GREENHOUSE GAS EMISSION INVENTORY CALCULATIONS

Aggregate Producers, Pulverized Mineral Producers, and Industrial Sand Producers
Revised and Updated, August 2021

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TABLE OF CONTENTS

ACRONYMS

ANFO	**Ammonium Nitrate and Fuel Oil**
AR4	**Fourth IPCC Emission Factor Assessment Report**
AR5	**Fifth IPCC Emission Factor Assessment Report**
CCAR	**California Climate Action Registry**
CO2e	**Carbon Dioxide Equivalent Emissions**
EPA	**U.S. Environmental Protection Agency**
GHG	**Greenhouse Gases**
GWP	**Greenhouse Warming Potential (100-Year)**
HFC	**Hydrofluorocarbons**
NF3	**Nitrogen trifluoride**
IPCC	**Intergovernmental Panel on Climate Change**
PFC	**Perfluorocarbons**
SAR	**Second Assessment Report**
TCR	**The Climate Registry**
WRI	**World Resources Institute**

Note: References indicated in brackets [ ]

GREENHOUSE GAS EMISSION INVENTORY CALCULATIONS
Aggregate Producers and Pulverized Mineral Producers

1. PURPOSE AND SCOPE

This emission inventory calculation program will help aggregate, pulverized minerals, and industrial sand producers calculate emissions of greenhouse gases (GHG) in an accurate, consistent, and verifiable manner. Using these procedures, National Stone, Sand & Gravel Association (NSSGA) member companies can determine if their emissions are above future regulatory thresholds and can participate in voluntary emissions registry programs such as The Climate Registry (TCR) and the California Climate Action Registry (CCAR). The GHG emission factors are based on default emission factor data published by TCR in May 2021[1]. IPCC and EPA GHG emission factors are not updated as frequently as those published by the TCR.

The NSSGA calculation procedures are based primarily on the simplified emission calculation methods described in the TCR General Reporting Protocol, Version 3.0 published in 2019 [2]. More detailed and advanced calculation procedures intended to improve the site-specific applicability of the emission inventory calculations are described in the TCR General Report Protocol, Version 3.0.

The GHG inventories will provide emission baselines that NSSGA member companies can use to evaluate the impact of future regulatory programs and receive consideration for any future regulatory initiatives such as the EPA Mandatory Report Rule, in 40 CFR Part 98 [3] concerning verified emission reductions. These procedures will also help determine the possible value of industry sector-specific GHG inventory procedures.

The GHG inventory data provide a useful tool for evaluating options for reducing GHG emissions. The GHG emissions data compiled based on these emission inventory calculations will help NSSGA member companies inform stockholders and public stakeholders concerning GHG emissions and emission reduction programs.

Another objective of this emission inventory program is to help NSSGA member companies establish GHG emission calculation procedures, record keeping procedures, verification procedures, and reporting procedures. NSSGA member companies can refine these GHG-related inventory calculations when regulatory agencies and standards-setting organizations establish programs for GHG emission trading and credits. At the present time, the GHG inventory procedures published by leading organizations such as TCR, the World Resources Institute (WRI), and CCAR are not designed to serve GHG emission trading and credit programs. The NSSGA GHG emission inventory program is based on TCR procedures; accordingly, this emission inventory program is also not designed to support emission trading and credit programs.

The scope of the NSSGA GHG emission inventory program includes all direct and indirect sources of greenhouse gas emissions typically present at aggregate producing plants, industrial mineral, and pulverized mineral producing plants. Direct emissions are those GHGs formed on plant property due to material production such as fuel combustion and fugitive emissions. Indirect emissions include the GHG emissions from non-owned facilities that result due to the use of electrical power on plant property. Direct sources of emissions addressed in this emission inventory program include fuel combustion of on-road vehicles, off-road vehicles, driers, process heaters, and blasting. Indirect emissions include all electrical power used in process equipment and office buildings. The scope of this emission inventory program does not include incidental indirect emissions such as employee commuting, customer truck travel, and employee air travel. The TCR, WRI and CCAR protocols describe the reporting of these incidental indirect emissions as optional.

