year for heating and cooling as a percentage of the total fuel consumed. This should be based on the increased fuel consumed during winter months and summer months respectively. Where monthly data is not available the best recommendation of a facility manger may be used. In cases where heating is the sole use of a fuel, it will be 100%. In most cases cooling will be exclusively electric and so cooling will be 0% of the total fuel consumed.

Then, determine the annual heating and cooling degree days in the region in the year being estimated and the proxy year. The national climate data center website provides information on the heating and cooling degree days by month and by state at www7.ncdc.noaa.gov/CDO/CDODivisionalSelect.jsp#.

Normalize for heating and cooling degree days using Equation 6.6.

Equation 6.6	Normalizing for Heating Degree Days And Cooling Degree Days

Estimated fuel consumed in inventory year =

$$\left[\frac{F_P \times F_h)}{D_{HP}} \times \frac{D_{HI}}{1}\right] + \left[\frac{F_P \times F_C}{D_{CP}} \times \frac{D_{CI}}{1}\right] + \left[(1 - F_h - F_C) \times F_P\right]$$

Where:

F_P = fuel used in proxy year (kWh)
F_h = percentage of fuel used for heating
D_{HP} = heating degree days in the proxy year
D_{HI} = heating degree days in inventory year
F_C = percentage of fuel used for cooling
D_{CP} = cooling degree days in the proxy year
D_{CI} = cooling degree days in inventory year

Now you can use your estimated fuel use from Equation 6.6 to follow the guidance in the recommended approach (Section 6.1.1) to estimate your CO_2, CH_4 and N_2O Scope 1 stationary combustion emissions from the facility.

6.1.2.2 Fuel Use Estimates - Comparable Facilities and Square Footage

Where actual fuel consumption records are not available, you can estimate fuel consumption based on the size and function of the building or facility. Typically this approach is used in cases of one or a few minor facilities. Generally, it should not be used as a substitute for a significant group of buildings or facilities or the entire buildings sector.

Local governments should disclose the use of any comparable facilities, including the facilities considered comparable in reporting as part of the methodology disclosure.

Use the following steps to estimate fuel consumption at your facility:

1. Identify fuel combusted at the facility;
2. Determine the size of the facility measured in floor area (square feet);
3. Identify comparable facilities with known annual fuel consumption rates and square footage;
4. Determine fuel used per square foot at comparable facility; and
5. Estimate total annual fuel consumed at the facility.

Step 1: Identify fuels combusted at the facility where fuel use is to be estimated.

First identify all fuels combusted at the facility. Examples of fuel types include bituminous coal, residual fuel oil, distillate fuel (diesel), liquefied petroleum gas (LPG), and natural gas.

Step 2: Determine the size of the facility measured in floor area (square feet).

Step 3: Identify comparable facilities with known annual fuel consumption rates and square footage.

If possible, these should be facilities owned or operated by your local government. The determination of comparability should include consideration of the primary function of the facility and types of fuel used. You may also consider the age, hours of operation, number of occupants and the type of heating and cooling systems employed.

If fuel consumption for another comparable facility owned or operated by the local government is not available, you may consult the US Energy Information Administration's Commercial Building Energy Consumption Survey for average energy use by fuel type, by facility type, and by region of the country at www.eia.doe.gov/emeu/cbecs/.

Step 4: Determine fuel used per square foot at comparable facility.

Divide the annual fuel use by fuel type at the comparable facility by its square footage to obtain a gallon or MMBtu/square foot coefficient for each fuel type.

Step 5: Estimate total annual fuel consumed at the facility.

For each fuel, multiply this coefficient by the area of the facility for which you are estimating the fuel use.

Equation 6.7	**Estimated Annual Fuel Consumption - Square Footage**
Estimated Annual Fuel Consumption =	

$$\frac{\text{Annual fuel consumption at comparable facility (volume or mass units)}}{\text{Size of Comparable Facility (sq. ft.)}} \times \text{Size of Facility Being Estimated (sq. ft.)}$$

Now you can use your estimated fuel use from Equation 6.7 to follow the guidance in the recommended approach (Section 6.1.1) to estimate your CO_2, CH_4 and N_2O Scope 1 stationary combustion emissions from the facility.

6.2 Electricity Use

All local governments are likely to have indirect emissions associated with the purchase and use of electricity. In some cases, indirect emissions from electricity use may comprise the majority of a local government's GHG emissions.

The generation of electricity through the combustion of fossil fuels typically yields carbon dioxide, and to a smaller extent, nitrous oxide and methane.

Below are the recommended and alternate activity data and emission factors for calculating your Scope 2 emissions from electricity use. The following sections detail how to calculate your emissions based on the activity data and emission factors you choose to utilize.

Local governments should report Scope 2 emissions in three separate sectors:

1. Street lighting and traffic signals
2. Waste and wastewater treatment and distribution facilities
3. Other buildings and facilities

Although the quantification methodologies for various types of Scope 2 emissions sources are the same (with the exception of an additional estimation methodology available for streetlights), there are generally different types of emissions reduction opportunities for streetlights and traffic signals and water/wastewater systems than at other types of facilities.

Additionally, reporting these sectors separately facilitates more accurate comparison between local governments that do not provide the same services. See Chapter 13 for more information on how to report emissions according to these sectors.

	RECOMMENDED	ALTERNATE
ACTIVITY DATA	Known electricity use ☑ (metered readings/utility bills)	Estimated electricity use for leased space ☑
		Proxy year electricity use data
		Estimated electricity use based on comparable facilities and square footage ☑
		Installed wattage (streetlights only)

	RECOMMENDED	ALTERNATE
EMISSION FACTOR	Verified utility-specific emission factor ☑ -or- eGRID subregion default emission factor[9] ☑	Utility-specific emission factor

6.2.1 Recommended Approach

To calculate indirect emissions from electricity use, follow these three steps:

[9] Local governments in California should use the California Grid Average Electricity Emission Factors instead of the eGRID subregion default emission factor. See Section for more information.

Determine your annual electricity use from each facility;
Select the appropriate emission factors that apply to the electricity used; and
Determine your total annual emissions in metric tons of carbon dioxide equivalent.

Step 1: Determine annual electricity consumption.

Reporting indirect emissions from electricity consumption begins with determining annual electricity use at each facility.

The preferred sources for determining annual electricity use are monthly electric bills or electric meter records. Both sources provide the number of kilowatt-hours (kWh) or megawatt-hours (MWh) of electricity consumed, giving a measure of the energy used by electric loads, such as lights, office equipment, air conditioning, or machinery.

Box 6.3 Potential Sources for Facility Electricity Activity Data

- Accounts payable
- Energy office
- Property management office
- Public works department
- Real estate department
- Utility

Record the electricity consumed each month at each facility. Then aggregate monthly bills to determine annual electricity use (in kWh or MWh) for each facility.

Step 2: Select appropriate emission factors.

An electricity emission factor represents the amount of GHGs emitted per unit of electricity consumed. It is usually reported in units of pounds of GHG per kWh or MWh. There are two options for recommended electricity emission factors under this Protocol:

Utility-specific emission factors that have been third-party verified to an existing reporting standard
eGRID regional default emission factors (by subregion)

If your electricity provider is a member of the California Climate Action Registry and has verified an electricity deliveries metric under CCAR's Power/Utility Protocol, you can use this factor to determine your CO_2 emissions from purchased electricity. These third-party verified emission factors can be found in Table C.5. As there is a delay in reporting and verifying these utility-specific metrics, it is appropriate to use the metric from the previous year when calculating your Scope 2 emissions from purchased electricity.

For CH_4 and N_2O emissions, use the default eGRID emission factors, as these emission factors are currently not being calculated under the Power/Utility Protocol.

California Local Governments and AB 32

If you are a California local government and your electricity provider does not report a utility-specific emission factor through CCAR, you should use the California Grid Average Electricity Emission Factors instead of the default eGRID subregion emission factors. Emission factors are available for 1990-2004 in Table C.6 . Use the 2004 emission factor as a proxy for more recent years until new emission factors become available.

These California-specific emission factors have been developed by ARB based on the total in-state and imported electricity emissions divided by the state's total consumption. These data came from ARB's statewide Greenhouse Gas Inventory, 1990-2004 and the California Energy Commission.

As it is not yet standard practice for utilities to calculate and verify company-specific electricity GHG emission factors, many local governments will be unable to obtain utility-specific factors. In this case, you should use the regional power pool emission factors supplied by US EPA eGRID that represent the average emissions rate of electric generators supplying power to the grid in your region.

To find the appropriate default emission factor for your local government, determine your eGRID subregion from the map in Figure C.1. If you are unsure of your subregion, use the EPA Power Profiler tool, available at www.epa.gov/cleanenergy/powerprofiler.html to find your subregion based on its zip code. Then, based on your subregion, find the appropriate emission factors for each gas in Table C.7.

Please note that the emission factors in Table C.7 are based on 2004 data, which are currently the most recent data available from eGRID. When possible, use emission factors that correspond to the calendar year of data you are reporting. Use the 2004 emission factors provided in Table C.7 as a proxy for more recent years until new eGRID emission factors become available. Use the historical eGRID CO_2 emission factor in Table C.8 for years prior to 2004.

Step 3: Determine total annual emissions and convert to metric tons of carbon dioxide equivalent.

To determine annual emissions, multiply annual electricity use (in MWh) from Step 1 by the emission factors for CO_2, CH_4, and N_2O (in pounds per MWh) from Step 2.

Note: If your electricity use data is in units of kWh, divide by 1,000 to convert to MWh. Then convert pounds into metric tons by dividing the total by 2,204.62 lbs/metric ton. To convert kilograms into metric tons, divide by 1,000 kg/metric ton (see Equation 6.8). Repeat this step for each gas.

Equation 6.8	**Calculating Indirect Emissions from Electricity Use**
CO_2 Emissions (metric tons) = Electricity Use (MWh) × Emission Factor (lbs CO_2/MWh) ÷ 2,204.62 (lbs/metric ton)	
CH_4 Emissions (metric tons) = Electricity Use (MWh) × Emission Factor (lbs CH_4/MWh) ÷ 2,204.62 (lbs/metric ton)	
N_2O Emissions (metric tons) = Electricity Use (MWh) × Emission Factor (lbs N_2O/MWh) ÷ 2,204.62 (lbs/metric ton)	

To convert CH_4 and N_2O into units of carbon dioxide equivalent, multiply total emissions of each gas (in metric tons) by its IPCC global warming potential (GWP) factor provided in Equation 6.9. Then sum the emissions of each of the three gases in units of CO_2 to obtain total greenhouse gas emissions (see Equation 6.9).

Equation 6.9	**Converting to CO_2-Equivalent and Determining Total Emissions**
CO_2 Emissions (metric tons CO_2e) = CO_2 Emissions (metric tons) × 1 (GWP)	
CH_4 Emissions (metric tons CO_2e) = CH_4 Emissions (metric tons) × 21 (GWP)	
N_2O Emissions (metric tons CO_2e) = N_2O Emissions (metric tons) × 310 (GWP)	

Total Emissions (metric tons CO_2e)	= CO_2 + CH_4 + N_2O (metric tons CO_2e)

6.2.2 Alternate Activity Data

If you are unable to obtain metered electricity use for your buildings or facilities, there are three alternate approaches for estimating your Scope 2 emissions:

1. Estimate electricity use for leased space based on the facility's total annual consumption,
2. Estimate electricity use based on proxy year data, or
3. Estimate electricity use based on known electricity use at comparable facilities.

6.2.2.1 Estimated Electricity Use for Leased Space

If purchase records, electricity bills, or meter readings are not available or applicable (for example if you lease office space in a building owned by another entity or your space is not separately metered), an alternate method is to estimate electricity use based on your share of the building's floor space and the building's total electricity consumption.

This method yields less accurate estimates than the known electricity use method because it is not specific to the particular space you occupy in the building and assumes that all occupants of the building have similar energy consuming habits.

Local governments should disclose the use of estimated electricity use in reporting as part of the calculation methodology disclosure.

To follow this method, you will need the following information, which should be available from your building's property manager:

- Total building area (square feet);
- Area of entity's space (square feet);
- Total building annual electricity use (kWh); and
- Building occupancy rate (e.g., if 75 percent of the building is occupied, use 0.75)

Use this information and Equation 6.10 to estimate your facility's share of the building's electricity use.

Equation 6.10	**Estimating Electricity Use for Leased Space**
Estimated Electricity Use (kWh) = Entity's Area (sq ft) ÷ Building Area (sq ft) × Building Electricity Use (kWh) ÷ Occupancy Rate	

Now you can use your estimated electricity use from Equation 6.10 to follow the guidance in the recommended approach (Section 6.2.1) to estimate to your CO_2, CH_4 and N_2O Scope 2 emissions from the facility.

6.2.2.2 Estimated Electricity Use - Proxy Year Data

You can estimate energy consumption for a facility based on the energy consumed at the building or facility in another year.

Local governments should disclose the use of any proxy years in reporting as part of the calculation methodology disclosure.

Use the following steps to estimate the annual electricity use at your facility:

1. Determine the electricity used in each facility in the proxy year; and
2. Normalize for heating degree days.

Step 1: Determine the electricity used in each facility in the proxy year.

The proxy year can be either another calendar year or else a fiscal year.

Step 2: Normalize for heating and cooling degree days.

Estimate the proportion of electricity used in a year for heating and cooling as a percentage of the total electricity consumed and the proportion of annual electricity used in a year for cooling as a percentage of the electricity consumed. This should be based on the increased electricity consumed during winter months and summer months respectively. Where monthly data is not available, the best recommendation of a facility manger may be used.

Then, determine annual heating and cooling degree days in the region in the year being estimated and the proxy year. The national climate data center website provides information on the heating and cooling degree days by month and by state at www7.ncdc.noaa.gov/CDO/CDODivisionalSelect.jsp#.

Normalize for heating and cooling degree days using Equation 6.11.

Equation 6.11	Normalizing for Heating Degree Days And Cooling Degree Days

Estimated energy consumed in inventory year (kWh)=

$$\left[\frac{E_P \text{ x } E_h)}{D_{HP}} \text{ X } \frac{D_{HI}}{1}\right] + \left[\frac{E_P \text{ x } E_C}{D_{CP}} \text{ X } \frac{D_{CI}}{1}\right] + \left[(1- E_h - E_C) \text{ X } E_P\right]$$

Where:

E_P = electricity used in proxy year (kWh)
E_h = percentage of electricity used for heating
D_{HP} = heating degree days in the proxy year
D_{HI} = heating degree days in inventory year
E_C = percentage of electricity used for cooling
D_{CP} = cooling degree days in the proxy year
D_{CI} = cooling degree days in inventory year

Now you can use your estimated electricity use from Equation 6.11 to follow the guidance in the recommended approach (Section 6.2.1) to estimate your CO_2, CH_4 and N_2O Scope 2 emissions from the facility.

6.2.2.3 Estimated Electricity Use - Comparable Facilities and Square Footage

Where actual electricity records are not available and total annual electricity consumption from the facility is unknown, you can estimate electricity based on the size and function of the facility. Typically this approach is used in cases of one or a few minor facilities. Generally, it should not be used as a substitute for a significant group of buildings or facilities or the entire buildings sector.

Local governments should disclose the use of any comparable facilities data in reporting as part of the calculation methodology disclosure.

Use the following steps to estimate the electricity use at your facility:

1. Determine the size of the facility measured in floor area (square feet);
2. Identify comparable facilities with known annual electricity use and square footage;
3. Determine electricity used per square foot at comparable facility; and
4. Estimate electricity used at facility.

Step 1: Determine the size of the facility measured in floor area (square feet).

Step 2: Identify comparable facilities with known annual electricity use rates and square footage.

If possible these should be facilities owned or operated by the same government. The determination of comparability should include consideration of the primary function of the facility and the primary uses of electricity at each facility. You may also consider the age, hours of operation, number of occupants and the type of heating and cooling systems employed.

If electricity consumption for another comparable facility owned or operated by the local government is not available, you may consult the US Energy Information Administration's Commercial Building Energy Consumption Survey for average energy use by facility type and region of the country at www.eia.doe.gov/emeu/cbecs.

Step 3: Determine electricity used per square foot at comparable facility.

Divide the annual electricity use at the comparable facility by its square footage to obtain a kWh/square foot coefficient.

Step 4: Estimate electricity used at facility.

Multiply this coefficient by the area of the facility for which you are estimating the electricity use.

Equation 6.12	**Estimated Annual Electricity Use - Square Footage**
Estimated Electricity Use (kWh) = $\frac{\text{Annual electricity use at comparable facility (kWh)}}{\text{Size of Comparable Facility (sq. ft.)}} \times \text{Size of Facility Being Estimated (sq. ft.)}$	

Now you can use your estimated electricity use from Equation 6.12 to follow the guidance in the recommended approach (Section 6.2.1) to estimate your CO_2, CH_4 and N_2O Scope 2 emissions from the facility.

6.2.2.4 *Streetlights Only:* Estimated Electricity Use - Installed Wattage

In many cases, metered electricity consumption records are not available for streetlights and traffic signals. In these cases, the most accurate alternate methodology for estimating activity data is based on installed wattage. To estimate indirect emissions from streetlight use based on installed wattage, follow the steps below:

1. Determine the number and wattage of all bulbs in the system;

2. Estimate the average annual daily operating hours for each group of lights;
3. Estimate annual electricity consumption for each group of lights

Step 1: Determine the number and wattage of all bulbs in the system.

Typically this information is available from either the Streets department or the electric utility.

Step 2: Estimate the average annual daily operating hours for each group of lights.

Average annual operating hours of streetlights will depend upon management practices, but is typically between 10 and 13 hours per day. Average annual operating hours for traffic signals will depend upon the use of the light but is generally about 8 hours per day. Consult the Streets department or the electric utility for assistance estimating average annual daily operating hours.

Step 3: Estimate annual electricity consumption for each group of lights.

Use Equation 6.13 for each lighting group, then sum all lighting groups for total estimated electricity use.

Equation 6.13	**Estimated Annual Streetlight Electricity Use - Installed Wattage**
Estimated Annual Electricity Use (kWh) =	

$$\frac{\text{Total installed wattage (watts)} \times \text{Avg. Annual Daily Operating Hours (hours/day)} \times 365\ \text{(days/year)}}{1000\ \text{(watts/kWh)}}$$

Now you can use your estimated electricity use from Equation 6.13 to follow the guidance in the recommended approach (Section 6.2.1) to estimate your CO_2, CH_4 and N_2O Scope 2 emissions from the streetlights.

6.2.3 Alternate Emission Factors

Situations may occur in which there is a desire to use utility-specific emission factors associated with electricity consumption rather than regional factors, but where utility-specific emission factors have not yet been derived and verified in accordance with the California Climate Action Registry as described above. Under such circumstances, it may be possible to obtain and use unverified utility-specific emission factors to estimate emissions associated with electricity consumption.

Unverified utility-specific emission factors should be obtained directly from the applicable utility company. Care should be taken to ensure that these emission factors take into account all of the power transmitted by the utility, including purchased electricity, not just power directly generated by the utility. These emission factors should be based on total quantities of fuel consumed and resulting power generated and delivered for end-use consumption, along with combustion technologies and other factors.

Once obtained, these unverified utility-specific emission factors should be used in Equation 6.7 as described above to estimate electricity-related emissions.

Note that this methodology may be disallowed under future versions of this protocol as the proportion of utilities with third-party verified emissions factors increases throughout the U.S.

6.2.4 Green Power and Renewable Energy Certificate Purchases

Some local governments may be engaged in a "green power" purchases (offered by an electric utility or an independent power provider) or may independently purchase renewable energy credits (RECs). These purchases are encouraged and should be reported as supplemental information in your local government emissions report. However, these purchases may not be deducted from your Scope 2 emissions. Scope 2 emissions result from the power you consume directly, either from a dedicated plant or from the grid, and represent your actual indirect emissions.

We recognize the need to develop a specific accounting framework for green power purchases in order to encourage and incentivize emission reduction efforts. There is not yet consensus on how to accurately and credibly track green power purchases in a GHG accounting framework, beyond allowing you to provide supplementary information about your green power and REC purchases in annual emission reports.

6.2.5 Accounting for Transmission and Distribution Losses

Some electricity is lost during the transmission and distribution (T&D) of power from electric generators to end users. T&D losses should be reported by the entity that owns or controls the T&D lines, not by the end user of the power. Thus, if the local government does not own or control the T&D system delivering the electricity you consume, you should not account for T&D losses as Scope 2 in your GHG inventory. You should only report the emissions associated with the amount of electricity you consume within your facilities as Scope 2.

Because of this, the default emission factors in the Protocol do not account for T&D losses and are therefore appropriate for end users who do not own or operate T&D lines. If your local government owns or controls the T&D system but generates (rather than purchases) the electricity transmitted through the system, you should not report the emissions associated with T&D losses under Scope 2, as they would already be accounted for under Scope 1. This is the case when generation, transmission, and distribution systems are vertically integrated and owned or controlled by the same entity.

However, if you purchase (rather than generate) electricity and transport it through a T&D system that you own or control, you should report the emissions associated with T&D losses from power purchases under Scope 2. See Chapter 8 for more information on how to calculate these Scope 2 emissions.

6.3 Steam and District Heating Purchases

Some local governments purchase steam or district heating for purposes like providing space heating in the buildings or providing process heating for industrial needs. Emissions associated with these sources are considered to be indirect. If you own or operate a combined heat and power (CHP) facility or conventional boiler plant, you should calculate your direct emissions from the combustion of the fossil fuels at the plant as described in Section 6.1 or Chapter 8 .

This section provides guidance on calculating Scope 2 emissions from imported steam or district heating that is produced at a conventional boiler plant (i.e., not a CHP facility). If you purchase steam or heat from a CHP facility, please refer to Section 6.4.

To estimate your GHG emissions from imported steam or district heating, follow these four steps:

1. Determine energy obtained from steam or district heating;
2. Determine appropriate emission factors for the steam or district heating;
3. Calculate emissions from imported steam or district heating; and
4. Convert to units of carbon dioxide equivalent, and determine total emissions.

Step 1: Determine energy obtained from steam or district heating.

First, determine the quantity of acquired steam or district heating. You may use metered records of energy use, purchase records, or utility/supplier energy bills to determine annual consumption. Monthly energy bills must be summed over the year to give annual consumption.

Consumption data should be expressed in units of million British thermal units (MMBtu). If your consumption data is expressed in therms, you can convert the values to units of MMBtu by multiplying by 0.1, as shown in Equation 6.14.

Equation 6.14	**Converting Steam Consumption from Therms to MMBtu**
Energy Consumption (MMBtu) = Energy Consumption (therms) x 0.1 (MMBtu/therm)	

If your steam consumption is measured in pounds (lbs), you either need to monitor the temperature and pressure of the steam you have received, or request it from the steam supplier. This information can be used with standard steam tables to calculate the steam's energy content. Calculate the thermal energy of the steam using saturated water at 212°F as the reference (Source: American Petroleum Institute, *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry*, 2001). The thermal energy consumption is calculated as the difference between the enthalpy of the steam at the delivered conditions and the enthalpy (or heat content) of the saturated water at the reference conditions (or heat content).

The heat content of the steam can be found in standard steam tables (for example, the *Industrial Formulation 1997 for the Thermodynamic Properties of Water and Steam* published by the International Association for the Properties of Water and Steam (IAPWS)). The enthalpy of saturated water at the reference conditions is 180 Btus per pound. The thermal energy consumption for the steam can then be calculated as shown in Equation 6.15.

Equation 6.15	**Converting Steam Consumption from Pounds to MMBtu**
Energy Consumption *(MMBtu)* = [Enthalpy of Delivered Steam *(Btu/lb)* - 180 *(Btu/lb)*] × Steam Consumed *(lbs)* ÷ 1,000,000 *(Btu/MMBtu)*	

Step 2: Determine the appropriate emission factors for the steam or district heating.

Because emissions vary with fuel type, you must know the type of fuels that are burned in the plant supplying your steam or hot water. You can obtain this information from the plant's energy supplier. Once you know the fuels combusted to generate the steam or hot water, determine the appropriate emission factors for each fuel combusted. You can then use default emission factors for CO2, CH4, and N2O from Table C.1 and Table C.3.

Next, you must determine the efficiency of the boiler used to produce the steam or hot water and any transport losses that occur in delivering the steam, and calculate a total efficiency factor using Equation 6.16. Boiler efficiency is the ratio of steam output to fuel input, in units of energy, which you should obtain from your steam or heat supplier. If transport losses or boiler efficiency vary seasonally, these factors should be calculated on a monthly or seasonal basis and summed to yield total annual factors.

Equation 6.16	Calculating System Efficiency
Total Efficiency Factor (%) = Boiler Efficiency x (100% - Transport Losses) (%) (%)	

Calculate carbon dioxide, methane, and nitrous oxide emission factors that reflect the efficiency and fuel mix of the boiler employed to generate your steam or hot water using Equation 6.17.

Equation 6.17	Calculating Emission Factors
CO_2 Emission Factor (kg CO_2 / MMBtu) = Fuel-Specific Emission Factor ÷ Total Efficiency Factor (kg CO_2 / MMBtu) (%)	
CH_4 Emission Factor (kg CH_4 / MMBtu) = Fuel-Specific Emission Factor ÷ Total Efficiency Factor (kg CH_4 / MMBtu) (%)	
N_2O Emission Factor (kg N_2O / MMBtu) = Fuel-Specific Emission Factor ÷ Total Efficiency Factor (kg N_2O / MMBtu) (%)	

If you are unable to obtain the specific system efficiency of the boiler that generated your steam or heat, apply a default total efficiency factor—boiler efficiency and transport losses combined—of 75 percent in Equation 6.17.

Step 3: Calculate emissions from imported steam or district heating.

Once you have both the value of total energy consumed from Step 1 and the appropriate emission factors from Step 2, use Equation 6.18 to calculate GHG emissions from imported steam or hot water.

Equation 6.18	Calculating Emissions From Imported Steam or Heat
Total CO_2 Emissions (metric tons) = Energy Consumed x Emission Factor x 0.001 (MMBtu) (kg CO_2 / MMBtu) (metric tons/kg)	
Total CH_4 Emissions (metric tons) = Energy Consumed x Emission Factor x 0.001 (MMBtu) (kg CH_4 / MMBtu)) (metric ton/kg)	
Total N_2O Emissions (metric tons) = Energy Consumed x Emission Factor x 0.001 (MMBtu) (kg N_2O / MMBtu) (metric ton/kg)	

Step 4: Convert to units of carbon dioxide equivalent and determine total emissions.

Use the IPCC global warming potential factors provided in Equation 6.19 to convert CH4 and N2O emissions to units of CO2 equivalent. Then sum your emissions of all three gases to determine your total indirect emissions from imported heat or steam (see Equation 6.19).

Equation 6.19	Converting to CO_2 Equivalent and Determining Total Emissions
CO_2 Emissions = CO_2 Emissions × 1 (metric tons CO_2e) (metric tons) (GWP)	

CH_4 Emissions = CH_4 Emissions × 21 (metric tons CO_2e) (metric tons) (GWP)	
N_2O Emissions = N_2O Emissions × 310 (metric tons CO_2e) (metric tons) (GWP)	
Total Emissions = $CO_2 + CH_4 + N_2O$ (metric tons CO_2e) (metric tons CO_2e)	

6.4 Heat and Power Purchases from a Combined Heat & Power Facility

Emissions from CHP facilities represent a special case for estimating indirect emissions. Because CHP simultaneously produces electricity and heat (or steam), attributing total GHG emissions to each product stream would result in double counting. Thus, when two or more parties receive the energy streams from CHP plants, GHG emissions must be determined and allocated separately for heat production and electricity production.

Since the output from CHP results simultaneously in heat and electricity, you can determine what "share" of the total emissions is a result of electricity and heat by using a ratio based on the Btu content of heat and/or electricity relative to the CHP plant's total output.

The process for estimating indirect emissions from heat and power produced at a CHP facility involves the following four steps:

1. Obtain total emissions and power and heat generation information from CHP facility;
2. Determine emissions attributable to net heat production and electricity production;
3. Calculate emissions attributable to your portion of heat and electricity consumed;
4. Convert to units of carbon dioxide equivalent and determine total emissions.

Step 1: Obtain emissions and power and heat information from the CHP facility.

You will need to obtain the following information from the CHP plant owner or operator to estimate indirect GHG emissions:

- Total emissions of carbon dioxide, methane, and nitrous oxide from the CHP facility, based on fuel input information;
- Total electricity production from the CHP plant, based on generation meter readings; and
- Net heat production from the CHP plant.

Net heat production refers to the useful heat that is produced in CHP, minus whatever heat returns to the boiler as steam condensate, as shown in Equation 6.20.

Equation 6.20	**Calculating Net Heat Production**
Heat of Heat of **Net Heat Production** = Steam Export - Return Condensate (MMBtu) (MMBtu) (MMBtu)	

Step 2: Determine emissions attributable to net heat production and electricity production for the CHP plant.

The most consistent approach for allocating GHG emissions in CHP applications is the efficiency method, which allocates emissions of CHP plants between electric and thermal outputs on the basis of the energy input used to produce the separate steam and electricity products. To use this method, you must know the total emissions from the CHP plant, the total steam (or heat) and electricity production, and the steam (or heat) and electricity efficiency of the facility. Use the following steps to determine the share of emissions attributable to steam (or heat) and electricity production.

Determine the total direct emissions from the CHP system.

Calculate total direct GHG emissions using the methods described in Section 6.1.1 or Chapter 8 .

Determine the total steam and electricity output for the CHP system.

To determine the total energy output of the CHP plant attributable to steam production, use published tables that provide heat content values for steam at different temperature and pressure conditions (for example, the Industrial Formulation 1997 for the Thermodynamic Properties of Water and Steam published by the International Association for the Properties of Water and Steam (IAPWS)). Energy content values multiplied by the quantity of steam produced at the temperature and pressure of the CHP plant yield energy output values in units of MMBtu.

Alternatively, determine net heat (or steam) production (in MMBtu) by subtracting the heat of return condensate (MMBtu) from the heat of steam export (MMBtu). To convert total electricity production from MWh to MMBtu, multiply by 3.412 MMBtu/MWh.

Determine the efficiencies of steam and electricity production.

Identify steam (or heat) and electricity production efficiencies. If actual efficiencies of the CHP plant are not known, use a default value of 80 percent for steam and a default value of 35 percent for electricity. The use of default efficiency values may, in some cases, violate the energy balance constraints of some CHP systems. However, total emissions will still be allocated between the energy outputs. If the constraints are not satisfied, the efficiencies of the steam and electricity can be modified until constraints are met.

Determine the fraction of total emissions allocated to steam and electricity production.

Allocate the emissions from the CHP plant to the steam and electricity product streams by using Equation 6.21.

Equation 6.21	Allocating CHP Emissions to Steam and Electricity
Step 1:	$E_H = (H \div e_H) \div [(H \div e_H) + (P \div e_P)] \times E_T$
Step 2:	$E_P = E_T - E_H$

where:

E_H = Emissions allocated to steam production;
H = Total steam (or heat) output (MMBtu);
e_H = Efficiency of steam (or heat) production;
P = Total electricity output (MMBtu);
e_P = Efficiency of electricity generation;
E_T = Total direct emissions of the CHP system; and
E_P = Emissions allocated to electricity production.

Step 3: Calculate emissions attributable to your portion of heat and electricity consumed.

Once you have determined total emissions attributable to heat (or steam) and electricity production, you will need to determine your portion of heat or electricity consumed, and thus your indirect GHG emissions associated with heat or electricity use. First, obtain your electricity and heat (or steam) consumption information, then use Equation 6.22 and Equation 6.23 to calculate your share of emissions, as appropriate.

Equation 6.22	Calculating Indirect Emissions Attributable To Electricity Consumption

Indirect Emissions Attributable to Electricity Consumption (*metric tons*) =

Total CHP Emissions Attributable to Electricity Production *(metric tons)* × (Your Electricity Consumption (*kWh*) ÷ Total CHP Electricity Production (*kWh*))

Equation 6.23	Calculating Indirect Emissions Attributable To Heat (or Steam) Consumption

Indirect Emissions Attributable to Heat Consumption (*metric tons*) =

Total CHP Emissions Attributable to Heat Production *(metric tons)* × (Your Heat Consumption *(MMBtu)* ÷ CHP Net Heat Production *(MMBtu)*)

Step 4: Convert to units of CO2 equivalent and determine total emissions.

Finally, use the IPCC global warming potential (GWP) factors provided in Equation 6.24 to convert methane and nitrous oxide emissions to units of carbon dioxide equivalent. Then sum your emissions of all three gases to determine your total emissions from stationary combustion (see Equation 6.24).

Equation 6.24	Converting to CO_2 Equivalent and Determining Total Emissions
CO_2 Emissions (metric tons CO_2e) = CO_2 Emissions (metric tons) × 1 (GWP)	
CH_4 Emissions (metric tons CO_2e) = CH_4 Emissions (metric tons) × 21 (GWP)	
N_2O Emissions (metric tons CO_2e) = N_2O Emissions (metric tons) × 310 (GWP)	
Total Emissions (metric tons CO_2e) = CO_2 + CH_4 + N_2O (metric tons CO_2e)	

6.5 District Cooling

Some local governments purchase cooling, such as chilled water, for either cooling or refrigeration when they do not operate cooling compressors on-site at their facilities. Conceptually, purchased chilled water is similar to purchased heat or steam, with the primary difference being the process used to generate the chilled water. When you purchase cooling services using district cooling, the compressor system that produces the cooling is driven by either electricity or fossil fuel combustion. Your Scope 2 emissions from district cooling represent your share of the total cooling demand from the cooling plant, multiplied by the total GHG emissions generated by that plant.

This approach allows you to estimate the portion of energy used at the district cooling plant directly attributable to your cooling by utilizing the ratio of cooling demand to energy input for the cooling plant, known as the "coefficient of performance" (COP).

Step 1: Determine your annual cooling demand.

While your cooling bill may be reported in terms of million Btu (MMBtu), it will typically report cooling demand in ton-hours. You can convert ton-hours of cooling demand to MMBtu using Equation 6.25. If you are billed monthly, sum together your monthly cooling demand to yield an annual total.

Equation 6.25	Calculating Annual Cooling Demand
Cooling Demand (MMBtu) = Cooling Demand (ton-hour) × 12,000 (Btus/ton-hour) ÷ 1,000,000 (MMBtu/Btu)	

Step 2: Estimate COP for the plant's cooling system.

The preferred approach is to obtain the source-specific COP for your cooling plant. If you can obtain the COP for the cooling plant, proceed to Step 3.

If you cannot obtain the COP for the plant itself, determine the type of chiller used by the district cooling plant. With that information, an estimate of the COP may be selected from the default values shown in Table 6.1.

Table 6.1 Typical Chiller Coefficients of Performance

Chiller Type	COP	Energy Source
Absorption Chiller	0.8	Natural Gas
Engine-Driven Compressor	1.2	Natural Gas
Electric-Driven Compressor	4.2	Electricity

Step 3: Determine energy input.

To determine the energy input to the system resulting from your cooling demand, use Equation 6.26. For an electric driven compressor, convert the energy input in MMBtu into kWh by multiplying by 293.1.

Equation 6.26	Calculating Energy Input
Energy Input = Cooling Demand ÷ COP (MMBtu) (MMBtu)	

Where Cooling Plant Uses Absorption Chillers or Combustion Engine-Driven Compressors. In this case, calculate the compressor's emissions using the stationary combustion methods outlined in Section 6.1. If you can determine what type of fuel is being used, multiply the energy input by source-specific or default emission factors for CO_2, CH_4, and N_2O from Table C.1 and Table C.3. If the fuel type cannot be determined, assume the fuel used is natural gas. Use Equation 6.27 to calculate emissions.

Equation 6.27	Calculating Total Cooling Emissions
Total CO_2 Emissions (metric tons) = Energy Input x Emission Factor x 0.001 (MMBtu) (kg CO_2 / MMBtu) (metric tons/kg)	
Total CH_4 Emissions (metric tons) = Energy Input x Emission Factor x 0.001 (MMBtu) (kg CH_4 / MMBtu) (metric tons/kg)	
Total N_2O Emissions (metric tons) = Energy Input x Emission Factor x 0.001 (MMBtu) (kg N_2O / MMBtu) (metric tons/kg)	

Where Cooling Plant Uses Electric-Driven Compressors. In this case, calculate emissions using the procedures for estimating indirect emissions from electricity use described in Section 6.2.

Step 4: Calculate GHG emissions resulting from cooling, convert to units of carbon dioxide equivalent, and determine total emissions.

Finally, convert emissions to units of carbon dioxide equivalent using Equation 6.28 and sum to determine total emissions from cooling.

Equation 6.28	**Converting to CO_2-equivalent and Determining Total Emissions**
CO_2 Emissions = CO_2 Emissions × 1 (metric tons CO_2e) (metric tons) (GWP)	
CH_4 Emissions = CH_4 Emissions × 21 (metric tons CO_2e) (metric tons) (GWP)	
N_2O Emissions = N_2O Emissions × 310 (metric tons CO_2e (metric tons) (GWP)	
Total Emissions = CO_2 + CH_4 + N_2O (metric tons CO_2e) (metric tons CO_2e)	

6.6 Fugitive Emissions from Refrigerants & Fire Suppression Equipment

Your buildings and facilities likely contain refrigeration systems, like air conditioners, chillers and refrigerators. These systems may use refrigerants that contain or consist of HFC compounds that are to be reported under this Protocol. Through the installation, use and disposal of these systems, refrigerant leaks are likely to occur. These leaks are considered Scope 1 fugitive emissions. While leakage from refrigeration systems may not seem like large source of GHG emissions, some of these compounds have high GWPs, and thus even small fugitive emissions can translate into significant emissions in terms of CO_2 equivalent.

Note that only those refrigerants that contain or consist of compounds of the GHGs in Appendix A should be reported. It is also possible that you use a refrigerant that is a blend of a number of compounds - refrigerant blends that should be reported under this Protocol land their associated GWPs are listed in Appendix A, Table A.2.

Your local government may also use HFCs in its fire suppression equipment. HFCs are the most widely employed replacements for Halon 1301 in total flooding applications, and are also employed as replacements for Halon 1211 in streaming applications. Since the production and sale of halons were banned in the United States in 1994, these non-ozone depleting extinguishing agents have emerged as the halon replacement agent of choice in some applications.[10]

As fire protection equipment is tested or deployed, emissions of these HFCs are released. Thus, if your local government owns or operate fire suppression systems and equipment and has tested or deployed these systems, you should assess whether any HFCs have been released.

Before beginning any calculations in this section, you should first confirm what refrigerants and HFCs are being used within your local government operations. Only those compounds listed in Table A.1 and Table A.2 should be included in your GHG inventory.

[10] US EPA *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2006*, April 2008, 4.20.

Box 6.4 Ozone Depleting Substances and Climate Change
Did you know that not all HFCs that affect climate change are considered greenhouse gas emissions? A number of widely-used refrigerants, including R-22 (more commonly known as Freon), are classified as ozone depleting substances (ODS) and are being phased out under the Montreal Protocol, an international treaty designed to protect the ozone layer that entered into force in 1989. While these substances do have a global warming potential, and therefore contribute to climate change, they are not classified as greenhouse gas emissions under the Kyoto Protocol because they are already being phased out under the Montreal Protocol. When assessing your fugitive emission sources, please keep in mind that CFC and HCFCs, including Freon, should not be included in your emissions report. You should only include emissions of the HFCs listed in Appendix A. For more information on ozone-depleting substances and the Montreal Protocol, visit EPA's ozone depletion website at http://www.epa.gov/ozone/strathome.html.

Below are the recommended and alternate approaches for calculating your Scope 1 fugitive emissions from refrigerant systems and fire suppression equipment in your facilities.

RECOMMENDED	ALTERNATE
Mass balance method ☑	Simplified mass balance ☑
	Estimations based on equipment inventory and use

6.6.1 Recommended Approach: Mass Balance Method

The mass balance approach is the most accurate method for determining HFC emissions. This method is recommended for local governments who service their own equipment. To calculate HFC emissions using the mass balance approach, follow these three steps:

1. Determine the base inventory for each HFC in use at each facility;
2. Calculate changes to the base inventory for each HFC based on purchases and sales of HFC and changes in total capacity of the equipment; and
3. Calculate annual emissions of each type of HFC, convert to units of carbon dioxide equivalent, and determine total HFC emissions for each facility.

Box 6.5 Potential Sources for Facility HFC Activity Data
• Accounts Payable • HV/AC maintenance

Step 1: Determine the base inventory for each HFC.

First determine the quantity of the HFC in storage at the beginning of the year (A) and the quantity in storage at the end of the year (B), as shown in Table 6.2. HFC in storage (or in inventory) is the total stored on site in cylinders or other storage containers and does not include HFC contained within equipment.

Step 2: Calculate changes to the base inventory.

Next, include any purchases or acquisitions of each HFC, sales or disbursements of each HFC, and any changes in capacity of equipment. Additions and subtractions refer to HFC placed in or removed from the stored inventory, respectively.

Purchases/Acquisitions. This is the sum of all the HFC acquired during the year either in storage containers or in equipment (item C in Table 6.2). Purchases and other acquisitions may include HFC:

- Purchased from producers or distributors,
- Provided by manufactures or inside equipment,
- Added to equipment by contractors or other service personnel (but not if that HFC is from your inventory), and
- Returned after off-site recycling or reclamation.

Sales/Disbursements. This is the sum of all the HFC sold or otherwise disbursed during the year either in storage containers or in equipment (item D in Table 6.2). Sales and disbursements may include HFC:

- In containers or left in equipment that is sold,
- Returned to suppliers, and
- Sent off-site for recycling, reclamation, or destruction.

Net Increase in Total Full Charge of Equipment. This is the net change to the total equipment volume for a given HFC during the year (item E in Table 6.2). Note that the net increase in total full charge of equipment refers to the full and proper charge of the equipment rather than to the actual charge, which may reflect leakage. It accounts for the fact that if new equipment is purchased, the HFC that is used to charge that new equipment should not be counted as an emission.

It also accounts for the fact that if the amount of HFC recovered from retiring equipment is less than the full charge, then the difference between the full charge and the recovered amount has been emitted. Note that this quantity will be negative if the retiring equipment has a total full charge larger than the total full charge of the new equipment.

If the beginning and ending total capacity values are not known, this factor can be calculated based on known changes in equipment. The total full charge of new equipment (including equipment retrofitted to use the HFC in question) minus the full charge of equipment that is retired or sold (including full charge of HFC in question from equipment that is retrofit to use a different HFC) also provides the change in total capacity.

Step 3: Calculate annual emissions of each type of HFC, convert to units of carbon dioxide equivalent, and determine total HFC emissions.

For each type of HFC or refrigerant blend, use Equation 6.29 and your data from Table 6.2 to calculate total annual emissions of each type of HFC at each of your facilities.

Table 6.2 Base Inventory and Inventory Changes

	Inventory	Amount (kg)
Base Inventory		
A	HFC in inventory (storage) at the beginning of the year	
B	HFC in inventory (storage) at the end of the year	
Additions to Inventory		
1	Purchases of HFC (including HFC in new equipment)	
2	HFC returned to the site after off-site recycling	
→ C	Total Additions (1+2)	
Subtractions from Inventory		
3	Returns to supplier	
4	HFC taken from storage and/or equipment and disposed of	
5	HFC taken from storage and/or equipment and sent off-site for recycling or reclamation	
→ D	Total Subtractions (3+4+5)	
Net Increase in Full Charge/Nameplate Capacity		
6	Total full charge of new equipment	
7	Total full charge of retiring equipment	
→ E	Change to nameplate capacity (6-7)	

Equation 6.29	**Calculating Emissions of Each Type of HFC Using the Mass Balance Method**

$$\textbf{Total Annual Emissions} \text{ (metric tons of HFC)} = \underset{(kg)}{(A} - \underset{(kg)}{B} + \underset{(kg)}{C} - \underset{(kg)}{D} - \underset{(kg)}{E)} \div \underset{(kg/metric\ tons)}{1{,}000}$$

Next, use Equation 6.30 and the appropriate global warming potential factors from Appendix A to convert each HFC to units of carbon dioxide equivalent.

Equation 6.30	**Converting to CO_2-equivalent**

$$\underset{(mt\ CO_2e)}{\textbf{HFC Type A Emissions}} = \underset{(metric\ tons\ HFC\ Type\ A)}{\text{HFC Type A Emissions}} \times \underset{(HFC\ A)}{\text{GWP}}$$

Finally, sum the totals of each type of HFC, in units of carbon dioxide equivalent, to determine total HFC emissions (see Equation 6.31) at each facility.

Equation 6.31	**Determining total HFC emissions**

$$\underset{(mt\ CO_2e)}{\textbf{Total HFC Emissions}} = \underset{(mt\ CO_2\text{-}e)}{\text{HFC Type A}} + \underset{(mt\ CO_2e)}{\text{HFC Type B}} + \ldots$$

6.6.2 Alternate Approaches

6.6.2.1 Simplified Mass Balance Method

If you do not have the necessary data to use the mass balance approach outlined above, you should use the simplified mass balance approach. This method may be used either by local governments that service their own equipment or by local governments that have contractors service their equipment. This method requires information on the quantity of HFC used to charge new equipment during installation, the quantity of HFC used to service equipment, the quantity of HFC recovered from retiring equipment, and the total full charges of new and retiring equipment.

To calculate HFC emissions using the simplified mass balance approach, follow these three steps:

1. Determine the types and quantities of HFC used at each facility;
2. Calculate annual emissions of each type of HFC; and
3. Convert to units of carbon dioxide equivalent and determine total HFC emissions at each facility.

Step 1: Determine the types and quantities of HFC used.

For each type of HFC used, determine the following quantities used or recovered during the reporting year, if applicable:

- Quantity of HFC used to charge new equipment during installation (if you installed new equipment that was not pre-charged by the manufacturer)
- Total full charge (capacity) of new equipment using this HFC (if you installed new equipment that was not pre-charged by the manufacturer)
- Quantity of HFC used to service equipment.
- Total full charge (capacity) of retiring equipment (if you disposed of equipment during the reporting year)
- Quantity of HFC recovered from retiring equipment (if you disposed of equipment during the reporting year)

If you have contractors that service your equipment, you should obtain the required information from the contractor. Always track and maintain the required information carefully in order to obtain accurate estimates of emissions.

Note that “total full charge” refers to the full and proper charge of the equipment rather than to the actual charge, which may reflect leakage. For more information, see the description of “Net Increase in Total Full Charge of Equipment” from Step 2 in the Mass Balance Approach above.

Step 2: Calculate annual emissions of each type of HFC.

Next, use Equation 6.32 to calculate emissions for each type of HFC used at your facility. Repeat Equation 6.32 for each type of HFC used.

Equation 6.32	**Calculating Emissions of Each Type of HFC**

Total Annual Emissions (metric tons) =
$$(P_N - C_N + P_S + C_D - R_D) \div 1{,}000$$
(kg) (kg) (kg) (kg) (kg) (kg/metric tons)

Where:
P_N = purchases of HFC used to charge new equipment *
C_N = total full charge of the new equipment *
P_S = quantity of HFC used to service equipment
C_D = total full charge of retiring equipment
R_D = HFC recovered from retiring equipment

* Omitted if the equipment has been pre-charged by the manufacturer

Step 3: Convert to units of carbon dioxide equivalent and determine total annual HFC emissions.

Use Equation 6.30 and the appropriate global warming potential factors from Appendix A to convert each HFC to units of carbon dioxide equivalent.

Finally, sum the totals of each type of HFC, in units of carbon dioxide equivalent, to determine total HFC emissions (see Equation 6.31).

6.6.2.2 Estimation Based on Equipment Inventory and Refrigerant Use

This alternate approach estimates emissions by multiplying the quantity of refrigerants used by default emission factors. Because default emission factors are highly uncertain, the resulting emissions estimates are considered much less accurate than the mass balance approach, and may result in an overestimation of your Scope 1 fugitive emissions.

Default emission factors are currently not available for fire suppression equipment or systems.

To estimate emissions using the alternative approach, follow these three steps:

1. Determine the types and quantities of refrigerants used;
2. Estimate annual emissions of each type of HFC; and
3. Convert to units of carbon dioxide equivalent and determine total HFC emissions.

Step 1: Determine the types and quantities of refrigerants used.

To estimate emissions, you must determine the number and types of refrigeration and air conditioning equipment, by equipment category; the types of refrigerant used; and the refrigerant charge capacity of each piece of equipment (see Table 6.3). If you do not know the refrigerant charge capacity of each piece of equipment, use the upper bound of the range provided by equipment type in Table 6.3.

Step 2: Estimate annual emissions of each type of refrigerant.

For each type of refrigerant, use Equation 6.33 to estimate annual emissions. Default emission factors are provided in Table 6.3 by equipment type. The equation includes emissions from installation, operation, and disposal of equipment. If you did not install or dispose of equipment during the reporting year, do not include emissions from these activities in your estimation.

Note that refrigerants may be blends of HFCs. Table A.2 lists the global warming potential factors for selected blends.

Step 3: Convert to units of carbon dioxide equivalent and determine total HFC emissions.

Use Equation 6.30 and the appropriate global warming potential factors from Appendix A to convert each HFC to units of carbon dioxide equivalent.

Finally, sum the totals of each type of HFC, in units of carbon dioxide equivalent, to determine total HFC emissions (see Equation 6.31).

Table 6.3 Default Emission Factors for Refrigeration / Air Conditioning Equipment

Type of Equipment	Capacity (kg)	Installation Emission Factor k (% of capacity)	Operating Emission Factor x (% of capacity / year)	Refrigerant Remaining at Disposal y (% of capacity)	Recovery Efficiency z (% of remaining)
Domestic Refrigeration	0.05 - 0.5	1 %	0.5 %	80 %	70 %
Stand-alone Commercial Applications	0.2 - 6	3 %	15 %	80 %	70 %
Medium & Large Commercial Refrigeration	50 - 2,000	3 %	35 %	100 %	70 %
Industrial Refrigeration including Food Processing and Cold Storage	10 - 10,000	3 %	25 %	100 %	90 %
Chillers	10 - 2,000	1 %	15 %	100 %	95 %
Residential and Commercial A/C including Heat Pumps	0.5 - 100	1 %	10 %	80 %	80 %

Source: IPCC, *Guidelines for National Greenhouse Gas Inventories* (2006), Volume 3: Industrial Processes and Product Use, Table 7.9.
Note: Emission factors above are the most conservative of the range provided by the IPCC. The ranges in capacity are provided for reference. You should use the actual capacity of your equipment. If you do not know your actual capacity, you should use the high end of the range provided (e.g., use 2,000 kg for chillers).

Equation 6.33	Estimating Emissions of Each Type of Refrigerant

For each type of refrigerant:

Total Annual Emissions = $[\,(C_N \times k) + (C \times x \times T) + (C_D \times y \times (1 - z))\,] \div 1{,}000$

(metric tons) (kg) (%) (kg) (%) (years) (kg) (%) (%) (kg/metric ton)

Where:

C_N = quantity of refrigerant charged into the new equipment [1]

C = total full charge (capacity) of the equipment

T = time in years equipment was in use (e.g., 0.5 if used only during half the year and then disposed)

C_D = total full charge (capacity) of equipment being disposed of [2]

k = installation emission factor [1]

x = operating emission factor

y = refrigerant remaining at disposal [2]

z = recovery efficiency [2]

[1] Omitted if no equipment was installed during the reporting year or the installed equipment was pre-charged by the manufacturer

[2] Omitted if no equipment was disposed of during the reporting year

Chapter 7 Vehicle Fleet

The Vehicle Fleet Sector within your inventory includes emissions from all vehicles owned or operated by the local government. A local government's vehicle fleet may contain a wide array of vehicles running on a variety of fuels (see Box 7.1).

This chapter provides guidance on calculating all GHGs emissions from your vehicle fleet including:

- Scope 1 mobile combustion emissions;
- Scope 1 fugitive emissions from mobile air conditioning;
- Biogenic CO2 emissions from the combustion of biofuels; and
- Emissions from alternative fuel vehicles.

Box 7.1 Common Types of Local Government Fleet Vehicles

Passenger fleet vehicles
Light, medium, and heavy-duty trucks
Police and fire equipment
Transit vehicles
Sanitation and street sweeping equipment
Port and airport on and off-road vehicles
Aircraft and maritime equipment
Construction Equipment
Forklifts and scissorlifts
Groundskeeping equipment

7.1 Mobile Combustion

Mobile combustion sources include both on-road and off-road vehicles such as automobiles, trucks, buses, trains, ships and other marine vessels, airplanes, tractors, and construction equipment. The combustion of fossil fuels in mobile sources emits CO_2, CH_4 and N_2O.

Emissions from mobile combustion can be estimated based on vehicle fuel use and miles traveled data. CO_2 emissions, which account for the majority of emissions from mobile sources, are directly related to the quantity of fuel combusted and thus can be calculated using fuel consumption data. CH_4 and N_2O emissions depend more on the emission control technologies employed in the vehicle and distance traveled. Calculating emissions of CH_4 and N_2O requires data on vehicle characteristics (which takes into account emission control technologies) and vehicle miles traveled. Because of this distinction, guidance on calculating CO_2 is provided separately from guidance on calculating CH_4 and N_20.

7.1.1 Mobile Combustion CO_2 Emissions

Below are the recommended and alternate activity data and emission factors for calculating your Scope 1 CO_2 emissions from mobile combustion. The following sections detail how to calculate your emissions based on the activity data and emission factors you choose to utilize.

	RECOMMENDED	ALTERNATE
ACTIVITY DATA	Known fuel use ☑	Fuel estimates based on detailed annual mileage and vehicle fuel economy ☑
		Fuel estimates based on annual mileage and vehicle fuel economy
		Fuel estimates based on dollars spent
		Proxy year fuel use data

	RECOMMENDED	ALTERNATE
EMISSION FACTOR	Published emission factor by fuel type (state- or region-specific) ☑	Default by fuel type (national) ☑

7.1.1.1 Recommended Approach

The recommended approach requires obtaining data on actual fuel consumption by fuel type to be used as activity data, and deriving or obtaining a state- or regionally-specific emission factors for each fuel type.

Calculating CO_2 emissions using this approach involves three steps:

1. Identify total annual fuel consumption by fuel type;
2. Determine the appropriate emission factor; and
3. Calculate total CO_2 emissions.

Step 1: Identify total annual fuel consumption by fuel type.

Methods include direct measurements of fuel use (official logs of vehicle fuel gauges or storage tanks); collected fuel receipts; and purchase records for bulk storage fuel purchases (in cases where you operate a fleet and store fuel at a facility). For bulk purchase records, use Equation 7.1 to account for changes in fuel stocks when determining your annual fuel consumption. Total annual fuel purchases should include both fuel purchased for the bulk fueling facility and fuel purchased for vehicles at other fueling locations.

Box 7.2 Potential Sources for Fleet Activity Data

- Accounts payable
- Departmental records
- Fleet manager
- Fuel tracking system
- Fuel vendors/suppliers
- Insurance department
- Maintenance records
- Mileage reimbursement records

Equation 7.1	**Accounting for Changes in Fuel Stocks From Bulk Purchases**
Total Annual Consumption = Total Annual Fuel Purchases + Amount Stored at Beginning of Year – Amount Stored at End of Year	

Step 2: Determine the appropriate CO_2 emission factor for each fuel.

As many states (and even some regions or air districts within states) are adopting renewable fuels standards[11] that mandate different blends of transportation fuels sold within their state, emission factors based on national fuel averages available from national agencies may not be the most accurate emission factors for fuels sold in your region.

Local governments are encouraged to contact their regional or state transportation or environmental agency to see if they have published CO_2 emission factors for the fuel blend sold in your jurisdiction.

If you cannot obtain regional- or state-specific emission factors, use the default CO_2 emission factors by fuel type in Table C.9

Step 3: Calculate total CO_2 emissions and convert to metric tons.

To determine your CO_2 emissions from mobile combustion, first multiply your fuel use from Step 1 by the CO_2 emission factor from Step 2, and then convert kilograms to metric tons. Repeat the calculation for each fuel type, then sum (see Equation 7.2).

[11] A renewable fuel standard is a government mandate calling for a certain amount of renewable fuel production by a set date, or a requirement of petroleum blenders to mix a certain percentage of ethanol with gasoline.

Equation 7.2	Calculating CO_2 Emissions From Mobile Combustion
Fuel A CO_2 Emissions (metric tons) = Fuel Consumed (gallons) × Emission Factor (kg CO_2/gallon) ÷ 1,000 (kg/metric ton)	
Fuel B CO_2 Emissions (metric tons) = Fuel Consumed (gallons) × Emission Factor (kg CO_2/gallon) ÷ 1,000 (kg/metric ton)	
Total CO_2 Emissions (metric tons) = CO_2 from Fuel A (metric tons) + CO_2 from Fuel B (metric tons) + … (metric tons)	

7.1.1.2 Alternate Approaches

7.1.1.2.1 Detailed Annual Mileage and Fuel Efficiency

If you do not have fuel use data, but have detailed information about your fleet and annual mileage by vehicle, you may estimate your fuel consumption using the following steps:

1. Identify the vehicle make, model, fuel type, and model years for all the vehicles you operate;
2. Identify the annual distance traveled by vehicle type;
3. Determine the fuel economy of each vehicle; and
4. Convert annual mileage to fuel consumption.

Step 1: Identify the vehicle make, model, fuel type, and model years for all the vehicles you operate.

Step 2: Identify the annual mileage traveled by vehicle.

Sources of annual mileage data include odometer readings, maintenance records or trip manifests that include distance to destinations.

Alternately, if you have reimbursement records that detail reimbursement amounts for trips made in local government fleet vehicles, you can use Equation 7.3 to convert dollars spent on reimbursement to mileage.

Equation 7.3	Estimating Annual Mileage Based on Travel Reimbursement Cost
Annual Mileage (miles) = Dollars Spent (dollars) ÷ Reimbursement Rate ($/mile)	

Step 3: Determine the fuel economy of each vehicle.

You can obtain fuel economy factors for passenger cars and light trucks from the EPA website www.fueleconomy.gov, which lists city, highway, and combined fuel economy factors by make, model, model year, and specific engine type.

Step 4: Convert annual mileage to fuel consumption.

If you have accurate information about the driving patterns of your fleet, you should apply a specific mix of city and highway driving, using Equation 7.4. Otherwise use the combined fuel economy factor from

EPA, which assumes 45 percent of your vehicles' mileage is highway driving and 55 percent is city driving.

For heavy-duty trucks, fuel economy data may be available from vehicle suppliers, manufactures, or in company records. If no specific information is available, you should assume fuel economy factors of 8.0 mpg for medium trucks (10,000-26,000 lbs) and 5.8 mpg for heavy trucks (more than 26,000 lbs)12. If you operate more than one type of vehicle, you must calculate the fuel use for each of your vehicle types and then sum them together.

Equation 7.4	**Estimating Fuel Use Based on Distance**
Estimated Fuel Use (gallons) = Distance ÷ [(City FE × City %) + (Highway FE × Hwy %)] (miles) (mpg) (mpg) FE = Fuel Economy	

Now you can use your estimated fuel use from Equation 7.4 to follow the guidance in the recommended approach (Section 7.1.1.1) to estimate your CO_2 Scope 1 emissions from your vehicles.

7.1.1.2.2 Fuel Estimates Based on Dollars Spent

If you cannot obtain fuel use data, mileage records or reimbursement data, but have information on dollars spent for fuel used by the vehicle fleet, you may estimate your fuel consumption using the following procedure:

1. Identify total annual dollars spent by fuel type;
2. Identify the cost per gallon for each fuel type;
3. Convert annual dollars spent to fuel consumption for each fuel type.

Step 1: Identify total annual dollars spent by fuel type.

Sources of annual dollars spent data include collected fuel receipts and purchase records for fuel station accounts. Note that you should subtract any taxes from the total dollar figure.

Step 2: Identify the cost per gallon for each fuel type.

If the cost per gallon of fuel is not indicated on the fuel receipts or purchase records, you can obtain average annual fuel prices for your region from the Energy Information Administration at http://tonto.eia.doe.gov/oog/info/gdu/gasdiesel.asp.

Step 3: Convert annual dollars spent to fuel consumption for each fuel type.

For each fuel type, use Equation 7.5 to convert annual dollars spent to estimated fuel use.

Equation 7.5	**Estimating Fuel Use Based on Dollars Spent**
Estimated Fuel Use (gallons) = (Dollars Spent - Taxes) ÷ Fuel Cost ($) ($/gallon)	

Now you can use your estimated fuel use from Equation 7.4 to follow the guidance in the recommended approach (Section 7.1.1.1) to estimate your CO_2 Scope 1 emissions from your vehicles.

[12] U.S. Department of Energy, Transportation Energy Data Book, Ed. 26, 2007, Table 5.4.

7.1.1.2.3 Proxy Year Fuel Use Data

If you cannot obtain fuel use data for the given analysis year, but have fuel use data for the following year or the prior year, you may estimate your fuel consumption using the following procedure:

Identify total annual fuel consumption by fuel type in proxy year; and
Adjust proxy year fuel consumption based on estimated changes in fleet size and composition.

Now you can use your estimated fuel use from Equation 7.4 to follow the guidance in the recommended approach (Section 7.1.1.1) to estimate your CO_2 Scope 1 emissions from your vehicles.

7.1.2 CO_2 Emissions from Vehicles Combusting Biofuels

Biofuels such as ethanol, biodiesel, and other various blends of biofuels and fossil fuels may be combusted in mobile sources. Due to their biogenic origin, you must report CO_2 emissions from the combustion of biofuels separately from your fossil fuel CO_2 emissions (see Chapter 4 , Section 4.6). For biofuel blends, such as E85 (85 percent ethanol and 15 percent gasoline) and B20 (20 percent biodiesel and 80 percent diesel), combustion results in emissions of both fossil CO_2 and biogenic CO_2. You must separately report both types of CO_2 emissions for each fuel.

Note that when calculating emissions from mobile combustion, you are responsible to account only for emissions resulting from your own activities (i.e., tailpipe emissions from fuel combustion) rather than taking into account life cycle impacts, such as the CO_2 sequestered during the growing of crops or emissions associated with producing the fuels. The life cycle impacts of combusting fuels falls into Scope 3.

Follow the steps below to calculate the anthropogenic and biogenic CO_2 emissions from a biofuel blend.

Step 1: Identify the biofuel blend being used.

E85 (85 percent ethanol and 15 percent gasoline) and B20 (20 percent biodiesel and 80 percent diesel) are popular blends, but many different biofuel blends are possible.

Step 2: Identify total annual biofuel consumption.

If you are a fleet operator and store fuel at any of your facilities, you can also determine your annual fuel consumption from bulk fuel purchase records.

Step 3: Based on the blend, calculate the annual consumption of petroleum-based fuel and biomass-based fuel for each biofuel blend consumed.

For example, if you are using B20, your annual consumption would have to be split into 20 percent biodiesel and 80 percent diesel fuel.

Step 4: Select the appropriate emission factor to separately calculate your anthropogenic and biogenic CO2 emissions.

Table C.9 provides default CO_2 emission factors for fuel combusted in motor vehicles and other forms of transport, including a number of biofuels.

Step 5: Multiply fuel consumed by the emission factor to calculate total CO_2 emissions and convert to metric tons.

Multiply your petroleum-based diesel use from Step 3 by the CO_2 emission factor from Step 4 (see Equation 7.2) and convert kilograms to metric tons.

Then multiply your biomass-based fuel use from Step 3 by the biogenic CO_2 emission factor from Step 4 and convert kilograms to metric tons.

To calculate the CH_4 and N_20 emissions from biofuels, follow the guidance given in Section 7.1.3 below.

7.1.3 Mobile Combustion CH_4 and N_2O Emissions

Below are the recommended and alternate activity data and emission factors for calculating your Scope 1 CH_4 and N_2O emissions from mobile combustion. The following sections detail how to calculate your emissions based on the activity data and emission factors you choose to utilize.

	RECOMMENDED	ALTERNATE
ACTIVITY DATA	Annual mileage by vehicle type, model year and fuel type ☑	Fuel use by vehicle type, model year and fuel type ☑
		Annual mileage by vehicle type and fuel type
		Proxy year data

	RECOMMENDED	ALTERNATE
EMISSION FACTOR	Default by vehicle type, model year and fuel type ☑	Default by fuel type, vehicle type

7.1.3.1 Recommended Approach

Estimating emissions of CH4 and N2O from mobile sources using the recommended activity data and emission factors involves five steps:

1. Identify the vehicle type, fuel type, and model year of each vehicle you own and operate;
2. Identify the annual mileage by vehicle type;
3. Select the appropriate emission factor for each vehicle type;
4. Calculate CH4 and N2O emissions for each vehicle type and sum to obtain total CH4 and N2O emissions; and
5. Convert CH4 and N2O emissions to units of CO2 equivalent and sum to determine total emissions.

Note that this procedure applies to highway vehicles and alternative fuel vehicles, but not to non-highway vehicles such as ships, locomotives, aircraft, and non-road vehicles. For these vehicles, estimation of CH4 and N2O emissions is based on fuel consumption rather than distance traveled. For these vehicles, use the same fuel consumption data used to estimate CO2 emissions in the previous section. Then follow Steps 3-5 below to estimate emissions using default factors provided in
Table C.12.

Step 1: Identify the vehicle type, fuel type, and technology type or model year of all the vehicles you own and operate.

You must first identify all the vehicles you own and operate, their vehicle type (such as passenger car or heavy-duty truck), their fuel type (such as gasoline or diesel), and their model year.

Step 2: Identify the annual mileage by vehicle type.

CH4 and N2O emissions depend more on distance traveled than volume of fuel combusted. Therefore, the recommended approach is to use vehicle miles traveled data by vehicle type. Sources of annual mileage data include odometer readings or trip manifests that include distance to destinations.

Step 3: Select the appropriate emission factor for each vehicle type.

Obtain emission factors for highway vehicles from Table C.10. Use Table C.11 for alternative fuel and Table C.12 for non-highway vehicles.

Step 4: Calculate CH4 and N2O emissions by vehicle type and sum to obtain total CH4 and N2O emissions.

Use Equation 7.6 to calculate CH4 emissions by vehicle type, convert to metric tons, and obtain total CH4 emissions. Then repeat the procedure using Equation 7.7 to obtain total N2O emissions.

Equation 7.6	Calculating CH_4 Emissions From Mobile Combustion
Vehicle Type A **CH_4 Emissions** (metric tons) = Annual Distance (miles) × Emission Factor (g CH_4/mile) ÷ 1,000,000 (g/metric ton)	
Vehicle Type B **CH_4 Emissions** (metric tons) = Annual Distance (miles) × Emission Factor (g CH_4/mile) ÷ 1,000,000 (g/metric ton)	
Total CH_4 Emissions = CH_4 from Type A (metric tons) + CH_4 from Type B (metric tons) + … (metric tons)	

Equation 7.7	Calculating N_2O Emissions From Mobile Combustion
Vehicle Type A **N_2O Emissions** (metric tons) = Annual Distance (miles) × Emission Factor (g N_2O/mile) ÷ 1,000,000 (g/metric ton)	
Vehicle Type B **N_2O Emissions** (metric tons) = Annual Distance (miles) × Emission Factor (g N_2O/mile) ÷ 1,000,000 (g/metric ton)	
Total N_2O Emissions = N_2O from Type A (metric tons) + N_2O from Type B (metric tons) + … (metric tons)	

Step 5: Convert CH4 and N2O emissions to units of CO2 equivalent and determine total emissions from mobile combustion.

Use the IPCC global warming potential (GWP) factors in Equation 7.8 to convert CH4 and N2O emissions to units of CO2 equivalent. Then sum your emissions of all three gases to determine your total emissions from mobile combustion (see Equation 7.8).

Equation 7.8	Converting to CO_2 equivalent and determining total emissions
CO_2 Emissions (metric tons CO_2e) = CO_2 Emissions (metric tons) × 1 (GWP)	
CH_4 Emissions (metric tons CO_2e) = CH_4 Emissions (metric tons) × 21 (GWP)	
N_2O Emissions (metric tons CO_2e) = N_2O Emissions (metric tons) × 310 (GWP)	

Total Emissions =	$CO_2 + CH_4 + N_2O$
(metric tons CO_2e)	(metric tons CO_2e)

7.1.3.2 Alternate Activity Data

7.1.3.2.1 Fuel use by vehicle type, model year and fuel type

If you do not have mileage data, but you do have fuel consumption data by vehicle type, you can estimate the vehicle miles traveled using fuel economy factors by vehicle type. See Step 3 in Section 7.1.1.2 for a discussion of determining appropriate fuel economy factors. If you operate more than one type of vehicle, you must separately calculate the fuel use for each of your vehicle types. If you have only bulk fuel purchase data, you should allocate consumption across vehicle types and model years in proportion to the fuel consumption distribution among vehicle type and model years, based on your usage data. Then use Equation 7.9 to estimate annual mileage.

Equation 7.9	**Estimating Mileage Based on Fuel Use**
Estimated Annual Mileage = Fuel Use × [(City FE × City %) + (Highway FE × Hwy %)] (gallons) (mpg) (mpg) FE = Fuel Economy	

Now you can use your estimated annual mileage from Equation 7.9 to follow the guidance in the recommended approach (Section 7.1.3.1) to estimate your CH_4 and N_2O Scope 1 emissions from your vehicles.

7.1.3.2.2 Annual mileage by vehicle type and fuel type

If you have mileage data categorized by fuel type and vehicle class but not the model years for the vehicles, you can estimate the CH4 and N2O from mobile sources using these five steps:

1. Identify the vehicle type and fuel type of each vehicle you own and operate;
2. Identify the annual mileage by vehicle type;
3. Select the appropriate emission factor for each vehicle type;
4. Calculate CH4 and N2O emissions for each vehicle type and sum to obtain total CH4 and N2O emissions; and
5. Convert CH4 and N2O emissions to units of CO2 equivalent and sum to determine total emissions.

Step 1: Identify the vehicle type, fuel type, and technology type for all the vehicles you own and operate.

You must first identify all the vehicles you own and operate, their vehicle type (such as passenger car or heavy-duty truck), their fuel type (such as gasoline or diesel).

Step 2: Identify the annual mileage by vehicle type.

CH_4 and N_2O emissions depend more on distance traveled than volume of fuel combusted. Therefore, the recommended approach is to use vehicle miles traveled data by vehicle type. Sources of annual mileage data include odometer readings or trip manifests that include distance to destinations.

Step 3: Select the appropriate emission factor for each vehicle type.

Obtain emission factors for highway vehicles from Table C.13.

Steps 4-5:

Steps 4 and 5 should be conducted as per the recommended methodology above (7.2.1.1) substituting the emission factors from Table C.13.

7.1.3.2.3 Proxy year data

If you cannot obtain vehicle mileage data for the current year, but have mileage use data for the following year or the prior year or a fiscal year, you may estimate your annual mileage using the following procedure:

1. Identify total annual fuel consumption by fuel type;
2. Adjust estimate based on any estimated changes in fleet size and composition;

7.1.3.3 Alternate Emission Factors

If you do not have data on the vehicle type, fuel type, and model year for each vehicle in your vehicle fleet, you can use the default emission factors in Table C.13.

These emission factors require you to break down your vehicle fleet based on vehicle type and fuel type only.

7.2 Emissions from Alternative Fuel Vehicles/Electric Vehicles

Emissions from alternative fuel vehicles are calculated in the same manner as other gasoline or diesel mobile sources, with the exception of electric vehicles. For instance, if you operate compressed natural gas or propane fueled vehicles, you must, as with gasoline or diesel, determine the total amount of fuel consumed and apply the appropriate emission factor to calculate your emissions. Electric vehicles are powered by internal batteries that receive a charge from the electricity grid. Therefore, using electric vehicles produces Scope 2 emissions from purchased electricity as opposed to Scope 1 emissions from mobile combustion. To calculate these emissions, you must determine the quantity of electricity consumed and apply an appropriate emission factor (see Chapter 6 , Section 6.2).

7.3 Fugitive Emissions from Motor Vehicle Air Conditioning

Most on-road vehicles owned and operated by your local government have air conditioning systems. These systems may use refrigerants that contain or consist of compounds that should be reported under this Protocol. Through the use and maintenance of these systems, refrigerant leaks are likely to occur. These leaks are considered Scope 1 fugitive emissions. While leakage from vehicle air conditioning systems may not seem like large source of GHG emissions, some of the refrigerant compounds used in these systems have high GWPs, and thus even small fugitive emissions can translate into significant emissions in terms of CO_2 equivalent.

Note that only those refrigerants that contain or consist of compounds of the GHGs listed in Appendix A should be reported. Hydrofluorocarbons (HFCs) are the primary GHG of concern for motor vehicle air conditioners. Today, HFC-134a is the standard refrigerant used for mobile air conditioning systems. It is also possible that your vehicles use a refrigerant that is a blend of a number of compounds - refrigerant blends that should be reported under this Protocol and their associated GWPs are also listed in Appendix A.

Below are the recommended and alternate approaches for calculating your Scope 1 fugitive emissions from mobile sources. Before beginning any calculations in this section, you should first confirm what refrigerants are being used within your air conditioning units. Only those HFCs and refrigerants blends listed in and Appendix A are to be included in your inventory.

RECOMMENDED	ALTERNATE
Mass balance method ☑	Estimation based on fleet inventory and refrigerants used

7.3.1 Recommended Approach

The mass balance approach is the most accurate method for determining HFC emissions. This method is recommended for local governments who service their own fleet vehicles. To calculate HFC emissions using the mass balance approach, follow these three steps:

1. Determine the base inventory for each refrigerant used in your fleet vehicles;
2. Calculate changes to the base inventory for each refrigerant based on purchases and sales of refrigerants and changes in total capacity of the equipment; and
3. Calculate annual emissions of each type of refrigerant, convert to units of carbon dioxide equivalent, and determine total HFC emissions.

Step 1: Determine the base inventory for each HFC.

First determine the quantity of the refrigerant in storage at the beginning of the year (A) and the quantity in storage at the end of the year (B), as shown in Table 7.1. Refrigerant in storage (or in inventory) is the total stored on site in cylinders or other storage containers and does not include refrigerants contained within equipment.

Step 2: Calculate changes to the base inventory.

Next, include any purchases or acquisitions of each refrigerant, sales or disbursements of each refrigerant, and any changes in capacity of refrigeration equipment. Additions and subtractions refer to refrigerants placed in or removed from the stored inventory, respectively.

Purchases/Acquisitions of Refrigerant. This is the sum of all the refrigerants acquired during the year either in storage containers or in equipment (item C in Table 7.1). Purchases and other acquisitions may include refrigerant:

- Purchased from producers or distributors,
- Provided by manufactures or inside vehicles,
- Added to vehicles by contractors or other service personnel (but not if that refrigerant is from your inventory), and
- Returned after off-site recycling or reclamation.

Sales/Disbursements of Refrigerant. This is the sum of all the refrigerants sold or otherwise disbursed during the year either in storage containers or in vehicles (item D in Table 7.1). Sales and disbursements may include refrigerant:

- In containers or left in vehicles that are sold,
- Returned to suppliers, and
- Sent off-site for recycling, reclamation, or destruction.

Net Increase in Total Full Charge of Equipment. This is the net change to the total equipment volume for a given refrigerant during the year (item **E** in Table 7.1). Note that the net increase in total full charge of equipment refers to the full and proper charge of the vehicle rather than to the actual charge, which may reflect leakage. It accounts for the fact that if new vehicles are purchased, the refrigerant that is used to charge those new vehicles should not be counted as an emission.

It also accounts for the fact that if the amount of refrigerant recovered from retiring vehicles is less than the full charge, then the difference between the full charge and the recovered amount has been emitted. Note that this quantity will be negative if the retiring vehicles have a total full charge larger than the total full charge of the new vehicles.

If the beginning and ending total capacity values are not known, this factor can be calculated based on known changes in equipment. The total full charge of new vehicles minus the full charge of vehicles that are retired or sold also provides the change in total capacity.

Table 7.1 Base Inventory and Inventory Changes

Inventory		Amount (kg)
Base Inventory		
A	Refrigerant in inventory (storage) at the beginning of the year	
B	Refrigerant in inventory (storage) at the end of the year	
Additions to Inventory		
1	Purchases of refrigerant (including refrigerant in new vehicles)	
2	Refrigerant returned to the site after off-site recycling	
→ C	Total Additions (1+2)	
Subtractions from Inventory		
3	Returns to supplier	
4	HFCs taken from storage and/or equipment and disposed of	
5	HFCs taken from storage and/or equipment and sent off-site for recycling or reclamation	
→ D	Total Subtractions (3+4+5)	
Net Increase in Full Charge/Nameplate Capacity		
6	Total full charge of new vehicles	
7	Total full charge of retiring vehicles	
→ E	Change to nameplate capacity (6-7)	

Step 3: Calculate annual emissions of each type of HFC, convert to units of carbon dioxide equivalent, and determine total HFC emissions.

For each type of refrigerant or refrigerant blend, use Equation 7.10 and your data from Table 7.1 to calculate total annual emissions of each type of HFC used in your fleet vehicles.

Equation 7.10	**Calculating Emissions of Each Type of HFC Using the Mass Balance Method**

Total Annual Emissions (metric tons of HFC) =

$$(A - B + C - D - E) \div 1{,}000$$

(kg) (kg) (kg) (kg) (kg) (kg/metric tons)

Next, use Equation 7.11 and the appropriate global warming potential factors from Appendix A to convert each HFC to units of carbon dioxide equivalent.

Equation 7.11	**Converting to CO_2-equivalent**
HFC Type A Emissions (mt CO_2e) = HFC Type A Emissions (metric tons HFC Type A) × GWP (HFC A)	

Finally, sum the totals of each type of HFC, in units of carbon dioxide equivalent, to determine total HFC emissions (see Equation 7.12) from your vehicle fleet.

Equation 7.12	**Determining total HFC emissions**
Total HFC Emissions (mt CO_2e) = HFC Type A (mt CO_2-e) + HFC Type B (mt CO_2e) + …	

7.3.2 Alternate Approach

The alternate approach estimates emissions by multiplying the quantity of refrigerants used by default emission factors. Because default emission factors are highly uncertain, the resulting emissions estimates are considered much less accurate than the mass balance approach, and will probably result in an overestimation of your Scope 1 fugitive emissions.

To estimate emissions using the alternate approach, follow these three steps:

1. Determine the types and quantities of refrigerants used;
2. Estimate annual emissions of each type of HFC; and
3. Convert to units of carbon dioxide equivalent and determine total HFC emissions.

Step 1: Determine the types and quantities of refrigerants used.

To estimate emissions, you must determine the number of vehicles with air conditioning equipment; the types of refrigerant used; and the refrigerant charge capacity of each piece of equipment (see Table 7.2). If you do not know the refrigerant charge capacity of each piece of equipment, use the upper bound of the range provided by equipment type in Table 7.2.

Step 2: Estimate annual emissions of each type of refrigerant.

For each type of refrigerant, use Equation 7.13 to estimate annual emissions. Default emission factors are provided in Table 7.2 by equipment type. The equation includes emissions from installation, operation, and disposal of equipment. If you did not install or dispose of equipment during the reporting year, do not include emissions from these activities in your estimation.

Note that refrigerants may be blends of HFCs. Table A.2 lists the global warming potential factors for selected blends.

Table 7.2 Default Emission Factors for Mobile Refrigeration / Air Conditioning Equipment

Type of Equipment	Capacity (kg)	Installation Emission Factor k (% of capacity)	Operating Emission Factor x (% of capacity / year)	Refrigerant Remaining at Disposal y (% of capacity)	Recovery Efficiency z (% of remaining)
Transport Refrigeration	3 - 8	1 %	50 %	50 %	70 %
Mobile Air Conditioning	0.5 – 1.5	0.5 %	20 %	50 %	50 %

Source: IPCC, *Guidelines for National Greenhouse Gas Inventories* (2006), Volume 3: Industrial Processes and Product Use, Table 7.9.
Note: Emission factors above are the most conservative of the range provided by the IPCC. The ranges in capacity are provided for reference. You should use the actual capacity of your equipment. If you do not know your actual capacity, you should use the high end of the range provided (e.g., use 2,000 kg for chillers).

Equation 7.13	**Estimating Emissions of Each Type of Refrigerant**

For each type of refrigerant:

$$\underset{\text{(metric tons)}}{\textbf{Total Annual Emissions}} = [\ (\underset{(kg)}{C_N} \times \underset{(\%)}{k}) + (\underset{(kg)}{C} \times \underset{(\%)}{x} \times \underset{(years)}{T}) + (\underset{(kg)}{C_D} \times \underset{(\%)}{y} \times (1 - \underset{(\%)}{z})\ )\ ] \div \underset{(kg/metric\ ton)}{1{,}000}$$

Where:
C_N = quantity of refrigerant charged into the new equipment [1]
C = total full charge (capacity) of the equipment
T = time in years equipment was in use (e.g., 0.5 if used only during half the year and then disposed)
C_D = total full charge (capacity) of equipment being disposed of [2]
k = installation emission factor [1]
x = operating emission factor
y = refrigerant remaining at disposal [2]
z = recovery efficiency [2]

[1] Omitted if no equipment was installed during the reporting year or the installed equipment was pre-charged by the manufacturer
[2] Omitted if no equipment was disposed of during the reporting year

Step 3: Convert to units of carbon dioxide equivalent and determine total HFC emissions.

Use Equation 7.11 and the appropriate global warming potential factors from Appendix A to convert each HFC to units of carbon dioxide equivalent.

Finally, sum the totals of each type of HFC, in units of carbon dioxide equivalent, to determine total HFC emissions (see Equation 7.12).

Chapter 8 Power Generation Facilities

Local governments that own or operate large combustion facilities may burn any combination of the following fuels: coal, oil, natural gas, biomass or others for the production of electricity and/or heat and steam. Although hydrocarbon fuel combustion emits CO_2, CH_4, and N_2O, the CO_2 emissions associated with stationary combustion facilities will be the largest source of emissions from these power generating facilities.

> **California Local Governments and AB 32**
>
> Note: If your local government operates a power generation facility with a nameplate capacity of 1 MW or higher and emits over 2,500 metric tons of CO_2 per year, you will be subject to ARB's mandatory reporting regulation under AB 32. The regulation has additional reporting requirements beyond what is described in this Protocol.
>
> For more information and to download the mandatory reporting requirements, visit www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.htm.

The amount of CO_2 emitted from hydrocarbon combustion predominantly depends on the quantity of the fuel and carbon content of fuel consumed. To a lesser extent, the oxidation fraction of a particular fuel, under standard operating conditions and practices, also influences CO_2 emissions. (An oxidation fraction reflects an incomplete combustion process, to the extent that all the carbon contained in the fuel does not oxidize into CO_2 but remains as ash or unburned carbon.)

Non-fossil carbon bearing fuels (e.g., landfill gas, wood and wood waste, etc.) may also be combusted in power generating facilities. You should not report biogenic CO_2 emissions as direct GHG emissions (see Chapter 4 , Section 4.6). However, it is important to identify the contribution of these emissions as a part of your overall activities. Thus, you must identify and report biomass CO_2 emissions as biogenic emissions in a category separate from fossil fuel emissions. Note that CH_4 and N_2O emissions from the combustion of biomass are not considered biogenic and should be calculated and reported as part of your direct emissions inventory.

Power generation facilities use a number of stationary combustion technologies to generate, transmit, and distribute electricity and produce heat and/or steam. Municipal utilities may also combust natural gas and other fossil fuels to transport, store, and distribute natural gas.

To quantify CO_2 emissions from stationary combustion a power generating facilities, local governments should use one of the following two methods:

1. Measurement-based methodology
2. Fuel use calculation-based methodology

For most municipal utilities, the information needed to quantify direct stationary combustion GHG emissions should be available or easily derived from existing reporting activities. For major stationary sources, most municipal utilities already account for and report air pollution emissions to local, state and/or federal regulatory agencies, as well as total annual fuel use, and electricity, steam and heat production.

Most large electric generating units have continuous emissions monitoring systems (CEMs) that track their CO_2 emissions. Smaller units, however, may have not installed these monitors, but rather rely on fuel use data to determine their emissions. Because of these varying requirements, you may have to use both the measurement-based and the calculation-based methodologies to fully quantify your GHG emissions from power generation.

To maintain consistency with other programs, entities that are required to report emissions to the U.S. EPA according to 40 CFR Part 75 and/or state or local environmental agencies are encouraged to report the same CO_2 emissions information through this Protocol.

Whichever method or combination of methods are used to calculate your GHG emissions inventory, you should use the same reporting methodology from year to year to maintain consistency and comparability between inventory years.

8.1 Stationary Combustion: Measurement-Based Methodology

Continuous emissions monitoring systems (CEMS) are the primary emissions monitoring method used in the power/utility sector. Local governments that report CO_2 emissions data to the U.S. EPA according to 40 CFR Part 75 and/or state/province or local environmental agencies can use the same CO_2 emissions information in their GHG inventory. CO_2 data should be monitored in accordance with the requirements of the 40 CFR Part 75 rule, which includes requirements for installing, certifying, operating, and maintaining CEMS for measuring and reporting CO_2 as well as SO_2, NO_2, O_2, opacity, and volumetric flow. You may use either of the two following CEMS configurations to determine annual CO_2 emissions:

A monitor measuring CO_2 concentration percent by volume of flue gas and a flow monitoring system measuring the volumetric flow rate of flue gas can be used to determine CO_2 mass emissions. Annual CO_2 emissions are determined based on the operating time of the unit.

A monitor measuring O_2 concentration percent by volume of flue gas and a flow monitoring system measuring the volumetric flow rate of flue gas combined with theoretical CO_2 and flue gas production by fuel characteristics can be used to determine CO_2 flue gas emissions and CO_2 mass emissions. Annual CO_2 emissions are determined based on the operating time of the unit.

You must specify which CEMS configuration you use. Refer to U.S. EPA's resources on 40 CFR Part 75 at www.epa.gov/airmarkets/emissions/rules.html.

Note that the Protocol requires that local governments identify and report biomass CO_2 emissions as biogenic emissions, separate from fossil fuel emissions. See Box 8.1 for information on biofuels, waste fuels and biomass co-firing in a unit with CEMS.

8.2 Stationary Combustion: Fuel Use-Based Methodology

Estimating emissions from stationary combustion using fuel use data involves the following six steps:

1. Determine annual consumption of each fuel combusted at your power-generating facility;
2. Determine the appropriate CO_2 emission factors for each fuel;
3. Determine the appropriate CH_4 and N_2O emission factors for each fuel;
4. Calculate each fuel's CO_2 emissions;
5. Calculate each fuel's CH_4 and N_2O emissions; and
6. Convert CH_4 and N_2O emissions to CO_2 equivalent and determine total emissions.

Step 1: Determine annual consumption of each fuel combusted at your power-generating facility.

First identify all fuels combusted at your power-generating facility. Examples of fuel types include bituminous coal, residual fuel oil, distillate fuel (diesel), liquefied petroleum gas (LPG), and natural gas.

Box 8.1 Biofuels, Waste Fuels, and Biomass Co-Firing in a Unit with CEMS

Biofuels

Biofuels such as landfill gas, wood, and wood waste may be combusted in addition to fossil fuels. You must report your CO_2 emissions from fossil fuel combustion separately from your CO_2 emissions from biomass combustion. CO_2 emissions from fossil fuel combustion are reported in Scope 1, while CO_2 emissions from biomass combustion are reported separately from the scopes. The same step-by-step procedure for determining GHG emissions from fossil fuels applies to non-fossil fuels. Note that emissions of CH_4 and N_2O from biomass combustion are included in Scope 1 and are not treated differently from CH_4 and N_2O emissions from fossil fuel combustion.

Waste Fuels

For facilities that combust municipal solid waste (MSW), you must calculate or monitor your CO_2 emissions resulting from the incineration of waste of fossil fuel origin (e.g. plastics, certain textiles, rubber, liquid solvents, and waste oil) and include those emissions as direct CO_2 emissions (Scope 1). Your CO_2 emissions from combusting the biomass portion of MSW (e.g., yard waste, paper products, etc.) must be separately calculated and reported as biogenic CO_2 emissions (reported separately from the scopes). Information on the biomass portion of MSW will be site-specific and should be obtained from a local waste characterization study. You may also use the methodology described in ASTM D6866 (see below for more information).

Biomass Co-Firing in a Unit with CEMS

The Protocol expects that participants identify and report biomass CO_2 emissions as "biogenic emissions," separate from fossil fuel emissions. Thus, if you combust biomass fuels in any of your units using CEMS to report CO_2 emissions, you must calculate the emissions associated with the biomass fuels (Equation 8.1) and subtract this from your total measured emissions (Equation 8.2). You must report these separately from your fossil fuel emissions, along with any other biogenic emissions.

The following example illustrates a case where biomass is co-fired and emissions are monitored through a CEMS. An electric utility company reports the CO_2 emissions from its major electric generating facilities using the CEMS already installed on those units. At one of its natural gas-fired units it co-fires with wood; the emissions associated with each combustion activity are mixed in the exhaust stack and measured collectively by the CEMS device. To report its CO_2 emissions from this unit, the utility must calculate the portion of CO_2 emissions from combusting wood, and subtract it from the measurement of total emissions. To do so, the entity must quantify the amount of biomass consumed by the unit, and multiply that value by the wood-specific CO_2 emission factor from Table C.2 (see Equation 8.1). This value is then subtracted from the total CO_2 emissions measured by the CEMS (see Equation 8.2).

Equation 8.1	Calculating Biomass CO2 Emissions (Fuel Consumption in MMBtu)
CO_2 from Biomass Combustion (metric tons) = Biomass Consumed (MMBtu) **x** Biomass Emission Factor (kg CO_2/MMBtu) **x** 0.001 (metric tons/kg)	

Equation 8.2	Backing Out Biomass CO2 Emissions from CEMS
CO_2 from Fossil Fuel Combustion (metric tons) = Total CEMS CO_2 Emissions (metric tons) **-** Total Biomass CO_2 Emissions (metric tons)	

Alternatively, instead of first calculating CO_2 from biomass combustion, you may first calculate CO_2 from fossil fuel combustion. To do this, multiply fossil fuel consumption by an appropriate fuel-specific emission factor from Table C.1 and Table C.2 (see Section 8.2, Step 2 below). After deriving total CO_2 from fossil fuel combustion, subtract this value from total CEMS CO_2 emissions to obtain CO_2 from biomass combustion. As a third option for separately calculating the portion of CO_2 emissions attributable to fossil fuel versus biomass, you may use the methodology described in ASTM D6866-06a, "Standard Test Methods for Determining the Biobased Content of Natural Range Materials Using Radiocarbon and Isotope Ratio Mass Spectrometry Analysis." For further specifications on using this method, see California Air Resources Board *Regulation for the Mandatory Reporting of Greenhouse Gas Emissions*, Section 95125(h)(2).

Then determine your annual fuel use by fuel type, measured in terms of physical units (mass or volume). For stationary combustion sources, the preferred method is to determine the amount of fuel combusted at each combustion unit by reading individual meters located at the fuel input point, if applicable. Alternatively, you may use fuel receipts or purchase records to calculate your total fuel usage. Convert fuel purchase and storage data to estimates of measured fuel use using Equation 8.3.

Equation 8.3	**Accounting for Changes in Fuel Stocks**
Total Annual Fuel Consumption = Annual Fuel Purchases - Annual Fuel Sales **+** Fuel Stock at Beginning of Year **-** Fuel Stock at End of Year	

Step 2: Determine the appropriate CO_2 emission factor for each fuel.

The most accurate method is to derive an emission factor for CO_2 using the measured characteristics of the fuels combusted. This method requires information on the heat content and/or carbon content of the fuels. This information can be determined either through fuel sampling and analysis or from data provided by fuel suppliers. Fuel sampling and analysis should be performed periodically, the frequency depending on the type of fuel. In general, the sampling frequency should be greater for more variable fuels (e.g., coal, wood, solid waste) than for more homogenous fuels (e.g., natural gas, diesel fuel). You should collect and analyze fuel data according to applicable industry-approved, national, or international technical standards regarding sampling frequency, procedures, and preparation.

For additional resources on sampling rates and methods, refer to:

- 40 CFR Part 75, Appendix G
- California Air Resources Board Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, Section 95125(c)-(e)
- European Union, Monitoring and Reporting Guidelines for the EU Emissions Trading Scheme (2006), Section 13, "Determination of Activity-Specific Data and Factors"
- WRI/WBCSD GHG Protocol Guidance: Direct Emissions from Stationary Combustion, Version 3.0 (July 2005), Annex D (http://www.ghgprotocol.org)

The carbon content of each fuel can be expressed in mass of carbon per mass of fuel (such as kg C/short ton), mass of carbon per volume of fuel (such as kg C/gallon), or mass of carbon per unit energy of fuel (such as kg C/MMBtu).

The heat content of each fuel is expressed in units of energy per unit mass or volume (such as MMBtu/short ton or MMBtu/gallon) and should be calculated based on higher heating values (HHV).

Multiply the heat content per unit mass or volume (such as Btu/ton or Btu/gallon) by the carbon content per unit energy (e.g., kg C/Btu) to determine the mass of carbon per physical unit of fuel (such as kg C/ton or kg C/gallon). If you have measured carbon content data expressed in mass of carbon per mass or volume of fuel, you do not need to multiply by a heat content factor, since your factor is already in physical units.

To account for the small fraction of carbon that may not be oxidized during combustion, multiply the carbon content in physical units by the fraction of carbon oxidized. If you do not have oxidation factors specific to the combustion source, use a default oxidation factor of 1.00 (100% oxidation). To convert from units of carbon to units of CO_2, multiply by 44/12, the molecular weight ratio of CO_2 to carbon (see Equation 8.4).

Equation 8.4	**Calculating CO_2 Emission Factors Using Measured Fuel Characteristics (Fuel Consumption in Gallons)**
Emission Factor (kg CO_2/gallon) = Heat Content (Btu/gallon) × Carbon Content (kg C/Btu) × % Oxidized × 44/12 (CO_2/C)	

You should use information on the measured fuel characteristics of the fuels you combust whenever possible. In some cases, you may be able to obtain measured heat content information (for example, from your fuel supplier), but unable to obtain measured carbon content data. Likewise, you may have measured carbon content data but no measured heat content data. In these cases, you should combine your more specific data with default factors from Table C.1 and Table C.2.

If you cannot determine the measured heat content or measured carbon content of your specific fuels, use the default emission factors provided by fuel type in Table C.1 and Table C.2. Emission factors are provided in units of CO_2 per unit energy and CO_2 per unit mass or volume. If you combust a fuel that is not listed in the table, you must derive an emission factor based on the specific properties of the fuel using Equation 8.4.

Step 3: Determine the appropriate CH_4 and N_2O emission factors for each fuel.

Estimating CH_4 and N_2O emissions depend not only on fuel characteristics, but also on technology type and combustion characteristics; usage of pollution control equipment; and maintenance and operational practices. Due to this complexity, estimates of CH_4 and N_2O emissions from stationary sources are much more uncertain than estimates of CO_2 emissions. CH_4 and N_2O also account for much smaller quantities of emissions from stationary combustion than CO_2.

If your facilities use direct monitoring to obtain specific emission factors based on periodic exhaust sampling, use these emission factors.

If you can determine either the specific type of combustion equipment used at your facilities, use factors from Table C.4 based on specific types of combustion equipment for the electricity generation sector.

Step 4: Calculate each fuel's CO_2 emissions and convert to metric tons.

To determine your facility's CO_2 emissions from stationary combustion, multiply your fuel use from Step 1 by the CO_2 emission factor from Step 2, and then convert kilograms to metric tons. Repeat the calculation for each fuel type, then sum (see Equation 8.5).

Note that Equation 8.5 expresses fuel use in gallons. If fuel use is expressed in different units (such as short tons, cubic feet, MMBtu, etc.), replace "gallons" in the equation with the appropriate unit of measure. Be sure that your units of measure for fuel use are the same as those in your emission factor.

Equation 8.5	**Calculating CO_2 Emissions From Stationary Combustion (Fuel use in gallons)**
Fuel A CO_2 Emissions (metric tons) = Fuel Consumed (gallons) × Emission Factor (kg CO_2/gallon) ÷ 1,000 (kg/metric ton)	
Fuel B CO_2 Emissions (metric tons) = Fuel Consumed (gallons) × Emission Factor (kg CO_2/gallon) ÷ 1,000 (kg/metric ton)	

Total CO_2 Emissions (metric tons) =
CO_2 from Fuel A + CO_2 from Fuel B + …
(metric tons) (metric tons) (metric tons)

Step 5: Calculate each fuel's CH_4 and N_2O emissions and convert to metric tons.

To determine your CH_4 emissions from stationary combustion at your facility, multiply your fuel use from Step 1 by the CH_4 emission factor from Step 3, and then convert grams to metric tons. Repeat the calculation for each fuel and technology type, then sum (see Equation 8.6).

Note that Equation 8.6 expresses fuel use in MMBtu. If fuel use is expressed in different units (such as gallons, short tons, cubic feet, etc.) you must convert your fuel use data to units of MMBtu.

If you have a measured heat content factor for your specific fuels, use it to convert fuel data to energy units. Otherwise, use a default heat content factor by fuel from Table C.1 and Table C.2. Be sure that your units of measure for fuel use are the same as those in your emission factor.

Follow the same procedure, using Equation 8.7, to calculate total emissions of N_2O at your facility.

Equation 8.6	**Calculating CH_4 Emissions From Stationary Combustion**
Fuel/Technology Type A **CH_4 Emissions =** Fuel Use × Emission Factor ÷ 1,000,000 (metric tons) (MMBtu) (g CH_4/MMBtu) (g/metric ton)	
Fuel/Technology Type B **CH_4 Emissions =** Fuel Use × Emission Factor ÷ 1,000,000 (metric tons) (MMBtu) (g CH_4/MMBtu) (g/metric ton)	
Total CH_4 Emissions (metric tons) = CH_4 from Type A + CH_4 from Type B + … (metric tons) (metric tons) (metric tons)	

Equation 8.7	**Calculating N_2O Emissions From Stationary Combustion**
Fuel/Technology Type A **N_2O Emissions =** Fuel Use × Emission Factor ÷ 1,000,000 (metric tons) (MMBtu) (g N_2O/MMBtu) (g/metric ton)	
Fuel/Technology Type B **N_2O Emissions =** Fuel Use × Emission Factor ÷ 1,000,000 (metric tons) (MMBtu) (g N_2O/MMBtu) (g/metric ton)	
Total N_2O Emissions (metric tons) = N_2O from Type A + N_2O from Type B + … (metric tons) (metric tons) (metric tons)	

Step 6: Convert CH_4 and N_2O emissions to units of CO_2 equivalent and determine total emissions from stationary combustion.

Use the IPCC global warming potential (GWP) factors provided in Equation 8.8 (and Appendix A) to convert CH_4 and N_2O emissions to units of CO_2 equivalent. Then sum your emissions of all three gases to determine your total emissions from stationary combustion at your facility (see Equation 8.8).

Equation 8.8	Converting to CO_2-Equivalent and Determining Total Emissions
CO_2 Emissions = CO_2 Emissions × 1 (metric tons CO_2e) (metric tons) (GWP)	
CH_4 Emissions = CH_4 Emissions × 21 (metric tons CO_2e) (metric tons) (GWP)	
N_2O Emissions = N_2O Emissions × 310 (metric tons CO_2e) (metric tons) (GWP)	
Total Emissions = CO_2 + CH_4 + N_2O (metric tons CO_2e) (metric tons CO_2e)	

8.3 Scope 2 Emissions from Transmission and Distribution Losses

If you purchase (rather than generate) electricity and transport it through a T&D system that you own or control, you should report the emissions associated with T&D losses under Scope 2.

To estimate these emissions, follow the same procedure described in Chapter 6 , Section 6.2.1 for estimating indirect emissions from electricity use.

In Step 1, use the electricity consumed in the T&D system (T&D losses) as your quantity of electricity consumed.

In Step 2, use either a generator-specific emission factor (if the purchased electricity comes directly from a known generation source rather than the grid) or a grid-average emission factor from the appropriate eGRID subregion if the power comes from the grid.

8.4 Fugitive Emissions

Fugitive emissions are unintentional releases of GHGs, for instance from joints, seals, and gaskets. Fugitive emissions at power generation facilities may include:

- SF_6 from electricity transmission and distribution systems;
- CH_4 from fuel handling, storage, transmission and distribution;
- HFCs from air conditioning and refrigeration systems (both stationary and mobile); and
- HFCs from fire suppression equipment.

8.4.1 SF_6 Emissions from Electricity Transmission and Distribution

Within the electric power industry, SF_6 is a gas often used for electrical insulation, arc quenching and current interruption equipment used to transmit and distribute electricity. SF_6 is extremely stable and long lasting, and is also a potent greenhouse gas. It is estimated that the electric power industry uses about 80% of the SF_6 produced worldwide, with circuit breaker applications accounting for most of this amount.[13]

Fugitive SF_6 emissions from the electricity transmission and distribution are the result of normal operations and routine maintenance, as well as the use of older equipment. SF_6 can escape to the atmosphere during normal operations, releases from properly functioning equipment (due to both static

[13] Other uses of SF_6 include: semiconductor processing, blanket gas for magnesium casting, reactive gas in aluminum recycling to reduce porosity, thermal and sound insulation, airplane tires, spare tires, "air sole" shoes, scuba diving voice communication, leak checking, atmospheric tracer gas studies, ball inflation, torpedo propeller quieting, wind supersonic channels, and high voltage insulation for many other purposes, such as AWACS radar domes and X-ray machines.

and dynamic operation) and old and/or deteriorated gaskets or seals. SF_6 can also escape when gas is either transferred into or extracted from equipment for disposal, recycling, or storage.

To calculate your fugitive SF_6 emissions from electricity transmission and distribution operations, you should use the mass balance method, as outlined below. This method is consistent with IPCC's guidance, with California Air Resources Board, *Draft Regulation for the Mandatory Reporting of Greenhouse Gas Emissions*, 2007, the California Climate Action Registry's *Power/Utility Reporting Protocol*, 2005, and U.S. EPA's SF_6 Emission Reduction Partnership for Electric Power Systems, *Emissions Inventory Reporting Protocol*.

Equation 8.9	**Fugitive SF_6 Mass Balance Method**

$$SF_6 \text{ Emissions} = (I_B - I_E + P - S - C)$$

Where:
SF_6 Emissions = annual fugitive SF_6 emissions
I_B = the quantity of SF_6 in inventory at the beginning of the year (in storage containers, not in equipment)
I_E = the quantity of SF_6 in inventory at the end of the year (in storage containers, not in equipment)
P = purchases/acquisitions of SF_6. This is the sum of all the SF_6 acquired from other entities during the year either in storage or in equipment, including SF_6 purchased from chemical producers or distributors in bulk, SF_6 purchased from equipment manufacturers or distributors with or inside of equipment, and SF_6 returned to site after off-site recycling.
S = sales/disbursements of SF_6. This is the sum of all the SF_6 sold or otherwise disbursed to other entities during the year either in storage containers or in equipment, including SF_6 returned to suppliers, SF_6 sent off-site for recycling, and SF_6 that is destroyed.
C = Change in total nameplate capacity of equipment (Nameplate Capacity of New Equipment – Nameplate Capacity of Retiring Equipment). This is the net increase in the total volume of SF_6-using equipment during the year. Note that "total nameplate capacity" refers to the full and proper charge of the equipment rather than to the actual charge, which may reflect leakage. This term accounts for the fact that if new equipment is purchased, the SF_6 that is used to charge that new equipment should not be counted as an emission. On the other hand, it also accounts for the fact that if the amount of SF_6 recovered from retiring equipment is less than the nameplate capacity, then the difference between the nameplate capacity and the recovered amount has been emitted.

8.4.2 Fugitive Emissions from Solid Fuel Handling and Storage

Coal Handling & Storage

In the course of mining, transporting and storing coal used for power generation, methane is emitted from underground mining, surface mining, and post-mining activities. Some methane remains in the coal after it is removed from the mine and can be emitted as the coal is transported, processed, and stored. Depending on the characteristics of the coal and the way it is handled after leaving the mine, the amount of methane released during post-mining activities can be significant and can continue for weeks or months. The greatest releases occur when coal is crushed, sized, and dried in preparation for industrial or utility uses. The actual amount of gas that escapes into the atmosphere will be a function of the rate of methane desorption, the coal's original gas content, and the amount of time elapsed before coal combustion occurs.

There are currently no standardized methodologies from calculating these emission sources. Local governments should use industry best practices to estimate the emissions from these sources.

Biomass Handling & Storage
In the handling and storage of biomass, CH_4 is formed where anaerobic digestion occurs. Whether or not anaerobic conditions occur in the pile largely depends on the characteristics of the pile and its surroundings (height, surface, temperature) and the content of the biomass itself (particle size, density, moisture content). Biomass piles may also be a source of N_2O emissions during the first stage of decomposition.

There are currently no standardized methodologies from calculating these emission sources. Local governments should use industry best practices to estimate the emissions from these sources.

Fugitive Emissions from Natural Gas Transmission & Distribution
This Protocol does not contain guidance or references for quantifying the fugitive methane emissions from these operations, as there are no existing methodologies for assessing these emissions at the facility-level. Local governments should use industry best practices to estimate the emissions from these sources.

The California Climate Action Registry is currently in the process developing an industry-specific protocol for natural gas transmission and distribution. This document should be available by the end of 2008, and will be a suitable reference document for local governments with natural gas transmission and distribution operations. New guidance will be incorporated into this Protocol as it becomes available.

Chapter 9 Solid Waste Facilities

Local governments are often responsible for providing solid waste services to their communities. This may include activities like collecting and transporting waste, sorting waste, managing recycling and composting programs and facilities, and managing landfills.

The collection, processing and disposal of solid waste can encompass many different sources of GHG emissions. This chapter focuses solely on estimating the fugitive CH_4 emissions released from solid waste facilities, namely landfills. For guidance on calculating the GHG emissions from other activities related to solid waste, you should refer to other chapters in the Protocol. Table 9.1 provides references to the appropriate chapter and section for common GHG sources related to solid waste management.

California Local Governments and AB 32

Note: If your local government operates a solid waste facility that includes a co-generation or power generation source with a nameplate capacity of 1 MW or higher and emits over 2,500 metric tons of CO_2 per year, or a stationary combustion source that emits over 25,000 metric tons of CO_2 per year, you will be subject to ARB's mandatory reporting regulation under AB 32. The regulation has additional reporting requirements beyond what is described in this Protocol.

For more information, see Chapter 14 and to download the mandatory reporting requirements, visit www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.htm.

Table 9.1 Protocol References for Solid Waste- Related Emission Sources

GHG type/source	Protocol Reference
CO_2, CH_4 and N_2O from fuel-combusting equipment	Chapter 6, Section 6.1
CO_2, CH_4 and N_2O from purchased electricity	Chapter 6, Section 6.2
CO_2, CH_4 and N_2O from waste-hauling fleet vehicles	Chapter 7
CO_2, CH_4 and N_2O from bulldozers, forklifts, etc.	Chapter 7

Why Do Landfills Create Methane Emissions?

After being placed in a landfill, organic waste (such as paper, food scraps, and yard trimmings) is initially decomposed by aerobic bacteria. After the oxygen has been depleted, the remaining waste is available for consumption by anaerobic bacteria, which break down organic matter into substances such as cellulose, amino acids, and sugars. These substances are further broken down through fermentation into gases and organic compounds that form the substrates for the growth of methanogenic bacteria. These CH_4-producing anaerobic bacteria convert the fermentation products into stabilized organic materials and biogas consisting of approximately 50 percent CO_2 and 50 percent CH_4, by volume.[14]

9.1 Organizational Boundary Issues

To determine what emissions associated with waste your local government is responsible for calculating and reporting under the Protocol, you will need to examine your solid waste activities according to the organizational boundary guidance in Chapter 3 . It is the same process you used to determine what facilities your local government is responsible for.

Remember you should consistently apply your organizational consolidation approach across all sources of emissions within your local government. Thus, if the rest of your local government's inventory is based on

[14] US EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2006, Chapter 8.

operational control, use the operational control conditions to determine if the solid waste facility that serves your local government falls under your control.

Many local governments contract for solid waste services - in order to determine if the GHG emissions associated with solid waste fall within your organizational boundaries, refer to the details of your contract. Most local governments will not have financial nor operational control over waste services they have contracted out.

9.2 Ongoing Research and Development

At the time of writing this Protocol, there is no widely accepted methodology to be recommended for directly measuring fugitive methane emissions from solid waste. Many industry- and government-sponsored studies are underway to develop and validate methods to more accurately determine or measure these emissions. The results of these studies will allow more specific and accurate guidance to be given for this source of emissions in the future. In the interim, the Protocol provides conservative estimation approaches so that this significant GHG source is not left out of local government GHG inventories. We expect the guidance in this chapter will change considerably in future versions of the Protocol as more information becomes available.

9.3 Estimation Methodologies

Fugitive methane emissions from landfills are a function of several factors, including:

1. The total amount of waste in landfills, which is related to total waste landfilled annually;
2. The characteristics of landfills receiving waste (i.e., composition of waste-in-place, size, climate, etc.)
3. The amount of CH_4 that is recovered and either flared or used for energy purposes; and
4. The amount of CH_4 oxidized in landfills instead of being released into the atmosphere.

The methodologies below are for use by local governments who have landfills within their organizational boundaries, and therefore need to report the fugitive CH_4 emissions from the landfill as a Scope 1 emission source. How to estimate the fugitive CH_4 emissions from your landfill is determined by the facility-specific data available to you, the type of landfill you have, and the type of landfill gas (LFG) collection system you have, if any.

Figure 9.1 will help you determine the appropriate methodology to use based on this information.

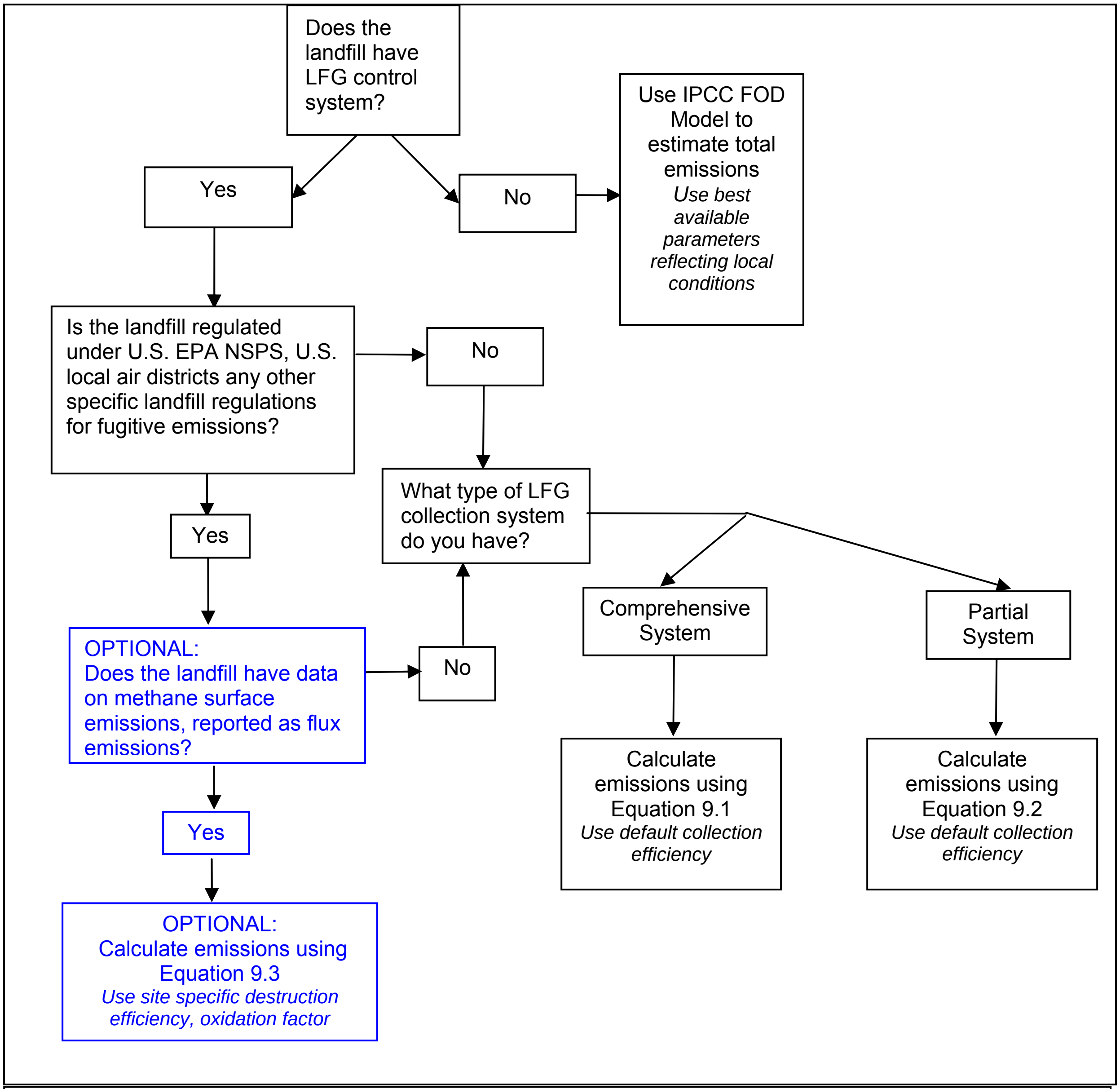
9.3.1 Landfills with No LFG Collection System

If your landfill does not have a LFG collection system in place, the fugitive CH_4 emissions can be estimated using a first order kinetics model based on the amount of waste disposed annually, its composition, and the climate and operational conditions of the landfill.

The Intergovernmental Panel on Climate Change has developed a FOD model for national governments to quantify waste emissions as part of its 2006 guidelines. The excel-based tool provided with this Protocol is based on the IPCC FOD model. The California Air Resources Board developed this tool for local governments that facilitates entry for waste characterization numbers and local parameters from EPA, state or local environmental agencies.

For those local governments that do not have facility-specific data to use in the model, default values are provided below for many variables. These default values are also available in the tool itself.

Figure 9.1 Methodology Decision Tree for CH_4 Emissions from Landfills



Notes: Reporters should use one of the methodologies in black (FOD model, Equation 9.1 or 9.2) to estimate CH4 emissions from landfills. The methodology in blue is an optional methodology that may be used by landfill operators who have site-specific data on methane surface emissions, in addition to the results of the FOD model, or Equation 9.1 or 9.2. See Section 9.4 for more information on this

To estimate the fugitive CH_4 emissions from your landfill, follow the steps below:

1. Determine the annual waste deposited in the landfill historically;
2. Input data into the excel-based FOD model; and
3. Calculate fugitive emissions in metric tons CH_4 and CO_2e.

Step 1: Determine the annual waste in place deposited in the landfill historically.

This should include all waste deposited for all years from the opening year of the landfill up to the year you wish to estimate emissions for. If the opening year is not known, then assume the opening year was 60 years prior to the calendar year for which the estimate is desired.

If you do not have all the years of waste deposition data, use the guidance in **Error! Not a valid bookmark self-reference.** to estimate data for the missing years. Also, your state waste board may have records of the waste deposited in individual landfills going back in time.

Box 9.1 How to Estimate Annual Waste in Place (WIP)

1. Obtain population estimates for the jurisdiction(s) depositing waste in your landfill for all years for which you have missing waste data.

2. Use the known waste deposition data for the year closest to the missing year and multiply this by the ratio of population for the year you want to estimate divided by the population for the known waste deposition year. Do this until all the missing years are estimated.

Step 2: Input data into the excel-based FOD model.

Use the excel-based FOD model provided with the Protocol to generate estimates of the amount of methane generated for the year in question, in units of metric tons of methane generated per year.

Below are the facility-specific data that you need to provide about your landfill in order to run the FOD model:

- Landfill's open year
- Landfill's close year (if applicable)
- Waste composition (percentage per waste type)
- Fraction of CH_4 in LFG from source testing (default value available)
- Average rainfall at landfill (inches/year) to determine appropriate methane generation rate constant (k) value (See Table 9.3 below)
- Type of cover (soil or synthetic)

The FOD model uses a series of equations to calculate the amount of methane generation based on the above inputs. The summary of primary IPCC FOD equations as applied by the ARB excel tool is presented in Table 9.2.

Table 9.2 Primary Equations from FOD Model

ANDOC (metric tons) = WIPyear (short tons) x 0.9072 (metric tons/short ton) x TDOC x DANF
CH_4 generation (metric tons) = $\{ANDOC_{year\ -\ start} \times [1 - exp^{-[k]}] - ANDOC_{deposited\ -\ last\ year} \times [1/k \times (exp^{-[k\ \times\ (1\ -\ M/12)]} - exp^{-[k]}) - (M/12) \times exp^{-[k]}] + ANDOC_{deposited\ -\ same\ year} \times [1 - ((1/k) \times (1 - exp^{-[k \times (1 - M/12)]}) + (M/12))]\} \times F_{CH4}$
CH_4 emitted (metric tons) = [CH_4 Generation (metric tons CH_4)] x (1 –OX)
CH_4 emitted (metric tons CO_2e) = CH_4 emitted (metric tons CH_4) x GWP

Where:

Term		Value	Value
WIP	=	Waste-in-Place (wet weight, short tons)	User Input
TDOC	=	Total Degradable Organic Carbon fraction of the total WIP (metric tons of TDOC/metric tons of Total WIP)	Defaults provided Table 9.4
DANF	=	Decomposable Anaerobic Fraction of the TDOC capable of decomposition in anaerobic conditions (metric tons of ANDOC/metric tons of TDOC)	Defaults provided Table 9.5
ANDOC	=	Anaerobically Degradable Organic Carbon (metric tons of carbon)	Calculated
ANDOC $_{year\text{-}start}$	=	ANDOC in place at the beginning of the inventory year in question	Calculated
ANDOC $_{deposited\text{-}last\ year}$	=	ANDOC deposited during the previous inventory year	Calculated
ANDOC $_{deposited\text{-}same\ year}$	=	ANDOC deposited during the inventory year in question	Calculated
exp	=	Exponential Function exp [x]	
k	=	Methane Generation Rate Constant	Defaults provided Table 9.3
M		Assumed delay before newly deposited waste begins to undergo substantial anaerobic decomposition (Months)	6 [1]
F_{CH4}	=	Fraction of decomposing carbon converted into CH_4	0.5 [1]
OX	=	Oxidation Factor	Defaults provided Table 9.6
GWP	=	Global Warming Potential to convert metric tons of methane into metric tons of CO_2 equivalents (CO_2e).	21
[1] Source: IPCC			

As you can see in the equations above, there are a number of inputs to the FOD model for which default values are provided. These inputs are listed below, along with their default values. If you have facility-specific information for any of these inputs, use them in place of the default values.

Table 9.3 Default k Values

Average Rainfall (inches/year)	k
<20	0.020
20 - 40	0.038
>40	0.057
Source: EPA	

Table 9.4 Total Organic Degradable Carbon per Waste Type (TDOC)

Waste Type	TDOC
Newspaper	46.5%
Office Paper	39.8%
Corrugated Boxes	40.5%
Coated Paper	40.5%
Food	11.7%
Grass	19.2%
Leaves	47.8%
Branches	27.9%
Lumber	43.0%
Textiles	24.0%
Diapers	24.0%
Construction/Demolition	4.0%
Medical Waste	15.0%
Sludge/Manure	5.0%
Source: IPCC	

Table 9.5 Default Decomposable Anaerobic Fraction (DANF) of the TDOC per waste type

Waste Type	DANF	DANF Source
Newspaper	16.1%	EPA
Office Paper	87.4%	EPA
Corrugated Boxes	38.3%	EPA
Coated Paper	21.0%	EPA
Food	82.8%	EPA
Grass	32.2%	EPA
Leaves	10.0%	EPA
Branches	17.6%	EPA
Lumber	23.3%	CEC
Textiles	50.0%	IPCC
Diapers	50.0%	IPCC
Construction/Demolition	50.0%	IPCC
Medical Waste	50.0%	IPCC
Sludge/Manure	50.0%	IPCC

Table 9.6 Landfill Cover Oxidation Value (OX)

Type of cover	OX
Soil	0.10
Synthetic	0.0
Source: IPCC and California Climate Action Registry *Landfill Project Reporting Protocol*, November 2007.	

Step 3: Calculate fugitive emissions in metric tons CH_4 and CO_2e.

The FOD model will estimate the annual fugitive CH_4 emissions from your landfill in metric tons, and will use a global warming potential of 21 to convert metric tons of CH_4 into metric tons of CO_2 equivalent.

9.3.2 Landfills with Comprehensive LFG Collection Systems

Fugitive CH_4 emissions from a landfill with an active and comprehensive LFG collection system can be derived using the data on actual LFG collected and applying a standard collection efficiency. For the purposes of this Protocol, if more than 75% of the waste mass is under extraction, the system is considered to be comprehensive. This can be determined by referencing the "as-built" records of the LFG system.

Below are the facility-specific data that you will use with Equation 9.1 in order to estimate the fugitive CH_4 emitted by your landfill:

- Annual landfill gas collected
- LFG control device technology
- Fraction of CH_4 in LFG from source testing (default value available)
-

Equation 9.1	***Landfills with Comprehensive LFG Collection Systems***
CH_4 emitted (metric tons CO_2E) = LFG collected x CH_4% x {(1 - DE) + [((1 – CE) / CE) x (1 – OX)]} x unit conversion x GWP	

Where:

Term		**Description**	**Value**
CH_4%	=	Fraction of CH_4 in LFG	0.5, if no facility-specific value is available
DE	=	CH_4 Destruction Efficiency, based on the type of combustion/flare system.	Site-specific or default based on control device - see Table 9.7
CE	=	Collection Efficiency	0.75
OX	=	Oxidation Factor	0.10 for soil 0.00 for synthetic covers
Unit conversion	=	Applies when converting million standard cubic feet of methane into metric tons of methane (volume units to mass units)	19.125
GWP	=	Global Warming Potential to convert metric tons of methane into metric tons of CO_2 equivalents (CO_2e).	21

Step 1: Determine the annual landfill gas collected for the landfill.

This data should be in units of million standard cubic feet (a standard cubic foot is measured at 60 degrees F and standard atmospheric pressure). This is called LFG (MMSCF) in Equation 9.1.

If this year happens to be the first year of operation of the system, use the estimation methodology in Section 9.3.1.

Step 2: Determine the methane fraction from the annual landfill gas data you collected.

If you perform source testing on the LFG according to the requirements of a local, state or national agency, you can use your site specific data for CH4% in Equation 9.1.

If you do not perform site-specific source testing, use the default methane fraction of 50%.

Step 3: Apply a standard collection efficiency of 75%.

The AP 42 emission factors for waste/landfills in the controlled emissions section states that landfill gas collection systems are not 100% efficient in collecting gas and therefore emissions of methane will still occur. Based on reported collection efficiencies between 60% – 85%, a value of 75% collection efficiency is stated as most commonly used[15], and is used in this Protocol as a conservative default collection efficiency.

Step 4: Determine the methane destruction efficiency of the control device.

You have the option to use either the default values for different control devices provided in Table 9.7, or use site-specific methane destruction efficiencies derived by a state or local agency accredited source test provider.

Table 9.7 Default Methane Destruction Efficiencies for LFG Control Devices

Flares		
Closed flare	=	.995
Open flare	=	.960
Electricity Generation		
Large gas turbine	=	.995
Microturbine	=	.995
Rich burn IC engines	=	.995
Lean burn IC engines	=	.936
Upgraded for other use		
Injection into natural gas transmission and distribution systems	=	.980
CNG and LNG vehicles	=	.950
Other		
Carbon adsorption systems	=	.010
Venting systems	=	0
Source: California Climate Action Registry *Landfill Project Reporting Protocol, Version 1.0*, November 2007.		

Step 5: Account for cover soil oxidation.
Assume a cover soil oxidation value (OX) of 10%. For landfills with synthetic covers, the OX value is equal to zero (0).

Step 6: Convert CH_4 to CO_2e.
Use a global warming potential of 21 to convert metric tons of methane into metric tons of CO_2 equivalent.

9.3.3 Landfills with Partial LFG Collection Systems

Fugitive CH_4 emissions for a landfill with a partial LFG collection system can be derived using the data on actual LFG collected together with a standard collection efficiency and a factor to account for the uncovered area. For the purposes of this Protocol, if less than 75% of the waste mass is under extraction, the system would be considered partial. This can be determined by referencing the “as-built” records of the LFG system. Partial systems tend to be located in one area or module only.

Below are the facility-specific data that you will use with Equation 9.2 in order to estimate the fugitive CH_4 emitted by your landfill:

[15] US EPA AP 42 Emission Factors, Solid Waste Disposal, 1998, pg 2, 4-6.

- Annual landfill gas collected
- LFG control device technology
- Fraction of CH_4 in LFG from source testing (default value available)
- Ratio of the uncovered area of the LFG collection system

Equation 9.2	***Landfills with Partial LFG Collection Systems***
CH_4 emitted (metric tons CO_2E) = LFG collected x CH_4% x {(1 - DE) + [((1 – CE) / CE) x (1 – OX)]} x AF x unit conversion x GWP	

Where:

Term		Description	Value
CH_4%	=	Fraction of CH_4 in LFG	0.5, if no source testing data is available
DE	=	CH_4 Destruction Efficiency, based on the type of combustion/flare system.	Site-specific or default based on control device - see Table 9.7
CE	=	Collection Efficiency (Collected LFG/Total Generation LFG). It is a function of multiple variables, active/passive systems, size of open face, type of cover and liner, etc.	0.75
OX	=	Oxidation Factor	0.10 for soil 0.00 for synthetic covers
AF	=	Uncovered Area Factor (Uncovered area of the LFG collection system/ total area of the landfill)	user input
Unit conversion	=	Applies when converting million standard cubic feet of methane into metric tons of methane (volume units to mass units)	19.125
GWP	=	Global Warming Potential to convert metric tons of methane into metric tons of CO2 equivalents (CO_2e).	21

Step 1: Determine the annual landfill gas collected for the landfill.

This data should be in units of million standard cubic feet (a standard cubic foot is measured at 60 degrees F and standard atmospheric pressure). This is called LFG (MMSCF).

If this year happens to be the first year of operation of the system, use the estimation methodology in Section 9.3.1.

Step 2: Determine the methane fraction from the annual landfill gas data you collected.

If you perform source testing on the LFG according to the requirements of a local, state or national agency, you can use your site specific data for CH4% in Equation 9.2.

If you do not perform site-specific source testing, use the default methane fraction of 50%.

Step 3: Determine the uncovered area factor for the landfill.

Calculate this ratio by dividing the uncovered area of the landfill by the total area of the landfill.

Step 4: Apply a standard collection efficiency of 75%.

The AP 42 emission factors for waste/landfills in the controlled emissions section states that landfill gas collection systems are not 100% efficient in collecting gas and therefore emissions of methane will still occur. Based on reported collection efficiencies between 60% – 85%, a value of 75% collection efficiency is stated as most commonly used[16], and is used in this Protocol as a conservative default collection efficiency.

Step 5: Determine the methane destruction efficiency of the control device.

You have the option to use either the default values for different control devices provided in Table 9.7, or use site-specific methane destruction efficiencies derived by a state or local agency accredited source test provider.

Step 6: Account for cover soil oxidation.

Assume a cover soil oxidation value (OX) of 10%. For landfills with synthetic covers, the OX value is equal to zero (0).

Step 7: Convert CH_4 to CO_2e.
Use a global warming potential of 21 to convert metric tons of methane into metric tons of CO_2 equivalent.

9.3.4 Optional Reporting Using Surface Measurements Data

In some case, fugitive CH_4 emissions from solid waste facilities are being directly measured and monitored using a number of different methods. Static flux chambers, tunable diode laser, Fourier-transformed infrared-red (FTIR), and integrated surface methane concentrations with air dispersion modeling are some of the current methods used for testing surface emissions. Measurements have to take into account the high spatial variability at these sites, included by not limited to: seasonal variations, comprehensive grid and measurement points, “hot spots”, and different types of cells, covers, and LFG collection systems.

The total emissions through the surface of the landfill are the sum of emissions from:

- Final covered areas/cells;
- Temporal covered areas/cells (daily covered);
- Diffuse sources such as areas of poor quality capping;
- Discrete features such as minor fissures/discontinuities in that capping;
- Lateral migration;
- Leaking gas wells;
- Faulty pipes; and
- Open leachate chambers.

There are not yet standardized methodologies for calculating fugitive CH_4 emissions using the methods mentioned above. However, there are a number of landfills operators taking the initiative to test these methods and help develop the data and techniques necessary to identify rigorous site-specific methodologies.

With this in mind, the Protocol encourages landfill operators who have conducted specific site studies and have estimated their fugitive emissions based on these studies to additionally report this information. This is considered optional[17], and care should be taken to not add together the optionally reported emission

[16] US EPA AP 42 Emission Factors, Solid Waste Disposal, 1998, pg 2, 4-6.

[17] For the CCAR program, optionally reported emissions and information are not subject to third-party verification.

estimates and the emission estimates from the methodologies above, which would grossly overestimate a local government's fugitive CH_4 emissions from its landfill.

Local governments who have collected site specific CH_4 surface emissions can use Equation 3 to estimate total fugitive CH_4 emissions from their landfill and report it optionally, in addition to the results from Equation 9.1 or Equation 9.2.

Equation 9.3	***Landfills with Surface Emissions Data***
CH_4 emitted (metric tons CO_2e) = [LFG Collected x CH_4 % x (1 - DE) x (unit conversion)] + [CH_4 surface emissions x (unit conversion)] x GWP	

Where:

Term		Description	Value
CH_4%	=	Fraction of CH_4 in LFG	0.5, if no field data is available
DE	=	CH_4 Destruction Efficiency, based on the type of combustion/flare system.	Site-specific or default based on control device - see Table 9.7
Unit conversion	=	Applies when converting million standard cubic feet of methane into metric tons of methane (volume units to mass units)	19.125
GWP	=	Global Warming Potential converts metric tons of methane into metric tons of CO2 equivalents (CO_2e).	21

9.4 Composting

Composting of organic waste, such as food waste, yard and park waste and sludge, is common in the United States. Advantages of composting include reduced volume in the waste material, stabilization of the waste, and destruction of pathogens in the waste material. The end products of composting, depending on its quality, can be recycled as fertilizer and soil enhancers, or be disposed of in a landfill.

Composting is an aerobic process and a large fraction of the degradable organic carbon in the waste material is converted into carbon dioxide. Methane is formed in anaerobic sections of the compost, but it is oxidized to a large extent in the aerobic sections of the compost. Anaerobic sections are created in composting piles when there is excessive moisture or inadequate aeration (or mixing) of the compost pile. The estimated CH_4 released into the atmosphere ranges from less than 1 percent to a few per cent of the initial carbon content in the material. Composting can also produce emissions of nitrous oxide. The range of the estimated emissions varies from less than 0.5 percent to 5 percent of the initial nitrogen content of the material.[18]

2008 was the first year EPA estimated national CH_4 and N_2O emissions from composting activities. The default emission factors used by EPA are supposed to account for emissions from small areas where compost is not aerated and is therefore producing fugitive emissions, on average, nation-wide. While these macro-level default emission factors may be appropriate on a national level, they are not suitable to estimate fugitive emissions from small, un-aerated areas at the individual facility level.

Because of the lack of existing data and guidance for this potential emission source, the Protocol does not include standardized methodologies to estimate fugitive emissions from composting at this time. As the state of the science for direct measurement of these emissions improves, this chapter will be updated with additional guidance.

[18] IPCC 2006.

Chapter 10 Centralized Wastewater Treatment Facilities

Local governments are often responsible for providing wastewater services to their communities. This may include activities like wastewater collection, managing septic systems, primary and secondary treatment, solids handling and effluent discharge.

The wastewater treatment process can encompass many different sources of GHG emissions. This chapter focuses solely on calculating the fugitive and process CH_4 and N_2O emissions created by centralized wastewater treatment. For guidance on calculating the GHG emissions from other activities related to wastewater treatment, you should refer to other chapters in the Protocol. Table 10.1 provides references to the appropriate chapter and section for common GHG sources related to solid waste.

California Local Governments and AB 32

Note: If your local government operates a wastewater facility that includes a co-generation or power generation source with a nameplate capacity of 1 MW or higher and emits over 2,500 metric tons of CO_2 per year, or a stationary combustion source that emits over 25,000 metric tons of CO_2 per year, you will be subject to ARB's mandatory reporting regulation under AB 32. The regulation has additional reporting requirements beyond what is described in this Protocol.

For more information, see Chapter 14 and to download the mandatory reporting requirements, visit www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.htm.

Table 10.1 Protocol References for Wastewater- Related Emission Sources

GHG type/source	Protocol Reference
CO_2, CH_4 and N_2O from fuel-combusting equipment	Chapter 6, Section 6.1
CO_2, CH_4 and N_2O from purchased electricity	Chapter 6, Section 6.2

10.1 Organizational Boundary Issues

To determine what emissions from wastewater treatment your local government is responsible for calculating and reporting under the Protocol, you will need to examine your wastewater treatment activities according to the organizational boundary guidance in Chapter 3 . It is the same process you used to determine what other facilities your local government is responsible for.

Remember you should consistently apply your organizational consolidation approach across all sources of emissions within your local government. Thus, if the rest of your local government's inventory is based on operational control, use the operational control conditions to determine if the wastewater treatment facility that serves your local government falls under your control.

Many local governments use regionally-serving wastewater treatment plants. Only the local government that has operational and/or financial control over the facility itself should report fugitive emissions from that facility as Scope 1 emissions. If you do not have financial or operational control over the treatment facility, you should not report the fugitive emissions from that facility as Scope 1 emissions. You can, however, optionally report these emissions as Scope 3.

10.2 Emissions Unique to Wastewater Treatment

Wastewater treatment processes can create a unique set of process and fugitive emissions.
Wastewater from domestic and industrial sources is treated to remove soluble organic matter, suspended solids, pathogenic organisms, and chemical contaminants. Centralized wastewater treatment systems may include a variety of processes, ranging from lagooning to advanced tertiary treatment technology for removing nutrients.

Soluble organic matter is generally removed using biological processes in which microorganisms consume the organic matter for maintenance and growth. The resulting biomass (sludge) is removed from the effluent prior to discharge to the receiving stream.

Microorganisms can biodegrade soluble organic material in wastewater under aerobic or anaerobic conditions - it is anaerobic conditions that lead to the production of methane. During collection and treatment, wastewater may be accidentally or deliberately managed under anaerobic conditions. In addition, the sludge may be further biodegraded under aerobic or anaerobic conditions.[19]

The generation of N_2O may also result from the treatment of domestic wastewater during both nitrification and denitrification of the nitrogen present, usually in the form of urea, ammonia, and proteins. These compounds are converted to nitrate (NO_3) through the aerobic process of nitrification. Denitrification occurs under anoxic conditions (without free oxygen), and involves the biological conversion of nitrate into dinitrogen gas (N_2). N_2O can be an intermediate product of both processes, but is more often associated with denitrification.[20]

Table 10.2 summarizes the sources of fugitive and process CH_4 and N_2O emissions discussed in this chapter. For many sources, there are two available methodologies - one that requires site-specific data and one that requires only population served by the facility. This table can be used as a reference to which equation your local government should use based on the data available to you.

Table 10.2 Summary of Wastewater Treatment Process and Fugitive Emission Sources

GHG type	GHG source	Data Available	Equation
Fugitive CH_4 emissions	Incomplete combustion of digester gas	• Digester gas (ft^3/day) • F CH_4	Equation 10.1
		Population served	Equation 10.2
Process CH_4 emissions	Wastewater treatment lagoons	• BOD_5 load (kg BOD_5/person/day) • F removed	Equation 10.3
		Population served	Equation 10.4
Fugitive CH_4 emissions	Septic systems	BOD_5 load (kg BOD_5/person/day)	Equation 10.5
		Population served	Equation 10.6
Process N_2O emissions	Centralized WWTP with nitrification/denitrification	Population served	Equation 10.7
Process N_2O emissions	Centralized WWTP without nitrification/denitrification	Population served	Equation 10.8
Process N_2O emissions	Effluent discharge to receiving aquatic environments	N load (kg N/day)	Equation 10.9
		Population served	Equation 10.10

[19] US EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2006, Chapter 8.
[20] Ibid.

10.3 Ongoing Research and Development

While IPCC, EPA and others have worked to estimate GHG emissions from wastewater on a gross basis, there are not existing widely-accepted, standardized guidelines to estimate emissions from wastewater treatment at a facility level.

Since local governments are often responsible for providing wastewater treatment services for their community, the Protocol provides guidance on estimating the process and fugitive emissions from wastewater treatment. These estimation methodologies are based largely on the existing "top-down" methodologies used by ARB, US EPA and others to estimate emissions for an entire state or country.

Box 10.1 The California Wastewater Climate Change Group
In a proactive approach to meeting future GHG regulatory requirements, California wastewater agencies have formed the California Wastewater Climate Change Group (CWGGC), whose purpose is to respond to climate change and forthcoming regulations and to provide a unified voice for the California wastewater industry. To that end, CWCCG is working to develop a stand-alone protocol for wastewater treatment plants in California that will provide detailed calculation methodologies.

CWCCG helped develop the methodologies in this chapter, which represent the first phase of their industry-specific protocol development effort. Phase II will incorporate a combination of mass balance, site specific testing, modeling and new emission factors that are being developed under a national research effort by the Water and Environment Research Foundation (WERF). These methodologies will allow for flexibility in the level of detail and data available and provide options best suited for a particular wastewater treatment plant type. Phase II is expected to be completed in 2010, and results from that effort will be incorporated into this Protocol, as appropriate.

For more information, refer to the *Discussion Paper for a Wastewater Treatment Plant Sector Greenhouse Gas Emissions Reporting Protocol* (April 2008), prepared for CWCCG by CH2MHILL.

10.3.1 CH_4 Emissions Estimation Methodologies

Within the wastewater treatment systems owned and/or operated by local governments, methane emissions can arise from septic systems, aerobic systems that are not well managed, anaerobic systems (anaerobic treatment lagoons and facultative lagoons), and from anaerobic digesters when the captured biogas is not completely combusted.

This section provides equations for calculating methane emissions from these sources based on the population served by the WWTP, or based on site-specific data. These methodologies are adapted for use by local governments from Section 6.2.2 of the IPCC Guidelines and Section 8.2 of the US EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks (1990-2005). For each term in the equations, this section provides a description and an appropriate value.

10.3.1.1 Fugitive Emissions from Incomplete Combustion of Digester Gas

Many local governments operate WWTPs that utilize anaerobic digesters to create and combust biogas produced by the wastewater treatment process. As there are some inefficiencies in these anaerobic digesters, these systems are a source of fugitive CH_4 emissions.

Equation 10.1 should be used by local governments that collect measurements of the volume of produced digester gas at their WWTP and the fraction of CH4 in their biogas in accordance with local, state and/or federal regulations or permits, or published industry standardized sampling and testing methodologies (e.g., 40 CFR 136, NSPS, APHA, AWWA, WEF, ASTM, EPA, etc.)[21].

If these site-specific data are not available, you should use Equation 10.2 to estimate this source of emissions.

Equation 10.1	Fugitive CH4 from Incomplete Combustion of Digester Gas (site-specific digester gas data)
Annual CH_4 emissions (metric tons) = Digester Gas x F_{CH4} x $\rho(CH_4)$ x (1-DE) x 0.0283 x 365.25 x 10^{-6}	

where:

Term	Description	Value
Digester Gas	= measured standard cubic feet of digester gas produced per day [ft^3/day]	user input
F CH_4	= measured fraction of CH_4 in biogas	user input
$\rho(CH_4)$	= density of methane at standard conditions [g/m^3]	662.00
DE	= CH_4 Destruction Efficiency, based on the type of combustion/flare system.	site-specific or default based on control device - see Table 10.3
0.0283	= conversion from ft^3 to m^3 [m^3/ft^3]	0.0283
365.25	= conversion factor [day/year]	365.25
10^-6	= conversion from g to metric ton [metric ton/g]	10^-6

Table 10.3 Default Methane Destruction Efficiencies for Digester Gas Control Devices

Flares		
Closed flare	=	.995
Open flare	=	.960
Electricity Generation		
Large gas turbine	=	.995
Microturbine	=	.995
Rich burn IC engines	=	.995
Lean burn IC engines	=	.936
Upgraded for other use		
Injection into natural gas transmission and distribution systems	=	.980
CNG and LNG vehicles	=	.950
Other		
Carbon adsorption systems	=	.010
Venting systems	=	0
Source: California Climate Action Registry *Landfill Project Reporting Protocol, Version 1.0*, November 2007.		

[21] Acronym definitions: CFR-Code of Federal Regulations; NSPS-National Source Performance Standard; APHA-American Public Health Association; AWWA-American Water Works Association; WEF-Water Environment Federation; ASTM-American Society for Testing and Materials

Equation 10.2	Fugitive CH_4 from Incomplete Combustion of Digester Gas (default)
Annual CH_4 emissions (metric tons) = P x Digester Gas x F_{CH4} x $\rho(CH_4)$ x (1-DE) x 0.0283 x 365.25 x 10^{-6}	

where

Term	**Description**	**Value**
P	= population served by the WWTP with anaerobic digesters	user input
Digester Gas	= cubic feet of digester gas produced per person per day [ft^3/person/day]	1.0
F_{CH4}	= fraction of CH_4 in biogas	0.65
$\rho(CH_4)$	= density of methane [g/m^3]	662.00
DE	= CH_4 Destruction Efficiency, based on the type of combustion/flare system.	site-specific or default based on control device - see Table 10.3
0.0283	= conversion from ft^3 to m^3 [m^3/ft^3]	0.0283
365.25	= conversion factor [day/year]	365.25
10^-6	= conversion from g to metric ton [metric ton/g]	10^-6

10.3.1.2 Process Emissions from Wastewater Treatment Lagoons

Equation 10.3 should be used by local governments with wastewater treatment lagoons that collect measurements of the average BOD5 load and the fraction of overall removal performance in accordance with local, state and/or federal regulations or permits, or published industry standardized sampling and testing methodologies (e.g., 40 CFR 136, NSPS, APHA, AWWA, WEF, ASTM, EPA, etc.).

If these site-specific data are not available, you should use Equation 10.4 to estimate this source of emissions.

Equation 10.3	Process CH_4 from Wastewater Treatment Lagoons (site-specific BOD_5 load, F removed values)
Annual CH_4 emissions (metric tons) = BOD_5 load x Bo x MCF anaerobic x F removed x 365.25 x 10^{-3}	

where

Term	**Description**	**Value**
BOD_5 load	= amount of BOD_5 produced per day [kg BOD_5/day]	user input
Bo	= maximum CH_4-producing capacity for domestic wastewater [kg CH_4/kg BOD_5]	0.6
MCF anaerobic	= CH_4 correction factor for anaerobic systems	0.8
F removed	= fraction of overall removal performance	user input
365.25	= conversion factor [day/year]	365.25
10^-3	= conversion from kg to metric ton [metric ton/kg]	10^-3

Equation 10.4	Process CH_4 from Wastewater Treatment Lagoons (default values)
Annual CH_4 emissions (metric tons) = P x BOD_5 load x Bo x MCF anaerobic x F removed x 365.25 x 10^{-3}	

where

Term	**Description**	**Value**
P	= population served by lagoons [person]	user input
BOD_5 load	= amount of BOD_5 produced per person per day [kg BOD_5/person/day]	0.090
Bo	= maximum CH_4-producing capacity for domestic wastewater [kg CH_4/kg BOD_5]	0.6
MCF anaerobic	= CH_4 correction factor for anaerobic systems	0.8
F removed	= fraction of overall removal performance	1
365.25	= conversion factor [day/year]	365.25
10^-3	= conversion from kg to metric ton [metric ton/kg]	10^-3

10.3.1.3 Fugitive Emissions from Septic Systems

In some jurisdictions, the local government may own or operate a network of septic systems. If your local government owns or operates septic systems, use the appropriate equation below to estimate the fugitive CH_4 from this emission source.

Equation 10.5 should be used when measurements of the average BOD5 load are collected in accordance with local, state and/or federal regulations or permits, or published industry standardized sampling and testing methodologies (e.g., 40 CFR 136, NSPS, APHA, AWWA, WEF, ASTM, EPA, etc.).

If this site-specific data is not available, you should use Equation 10.6 to estimate this source of emissions.

Equation 10.5	Fugitive CH_4 from Septic Systems (site-specific BOD_5 load data)
Annual CH_4 emissions (metric tons) = BOD_5 load x Bo x MCF_{septic} x 365.25 x 10^{-3}	

where

Term	**Description**	**Value**
BOD_5 load	= amount of BOD_5 produced per day [kg BOD_5/day]	user input
Bo	= maximum CH_4-producing capacity for domestic wastewater [kg CH_4/kg BOD_5]	0.6
MCF_{septic}	= CH_4 correction factor for septic systems	0.5
365.25	= conversion factor [day/year]	365.25
10^-3	= conversion from kg to metric ton [metric ton/kg]	10^-3

Equation 10.6	Fugitive CH_4 from Septic Systems (default BOD_5 load)
Annual CH_4 emissions (metric tons) = $P \times BOD_5 \text{ load} \times Bo \times MCF_{septic} \times 365.25 \times 10^{-3}$	

where

Term	**Description**	**Value**
P	= population served by septic systems [person]	user input
BOD_5 load	= amount of BOD_5 produced per person per day [kg BOD_5/person/day]	0.090
Bo	= maximum CH_4-producing capacity for domestic wastewater [kg CH_4/kg BOD_5]	0.6
MCF_{septic}	= CH_4 correction factor for septic systems	0.5
365.25	= conversion factor [day/year]	365.25
10^-3	= conversion from kg to metric ton [metric ton/kg]	10^-3

10.3.2 N_2O Emissions Methodologies

This section provides equations for calculating N_2O emissions from a centralized WWTP with nitrification/denitrification, centralized WWTP without nitrification/denitrification, and effluent discharge to receiving aquatic environments. They are adapted for use by local governments from Section 6.3 of the IPCC Guidelines and Section 8.2 of the US EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks (1990-2005). For each term in the equations, this section provides a description and an appropriate value.

10.3.2.1 Process Emissions from WWTP with Nitrification/Denitrification

Equation 10.7	Process N_2O Emissions from WWTP with Nitrification/Denitrification
Annual N_2O emissions (metric tons) = $P \times EF \text{ nit/denit} \times 10^{-6}$	

where

Term	**Description**	**Value**
P	= population that is served by the centralized WWTP with nitrification/denitrification [person]	user input
EF nit/denit	= emission factor for a WWTP with nitrification/denitrification [g N_2O/person/year]	7
10^-6	= conversion from g to metric ton [metric ton/g]	10^-6

10.3.2.2 Process Emissions from WWTP without Nitrification/Denitrification

Equation 10.8	Process N_2O Emissions from WWTP without Nitrification/Denitrification
Annual N_2O emissions (metric tons) = P x EF w/o nit/denit x 10^{-6}	

where

Term	**Description**	**Value**
P	= population that is served by the centralized WWTP with nitrification/denitrification [person]	user input
EF w/o nit/denit	= emission factor for a WWTP without nitrification/denitrification [g N_2O/person/year]	3.2
10^-6	= conversion from g to metric ton [metric ton/g]	10^-6

10.3.2.3 Process Emissions from Effluent Discharge

Equation 10.9 should be used by local governments that collect measurements of the average total nitrogen discharged in accordance with local, state and/or federal regulations or permits, or published industry standardized sampling and testing methodologies (*e.g.*, 40 CFR 136, NSPS, APHA, AWWA, WEF, ASTM, EPA, *etc.*).

If this site-specific data is not available, you should use Equation 10.10 to estimate this source of emissions.

Equation 10.9	Process N_2O Emissions from Effluent Discharge (site-specific N load data)
Annual N_2O emissions (metric tons) = N Load x EF effluent x (44/28) x (1 - F plant nit/denit) x 365.25 x 10^{-3}	

where

Term	**Description**	**Value**
N Load	= measured average total nitrogen discharged [kg N/day]	user input
EF effluent	= emission factor [kg N_2O-N/kg sewage-N produced]	0.005
44/28	= molecular weight ratio of N_2O to N_2	1.57
F plant nit/denit	= fraction of nitrogen removed for the centralized WWTP with nitrification/denitrification	0.7
	= fraction of nitrogen removed for the centralized WWTP w/o nitrification/denitrification	0
365.25	= conversion factor [day/year]	365.25
10^-3	= conversion from kg to metric ton [metric ton/kg]	10^-3

Equation 10.10	Process N_2O Emissions from Effluent Discharge (default N load data)
Annual N_2O emissions (metric tons) = P x (Total N Load x F ind-com - N uptake x BOD_5 load) x EF effluent x 44/28 x (1 - F plant nit/denit) x 365.25 x 10^{-3}	

where

Term	**Description**	**Value**
P	= population served [person]	user input
Total N Load	= total nitrogen load [kg N/person/day]	0.026
F ind-com	= factor for industrial and commercial co-discharge of protein into the sewer system	1.25
N uptake	= nitrogen uptake for cell growth in aerobic system	0.05
	= nitrogen uptake for cell growth in anaerobic system (e.g., lagoon)	0.005
BOD_5 load	= amount of BOD_5 produced per person per day [kg BOD_5/person/day]	0.090
EF effluent	= emission factor [kg N_2O-N/kg sewage-N produced]	0.005
44/28	= molecular weight ratio of N_2O to N_2	1.57
F plant nit/denit	= fraction of nitrogen removed for the centralized WWTP with nitrification/denitrification	0.7
	= fraction of nitrogen removed for the centralized WWTP w/o nitrification/denitrification	0.0
365.25	= conversion factor [day/year]	365.25
10^-3	= conversion from kg to metric ton [metric ton/kg]	10^-3

Chapter 11 Other Process and Fugitive Emissions

Most local governments will not have process or fugitive emission sources within their operations beyond those already identified in the Protocol (i.e., fugitive emissions of refrigerants, fugitive emissions from landfills, and process and fugitive emissions from wastewater treatment). However, as the services provided by local governments vary greatly from jurisdiction to jurisdiction, it is possible that your local government may own and/or operate other industrial sources of GHG emissions.

You should therefore assess your local government's operations to see if there are any other potential sources of GHG emissions within your organizational boundary. To assist you, the Protocol provides a list of activities that are sources of process or fugitive GHG emissions, and references to existing methodologies for quantifying those emissions. While this list is not exhaustive, it includes most industrial processes that result in fugitive or process GHG emissions.

Fugitive Emissions from Natural Gas Transmission & Distribution
Some local governments may own or operate natural gas operations, including natural gas storage, transmission and distribution. This Protocol does not contain guidance or references for quantifying the fugitive methane emissions from these operations, as there are no existing methodologies for assessing these emissions at the facility-level.

CCAR is currently in the process developing an industry-specific protocol for natural gas transmission and distribution. This document should be available by the end of 2008, and will be a suitable reference document for any local governments with natural gas transmission and distribution operations.

Adipic acid production (process N_2O emissions)
- IPCC 2006 Guidelines, Equation 3.8.
- WRI/WBCSD, *Calculating N_2O Emissions from the Production of Adipic Acid*, 2001

Aluminum production (process CO_2 and PFC emissions)
- CO_2: IPCC 2006 Guidelines, Equations 4.21 - 4.24.
- PFCs: IPCC 2006 Guidelines, Equations 4.25 - 4.27.

Ammonia production (process CO_2 emissions)
- IPCC 2006 Guidelines, Equation 3.3.

Cement production (process CO_2 emissions)
- California Air Resources Board, *Draft Regulation for the Mandatory Reporting of Greenhouse Gas Emissions*, 2007
- California Climate Action Registry's *Cement Reporting Protocol*, 2005.
- Cement Sustainability Initiative, *The Cement CO_2 Protocol: CO_2 Accounting and Reporting Standard for the Cement Industry* (2005) Version 2.0.

HCFC-22 production (process HFC-23 emissions)
- IPCC 2006 Guidelines, Equations 3.31 - 3.33.
- WRI/WBCSD, *Calculating HFC-23 Emissions from the Production of HCFC-22,* 2001.

Iron and steel production (process CO_2 emissions)
- IPCC 2006 Guidelines, Equations 4.9 - 4.11.

Lime production (process CO_2 emissions)
- IPCC 2006 Guidelines, Equation 2.5 - 2.7.

Nitric acid production (process N_2O emissions)

- IPCC 2006 Guidelines, Equation 3.6.
- WRI/WBCSD, *Calculating N_2O Emissions from the Production of Nitric Acid*, 2001.

Pulp and paper production (process CO_2 emissions)

- IPCC 2006, Section 2.5
- International Council of Forest and Paper Associations (ICFPA), *Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills,* Version 1.1, 2005.
- European Union, *Guidelines for the monitoring and reporting of greenhouse gas emissions*, 2006, Annex XI)

Refrigeration and air condition equipment manufacturing (process HFC and PFC emissions)

- U.S. EPA Climate Leaders, *Direct HFC and PFC Emissions from Manufacturing Refrigeration and Air Conditioning Units*, 2003
- WRI/WBCSD, *Calculating HFC and PFC Emissions from the Manufacturing, Installation, Operation and Disposal of Refrigeration & Air-conditioning Equipment* (Version 1.0) 2005,

Semiconductor manufacturing (process PFC and SF_6 emissions)

- IPCC 2006, Equations 6.7 - 6.11.

Chapter 12 Scope 3 Emission Sources

In addition to the scope 1 and 2 emission sources described in the previous chapters, a number of additional emissions sources of potential policy relevance to local government operations can be measured and analyzed. These include emission sources related to local government operations, but over which local governments do not have clear operational or financial control.

Scope 3 emissions include all other indirect emissions not covered in Scope 2, such as emissions from waste generated by local government operations (if your local government does not own the landfill where waste is being sent), emissions resulting from the extraction and production of purchased materials and fuels, transport-related activities in vehicles not owned or controlled by the reporting entity (e.g., employee commuting and business travel), outsourced activities, etc.

Local governments are encouraged to identify and measure all Scope 3 emission sources to the extent possible. Reporting of Scope 3 emission sources is optional, though individual programmatic reporting requirements may specify a subset of Scope 3 emissions for inclusion in reporting.

Remember, it is possible that the same Scope 3 emissions may be reported as Scope 3 emissions by more than one entity. For example, both a local government and a landfill operator who outsources waste hauling may choose to report the emissions associated with transporting waste from its point of generation to the landfill as Scope 3 emissions. For this reason, Scope 3 emissions should never be summed across entities or mixed with Scope 1 and Scope 2 emissions.

12.1 Assessing the Relevance of Optional Emission Sources

While reporting of Scope 3 emissions is considered optional, doing so provides an opportunity for innovation in GHG management. Local governments should focus on accounting for and reporting those activities that are relevant to their GHG programs and goals, and for which they have reliable information. Since you have discretion over which categories you choose to report, Scope 3 may not lend itself well to comparisons across local government.

And while data availability and reliability may influence which Scope 3 activities are included in the inventory, it is accepted that data accuracy may be lower than Scope 1 and Scope 2 data. It may be more important to understand the relative magnitude of and possible changes to Scope 3 activities. Emission estimates are acceptable as long as there is transparency with regard to the estimation approach, and the data used for the analysis are adequate to support the objectives of the inventory.

You might consider the following questions to determine what Scope 3 emission sources are most relevant to your local government:

- Is the emission-causing activity large (or believed to be large) relative to your Scope 1 and Scope 2 emissions?
- Is the emission-causing activity crucial to the core services of a local government?
- Do your stakeholders - for example, citizens, your city council, local businesses, or your staff - believe that it is important to account for particular emission-causing activities?
- Can you reduce or mitigate some of these emissions? For example, emissions from employee business travel and commuting may represent a large source of emissions that the local government may be able to influence through travel policies and incentive programs.
- Do you now outsource an activity that it previously categorized as Scope 1? If so, it may be relevant to report the outsourced activity as a Scope 3 emission source.
- Are you able to find reliable data for the activity? The data for Scope 3 emissions often are less accurate and reliable than those for Scope 1 and Scope 2 emissions. In fact, the data's availability

and reliability may determine whether or not you decide to include some Scope 3 emission sources in your inventory.

12.2 Potential Emission Sources

Below are examples of local government Scope 3 emission sources. Note that some of these activities will be included under scope 1 if the pertinent emission sources are owned or controlled by the local government (e.g., if the local government owns or controls a waste disposal facility, the emissions from waste disposal should be accounting for as Scope 1 emissions). To determine if an activity falls within Scope 1 or Scope 3, refer to the selected control approach (operational or financial) used in setting your organizational boundaries.

While some guidance is provided below, this Protocol does not currently include detailed calculation methodologies for all Scope 3 emissions - local governments interested in computing their Scope 3 emissions are referred to the WRI/WBCSD GHG Protocol calculation tools and calculation guidance (available at www.ghgprotocol.org). Local governments seeking to represent emissions reductions from Scope 3 emission sources relative to a base year emissions inventory must ensure that those Scope 3 emissions were reported in the base year inventory.

12.2.1 Transportation Related Sources

Employee Commute
Emissions associated with the travel of employees to and from work in personal vehicles not owned and operated by the local government are classified as Scope 3 emissions. Local governments can often influence these emissions through various programs (e.g., carpools, telecommute options, flex schedule options) despite not having direct control over them.

Local governments can calculate energy use and emissions associated with employee travel to and from work by first conducting a survey of all employees regarding commute distance, mode and frequency. A similar emissions quantification methodology to that described in Chapter 7 should be used for estimating emissions associated with employee commuting.

Employee Business Travel
Emissions associated with government employees traveling on behalf of the local government in vehicles that are not owned or maintained by the local government are considered Scope 3 emissions. This includes emissions associated with personal and rented vehicles, mass transit, marine and air travel. In some cases local governments may determine that employee air travel while on government business, for examples, constitutes a significant source of local government emissions and should be reported separate from but in addition to other government operations emissions.

Local governments can calculate energy use and emissions associated with employee business travel by establishing a mechanism for tracking travel distance and mode for all business-related travel. A similar emissions quantification methodology to that described in Chapter 7 should be used for estimating emissions associated with employee business travel.

Emissions from Contracted Services
Local governments frequently contract provision of services to other organizations. These contracted services are then provided using facilities, vehicles, etc, outside of the operational control of the local government, and therefore are not included as Scope 1 or 2 emission sources. While the range of contracted services can vary widely among local governments (e.g., waste hauling, water treatment, bus systems, fire services), contract mechanisms are often available enabling some degree of influence by the local government on associated GHG emissions.

Local governments should consider the following questions in deciding whether or not to measure and report GHG emissions from contracted services:

- Is the service provided by the contractor a service which is normally provided by local government? If so, consider including these emissions to allow accurate comparison with other local governments.
- In any previous emissions inventory, was the contracted service provided by the local government and therefore included in the earlier inventory? If so, consider including these emissions to allow an accurate comparison to the historical base year inventory.
- Are the emissions resulting from the contractor a source over which the local government exerts significant influence? If so, consider including these emissions in order to provide the most policy relevant emissions information.

Gathering data associated with contractor services can often be difficult, but this can be facilitated through reporting requirements integrated with local government contracts. Quantification methodologies described in previous chapters should be used to estimate emissions associated with contracted services.

12.2.2 Supply Chain Sources

Upstream Production of Materials and Fuels

Upstream activities associated with, for example, the mining, extraction, refining, manufacturing, and production of materials, fuels and electricity consumed by or associated with activities of the local government are classified as Scope 3 emission sources from the perspective of the local government. This includes purchased materials and fuels.22

While it is often difficult to gather data related to these upstream emissions, evolving science and data availability will make this increasingly possible. In each case, consider whether the quantification methodologies described in the chapters above could be useful in estimating emissions.

Upstream and Downstream Transportation of Materials and Fuels

Both up and down the supply chain, materials and fuels related to current local government operational activities require transportation between each element of the supply chain. When these transportation impacts occur outside of vehicles owned and operated by the local government, as is usually the case, associated emissions are classified as Scope 3 from the perspective of the local government.

While it is often difficult to gather data related to these upstream and downstream transportation emissions, evolving science and data availability will make this increasingly possible. A similar emissions quantification methodology to that described in Chapter 7 should be used for estimating emissions associated with upstream and downstream transportation of materials and fuels.

Waste Related Scope 3 Emission Sources

If the local government does not own or operate the solid waste facility where its waste is disposed of, the emissions associated with the decomposition of waste produced directly or indirectly by government operations activities are classified as Scope 3 emissions sources. Chapter 9 provides guidance on how to estimate the fugitive emissions from waste if you own or operate a landfill; this guidance may be helpful to local governments in their efforts to estimate Scope 3 emissions from waste.

[22] "Purchased materials and fuels" is defined as material or fuel that is purchased or otherwise brought into the organizational boundary of the local government.

California Local Governments and AB 32

Because of ARB's statewide GHG inventory efforts under AB 32, there is a wealth of data available to California local governments about the estimated methane emissions from landfills within the state. If you local government does not own or operate the landfill where you send your waste, you can use this information to estimate your Scope 3 waste-related emissions.

The California Integrated Waste Management Board also has data available regarding waste characterization and waste-in-place in the state's landfills.

PART IV Reporting Your Emissions

Chapter 13 Local Government Operations Standard Inventory Report

A standardized reporting form was developed that mirrors the guidance in the Protocol and provides a common mechanism for disclosing emissions quantified under this protocol. The Standard Inventory Report is intended to for use by all local governments utilizing this protocol. Some reporting programs may require additional information be disclosed. For details see Chapters 14-16 which describe the specific reporting programs.

The report is organized into four sections:

Section 1 - Local Government Profile Information
Section 2 - Greenhouse Gas Inventory Details
Section 3 - Activity Data Disclosure
Section 4 - Methodology/Emission Factors Disclosure

Please note that a number of items are identified as “optional” in this chapter and throughout the Protocol. The Local Government Operations Protocol establishes a program-neutral standard. Local governments are not required to utilize this protocol, so in a sense the entire report is optional. However, in this context “optional” has a more specific meaning. Line items which are not identified as “optional” in the Protocol should be included in every complete report in order to meet the standard. Items considered “optional” are encouraged as good practice, but a report can be considered complete to the standard established by this Protocol without them.

13.1 Instructions for Completing the Standard Inventory Report

13.1.1 Local Government Profile Information

Section 1 of the Local Government Operations Standard Inventory Report provides a basic overview of the government being inventoried. In addition to the basic identification and contact information, several indicators should be provided. These indicators should be reported as of the year of the inventory being reported.

- **Size** (square miles) – total area within the local government’s jurisdictional boundaries.
- **Population** – number of year round residents of the jurisdiction.
- **Annual Budget** – Total budget under the control of the local government including all general funds, restricted funds and enterprise funds wherever operations included in the emissions inventory are paid for by these funds.
- **Employees** – The number of full time equivalent (FTE) staff employed by the local government.

Indicators are provided primarily in order to increase end user’s understanding of the context of the emissions being reported. Some users may choose to take an additional step and calculate metrics of emissions per indicator (e.g. metric tons CO_2e per FTE employee). These may be valuable benchmarks for a government’s internally established greenhouse gas goals and are not discouraged. However, due to the numerous variations in functions served by local governments this protocol does not recommend or provide any standard comparison metrics.

In addition to the indicators of the size of government, a checklist of services has been provided in order to improve the comparability between reporting jurisdictions Users should indicate all of the services that are provided by the local government and reported as part of either Scope 1 or Scope 2. Services provided by contractors working for the local governments (the emissions of which may be included in the inventory as Scope 3) should not be checked on the checklist.

13.1.2 Greenhouse Gas Inventory Details

Section 2 of the report summarizes the greenhouse gas emissions, information items and optional indicators. Space is provided for users to disclose the reporting year, the version of this protocol being used (currently Version 1.0, August 2008) and whether they are reporting emissions from sources over which they exert operational control or financial control.

All emissions reported in Section 2 should be reported in metric tons. Emissions should be reported by weight of each type of gas separately and an aggregate CO2e figure should be calculated and reported.

13.1.2.1 Scope 1 and 2 Emissions

Emissions should be reported by sector of local government operations. The standard report includes eight sectors which are defined below.

As not all local governments provide the same services, some local governments will have zero emissions to report in some sectors. Those sections of the report should be marked with a “not applicable” (N/A), so it is clear that you do not have emissions in that sector, rather than you are choosing not to report emissions in that sector.

- **Buildings and Other Facilities** includes stationary (6.1) and fugitive (6.6) emissions as well as Scope 2 emissions (6.2-6.5) related to any facilities not included in any other sector below. Typically this will include administrative facilities, public venues, libraries, parks and recreational facilities, storm water pumping, storage facilities, etc.

- **Streetlights and Traffic Signals** includes indirect emissions from electricity (6.2) related to these types of lighting, including crosswalk signals, amber flashers. Other outdoor lighting that can be segregated from the facilities that it serves can be included in this sector rather than in the buildings and other facilities sector – often times the outdoor lighting at a given building is provided for by the same meter as the rest of the facility and in these cases it should be reported in buildings and other facilities.

- **Water Facilities** includes stationary (6.1) and fugitive (6.6) emissions as well as Scope 2 emissions (6.2-6.5) related to any facilities used for the transportation, treatment of distribution, of drinking water. Typically this will include treatment facilities, booster stations, lift stations, in-line pumps, storage facilities, reservoirs and irrigation systems.

- **Wastewater Facilities** includes stationary (6.1) fugitive and process (6.6 and 10) emissions as well as Scope 2 emissions (6.2-6.5) related to any facilities used for the transportation, collection or treatment of wastewater/sewage. Typically this will include treatment facilities, booster stations, in-line pumps, and lift stations.

- **Vehicle Fleet** includes mobile combustion (7.1 and 7.2) and fugitive emissions (7.4) as well as Scope 2 emissions from purchased electricity (7.3) for all electric vehicles and other electrified mobile equipment operated by the local government. Note that all vehicles should be reported here rather than in the sector with which their use is associated (i.e. vehicles used at the solid waste disposal facility should be reported with the vehicle fleet and not in the solid waste disposal facilities sector). Typically this will include cars, trucks, vans, buses, heavy equipment, boats, planes, helicopters, tractors, backhoes, lawn mowers, etc.

- **Power Generation Facilities** includes stationary combustion (8.1 and 8.2) and fugitive (8.4) emissions as well as Scope 2 emissions from electricity purchased and consumed (6.2), transmission and distribution losses from purchased power (8.3), and purchased steam and any district heating/cooling systems (6.3 – 6.5) related to any facilities used to generate or distribute power.
    - In cases where a municipal utility provides power to the local government, then all of the emissions should be reported as Scope 1 and that government will not report the scope 2 emissions from their consumption of that power. However, in order to improve comparability of reports and to highlight this policy-relevant consumption of energy, these governments should report the electricity that they consume as an indicator in the power generation faculties sector. In addition to the kWh consumed, they should also report greenhouse gas emissions, in CO_2e, resulting from that consumption.

- **Solid Waste Facilities** includes stationary (6.1) and fugitive (10 and 6.6) emissions as well as Scope 2 emissions (6.2-6.5) related to local government owned/operated disposal facilities.

- **Other Process and Fugitive Emissions** – (11) should include emissions from natural gas system leaks where the government operates the transmission system and other process and fugitive emissions discussed in Chapter 11.

13.1.2.2 Optional Scope 3 Emissions

In addition to the Scope 1 and 2 emissions, each sector may also include optional Scope 3 emissions sources. These sources are described in Chapter 12 and the common sources are listed at the bottom of the standard reporting template for convenience. Scope 3 sources only need to be reported in CO2e, not by individual gas.

While Scope 3 emissions are considered optional in this protocol, some reporting programs utilizing this protocol may require that some Scope 3 sources be reported. See the reporting program specific chapters for additional details.

13.1.2.3 Optional Indicators

In addition to the greenhouse gas emissions, local governments are encouraged to report optional indicators for each sector.

- Water pumped (gallons)in the water sector
- Water Treated (gallons) in the water sector
- Wastewater pumped (gallons) in the wastewater sector
- Wastewater treated (gallons) in the wastewater sector
- Number of on road vehicles in the vehicle sector
- Total vehicle miles travel by on road vehicles
- Number of non-road vehicles and other equipment in the vehicle sector
- Hours of operation of non-road vehicles and equipment
- Tons of solid waste accepted in the inventory year
- Number of years that a landfill has been operating
- Total electricity generated (MWh) at electricity generating facilities
- Total power generated at non-electric power generating faculties (MMBtu at generation)

Indicators are provided primarily in order to increase end user's understanding of the context of the emissions being reported. Some users may choose to take an additional step and calculate metrics of emissions per indicator (e.g. metric tons CO_2e per gallon of wastewater). These may be valuable benchmarks for a government's internally established greenhouse gas goals and are not discouraged. However, due to the numerous variations in the way that local governments provide these functions this protocol does not recommend or provide any standard comparison metrics.

13.1.2.4 Information Items

In addition to emissions and indicators, several information items should be reported in order to present a more complete picture of a local government's energy use patterns and impact on the climate.

Biogenic CO_2 from biomass combustion. Following established international greenhouse gas management principles, emissions of CO_2 from combustion of biomass are not included as a Scope 1 source because the carbon embodied in these emissions is not new to the atmosphere. However, in order to more completely represent the local government's energy use, the total CO_2 released from biogenic combustion should be reported as an information item. Biogenic combustion here includes both stationary and mobile sources.

Carbon offsets purchased/sold. Local governments should account for and report all carbon offsets which they purchase and retire. These offsets may not be deducted from Scope 1 or Scope 2 emissions due to the fact that a complete accounting framework which accurately and credibly tracks the ownership and retirement of these credits has not yet been established.

Local governments should also report any offsets that they sell as part of a climate mitigation project.

Renewable Energy Credits purchased/sold. Local governments should account for and report Renewable Energy Credits (also called RECs or green tags) which they purchase and retire either from a utility or through another market channel. These credits may not be deducted from Scope 2 emissions as a complete accounting framework which accurately and credibly tracks the ownership and retirement of these credits has not yet been established.

Local governments should also report any RECs that they sell as part of a climate mitigation project. Local governments operating renewable energy projects should verify whether the credits are being retained by the government or sold.

13.1.3 Activity Data Disclosure

In addition to reporting emissions, local governments need to disclose the methodology employed to calculate the emissions. In general, every number reported in Section 2 must be accompanied by a reference for activity data. Detailed disclosure should be made of the activity data used for each primary calculation methodology used for each gas, in each scope, and in each sector. This disclosure should site the source of the data and the methodology used and whether that methodology is a recommended method or an alternate method.

Deviations from the primary methodology should be explained in the same level of detail and the scale of the deviation should be described. All assumptions and estimations should be cited as such. Local governments may also use this space in the reporting format to discuss the rational for the inclusion or exclusion of optional inventory components.

It is good practice to include appropriate citations (such as website URL, report title, etc). It is also good practice to include the quantitative data (e.g. kWh, gallons of diesel, etc) used so that the calculation can be repeated.

See some examples of appropriate activity data disclosure below.

Example A

Scope 2 Purchased Electricity

Description (EXAMPLE)	☒ Primary or ☒ Alternate Method Name: __*Recommended methodology and Installed Wattage Methodology*___________
Scope 2 emissions from Streetlights and Traffic Signals were determined based on meter readings provided by the Streets Division in its Annual Streets Division Report. Twenty street lighting accounts were not metered according to the report (see page 35) and so, for each wattage class, it was assumed they operate 11 hours / day. Unmetered streetlights account for 15% of the emissions in Streetlights and Traffic Signals sector.	
References: *Cityville Streets Division Report, Vol. 4, 2006. (http://cityville.gov/pwd/reports)*	

Example B

Scope 1 Fugitive

Description	☐ Recommended or ☒ Alternate Method Name: __Alternate Methodology___________
For calculating mobile refrigerant fugitive emissions, we used the alternate method as described by equation 7.13. For default coefficients used in that formula, we used defaults provided in Table 7.7, EXCEPT for the recovery efficiency of remaining refrigerant at disposal. Rather than 50% as listed in the table, we used 70% based on new research in our state into current rates now that the states vehicle recycling laws are in effect (State Transport Department, 2008). Based on the default range of HFC charge per vehicle of 0.5-1.5 kg/vehicle, we assumed that our vehicles contained an average of 1kg of HFC charge per vehicle.	
References: *Mobile Refrigerant Leakage Report, State Transport Department, Vol 4, page 47, 2008*	

13.1.4 Methodology / Emission Factors Disclosure

The emission factors used should also be cited. In general, every number reported in Section 2 must be accompanied by a reference for emissions factors. The use of default emissions factors from this protocol should be identified as such. Where emission factors other than the default values are used, local governments should carefully cite the source of the alternate emissions factor and must also include the value used (emissions per unit).

13.2 Local Government Operations Standard Inventory Report Template

Local Government Operations Standard Inventory Report

1. Local Government Profile

Jurisdiction Name:
Street Address:
City, State ZIP Country:
Website Address:

Size (sq. miles):
Population:
Annual Budget:
Employees (Full Time Equivalent):

Contact person:
Name:
email:
phone number:

Services Provided:

☐ Water treatment	☐ Mass transit (buses)	☐ Airport
☐ Water distribution	☐ Mass transit (light rail)	☐ Seaport/shipping terminal
☐ Wastewater treatment	☐ Mass transit (ferries)	☐ Marina
☐ Wastewater collection	☐ Schools (primary/secondary)	☐ Stadiums/sports venues
☐ Electric utility	☐ Schools (colleges and universities	☐ Convention center
☐ Fire Protection	☐ Solid waste collection	☐ Street lighting and traffic signals
☐ Police	☐ Solid waste disposal	☐ Natural gas utility
	☐ Hospitals	☐ Other

Local Government Description:

2. GHG Inventory Details

Reporting Year:
Protocol Used:
Control Approach:

GHG Emissions Summary (All Units in Metric Tons Unless Stated Otherwise)

BUILDINGS & OTHER FACILITIES (Chapter 6)								
SCOPE 1		CO2e	CO2	CH4	N2O	HFCs	PFCs	SF6
	Stationary Combustion							
	Fugitive Emissions							
	Total Direct Emissions from Buildings & Facilities							
SCOPE 2		CO2e	CO2	CH4	N2O			
	Purchased Electricity							
	Purchased Steam							
	District Heating & Cooling							
	Total Indirect Emissions from Buildings & Facilities							
SCOPE 3		CO2e						
	See list at bottom for some examples							
INDICATORS								

STREETLIGHTS AND TRAFFIC SIGNALS (Chapter 6.2)					
SCOPE 2		CO2e	CO2	CH4	N2O
	Purchased Electricity				
	Total Indirect Emissions from Streetlights and Traffic Signals				
SCOPE 3		CO2e			
	See list at bottom for some examples				
INDICATORS					

WATER SUPPLY FACILITIES (Chapter 6)								
SCOPE 1		CO2e	CO2	CH4	N2O	HFCs	PFCs	SF6
	Stationary Combustion							
	Total Direct Emissions from Water and Wastewater Facilities							
SCOPE 2		CO2e	CO2	CH4	N2O			
	Purchased Electricity							
	Purchased Steam							
	District Heating & Cooling							
	Total Indirect Emissions from Water and Wastewater Facilities							
SCOPE 3		CO2e						
	See list at bottom for some examples							
INDICATORS	Gallons of Drinking Water Treated							
	Gallons of Water Transported							

WASTEWATER FACILITIES (Chapters 6 and 10)								
SCOPE 1		CO2e	CO2	CH4	N2O	HFCs	PFCs	SF6
	Stationary Combustion							
	Fugitive Emissions							
	Process Emissions							
	Total Direct Emissions from Water and Wastewater Facilities							
SCOPE 2		CO2e	CO2	CH4	N2O			
	Purchased Electricity							
	Purchased Steam							
	District Heating & Cooling							
	Total Indirect Emissions from Water and Wastewater Facilities							
SCOPE 3		CO2e						
	See list at bottom for some examples							
INDICATORS	Gallons of Wastewater Treated							
	Gallons of Wastewater Transported							

VEHICLE FLEET (Chapter 7)							
SCOPE 1		CO2e	CO2	CH4	N2O	HFCs	PFCs
	Mobile Combustion						
	Fugitive Emissions						
	Total Direct Emissions from Vehicle Fleet						
SCOPE 2		CO2e	CO2	CH4	N2O		
	Purchased Electricity for Electric Vehicles						
	Total Indirect Emissions from Vehicle Fleet						
SCOPE 3		CO2e					
	See list at bottom for some examples						
	e.g., Employee Commute						
	e.g., Employee Business Travel						
INDICATORS	Number of Vehicles						
	Vehicle Miles Traveled						
	Number of Pieces of Equipment						
	Equipment Operating Hours						

POWER GENERATION FACILITIES (Chapter 8)								
SCOPE 1		CO2e	CO2	CH4	N2O	HFCs	PFCs	SF6
	Stationary Combustion							
	Process Emissions							
	Fugitive Emissions							
	Total Direct Emissions from Power Generation Facilities							
SCOPE 2		CO2e	CO2	CH4	N2O			
	Purchased Electricity							
	Purchased Steam							
	District Heating & Cooling							
	Total Indirect Emissions from Power Generation Facilities							
SCOPE 3		CO2e						
	See list at bottom for some examples							
INDICATORS	Electicity Generated (MWh)							
	Electricity consumption by government operations							

SOLID WASTE FACILITIES (chapters 6 and 9)							
SCOPE 1	CO2e	CO2	CH4	N2O	HFCs	PFCs	SF6
Stationary Combustion							
Process Emissions							
Fugitive Emissions							
Total Direct Emissions from Solid Waste Facilities							
SCOPE 2	CO2e	CO2	CH4	N2O			
Purchased Electricity							
Purchased Steam							
District Heating & Cooling							
Total Indirect Emissions from Solid Waste Facilities							
SCOPE 3	CO2e						
See list at bottom for some examples							
INDICATORS							

OTHER PROCESS & FUGITIVE EMISSIONS (Chapter 11)							
SCOPE 1	CO2e	CO2	CH4	N2O	HFCs	PFCs	SF6
Process Emissions							
Fugitive Emissions							
Total Direct Emissions from Other Process & Fugitive Emissions							
SCOPE 3	CO2e						
See list at bottom for some examples							
INDICATORS — % electricity consumption offset with greentags							

INFORMATION ITEMS		
Biogenic CO2 from Combustion	CO2e:	
Carbon Offsets Purchased	CO2e:	
Carbon Offsets Sold	CO2e:	
Renewable Energy Credits (Green Power) Purchased	MWH:	CO2e:
% of Total electricity use offset by Green Power	%:	
Renewable Energy Credits (Green Power) Sold	MWH:	CO2e:

POSSIBLE SOURCES OF OPTIONAL SCOPE 3 EMISSIONS
Employee Commute
Employee Business Travel
Emissions From Contracted Services
Upstream Production of Materials and Fuels
Upstream and Downstream Transportation of Materials and Fuels
Waste Related Scope 3 Emissions
Purchase of Electricity Sold to an End User
Transmission and Distribution Losses from Consumed Electricity
Other Scope 3

3. Activity Data Disclosure

Buildings & Other Facilities

Scope 1 Stationary Combustion

Description	☐ Recommended or ☐ Alternate Method Name:
References	

Scope 1 Fugitive Emissions

Description	☐ Recommended or ☐ Alternate Method Name:
References	

Scope 2 Purchased Electricity

	☐ Recommended or ☐ Alternate Method Name:

Scope 2 Purchased Steam

Description
References

Scope 2 Purchased District Heating and Cooling

Description
References

Scope 3

Description
References

Street Lighting and Traffic Signals

Scope 2 Purchased Electricity

Description	☐ Recommended or ☐ Alternate Method Name:
References	

Scope 3

Description
References

Water Supply and Wastewater Facilities

Scope 1 Stationary Combustion

Description	☐ Recommended or ☐ Alternate Method Name:
References	

Scope 1 Process Emissions

Description	Name:
References	

Scope 1 Fugitive Emissions

Description	☐ Recommended or ☐ Alternate Method Name:
References	

Scope 2 Purchased Electricity

Description	☐ Recommended or ☐ Alternate Method Name:
References	

Scope 2 Purchased Steam

Description
References

Scope 2 District Heating and Cooling

Description
References

Scope 3

Description
References

Vehicle Fleet

Scope 1 Mobile Combustion

Description	☐ Recommended or ☐ Alternate Method Name:
References	

Scope 1 Fugitive Emissions

Description	☐ Recommended or ☐ Alternate Method Name:
References	

Scope 2 Purchased Electricity for Electric Vehicles

Description	☐ Recommended or ☐ Alternate Method Name:
References	

Scope 3 Employee Commute

Description
References

Scope 3 Employee Business Travel

Description
References

Power Generation Facilities

Scope 1 Stationary Combustion

Description	Name:
References	

Scope 1 Process Emissions

Description
References

Scope 1 Fugitive Emissions

Description	☐ Recommended or ☐ Alternate Method Name:
References	

Scope 2 Purchased Electricity

Description	☐ Recommended or ☐ Alternate Method Name:
References	

Scope 2 Purchased Steam

Description
References

Scope 2 District Heating and Cooling

Description
References

Solid Waste Facilities

Scope 1 Stationary Combustion

Description	☐ Recommended or ☐ Alternate Method Name:
References	

Scope 1 Process Emissions

Description	Name:
References	

Scope 1 Fugitive Emissions

Description	Name:
References	

Scope 2 Purchased Electricity

Description	☐ Recommended or ☐ Alternate Method Name:
References	

Scope 2 Purchased Steam

Description
References

Scope 2 District Heating and Cooling

Description
References

Scope 3 Waste Related

Description
References

Other Processes and Fugitive Emissions

Scope 1 Process Emissions

Description
References

Scope 1 Fugitive Emissions

Description
References

Informational Items

Biogenic CO2 from Combustion

Description
References

Carbon Offsets Purchased

Description
References

Carbon Offsets Sold

Description
References

Renewable Energy Credits Purchased

Description
References

Renewable Energy Credits (Green Power) Sold

Description
References

Other Scope 3 Emissions

Upstream Emissions from Materials and Fuels Consumed.

Description
References

ETC, ETC…. add for additional scope three sources…

4. Calculation Methodology Disclosure

Please report the methods you used to convert the activity data disclosed above into emissions reported. This may include formulas, emission factors, and other methods.

Scope 1 Stationary Combustion

Description of computational method	☐ Recommended or ☐ Alternate Method Name:
References	

Scope 1 Process Emissions

Description of computational method
References

Scope 1 Fugitive

Description of computational methods
References

Scope 2 Purchased Electricity

Description of computational method	☐ Recommended or ☐ Alternate Method Name:
References	

Scope 2 Purchased Steam

Description of computational method
References

Scope 2 District Heating and Cooling

Description of computational method
References

Scope 3 Employee Commute

Description of computational method	☐ Recommended or ☐ Alternate Method Name:
References	

Scope 3 Upstream Emissions from Materials and Fuels Consumed

Description of computational method
References

Etc, Etc., add as needed for additional Scope 3 sources

Chapter 14 Program-Specific Reporting Requirements - California Air Resources Board

14.1 Background on the California Air Resources Board

The California Air Resources Board (ARB) is a part of the California Environmental Protection Agency, an organization which reports directly to the Governor's Office in the Executive Branch of California State Government. The mission of the ARB is to promote and protect public health, welfare and ecological resources through the effective and efficient reduction of air pollutants while recognizing and considering the effects on the economy of the state.

14.2 Background on AB 32

The Global Warming Solutions Act of 2006 (AB 32, Nunez, Statutes of 2006, chapter 488) is the cornerstone of California's efforts to deal with climate change. In September 2006, the Legislature and the Governor codified the 2020 target and gave the ARB the primary responsibility of monitoring and regulating sources of greenhouse gases in order to reduce emissions. In 2007, ARB released a list of early regulatory actions, developed a mandatory reporting program, and established the 1990 baseline level at 427 MMT CO_2e. Efforts are currently underway to develop and adopt a plan for achieving the 2020 target.

Local government greenhouse gas (GHG) emissions inventory protocols are an integral tool in ARB's implementation of AB 32. More information is available at www.arb.ca.gov/cc/protocols/localgov/localgov.htm.

14.2.1 Why Local Governments are Important

Local governments can contribute significantly to California's efforts to reduce GHG emissions. Local governments have the ability to influence community-scale planning efforts and have direct control over emissions resulting from municipal operations, such as energy use in government buildings, fuel use in vehicle fleets, energy efficiency of water/wastewater treatment, and methane capture at solid waste facilities. Many local governments are already taking action to reduce greenhouse gas emissions resulting from these activities.

In order to effectively reduce GHG emissions, cities and counties must first measure their carbon footprint. The Local Government Operations Protocol provides the methods necessary for local governments to inventory emissions from municipal operation activities.

14.2.2 Baseline Emissions

Currently, there is no ARB policy for establishing a baseline year for local governments. ARB may designate a specific baseline year from which to measure progress in the future.

14.3 Mandatory Greenhouse Gas Emissions Reporting

On December 6, 2007, ARB approved a regulation for the mandatory reporting of GHG emissions from major sources, pursuant to AB 32. The regulation requires the mandatory reporting and verification of greenhouse gas (GHG) emissions.

Local governments must use the methods provided by the State of California to quantify GHG emissions for facilities subject to mandatory reporting.

The following sections highlight some of the differences between guidance in the Protocol and the requirements of California's mandatory reporting regulation.

14.3.1 Facility Definition

California's mandatory reporting program requires reporting at the facility level. The regulation defines a facility as "any property, plant, building, structure, stationary source, stationary equipment or grouping of stationary equipment or stationary sources located on one or more contiguous or adjacent properties, in actual physical contact or separated solely by a public roadway or other public right-of way, and under common operational control, that emits or may emit any greenhouse gas…." The Protocol defines a facility similarly; however, it also allows local governments with facilities under financial control to report GHG emissions.

14.3.2 Organizational Boundaries

The LGO Protocol encourages local governments to report GHG emissions using operational control. ARB's mandatory reporting program requires facilities to report GHG emissions using operational control.

14.3.3 Difference in Stationary Combustion Default Emission Factors

Stationary combustion default emission factors for California's mandatory reporting program are slightly lower than those included in the Protocol. ARB uses 3.664 as the CO_2 to carbon molar ratio, which is based on best available internationally accepted elemental atomic weights. It is also consistent with the European Union Emissions Trading Scheme. The Protocol uses 3.667 as the CO_2 to carbon molar ratio, which is consistent with IPCC, The Climate Registry and the California Climate Action Registry.[23]

For the purposes of reporting stationary source combustion emissions, local governments are encouraged to use the emission factors presented in this Protocol. However, if a local government facility is subject to mandatory reporting, then they should use the emission factors in the regulation.

14.3.4 De Minimis Emissions

The LGO Protocol adopts the same *de minimis* threshold as the California Registry General Reporting Protocol, which permits up to 5 percent of local government emissions to be reported as *de minimis*. California's Mandatory Reporting regulation limits GHG emissions claimed as *de minimis* to no more than 3 percent of total facility emissions, not to exceed 20,000 metric tons of CO_2 equivalent emissions. Emissions must still be estimated and reported for the selected *de minimis* sources, but alternative emission estimation methods can be used.

14.3.5 Verification

Local governments with facilities subject to mandatory reporting will be required to have the greenhouse gas emissions for these facilities verified beginning in 2010, for the year 2009 reported emissions. Facilities are subject to either annual or triennial verification. Only ARB accredited verification bodies may provide verification services for the purposes of mandatory greenhouse gas emissions reporting.

Local governments that report GHG emissions using the LGO Protocol should utilize the site visit schedule based on the mandatory reporting program for facilities subject to mandatory reporting; the California Climate Action Registry General Verification Protocol can be followed for the remaining local government facilities and sources.

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[23] ARB uses the following formula: $CO_2/C = 44.0098/12.011 = 3.66412455$. This number is rounded to 3.664 for usage in the mandatory reporting program. The Protocol uses the following formula: $CO_2/C = 44/12 = 3.666666666666667$ and rounds to 3.667 as the CO_2 to carbon molar ratio.

Chapter 15 Program-Specific Reporting Requirements - California Climate Action Registry

15.1 Background on the California Climate Action Registry

The California Registry is a non-profit public/private partnership that serves as a voluntary greenhouse gas registry to protect, encourage, and promote early actions to reduce GHG emissions. The California Registry provides leadership on climate change by promulgating credible and consistent GHG reporting standards and tools for organizations to measure, report, verify, and reduce their GHG emissions in California and/or the U.S. Following considerable initiative and input from various stakeholders from the business, government, and environmental communities, the California State Legislature established the California Registry in 2000, with technical modifications in 2001.[24]

The purposes of the California Registry are as follows:

- To enable participating entities to voluntarily measure and record GHG emissions produced after 1990 in an accurate manner and consistent format that is independently verified;
- To establish standards that facilitate the accurate, consistent, and transparent measurement and monitoring of GHG emissions;
- To help various entities establish emissions baselines against which any future state or federal GHG emissions reduction requirements may be applied;
- To encourage voluntary actions to increase energy efficiency and reduce GHG emissions;
- To ensure that participating organizations receive appropriate consideration for verified emissions results under any future state, federal or international regulatory regime relating to GHG emissions;
- To recognize, publicize, and promote participants in the California Registry; and
- To recruit broad participation in the process.

The California Registry was created by the State of California to be a non-profit organization operating outside of the state government, but working closely with the State to develop its reporting and verification procedures such that the State is confident in the quality of the data. To this end, the State has worked closely with the California Registry since its inception to develop its reporting and verification guidance.

Joining the California Registry provides several benefits, such as:

- Addressing inefficiency – understanding that emissions indicate waste and inefficiency has led many companies to insights for redesigning business operations and processes, spurring innovation, improving products and services, and helping to build competitive advantage.
- Managing risk – taking steps to protect early actions ahead of possible future GHG regulations is a wise risk-management strategy.
- Preparing for trading – developing credible and transparent measurement, verification and reporting methods in order to participate in any future emission trading system.

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[24] California Senate Bill 1771 was signed into law on September 30, 2000, and Senate Bill 527 on October 13, 2001. The laws have since sunset, but the California Registry maintains a strong relationship with the State of California and its agencies, and the State maintains its oversight of verifications under the California Registry reporting program.

- Showing environmental leadership – acting early to address climate change to better influence future policy, and to understand the most cost-effective means of managing and reducing emissions.
- Demonstrating action on GHG emissions – reporting verified information to the California Registry helps to address shareholder concerns about adequate corporate actions to reduce GHG emissions.
- Preparing for regulation – verifying annual GHG inventory helps to prepare for mandatory GHG reporting.

15.2 Definition of Local Government

For purposes of the California Registry program, local governments are defined as follows:

Local Government: a general purpose government at the town, city or county level.

California Registry participants meeting the above definition are required to follow the guidance in this Protocol when developing greenhouse gas emissions inventories for its operations. This definition does not include single purpose special districts or other similar agencies that may overlay general purpose government agencies (e.g., water district, sanitation district, recreation district, etc.).

15.3 Reporting Requirements

The information presented below is a summary of the reporting requirements detailed in the California Registry's General Reporting Protocol (GRP). All California Registry participants are subject to the general guidelines in the GRP, along with any additional industry-specific reporting guidance provided by the California Registry.

This Local Government Operations Protocol is industry-specific guidance for California Registry local government participants. Thus, local governments participating in the California Registry should follow the guidance detailed in this Protocol, and refer to the General Reporting Protocol if additional guidance is needed.

15.3.1 Scope of Required Reporting

California Registry participants must submit their GHG emissions to the California Registry each year. At a minimum, participants must report their entity-wide emissions for each of the following categories:

- Direct emissions from mobile source combustion,
- Direct emissions from stationary combustion,
- Indirect emissions from electricity use, imported steam and district heating and cooling,
- Direct process emissions, and
- Direct fugitive emissions.

Each annual GHG emissions report (emissions report) must contain at least the following information:

- The geographic scope of the emissions report (whether California-only or nationwide);
- The operational and organizational boundaries of the reporting entity for which GHG emission data is reported;
- Total significant direct GHG emissions (including mobile and stationary combustion, process, and fugitive);
- Total significant indirect GHG emissions (from electricity usage, and from co-generation, steam imports, district heating and cooling); and
- Total direct and indirect emissions classified as de minimis.

Each emissions report must represent the emissions from a full calendar year - January 1 through December 31.

15.3.2 GHGs Required to be Reported

For the first three years after joining the California Registry, participants must report at a minimum their CO_2 emissions. Starting with the fourth year, participants must report all Kyoto GHGs (CO_2, CH_4, N_2O, HFCs, PFCs, SF_6).

15.3.3 Calculation Methodology Requirements

This Protocol includes an array of activity data and emission factors that can be combined to create calculation methodologies. As the Local Government Operations Protocol effort is a joint effort to satisfy the needs of many programs and stakeholders, in some cases alternate activity data and emission factors have been included that do not meet the standards of the California Registry General Reporting Protocol.

Throughout the chapters in Part II, activity data and emission factors are labeled as *recommended* or *alternate*. All *recommended* activity data and emission factors included in the Protocol meet the standards of the California Registry. In some instances, there are alternate activity data and emission factors that also meet California Registry standards.

To ensure that all California Registry participants are calculating and reporting their emissions in an equally rigorous and accurate way, the California Registry will only accept emissions reports that are calculated using California Registry approved activity data and emission factors as identified in this Protocol. All activity data and emission factors accepted by the California Registry are denoted in the Protocol with the following icon:

☑

If you are a California Registry participant, please ensure that you have used acceptable activity data and emission factors when calculating your emissions.

Table 15.1 provides a summary of activity data and emission factors accepted by the California Registry.

Please note, for de minimis emissions estimations, all alternate activity data and emission factors in the Protocol may be appropriate. This is subject to the professional judgment of your third-party verifier.

15.3.4 Reporting Uncertainty vs. Inherent Uncertainty

Reporting uncertainty entails the mistakes made in identifying emissions sources, managing data or information, and calculating GHG emissions. Inherent uncertainty refers to scientific uncertainty associated with measuring GHG emissions. The California Registry is aware that there is inherent uncertainty in emissions factors and measurement of activity data through metering and instrumentation – even after the calibration of meters and other data collection methods are verified as accurate.

The GHG emissions accounting and reporting guidelines in the General Reporting Protocol and the independent verification process developed by the California Registry are designed to reduce reporting uncertainty such that it is less than the minimum quality standard. Determining scientific accuracy is not the focus of the California Registry, its General Reporting Protocol, or the Local Government Operations Protocol.

Table 15.1 Activity Data and Emission Factors Accepted by CCAR

Sector	Emission Source	CCAR Accepted Activity Data	CCAR Accepted Emission Factors
Facilities	Stationary Combustion (6.1)	Known fuel use (recommended)	Default by fuel type (recommended)
	Electricity Use (6.2)	Known electricity use (recommended)	Verified utility-specific emission factor (recommended)
		Estimated electricity use (alternate)	eGRID subregion emission factor (recommended)
		Estimated electricity use based on comparable facilities and square footage (alternate)	
	Fugitive Emissions (6.6)	Mass balance method (recommended)	n/a
		Simplified mass balance method (alternate)	
Vehicle Fleet	Mobile Combustion - CO_2 Emissions (7.1.1)	Known fuel use (recommended)	Published emission factor by fuel type, state- or region-specific (recommended)
		Fuel estimates based on detailed annual mileage and vehicle fuel economy (alternate)	Default by fuel type (alternate)
	Mobile Combustion - CH_4 and N_2O Emissions (7.2.1)	Annual mileage by vehicle type, model year and fuel type (recommended)	Default by vehicle type, model year and fuel type (alternate)
		Fuel Use by vehicle type, model year and fuel type (alternate)	
	Fugitive Emissions (7.4)	Mass balance method	n/a

15.3.5 Web-Based Reporting via CARROT

California Registry participants must report annual GHG emissions reports via the California Registry's web-based reporting application and database, known as the Climate Action Registry Reporting Online Tool (CARROT).

CARROT has four main functions:

1. Helps California Registry participants calculate their annual GHG emissions and/or report these emissions to the California Registry.
2. Allows approved verifiers to review participants' annual GHG emissions reports and submit their verification information to the California Registry.
3. Permits the general public to view aggregated reports of participants' annual GHG emissions and their progress in managing these emissions.
4. Enables California Registry staff to efficiently manage and track participants' data.

CARROT provides you with a secure, online workspace to manage, report, verify, and register your emissions.

The California Registry has designed CARROT to facilitate and ease emissions reporting. CARROT is also designed to streamline the emissions registration process by providing emissions calculations tools, simple reporting features, and administrative controls that allow participants to delegate reporting within your organization.

When you join the California Registry, your organization's technical contact will be provided a UserID and Password that will allow you to access CARROT through the California Registry's website, www.climateregistry.org/CARROT. Other users within your organization can request access from your organization's technical contact.

15.3.6 Public Reporting

In addition to collecting your GHG emissions data, CARROT will also make limited information about your GHG emissions report available to the public. The public will see the following information that you are required to report:

- Organization name, address, and contact;
- Reporting year;
- Total emissions, by gas and by category (stationary combustion, mobile combustion, process emissions, fugitive emissions, indirect emissions and de minimis emissions); and
- Baseline year (if chosen).

In addition, the public will see the following information that you may choose to report. This optional information is not verified. This may include:

- Reduction goals, projects, management programs
- Entity description
- Total optional emissions, by gas and by category
- Other optional information

Public CARROT reports can be accessed through the California Registry website at www.climateregistry.org/CARROT/public/reports.aspx.

15.4 Establishing and Updating a Baseline

A baseline is a datum or reference point against which to measure GHG emissions increases and decreases over time. Baselines are used in a regulatory context to establish a clear threshold for compliance and non-compliance. Setting a baseline also allows participants to scale structural changes to their organization back to a benchmark emission profile. This aspect of baselines is called "normalization".

For example, an annexation of land could dramatically increase a participant's emissions relative to previous reporting years. To account for the impact on its emissions profile due to acquisition, a participant would adjust its baseline to incorporate the additional emissions associated with the annexed property, thereby showing that the change in emissions occurred because of structural changes.

Although the California Registry strongly encourages participants to set a baseline, you are not required to do so. However, if you choose not to establish a baseline, reviewers of your emission trend might compare successive reporting years back to your first year of reporting, regardless of whether it is indicative of your current structure or operating conditions.

Participants select their baseline according to the year that best represents their standard emissions profile. In the context of the California Registry, a baseline is a "base year" that serves as a benchmark to compare emissions produced by an entity over time. The baseline is adjusted to reflect structural changes in your organization.[25] A baseline may also change if there are fundamental changes in generally accepted GHG emissions accounting methodologies.

A participant may begin reporting emissions to the California Registry for any year from 1990 forward; likewise it can establish as its baseline any reporting year from 1990 forward. After establishing a baseline participants should report verified emissions results for each subsequent year. If an organization's participation in the California Registry lapses temporarily, it must report emissions for all intervening years upon renewing its participation or establish a new baseline. If its boundaries do not change significantly, the baseline will remain fixed over time.

Your baseline should not be adjusted for the organic growth or decline of your local government. In a local government context, organic growth or decline refers to an increase or decrease in population, construction or decommissioning of facilities or buildings, and other situations that are not the result of changes in the structure of the local government. Many organizations experience growth and thus their total absolute emissions will increase from year to year, regardless of their organization's operational efficiency.

15.4.1 Conditions for Updating Your Baseline

The purpose of a baseline is to compare your local government's emission levels from a point in the past. To allow for this comparison, you must have comparable boundaries over time. If your organization's boundaries change with time, you will need to adjust baseline emissions to permit accurate comparison.[26] This Protocol identifies six circumstances that would require you to update your baseline:

Structural Changes in Your Organization

1. Mergers and acquisitions (annexation or incorporation of new areas into the local government jurisdiction);
2. Divestitures (ceding of land or secession of an area);
3. Outsourcing – contracting activities to outside parties that were previously conducted internally;
4. Insourcing – conducting activities internally that were previously contracted to outside parties; and
5. Improved GHG Accounting Methodologies - Fundamental changes in generally accepted GHG emissions accounting methodologies (e.g., significant changes in emission factors or understanding of Global Warming Potential).

All required sources of direct and indirect emissions must be included in a participant's entity-wide baseline for reporting and adjustment purposes. However, participants identify and account for direct and indirect emissions separately. Thus, participants may consider tracking both types of emissions separately in terms of a baseline. Both direct and indirect emission baselines are meaningful for the purposes of the California Registry.

15.4.2 Threshold for Updating a Baseline

Rather than requiring baseline adjustments whenever any changes occur in your organization, however insignificant, you need only adjust your baseline whenever you estimate that the cumulative effect of such changes affects your organization's total reported emissions by plus or minus 10% relative to the baseline. You may adjust your baseline every year, if you wish. You do not need to adjust your baseline when emissions change by plus or minus 10% at any individual facility unless this facility-level change also affects your total entity emissions by plus or minus 10%.

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[25] In this Protocol and the GRP, baselines refer strictly to entity-level baselines. These documents do not provide guidance on setting project-level baselines. Participants should refer to the California Registry project protocols for direction on this activity.
[26] Participants also have the option to change their baseline at their discretion.

In some situations, year-to-year changes to total emissions resulting from structural or other changes to your organization may fall below the 10% threshold for updating your baseline. You will need to update your baseline if and when the cumulative effect is greater than 10%.

When you specify a baseline, for every year after the baseline year, your verifier will also need to verify that your total emissions have not changed by more than 10% from the baseline due to any cause except organic growth. This is intended to provide a check that you are correctly tracking and reporting the emissions associated with your organization's structure.

15.4.3 Timing for Updating a Baseline

When significant structural changes occur during the middle of the year that trigger a baseline update, your baseline should be recalculated for the entire year, rather than only for the remainder of the reporting period after the structural change occurred. For example, if your local government annexes new land in June, then the emissions associated with the annexation starting from January 1 of the baseline year should be added to your baseline, not just the emissions from June – December. Similarly, all years following the baseline year, including the current year emissions (i.e. the year that the structural changes occur) should be recalculated for the entire year to maintain consistency with the baseline recalculation.

15.4.4 Updating a Baseline for Facilities That Did Not Exist in the Baseline Year

Baseline emissions are not recalculated if your organization makes an acquisition of (or insources) operations that did not exist in its baseline year. There should only be a recalculation of historic data back to the year in which the acquisition came into existence. For instance, if your baseline is 2004, and you acquire a facility in 2008 that began operations in 2006, you would revise your 2006 and 2007 emissions reports to add the associated emissions. However, you would not adjust your 2004 baseline. The same applies to cases where your organization divests (or outsources) operations that did not exist in the baseline year.

Refer to Chapter 4 in the California Registry's GRP for more information and examples of updating a baseline.

15.5 De Minimis Emissions

For the purposes of the California Registry program, de minimis emissions are a quantity of GHG emissions from any combination of sources and/or gases, which, when summed equal less than 5% of your local government's total emissions. Significant emissions are any emissions of GHGs that are not de minimis in quantity when summed across all sources of your local government.

For many participants, identifying and quantifying all of their GHG emissions according to the methodologies presented in this Protocol would be unduly burdensome and not cost-effective. To reduce the reporting burden, the California Registry requires that entities calculate at least 95% of their emissions according to the Protocol's methodologies. Thus, if necessary, up to 5% of emissions can be classified and reported as de minimis. However, the California Registry strongly encourages entities to report 100% of their emissions according to the methodologies laid out in the Protocol when possible.

You must identify and report all sources of emissions in your inventory. For significant sources, you must calculate these emissions using required methodologies. For insignificant sources (i.e. potential de minimis sources), you may use a rough, upper bounds estimate to determine the amount of emissions that are de minimis. In the first year, you need to identify what sources fall into the de minimis pool and their estimated total emissions. This information must be disclosed in your emissions report, and reviewed and accepted by your verifier. In subsequent years, if these emissions do not change significantly, you can hold these assumptions constant and your verifier may not need to re-examine your estimates. However, you must continue to report your de minimis sources in CARROT each year.

For example, a participant estimates they emit about 1,000 metric tons of CO_2 each year. Most of these emissions come from an on-site heating and cooling system that services their buildings. In addition, this participant also has one fleet vehicle that is driven about 20,000 miles each year. This participant estimates that between 800 and 1000 gallons of gasoline are consumed by this car each year. Taking the upper estimate of 1000 gallons, the participant calculates the emissions from this source as 8.8 metric tons of CO_2/year, and finds that this amount falls below the de minimis threshold of 5% or 50 tons CO_2/year.

The participant can report this emission source as de minimis in CARROT and provide this estimation to the verifier, along with vehicle records showing the actual miles traveled of the car. In subsequent years, where the operation patterns do not change significantly, the participant can continue to declare the emissions from this source de minimis, and will need to re-calculate this information only every three years.

You may use alternative methods to demonstrate that emissions are de minimis. For example, if your emissions come only from electricity and fuel consumption, it would be sufficient to show that the emission factors for methane and nitrous oxide, when multiplied by their global warming potentials and added together, are less than 5% of the corresponding emission factor for carbon dioxide. Assuming you deemed no other type of emissions to be de minimis, the total de minimis emissions would be less than the 5% threshold.

Your estimations and assumptions in calculating your de minimis emissions will need to be disclosed in your emissions report and provided to and verified by your verifier. If your operations do not change significantly from year to year, you will only need to re-calculate and have verified your de minimis emissions every three years.

The sources and gases that will be de minimis will vary from participant to participant. There may be instances where you identify multiple sources as de minimis, which, when added together, equal less than 5% of your emissions. Different kinds of gases can also be considered de minimis if their combined total is less than 5% of your overall emissions.

15.5.1 Using CARROT to Document De Minimis Emissions

CARROT helps you to calculate and track your de minimis emissions over time. In the first year you report using CARROT, you will enter information to calculate all of your emissions. Once you have reported your inventory, you can designate any combination of individual sources or gases as de minimis. CARROT will then track this information for you, and report it in a category separate from the rest of your emissions.

Refer to Chapter 5 in the California Registry's GRP for more information and examples of de minimis emissions.

15.6 Technical Assistance

The California Registry has a number of ways to help you as you proceed through the emissions reporting process. You can contact California Registry staff if you have questions or problems at:

- help@climateregistry.org
- 213-891-1444 and ask for Member Services

Should you need additional assistance, you can also hire a firm to provide technical assistance. A list of State- and California Registry-approved technical assistance providers is on the California Registry's website as a reference.

15.7 Verification

See Chapter 14 in the GRP for more information on verification. You can also refer to the General Verification Protocol, available on the California Registry's website.

Before emissions reports will be accepted by the California Registry, this information must be verified by an approved verifier. Approved verifiers are screened and approved by the State of California and the California Registry to ensure that they have the necessary skills to appropriately evaluate emissions reports.

Verification is the process used to ensure that a participant's GHG emissions report has met a minimum quality standard and complied with an appropriate set of California Registry-approved procedures and protocols for submitting emissions inventory information. For local governments, this means meeting the requirements of the General Reporting Protocol and the Local Government Operations Protocol.

The California Registry's verification process has been designed to promote the credibility, accuracy, transparency, and usefulness of emissions data reported to the California Registry. Once an approved verifier has determined that the emissions report meets a minimum quality standard and is free of material discrepancies, the participant's reported emissions data will be reviewed by the California Registry and accepted into the California Registry's database.

If you are interested in understanding and preparing for the verification process in more detail, and to see the specific process approved verifiers will be using to verify your GHG emissions report, you may obtain a copy of the Verification Protocol, the California Registry's guidance for approved verifiers, from the California Registry's website.

15.7.1 Minimum Quality Standard

An emissions report submitted to the California Registry must be free of material discrepancies to be verified. In other words, a verifier's calculation estimates of the entire inventory must not differ from a participant's estimates of the entire inventory by more than 5%. It is possible that during the verification process differences will arise between the emissions totals estimated by participants and those estimated by verifiers. Differences of this nature may be classified as either material or immaterial discrepancies. A discrepancy is considered to be material if the overall reported emissions differ from the overall emissions estimated by the verifier by 5% or more. Otherwise, it is immaterial.

15.7.2 Core Verification Activities

The verification process is designed to ensure that there have been no material discrepancies of your reported entity-wide inventory. In order to ensure consistency in the application of verification, the California Registry provides all verifiers with a Verification Protocol that is based on the guidance contained in this Protocol and any industry-specific protocol. The Verification Protocol is a guidance document. However, since verifiers face potential financial liability for reports they have verified, it is ultimately at the verifier's discretion whether to verify your report.

Once the verifier has completed the preparations for verification including the kick-off meeting and the selection of a general approach to verification, the core verification activities can begin.

The core verification activities include three primary elements:

1. Identifying emissions sources;
2. Understanding management systems and estimation methods used;
3. Verifying emission estimates.

The core verification activities are fundamentally a risk assessment and data sampling effort aimed at ensuring that no significant sources are excluded and that the risk of error is assessed and addressed through appropriate sampling and review.

15.7.3 Professional Judgment

Approved verifiers must verify participants' annual GHG emissions reports against the California Registry's General Reporting Protocol using the process outlined in the Verification Protocol. The California Registry asks verifiers to use their professional judgment when executing the verification activities described in this Verification Protocol. The purpose of the verifier approval process is to find verification firms that demonstrate, through their staff's professional qualifications and experience, their ability to render sound professional judgments about GHG emissions reports.

Application of a verifier's professional judgment is expected in the following areas:

- Implementation of verification activities with appropriate rigor for the size and complexity of a participant's organization and with regard to the uncertainty of calculations associated with the participant's emissions sources;
- Review of the appropriateness of a participant's GHG emissions tracking and monitoring procedures, calculation methodologies, and management systems for providing information to the California Climate Action Registry;
- Evaluation of participant compliance with the California Registry's applicable protocol(s);
- Assessment of methods used for estimating emissions from sources for which the Protocol does not provide specific guidance, such as process and fugitive emissions, and indirect emissions from sources other than electricity, imported steam, district heating/cooling; and
- Appraisal of assumptions, and estimation methods and emission factors that are selected as alternatives to those provided in the Protocol.

The Verification Protocol and training provided by the California Registry are intended to explain to the verifier the California Registry's guidelines and expectations and thus what types of professional judgments are appropriate for this program. In addition to these resources, verifiers and participants may contact the California Registry at any time for clarification of California Registry guidelines, expectations and policies.

15.7.4 Conflict of Interest

In order to ensure the credibility of the emissions data reported to the California Registry and its applicability under any future regulatory regime, it is critical that the verification process is completely independent from the influence of the participant submitting the emissions report. While conducting verification activities for California Registry participants, verifiers must work in a credible, independent, nondiscriminatory and transparent manner, complying with applicable state and federal law and the California Registry's Conflict of Interest (COI) determination process.

In their applications to become approved, verifiers must provide information to the California Registry about their organizational relationships and internal structures for identifying potential conflicts of interest (organizational COI). Then, on an individual basis, the California Registry will review any pre-existing relationship between a verifier and participant and will assess the potential for conflict of interest (case-by-case COI) in conducting a verification. When the California Registry determines there is a low risk of COI, the participant and verifier can finalize negotiations of their contract. Following completion of a verification, the verifier must monitor their business relationships for the next year for situations that may create a COI (emerging COI), and notify the California Registry before entering into new business relationships with these participants.

This conflict of interest clause does not preclude a verifier from engaging in consulting services for other clients that participate in the California Registry for whom the verifier does not provide any verification activities.

Verifiers must submit an updated COI form each year, even if they have verified previous years' emissions reports for a participant.

As an added protection, a verifier may provide verification services to a California Registry participant for, at most, six consecutive years. After a six-year period, the California Registry participant must engage a different verifier. The original verifier may not provide verification services to that participant for three years. This three year hiatus begins with any lapse in providing annual verification services to a California Registry participant.

In the event that a verifier violates these conditions, the California Registry, in consultation with the State of California, and at its discretion, may disqualify an approved verifier for a period of up to five years.

15.8 Reporting and Verification Deadlines

You must submit your annual emissions report by June 30 of the year following the emissions year to the California Registry to initiate verification activities. Verification should be completed by October 31 of the year the report is submitted to the California Registry. In other words, a GHG emissions report for 2009 emissions should be submitted by June 30, 2010, and the verification process should be completed by October 31, 2010.

Reporting Deadline	June 30
Verification Deadline	October 31

Table 15.2 illustrates the minimum reporting requirements over time for a new participant.

Table 15.2 Reporting Years and Actions

Year	Local Government Action
2009	Local Government joins the California Registry and tracks 2009 emissions
2010	Local Government tracks 2010/reports 2009 CO_2 emissions
2011	Local Government tracks 2011/reports 2010 CO_2 emissions
2012	Local Government tracks 2012 emissions for all six GHGs/reports 2011 CO_2 emissions
2013	Local Government tracks 2013 /reports 2012 emissions for all six GHGs

Participants who are not able to meet these deadlines must request a reporting or verification extension from the California Registry.

15.9 Record Keeping and Retention

You should maintain any relevant records from which emissions results have been calculated. Such records may include, but not be limited to, utility bills, fuel consumption records, emissions data, process data and schedules, and past reports. Although it is not possible to predict what any future regulatory regime may require regarding record keeping and retention, it is inadvisable for you to dispose of relevant records immediately after filing emissions reports. This would hinder any future verification or review activities, placing you at a disadvantage in case of some need to re-estimate the emissions results.

Chapter 16 Program-Specific Reporting Requirements - ICLEI

In progress

Chapter 17 Glossary of Terms

Activity data	Data on the magnitude of a human activity resulting in emissions taking place during a given period of time. Data on energy use, fuel used, miles traveled, input material flow, and product output are all examples of activity data that might be used to compute GHG emissions.
Annual	A frequency of once a year; unless otherwise noted, annual events such as reporting requirements will be based on the calendar year.
Anthropogenic emissions	GHG emissions that are a direct result of human activities or are the result of natural processes that have been affected by human activities.
Barrel	Commonly used to measure quantities of various petroleum products, a volumetric measure for liquids equal to 42 U.S. gallons at 60 degrees Fahrenheit.
Base year	A specific year against which an entity's emissions are tracked over time.
Base year emissions	GHG emissions in the base year.
Biofuel	Fuel made from biomass, including wood and wood waste, sulphite lyes (black liquor), vegetal waste (straw, hay, grass, leaves, roots, bark, crops), animal materials/waste (fish and food meal, manure, sewage sludge, fat, oil and tallow), turpentine, charcoal, landfill gas, sludge gas, and other biogas, bioethanol, biomethanol, bioETBE, bioMTBE, biodiesel, biodimethylether, fischer tropsch, bio oil, and all other liquid biofuels which are added to, blended with, or used straight as transportation diesel fuel.
Biogenic emissions from combustion	CO_2 emissions produced from combusting a variety of biofuels and biomass, such as biodiesel, ethanol, wood, wood waste and landfill gas.
Biomass	Non-fossilized and biodegradable organic material originating from plants, animals, and micro-organisms, including products, byproducts, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material.
Boundaries	GHG accounting and reporting boundaries can have several dimensions, i.e., organizational, operational and geographic. These boundaries determine which emissions are accounted for and reported by the entity.
British thermal unit (Btu)	The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit at about 39.2 degrees Fahrenheit.
Butane	A normally gaseous straight-chain or branch chain hydrocarbon extracted from natural gas or refinery fuel gas streams and is represented by the chemical formula C_4H_{10}. Butane includes normal butane and refinery-grade butane.
Calendar year	The time period from January 1 through December 31.

Capital lease	A lease which transfers substantially all the risks and rewards of ownership to the lessee and is accounted for as an asset on the balance sheet of the lessee. Also known as a finance lease or financial lease. Leases other than capital or finance leases are operating leases. Consult an accountant for further detail as definitions of lease types differ between various accepted financial standards.
Carbon dioxide (CO_2)	The most common of the six primary GHGs, consisting of a single carbon atom and two oxygen atoms, and providing the reference point for the GWP of other gases. (Thus, the GWP of CO2 is equal to 1.)
CO_2 equivalent (CO_2e)	The universal unit for comparing emissions of different GHGs expressed in terms of the GWP of one unit of carbon dioxide.
Co-generation	An energy conversion process in which more than one useful product (e.g., electricity and heat or steam) is generated from the same energy input stream. Also referred to as combined heat and power (CHP).
Combined heat and power (CHP)	Same as co-generation.
Continuous emissions monitoring system (CEMS)	The total equipment required to obtain a continuous measurement of a gas concentration or emission rate from combustion or industrial processes.
Control approach	An emissions accounting approach for defining organizational boundaries in which an entity reports 100 percent of the GHG emissions from operations under its financial or operational control.
Datum	A reference or starting point.
De minimis	Per the California Climate Action Registry's program-specific requirements, emissions reported for a source or sources that are estimated using alternate methodologies that does not meet CCAR's third-party verification requirements. De minimis emissions can be from one or more sources, for one or more gases which, when summed, equal less than 5% of an organization's total emissions.
Direct emissions	Emissions from sources within the reporting entity's organizational boundaries that are owned or controlled by the reporting entity, including stationary combustion emissions, mobile combustion emissions, process emissions, and fugitive emissions. All direct emissions are Scope 1 emissions, with the exception of biogenic CO_2 emissions from biomass combustion.
Direct monitoring	Direct monitoring of exhaust stream contents in the form of continuous emissions monitoring (CEM) or periodic sampling.
Double counting	Two or more reporting entities taking ownership of the same emissions or reductions.

Emission factor	A unique value for determining an amount of a GHG emitted on a per unit activity basis (for example, metric tons of CO_2 emitted per million Btus of coal combusted, or metric tons of CO_2 emitted per kWh of electricity consumed).
Entity	Any business, corporation, institution, organization, government agency, etc., recognized under U.S. law and comprised of all the facilities and emission sources delimited by the organizational boundary developed by the entity, taken in their entirety.
Ethane	A normally gaseous straight-chained hydrocarbon that boils at a temperature of -127.48 degrees Fahrenheit with a chemical formula of C_2H_6.
Facility	Any property, plant, building, structure, stationary source, stationary equipment or grouping of stationary equipment or stationary sources located on one or more contiguous or adjacent properties, in actual physical contact or separated solely by a public roadway or other public right-of way, and under common operational or financial control, that emits or may emit any greenhouse gas.
Finance lease	Same as capital lease.
Financial control	The ability to direct the financial and operating policies of an operation with an interest in gaining economic benefits from its activities.
Fixed asset investment	Equipment, land, stocks, property, incorporated and non-incorporated joint ventures, and partnerships over which an entity has neither significant influence nor control.
Fossil fuel	A fuel, such as coal, oil, and natural gas, produced by the decomposition of ancient (fossilized) plants and animals.
Fugitive emissions	Emissions that are not physically controlled but result from the intentional or unintentional release of GHGs. They commonly arise from the production, processing, transmission, storage and use of fuels or other substances, often through joints, seals, packing, gaskets, etc. Examples include HFCs from refrigeration leaks, SF_6 from electrical power distributors, and CH_4 from solid waste landfills.
Global warming potential (GWP)	The ratio of radiative forcing (degree of warming to the atmosphere) that would result from the emission of one mass-based unit of a given GHG compared to one equivalent unit of carbon dioxide (CO_2) over a given period of time.
Greenhouse gases (GHGs)	For the purposes of this Protocol, GHGs are the six gases identified in the Kyoto Protocol: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).
Greenhouse gas credit	GHG offsets can be converted into GHG credits when used to meet an externally imposed target. A GHG credit is a convertible and transferable instrument usually bestowed by a GHG program.

Greenhouse gas offset	Offsets are discrete GHG reductions used to compensate for (i.e., offset) GHG emissions elsewhere, for example to meet a voluntary or mandatory GHG target or cap. Offsets are calculated relative to a baseline that represents a hypothetical scenario for what emissions would have been in the absence of the mitigation project that generates the offsets.
Greenhouse gas sink	Any physical unit or process that stores GHGs; usually refers to forests and underground/deep sea reservoirs of CO_2.
Greenhouse gas source	Any physical unit or process which releases GHG into the atmosphere.
Green power	A generic term for renewable energy sources and specific clean energy technologies that emit fewer GHG emissions relative to other sources of energy that supply the electric grid. Includes solar photovoltaic panels, solar thermal energy, geothermal energy, landfill gas, low-impact hydropower, and wind turbines.
Heating value	The amount of energy released when a fuel is burned completely. Care must be taken not to confuse higher heating values (HHVs), used in the US and Canada, and lower heating values, used in all other countries.
Higher heating value (HHV)	The high or gross heat content of the fuel with the heat of vaporization included. The water vapor is assumed to be in a liquid state.
Hydrofluorocarbons (HFCs)	One of the six primary GHGs, a group of manmade chemicals with various commercial uses (e.g., refrigerants) composed of one or two carbon atoms and varying numbers of hydrogen and fluorine atoms. Most HFCs are highly potent GHGs with 100-year GWPs in the thousands.
Indirect emissions	Emissions that are a consequence of activities that take place within the organizational boundaries of the reporting entity, but that occur at sources owned or controlled by another entity. For example, emissions of electricity used by a manufacturing entity that occur at a power plant represent the manufacturer's indirect emissions.
Intergovernmental Panel on Climate Change (IPCC)	International body of climate change scientists. The role of the IPCC is to assess the scientific, technical and socio-economic information relevant to the understanding of the risk of human-induced climate change (www.ipcc.ch).
Inventory	A comprehensive, quantified list of an organization's GHG emissions and sources.
Inventory boundary	An imaginary line that encompasses the direct and indirect emissions included in the inventory. It results from the chosen organizational and operational boundaries.
Joule	A measure of energy, representing the energy needed to push with a force of one Newton for one meter.
Kerosene	A light distillate fuel that includes No. 1-K and No. 2-K as well as other grades of range or stove oil that have properties similar to those of No. 1

	fuel oil.
Kilowatt hour (KWh)	The electrical energy unit of measure equal to one thousand watts of power supplied to, or taken from, an electric circuit steadily for one hour. (A Watt is the unit of electrical power equal to one ampere under a pressure of one volt, or 1/746 horsepower.)
Kyoto Protocol	A protocol to the United Nations Framework Convention on Climate Change (UNFCCC). Ratified in 2005, it requires countries listed in its Annex B (developed nations) to meet reduction targets of GHG emissions relative to their 1990 levels during the period of 2008–12.
Life Cycle Analysis	Assessment of the sum of a product's effects (e.g. GHG emissions) at each step in its life cycle, including resource extraction, production, use and waste disposal.
Liquefied petroleum gas (LPG)	A group of hydrocarbon-based gases derived from crude oil refining or natural gas fractionation. They include propane, propylene, normal butane, butane, butylene, isobutene A-14 and isobutylene. For convenience of transportation, these gases are liquefied through pressurization.
Lower heating value (LHV)	Low or net heat content with the heat of vaporization excluded. The water is assumed to be in the gaseous state.
Methane (CH_4)	One of the six primary GHGs, consisting of a single carbon atom and four hydrogen atoms, possessing a GWP of 21, and produced through the anaerobic decomposition of waste in landfills, animal digestion, decomposition of animal wastes, production and distribution of natural gas and petroleum, coal production, and incomplete fossil fuel combustion.
Metric ton (MT, tonne)	Common international measurement for the quantity of GHG emissions, equivalent to about 2,204.6 pounds or 1.1 short tons.
Mobile combustion	Emissions from the combustion of fuels in transportation sources (e.g., cars, trucks, buses, trains, airplanes, and marine vessels) and emissions from non-road equipment such as equipment used in construction, agriculture, and forestry. A piece of equipment that cannot move under its own power but that is transported from site to site (e.g., an emergency generator) is a stationary, not a mobile, combustion source.
Nameplate (generating) capacity	The maximum rated output of a generator under specific conditions designated by the manufacturer, expressed in megawatts (MW) or kilowatts (kW).
Naphtha	A generic term applied to a petroleum fraction with an approximate boiling range between 122 degrees Fahrenheit and 400 degrees Fahrenheit.
Natural gas	A naturally occurring mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions.

Nitrous oxide (N_2O)	One of the six primary GHGs, consisting of two nitrogen atoms and a single oxygen atom, possessing a GWP of 310, and typically generated as a result of soil cultivation practices, particularly the use of commercial and organic fertilizers, fossil fuel combustion, nitric acid production, and biomass burning.
Operating lease	A lease which does not transfer the risks and rewards of ownership to the lessee and is not recorded as an asset in the balance sheet of the lessee. Leases other than operating leases are capital, finance, or financial leases. Consult an accountant for further detail as definitions of lease types differ between various accepted financial standards.
Operational boundaries	The boundaries that determine the direct and indirect emissions associated with operations within the entity's organizational boundaries.
Operational control	Full authority to introduce and implement operating policies at an operation.
Operator	The entity having operational control of a facility or other entity.
Organizational boundaries	The boundaries that determine the operations owned or controlled by the reporting entity, depending on the consolidation approach taken.
Perfluorocarbons (PFCs)	One of the six primary GHGs, A group of man-made chemicals composed of one or two carbon atoms and four to six fluorine atoms, containing no chlorine. Originally introduced as alternatives to ozone depleting substances, PFCs have few commercial uses and are typically emitted as by-products of industrial and manufacturing processes. PFCs have very high GWPs and are very long-lived in the atmosphere.
Process emissions	Emissions from physical or chemical processing rather than from fuel combustion. Examples include emissions from manufacturing cement, aluminum, adipic acid, ammonia, etc.
Propane	A normally straight chain hydrocarbon that boils at -43.67 degrees Fahrenheit and is represented by the chemical formula C_3H_8.
Residual fuel oil	A general classification for the heavier oils, known as No. 5 and No. 6 fuel oils, that remain after the distillate fuel oils and lighter hydrocarbons are distilled away in refinery operations.
Scope	Defines the operational boundaries in relation to indirect and direct GHG emissions.
Scope 1 emissions	All direct GHG emissions, with the exception of direct CO_2 emissions from biogenic sources.
Scope 2 emissions	Indirect GHG emissions associated with the consumption of purchased or acquired electricity, heating, cooling, or steam.
Scope 3 emissions	All indirect emissions not covered in Scope 2. Examples include upstream and downstream emissions, emissions resulting from the extraction and production of purchased materials and fuels, transport-related activities in vehicles not owned or controlled by the reporting entity, use of sold

	products and services, outsourced activities, recycling of used products, waste disposal, etc.
Short ton (ton)	Common measurement for a ton in the U.S. and equivalent to 2,000 pounds or about 0.907 metric tons.
Standard cubic foot (scf)	The amount of gas that would occupy a volume of one cubic foot if free of combined water at standard conditions.
Stationary	Neither portable nor self propelled, and operated at a single facility.
Stationary combustion	Emissions from the combustion of fuels to produce electricity, steam, heat, or power using equipment (boilers, furnaces, etc.) in a fixed location.
Still gas	Gas generated at a petroleum refinery or any gas generated by a refinery process unit, and that is combusted separately or in any combination with any type of gas or used as a chemical feedstock.
Sulfur hexafluoride (SF_6)	One of the six primary GHGs, consisting of a single sulfur atom and six fluoride atoms, possessing a very high GWP of 23,900, and primarily used in electrical transmission and distribution systems.
Therm	A measure of one hundred thousand (10^5) Btu.
United Nations Framework Convention on Climate Change (UNFCCC)	Signed in 1992 at the Rio Earth Summit, the UNFCCC is a milestone Convention on Climate Change treaty that provides an overall framework for international efforts to mitigate climate change. The Kyoto Protocol is a protocol to the UNFCCC.
Verification	An independent assessment of the reliability (considering completeness and accuracy) of a GHG inventory. For the purposes of this Protocol, the method used to ensure that a given participant's GHG emissions inventory has met a minimum quality standard and complied with an appropriate set of California Registry- or California Air Resource Board-approved procedures and protocols for submitting emissions inventory information.

Appendix A Global Warming Potentials

Global Warming Potential (GWP) factors represent the ratio of the heat-trapping ability of each greenhouse gas relative to that of carbon dioxide. For example, the GWP of methane is 21 because one metric ton of methane has 21 times more ability to trap heat in the atmosphere than one metric ton of carbon dioxide. To convert emissions of non-CO_2 gases to units of CO_2 equivalent, multiply the emissions of each gas in units of mass (e.g., metric tons) by the appropriate GWP factors in the following table.

Note: Since the Second Assessment Report (SAR) was published in 1995, the IPCC has published updated GWP values in its Third Assessment Report (TAR) and Fourth Assessment Report (AR4) that reflect new information on atmospheric lifetimes of greenhouse gases and an improved calculation of the radiative forcing of CO_2.

However, GWP values from the SAR are still used by international convention to maintain consistency in GHG reporting, including by the United States when reporting under the United Nations Framework Convention on Climate Change. TAR GWP values are often used for gases that were not reported in the SAR.

If more recent GWP values are adopted as standard practice by the international community, the Protocol will likewise update its GWP requirements to reflect international practices.

Table A.1 GWP Factors for Greenhouse Gases

Common Name	Formula	Chemical Name	GWP
Carbon dioxide	CO_2		1
Methane	CH_4		21
Nitrous oxide	N_2O		310
Sulfur hexafluoride	SF_6		23,900
Hydrofluorocarbons (HFCs)			
HFC-23	CHF_3	trifluoromethane	11,700
HFC-32	CH_2F_2	difluoromethane	650
HFC-41	CH_3F	fluoromethane	150
HFC-43-10mee	$C_5H_2F_{10}$	1,1,1,2,3,4,4,5,5,5-decafluoropentane	1,300
HFC-125	C_2HF_5	pentafluoroethane	2,800
HFC-134	$C_2H_2F_4$	1,1,2,2-tetrafluoroethane	1,000
HFC-134a	$C_2H_2F_4$	1,1,1,2-tetrafluoroethane	1,300
HFC-143	$C_2H_3F_3$	1,1,2-trifluoroethane	300
HFC-143a	$C_2H_3F_3$	1,1,1-trifluoroethane	3,800
HFC-152	$C_2H_4F_2$	1,2-difluoroethane	43*
HFC-152a	$C_2H_4F_2$	1,1-difluoroethane	140
HFC-161	C_2H_5F	fluoroethane	12*
HFC-227ea	C_3HF_7	1,1,1,2,3,3,3-heptafluoropropane	2,900
HFC-236cb	$C_3H_2F_6$	1,1,1,2,2,3-hexafluoropropane	1,300*
HFC-236ea	$C_3H_2F_6$	1,1,1,2,3,3-hexafluoropropane	1,200*
HFC-236fa	$C_3H_2F_6$	1,1,1,3,3,3-hexafluoropropane	6,300
HFC-245ca	$C_3H_3F_5$	1,1,2,2,3-pentafluoropropane	560
HFC-245fa	$C_3H_3F_5$	1,1,1,3,3-pentafluoropropane	950*
HFC-365mfc	$C_4H_5F_5$	1,1,1,3,3-pentafluorobutane	890*
Perfluorocarbons (PFCs)			
Perfluoromethane	CF_4	tetrafluoromethane	6,500
Perfluoroethane	C_2F_6	hexafluoroethane	9,200
Perfluoropropane	C_3F_8	octafluoropropane	7,000
Perfluorobutane	C_4F_{10}	decafluorobutane	7,000
Perfluorocyclobutane	c-C_4F_8	octafluorocyclobutane	8,700
Perfluoropentane	C_5F_{12}	dodecafluoropentane	7,500
Perfluorohexane	C_6F_{14}	tetradecafluorohexane	7,400

Source: Intergovernmental Panel on Climate Change (IPCC) Second Assessment Report published in 1995, unless no value was assigned in the document. In that case, the GWP values are from the IPCC Third Assessment Report published in 2001 (those marked with *). GWP values are from the Second Assessment Report (unless otherwise noted) to be consistent with international practices. Values are 100-year GWP values.

Table A.2 Global Warming Potentials of Refrigerant Blends

Refrigerant Blend	Global Warming Potential
R-401A	18
R-401B	15
R-401C	21
R-402A	1,680
R-402B	1,064
R-403A	1,400
R-403B	2,730
R-404A	3,260
R-406A	0
R-407A	1,770
R-407B	2,285
R-407C	1,526
R-407D	1,428
R-407E	1,363
R-408A	1,944
R-409A	0
R-409B	0
R-410A	1,725
R-410B	1,833
R-411A	15
R-411B	4
R-412A	350
R-413A	1,774
R-414A	0
R-414B	0
R-415A	25
R-415B	105
R-416A	767
R-417A	1,955
R-418A	4
R-419A	2,403
R-420A	1,144
R-500	37
R-501	0
R-502	0
R-503	4,692
R-504	313
R-505	0
R-506	0
R-507 or R-507A	3,300
R-508A	10,175
R-508B	10,350
R-509 or R-509A	3,920
Source: ASHRAE Standard 34	

Appendix B Standard Conversion Factors

Mass			
1 pound (lb) =	453.6 grams (g)	0.4536 kilograms (kg)	0.0004536 metric tons (tonnes)
1 kilogram (kg) =	1,000 grams (g)	2.2046 pounds (lb)	0.001 metric tons (tonnes)
1 short ton (ton) =	2,000 pounds (lb)	907.18 kilograms (kg)	0.9072 metric tons (tonnes)
1 metric ton (tonne) =	2,204.62 pounds (lb)	1,000 kilograms (kg)	1.1023 short tons (tons)
Volume			
1 cubic foot (ft^3) =	7.4805 US gallons (gal)	0.1781 barrels (bbl)	
1 cubic foot (ft^3) =	28.32 liters (L)	0.02832 cubic meters (m^3)	
1 US gallon (gal) =	0.0238 barrels (bbl)	3.785 liters (L)	0.003785 cubic meters (m^3)
1 barrel (bbl) =	42 US gallons (gal)	158.99 liters (L)	0.1589 cubic meters (m^3)
1 liter (L) =	0.001 cubic meters (m^3)	0.2642 US gallons (gal)	0.0063 barrels (bbl)
1 cubic meter (m^3) =	6.2897 barrels (bbl)	264.17 US gallons (gal)	1,000 liters (L)
Energy			
1 kilowatt hour (kWh) =	3,412 Btu (Btu)	3,600 kilojoules (KJ)	
1 megajoule (MJ) =	0.001 gigajoules (GJ)		
1 gigajoule (GJ) =	0.9478 million Btu (MMBtu)	277.8 kilowatt hours (kWh)	
1 British thermal unit (Btu) =	1,055 joules (J)	1.055 kilojoules (KJ)	
1 million Btu (MMBtu) =	1.055 gigajoules (GJ)	293 kilowatt hours (kWh)	
1 therm =	100,000 Btu	0.1055 gigajoules (GJ)	29.3 kilowatt hours (kWh)
Other			
kilo =	1,000		
mega =	1,000,000		
giga =	1,000,000,000		
tera =	1,000,000,000,000		
peta =	1,000,000,000,000,000		
1 mile =	1.609 kilometers		
1 metric ton carbon (C) =	$^{44}/_{12}$ metric tons CO_2		

Example Calculation: Convert 1,000 lb C/kWh into metric tons CO_2 /GJ

$$1{,}000\ \frac{\text{lb C}}{\text{kWh}} \times 277.8\ \frac{\text{kWh}}{\text{GJ}} \times 0.0004536\ \frac{\text{metric tons}}{\text{lb}} \times 44/12\ \frac{CO_2}{C} = 462.04\ \frac{\text{metric tons } CO_2}{\text{GJ}}$$

Appendix C Default Emission Factors

Table C.1 Default Factors for Calculating CO_2 Emissions from Fossil Fuel Combustion

Fuel Type	Heat Content	Carbon Content (Per Unit Energy)	Fraction Oxidized	CO_2 Emission Factor (Per Unit Energy)	CO_2 Emission Factor (Per Unit Mass or Volume)
Coal and Coke	**MMBtu / Short ton**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / Short ton**
Anthracite Coal	25.09	28.26	1.00	103.62	2,599.83
Bituminous Coal	24.93	25.49	1.00	93.46	2,330.04
Sub-bituminous Coal	17.25	26.48	1.00	97.09	1,674.86
Lignite	14.21	26.30	1.00	96.43	1,370.32
Unspecified (Residential/ Commercial)	22.05	26.00	1.00	95.33	2,102.29
Unspecified (Industrial Coking)	26.27	25.56	1.00	93.72	2,462.12
Unspecified (Other Industrial)	22.05	25.63	1.00	93.98	2,072.19
Unspecified (Electric Utility)	19.95	25.76	1.00	94.45	1,884.53
Coke	24.80	31.00	1.00	113.67	2,818.93
Natural Gas (By Heat Content)	**Btu / Standard cubic foot**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / Standard cub. ft.**
975 to 1,000 Btu / Std cubic foot	975 – 1,000	14.73	1.00	54.01	Varies
1,000 to 1,025 Btu / Std cubic foot	1,000 – 1,025	14.43	1.00	52.91	Varies
1,025 to 1,050 Btu / Std cubic foot	1,025 – 1,050	14.47	1.00	53.06	Varies
1,050 to 1,075 Btu / Std cubic foot	1,050 – 1,075	14.58	1.00	53.46	Varies
1,075 to 1,100 Btu / Std cubic foot	1,075 – 1,100	14.65	1.00	53.72	Varies
Greater than 1,100 Btu / Std cubic foot	> 1,110	14.92	1.00	54.71	Varies
Weighted U.S. Average	1,029	14.47	1.00	53.06	0.0546
Petroleum Products	**MMBtu / Barrel**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / gallon**
Asphalt & Road Oil	6.636	20.62	1.00	75.61	11.95
Aviation Gasoline	5.048	18.87	1.00	69.19	8.32
Distillate Fuel Oil (#1, 2 & 4)	5.825	19.95	1.00	73.15	10.15
Jet Fuel	5.670	19.33	1.00	70.88	9.57
Kerosene	5.670	19.72	1.00	72.31	9.76
LPG (average for fuel use)	3.849	17.23	1.00	63.16	5.79
Propane	3.824	17.20	1.00	63.07	5.74
Ethane	2.916	16.25	1.00	59.58	4.14
Isobutene	4.162	17.75	1.00	65.08	6.45
n-Butane	4.328	17.72	1.00	64.97	6.70
Lubricants	6.065	20.24	1.00	74.21	10.72
Motor Gasoline	5.218	19.33	1.00	70.88	8.81
Residual Fuel Oil (#5 & 6)	6.287	21.49	1.00	78.80	11.80
Crude Oil	5.800	20.33	1.00	74.54	10.29
Naphtha (<401 deg. F)	5.248	18.14	1.00	66.51	8.31
Natural Gasoline	4.620	18.24	1.00	66.88	7.36
Other Oil (>401 deg. F)	5.825	19.95	1.00	73.15	10.15
Pentanes Plus	4.620	18.24	1.00	66.88	7.36
Petrochemical Feedstocks	5.428	19.37	1.00	71.02	9.18
Petroleum Coke	6.024	27.85	1.00	102.12	14.65
Still Gas	6.000	17.51	1.00	64.20	9.17
Special Naphtha	5.248	19.86	1.00	72.82	9.10
Unfinished Oils	5.825	20.33	1.00	74.54	10.34
Waxes	5.537	19.81	1.00	72.64	9.58

Source: U.S. EPA, *Inventory of Greenhouse Gas Emissions and Sinks: 1990-2005* (2007), Annex 2.1, Tables A-31, A-32, A-35, and A-36, except: heat content factors for Unspecified Coal (by sector), Naphtha (<401 deg. F), and Other Oil (>401 deg. F) (from U.S. Energy Information Administration, *Annual Energy Review 2006* (2007), Tables A-1 and A-5) and Carbon Content and Heat Content factors for Coke and LPG (from EPA Climate Leaders, Stationary Combustion Guidance (2007), Table B-1). A fraction oxidized value of 1.00 is from the Intergovernmental Panel on Climate Change (IPCC), *Guidelines for National Greenhouse Gas Inventories* (2006).
Note: Default CO_2 emission factors (per unit energy) are calculated as: Carbon Content × Fraction Oxidized × 44/12. Default CO_2 emission

Table C.2 Default Factors for Calculating CO_2 Emissions from Non-Fossil Fuel Combustion

Fuel Type	Heat Content	Carbon Content (Per Unit Energy)	Fraction Oxidized	CO_2 Emission Factor (Per Unit Energy)	CO_2 Emission Factor (Per Unit Mass or Volume)
Fuel Partly Derived from Biomass	**MMBtu / Short ton**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / Short ton**
Municipal Solid Waste (65% C from biomass origin)	8.70	24.74	1.00	90.65	788.70
Waste Tires (20% C from biomass origin)	33.00	n/a	1.00	89.70	2,960.00
Non-Fossil Fuels (Solid)	**MMBtu / Short ton**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / Short ton**
Wood and Wood Waste (12% moisture)	15.38	25.60	1.00	93.87	1,443.67
Kraft Black Liquor (North American hardwood)	11.98	25.75	1.00	94.41	1,130.76
Kraft Black Liquor (North American softwood)	12.24	25.95	1.00	95.13	1,164.02
Non-Fossil Fuels (Gas)	**Btu / Standard cubic foot**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / Standard cub. ft.**
Landfill Gas or biogas[1] (50% CH_4 / 50% CO_2)	502.50	14.20	1.00	52.07	0.0262

Note: The CO_2 emissions from burning non-fossil fuels are considered biogenic and should be tracked and reported separately from your Scope 1 stationary combustion emissions.

[1] The emission factor for landfill gas and biogas includes both the biogenic CO_2 from combustion and the biogenic pass-through CO_2, which are assumed to be in equal proportions.

Source: : U.S. EPA, *Inventory of Greenhouse Gas Emissions and Sinks: 1990-2005* (2007), Annex 2.1, Tables A-28, A-31, A-32, A-35, and A-36, except:

- Heat Content factors: values for wood and wood waste, and landfill gas from EPA Climate Leaders, Stationary Combustion Guidance (2004), Tables B-1 and B-2; values for MSW and waste tires are the average of 2004 values for California retrieved from Energy Information Administration's Form EIA-906 and EIA-920 Databases: monthly and annual data on generation and fuel consumption at the power plant and prime mover level. Available online at: http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html.
- CO_2 emissions factor: value for waste tires from WBCSD/WRI, *The Cement CO_2 Protocol: CO_2 Accounting and Reporting Standard for the Cement Industry* Calculation Tool (2005).

Percent carbon from biomass origin: value for tires from Rubber Manufacturers Association website. Scrap tires characteristics. Accessed online at: http://www.rma.org/scrap_tires/scrap_tire_markets/scrap_tire_characteristics/; value for MSW from a personal communication (source test data) between Larry Hunsaker of CA Air Resources Board and Jeffrey Hahn, Environmental Director of Covanta Energy.

Note: Default CO_2 emission factors (per unit energy) are calculated as: Carbon Content × Fraction Oxidized × 44/12. Default CO_2 emission factors (per unit mass or volume) are calculated using Equation 12d: Heat Content × Carbon Content × Fraction Oxidized × 44/12 × Conversion Factor (if applicable). Heat content factors are based on higher heating values (HHV).

Table C.3 Default CH_4 and N_2O Emission Factors By Fuel Type and Sector[27]

Fuel Type / End-Use Sector	CH_4 (g/MMBtu)	N_2O (g/MMBtu)
Coal		
Residential	316	1.6
Commercial/Institutional	11	1.6
Manufacturing/Construction	11	1.6
Electric Power	1	1.6
Petroleum Products		
Residential	11	0.6
Commercial/Institutional	11	0.6
Manufacturing/Construction	3	0.6
Electric Power	3	0.6
Natural Gas		
Residential	5	0.1
Commercial/Institutional	5	0.1
Manufacturing/Construction	1	0.1
Electric Power	1	0.1
Wood		
Residential	316	4.2
Commercial/Institutional	316	4.2
Manufacturing/Construction	32	4.2
Electric Power	32	4.2
Pulping Liquors		
Manufacturing	2.5	2.0
Source: EPA Climate Leaders, Stationary Combustion Guidance (2007), Table A-1, based on U.S. EPA, *Inventory of Greenhouse Gas Emissions and Sinks: 1990-2005* (2007), Annex 3.1.		

[27] Currently, CCAR's General Reporting Protocol Version 3.0 (April 2008) uses different CH_4 and N_2O emission factors than presented here. CCAR will be replacing the current CH_4 and N_2O emission factors with these emission factors in the next version of its GRP. CCAR members are encouraged to use these emission factors for consistency with The Climate Registry and this Protocol.

Table C.4 Default CH_4 and N_2O Emission Factors by Technology Type for the Electricity Generation Sector

Fuel Type and Basic Technology	Configuration	CH_4 (g/MMBtu)	N_2O (g/MMBtu)
Liquid Fuels			
Residual Fuel Oil/Shale Oil Boilers	Normal Firing	0.8	0.3
	Tangential Firing	0.8	0.3
Gas/Diesel Oil Boilers	Normal Firing	0.9	0.4
	Tangential Firing	0.9	0.4
Large Diesel Oil Engines >600hp (447kW)		4.0	NA
Solid Fuels			
Pulverized Bituminous Combustion Boilers	Dry Bottom, wall fired	0.7	0.5
	Dry Bottom, tangentially fired	0.7	1.4
	Wet Bottom	0.9	1.4
Bituminous Spreader Stoker Boilers	With and without re-injection	1.0	0.7
Bituminous Fluidized Bed Combustor	Circulating Bed	1.0	61.1
	Bubbling Bed	1.0	61.1
Bituminous Cyclone Furnace		0.2	1.6
Lignite Atmospheric Fluidized Bed		NA	71.2
Natural Gas			
Boilers		0.9	0.9
Gas-Fired Gas Turbines >3MW		3.8	0.9
Large Dual-Fuel Engines		245	NA
Combined Cycle		0.9	2.8
Peat			
Peat Fluidized Bed Combustor	Circulating Bed	3.0	7.0
	Bubbling Bed	3.0	3.0
Biomass			
Wood/Wood Waste Boilers		9.3	5.9
Wood Recovery Boilers		0.8	0.8

Source: IPCC, Guidelines for National Greenhouse Gas Inventories (2006), Chapter 2: Stationary Combustion, Table 2.6. Values were converted back from LHV to HHV using IPCC's assumption that LHV are 5 percent lower than HHV for coal and oil, 10 percent lower for natural gas, and 20 percent lower for dry wood. (The IPCC converted the original factors from units of HHV to LHV, so the same conversion rates were used here to obtain the original values in units of HHV. For purposes of reporting, the conversion factor of 20 percent for wood should not be used to convert between LHV and HHV values; instead you should use a value of 5 percent. Refer to the box on "Estimating Emissions Based on Higher Heating Values" in Section 12.2.) Values were converted from kg/TJ to g/MMBtu using 1 kg = 1000 g and 1 MMBtu = 0.001055 TJ. NA = data not available.

Table C.5 Utility-Specific Verified Electricity CO_2 Emission Factors (2000-2006)

Utility	CO_2 (lbs/MWh)						
	2000	2001	2002	2003	2004	2005	2006
Anaheim Public Utilities						1,399.80	1,416.74
Austin Energy						1,127.37	1,077.97
East Bay Municipal Utility District						239.16	
Glendale Water & Power						1,065.00	
Los Angeles Department of Water & Power	1,407.44	1,403.39	1,348.48	1,360.07	1,360.60	1,303.58	1,238.52
Northern California Power Agency						55.38	
Pacific Gas & Electric Company					566.20	489.16	455.81
PacifiCorp					1,811.00	1,812.22	1,747.3
Pasadena Water & Power						1,409.65	
Platte River Power Authority						1,970.93	1,955.66
Riverside Public Utilities						1,333.45	1,346.15
Roseville Electric							565.52
Sacramento Municipal Utility District					769.00	616.07	555.26
Salt River Project							1,546.28
San Diego Gas & Electric					613.75	546.46	780.79
Southern California Edison					678.88	665.72	641.26
Source: California Climate Action Registry Power/Utility Protocol Public Reports (as of June 2008). http://www.climateregistry.org/CARROT/public/reports.aspx							

Table C.6 California Grid Average Electricity Emission Factors (1990-2004)

Year	CO_2 (lbs/MWh)	CH_4 (lbs/MWh)	N_2O (lbs/MWh)
1990	1,031.14	0.040	0.014
1991	994.03	0.037	0.013
1992	984.42	0.040	0.012
1993	1,007.26	0.037	0.013
1994	1,071.19	0.040	0.013
1995	929.77	0.031	0.012
1996	827.65	0.029	0.011
1997	874.96	0.029	0.011
1998	941.54	0.029	0.011
1999	917.60	0.031	0.011
2000	829.50	0.029	0.009
2001	1,009.75	0.033	0.011
2002	865.28	0.031	0.010
2003	888.41	0.031	0.011
2004	958.49	0.029	0.011
Source: Calculated from total in-state and imported electricity emissions divided by total consumption in MWh. Emissions from California Air Resources Board, Greenhouse Gas Inventory, 1990 – 2004 (November 17, 2007 version), available on line at http://www.arb.ca.gov/cc/inventory/data/data.htm. Consumption data from California Energy Commission, http://www.energy.ca.gov			

Figure C.1 Map of U.S. eGRID Subregions

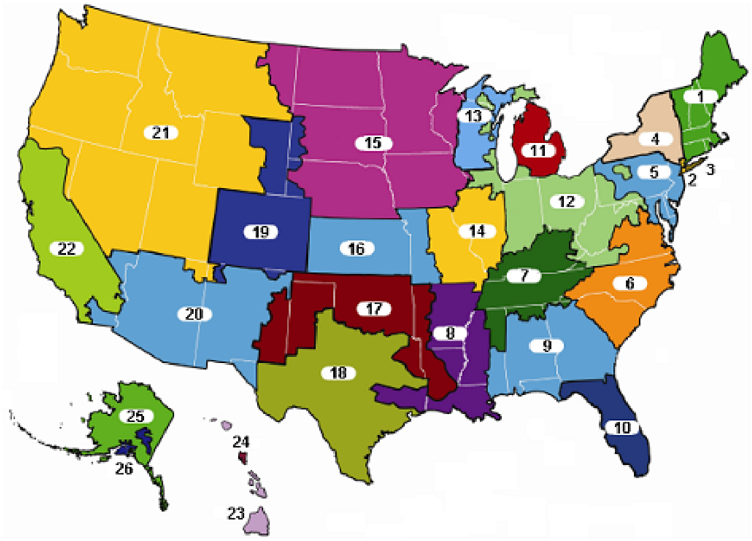

Table C.7 eGRID Electricity Emission Factors by eGRID Subregion (2004 data)[28]

Map No.	eGRID 2006 Subregion	eGRID 2006 Subregion Name	2004 Emission Factors		
			(lbs CO_2/MWh)	(lbs CH_4/MWh)	(lbs N_2O/MWh)
1	NEWE	NPCC New England	908.90	0.080	0.015
2	NYCW	NPCC NYC/Westchester	922.22	0.038	0.006
3	NYLI	NPCC Long Island	1,412.20	0.102	0.016
4	NYUP	NPCC Upstate NY	819.68	0.024	0.011
5	RFCE	RFC East	1,095.53	0.028	0.017
6	SRVC	SERC Virginia/Carolina	1,146.39	0.029	0.019
7	SRTV	SERC Tennessee Valley	1,494.89	0.023	0.024
8	SRMV	SERC Mississippi Valley	1,135.46	0.042	0.013
9	SRSO	SERC South	1,490.37	0.040	0.025
10	FRCC	FRCC All	1,327.66	0.054	0.016
11	RFCM	RFC Michigan	1,641.41	0.035	0.025
12	RFCW	RFC West	1,556.39	0.020	0.024
13	MORE	MRO East	1,858.72	0.041	0.030
14	SRMW	SERC Midwest	1,844.34	0.021	0.029
15	MROW	MRO West	1,813.81	0.028	0.029
16	SPNO	SPP North	1,971.42	0.024	0.030
17	SPSO	SPP South	1,761.14	0.030	0.023
18	ERCT	ERCOT All	1,420.56	0.021	0.015
19	RMPA	WECC Rockies	2,035.81	0.024	0.030
20	AZNM	WECC Southwest	1,254.02	0.018	0.015
21	NWPP	WECC Northwest	921.10	0.022	0.014
22	CAMX	WECC California	see	0.036	0.008
23	HIMS	HICC Miscellaneous	1,456.17	0.101	0.018
24	HIOA	HICC Oahu	1,728.12	0.0911	0.0212
25	AKMS	ASCC Miscellaneous	480.10	0.0239	0.0044
26	AKGD	ASCC Alaska Grid	1,257.19	0.0266	0.0064
Source: U.S. EPA eGRID2006 Version 2.1 (2004 data); CH_4 and N_2O factors provided by EPA Climate Leaders based on eGRID2006 fuel consumption and electricity generation data and U.S. EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005,* April 2007 (Annex 3, Table A-69). Factors do not include emissions from transmission and distribution losses.					

[28] Currently, CCAR's General Reporting Protocol Version 3.0 (April 2008) uses state-specific CH_4 and N_2O emission factors. CCAR will be replacing the current CH_4 and N_2O emission factors with eGRID emission factors in the next version of its GRP. CCAR members are encouraged to use the eGRID emission factors for consistency with The Climate Registry and this Protocol.

Table C.8 Historical eGRID Electricity Emission Factors by eGRID Subregion (2000 data)

Note: This table provides CO_2 electricity emission factors by eGRID subregion for use in reporting historical data for calendar years 1990-2004. These emission factors should not be used for current year reporting. For current year reporting, use the emission factors in Table C.7.

eGRID 2006 Subregion	eGRID 2006 Subregion Name	(lbs CO_2/MWh)
AKMS	ASCC Miscellaneous	757.81
ECMI	ECAR Michigan	1,632.06
ECOV	ECAR Ohio Valley	1,966.53
ERCT	ERCOT All	1,408.27
FRCC	FRCC All	1,390.04
HIMS	HICC Miscellaneous	1,702.93
HIOA	HICC Oahu	1,721.69
MAAC	MAAC All	1,097.56
MANN	MAIN North	1,761.09
MANS	MAIN South	1,237.29
MAPP	MAPP All	1,838.83
NYLI	NPCC Long Island	1,659.76
NEWE	NPCC New England	897.11
NYCW	NPCC NYC/Westchester	1,090.13
NYUP	NPCC Upstate NY	843.04
OFFG	Off-Grid	1,706.71
SRMV	SERC Mississippi Valley	1,331.34
SRSO	SERC South	1,561.51
SRTV	SERC Tennessee Valley	1,372.70
SRVC	SERC Virginia/Carolina	1,164.19
SPNO	SPP North	2,011.15
SPSO	SPP South	1,936.65
CALI	WECC California	804.54
NWGB	WECC Great Basin	852.31
NWPN	WECC Pacific Northwest	671.04
ROCK	WECC Rockies	1,872.51
WSSW	WECC Southwest	1,423.95
Source: EPA eGRID2002 Version 2.01(Year 2000 Data)		

Table C.9 Default CO_2 Emission Factors for Transport Fuels

Fuel Type	Carbon Content (Per Unit Energy)	Heat Content	Fraction Oxidized	CO_2 Emission Factor (Per Unit Volume)
Fuels Measured in Gallons	**kg C / MMBtu**	**MMBtu / barrel**		**kg CO_2 / gallon**
Aviation Gasoline	18.87	5.048	1.00	8.32
Crude Oil	20.33	5.80	1.00	10.29
Diesel Fuel No.1 and 2	19.95	5.825	1.00	10.15
Jet Fuel (Jet A or A-1)	19.33	5.670	1.00	9.57
Kerosene	19.72	5.670	1.00	9.76
Liquefied Natural Gas (LNG) +	NA	NA	1.00	4.46
Liquefied Petroleum Gas (LPG) +	17.23	3.849	1.00	5.79
Ethane	16.25	2.916	1.00	4.14
Isobutane	17.75	4.162	1.00	6.45
n-Butane	17.72	4.328	1.00	6.70
Propane	17.20	3.824	1.00	5.74
Methanol	NA	NA	1.00	4.10
Motor Gasoline	19.33	5.218	1.00	8.81
Residual Fuel Oil (#5,6)	21.49	6.287	1.00	11.80
Fuels Measured in Standard Cubic Feet	**kg C / MMBtu**	**Btu / Standard cubic foot**		**kg CO_2 / Standard cubic foot**
Compressed Natural Gas (CNG) +	14.47	1,027	1.00	0.054
Non-Fossil Fuels*	**kg C / MMBtu**	**MMBtu / barrel**		**kg CO_2 / gallon**
Biodiesel (B100) +	NA	NA	1.00	9.46
Ethanol (E100) +	17.99	3.539	1.00	5.56

* The CO_2 emissions from burning non-fossil fuels are considered biogenic and should be tracked and reported separately from your Scope 1 stationary combustion emissions.
Source: U.S. EPA, *Inventory of Greenhouse Gas Emissions and Sinks: 1990-2005* (2007), Annex 2.1, Tables A-31, A-34, A-36, A-39, except those marked + (from EPA Climate Leaders, Mobile Combustion Guidance, 2008). Methanol emission factor is derived from the properties of pure compounds.
Note: Default CO_2 emission factors are calculated using Equation 12d: Heat Content × Carbon Content × Fraction Oxidized × 44/12 × Conversion Factor. Heat content factors are based on higher heating values (HHV). A fraction oxidized value of 1.00 is from the IPCC, *Guidelines for National Greenhouse Gas Inventories* (2006). NA = data not available.

Table C.10 Default CH_4 and N_2O Emission Factors for Highway Vehicles by Model Year[29]

Vehicle Type and Year	N_2O (g/mi)	CH_4 (g/mi)
Gasoline Passenger Cars		
Model Years 1984-1993	0.0647	0.0704
Model Year 1994	0.0560	0.0531
Model Year 1995	0.0473	0.0358
Model Year 1996	0.0426	0.0272
Model Year 1997	0.0422	0.0268
Model Year 1998	0.0393	0.0249
Model Year 1999	0.0337	0.0216
Model Year 2000	0.0273	0.0178
Model Year 2001	0.0158	0.0110
Model Year 2002	0.0153	0.0107
Model Year 2003	0.0135	0.0114
Model Year 2004	0.0083	0.0145
Model Year 2005	0.0079	0.0147
Gasoline Light Trucks (Vans, Pickup Trucks, SUVs)		
Model Years 1987-1993	0.1035	0.0813
Model Year 1994	0.0982	0.0646
Model Year 1995	0.0908	0.0517
Model Year 1996	0.0871	0.0452
Model Year 1997	0.0871	0.0452
Model Year 1998	0.0728	0.0391
Model Year 1999	0.0564	0.0321
Model Year 2000	0.0621	0.0346
Model Year 2001	0.0164	0.0151
Model Year 2002	0.0228	0.0178
Model Year 2003	0.0114	0.0155
Model Year 2004	0.0132	0.0152
Model Year 2005	0.0101	0.0157
Gasoline Heavy-Duty Vehicles		
Model Years 1985-1986	0.0515	0.4090
Model Year 1987	0.0849	0.3675
Model Years 1988-1989	0.0933	0.3492
Model Years 1990-1995	0.1142	0.3246
Model Year 1996	0.1680	0.1278
Model Year 1997	0.1726	0.0924
Model Year 1998	0.1693	0.0641
Model Year 1999	0.1435	0.0578
Model Year 2000	0.1092	0.0493
Model Year 2001	0.1235	0.0528
Model Year 2002	0.1307	0.0546
Model Year 2003	0.1240	0.0533
Model Year 2004	0.0285	0.0341
Model Year 2005	0.0177	0.0326

Vehicle Type and Year	N_2O (g/mi)	CH_4 (g/mi)
Diesel Passenger Cars		
Model Years 1960-1982	0.0012	0.0006
Model Years 1983-2004	0.0010	0.0005
Diesel Light Trucks		
Model Years 1960-1982	0.0017	0.0011
Model Years 1983-1995	0.0014	0.0009
Model Years 1996-2004	0.0015	0.0010
Diesel Heavy-Duty Vehicles		
All Model Years	0.0048	0.0051

Source: Gasoline vehicle factors from EPA Climate Leaders, Mobile Combustion Guidance, (2007) based on U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and* Sinks: 1990-2005 (2007). Diesel vehicle factors based on U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005* (2007), Annex 3.2, Table A-98.

[29] Currently, CCAR's General Reporting Protocol Version 3.0 (April 2008) uses different CH_4 and N_2O emission factors. CCAR will be replacing the current CH_4 and N_2O emission factors with these emission factors in the next version of its GRP. CCAR members are encouraged to use these emission factors for consistency with The Climate Registry and this Protocol.

Table C.11 Default CH_4 and N_2O Emission Factors for Alternative Fuel Vehicles[30]

Vehicle Type	N_2O (g/mi)	CH_4 (g/mi)
Light Duty Vehicles		
Methanol	0.067	0.018
CNG	0.050	0.737
LPG	0.067	0.037
Ethanol	0.067	0.055
Heavy Duty Vehicles		
Methanol	0.175	0.066
CNG	0.175	1.966
LNG	0.175	1.966
LPG	0.175	0.066
Ethanol	0.175	0.197
Buses		
Methanol	0.175	0.066
CNG	0.175	1.966
Ethanol	0.175	0.197
Source: U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005* (2007), Annex 3.2, Table A-100.		

Table C.12 Default CH_4 and N_2O Emission Factors for Non-Highway Vehicles[31]

Vehicle Type / Fuel Type	N_2O (g / gallon fuel)	CH_4 (g / gallon fuel)
Ships and Boats		
Residual Fuel Oil	0.30	0.86
Diesel Fuel	0.26	0.74
Gasoline	0.22	0.64
Locomotives		
Diesel Fuel	0.26	0.80
Agricultural Equipment		
Gasoline	0.22	1.26
Diesel Fuel	0.26	1.44
Construction		
Gasoline	0.22	0.50
Diesel Fuel	0.26	0.58
Other Non-Highway		
Snowmobiles (Gasoline)	0.22	0.50
Other Recreational (Gasoline)	0.22	0.50
Other Small Utility (Gasoline)	0.22	0.50
Other Large Utility (Gasoline)	0.22	0.50
Other Large Utility (Diesel)	0.26	0.58
Aircraft		
Jet Fuel	0.31	0.27
Aviation Gasoline	0.11	7.04
Data Source: U.S. EPA Climate Leaders, Mobile Combustion Guidance (2008) based on U.S. EPA *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005* (2007), Annex 3.2, Table A-101.		

[30] Currently, CCAR's General Reporting Protocol Version 3.0 (April 2008) uses different CH_4 and N_2O emission factors. CCAR will be replacing the current CH_4 and N_2O emission factors with these emission factors in the next version of its GRP. CCAR members are encouraged to use these emission factors for consistency with The Climate Registry and this Protocol.
[31] Ibid.

Table C.13 Alternate Methodology CH_4 and N_2O Emission Factors for Highway Vehicles by Inventory Year

In Progress

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