The scope of the NSSGA GHG emission inventory program includes all seven categories of pollutants addressed in the Kyoto Protocol: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), nitrogen trifluoride (NF_3), hydrofluorocarbons (designated HFCs), perfluorocarbons (designated PFCs), and sulfur hexafluoride (SF_6).

2. ATTRIBUTES OF THE NSSGA INVENTORY PROGRAM

The TCR inventory procedures are based on well-accepted calculation methods established by the WRI and EPA. Use of the TCR-based calculation methods ensures consistency with GHG emission inventories prepared by numerous industrial sectors. This approach also minimizes the time commitment required by NSSGA member companies who are already participating as members of TCR and CCAR.

The calculation procedures have been adapted to eliminate irrelevant information and to convert units-of-measure to forms common in the aggregate, industrial, and pulverized mineral industries. The NSSGA inventory calculation program includes provisions for the use of site-specific GHG emission factor data, which may be more accurate than the published default emission factors.

2.1 Corporate-Level Reporting

The NSSGA inventory program compiles GHG emission data on a corporate entity level. Data for multiple facilities are combined to ensure that information such as fuel use rates and power consumption rates cannot be used by knowledgeable competitors to estimate the production capacity of specific facilities. Entity-level reports also facilitate GHG data evaluation and reporting.

The scope of the inventory procedures is limited to U.S. facilities. No attempt is made to include GHG emissions from other countries.

2.2 Baseline and Annual Emission Reporting

The NSSGA GHG inventory program will allow NSSGA member companies to determine GHG emissions for a baseline year. The procedures include annual updating of the emission factors to take into account (1) changes in the mix of energy sources used to provide electrical power for each geographical area and (2) improvements in emission factors. As part of the annual emission reporting, members will also have to consider any organizational changes (acquisitions, divestures, new facilities) that change the baseline inventory.

2.3 Accuracy

Factors affecting GHG inventory accuracy include (1) the completeness of the emission inventory, (2) the accuracy of fuel use data, (3) the accuracy of electrical power meters, (4) the representativeness of default emission factors used when site-specific ultimate analyses of fuels are not available, and (5) the representativeness of certain non-CO_2 emission factors to heavy construction equipment used at NSSGA member facilities.

2.4 Completeness Goal

In accordance with TCR guidelines, the NSSGA inventory program provides for GHG emission inventories that include a minimum of 95% of the direct and indirect sources. This 95% target level does not include the incidental indirect emissions associated with employee commuting, customer truck traffic, barge or rail transport of products, or employee airline travel.

2.5 Transparency and Verification

The NSSGA GHG inventory program is based on a set of readily available records. No emission testing or specialized data gathering effort is required.

The results are provided in a format that simplifies auditing by independent organizations. NSSGA member companies presently participating in the TCR and CCAR registry programs are already subject to the independent verification requirements of annual reports. The procedures in this emission inventory program facilitate this verification step and minimize the associated costs.

2.6 Confidentiality

The NSSGA GHG inventory program is based on records and facility-level activity data that can be kept confidential. Information concerning the methodology used to calculate emissions and facility-level data is available only to registry groups such as TCR, CCAR, and independent verification auditors. Publically available data are limited to the corporate identification information, the geographical scale of the emissions, and the summary data for the CO_2 equivalent emissions.

2.7 Greenhouse Gas Warming Potential Factors

This updated NSSGA GHG inventory program uses the Fifth Assessment Report (AR5) global warming potential (GWP) factors published in 2014 [4] by the Intergovernmental Panel on Climate Change (IPCC). These are the latest set of GWP factors available.

These AR5-based GWP values are slightly different than the values published by EPA in 40 CFR Part 98 Table A-1 [3], which are based on GWP factors in AR4 [5]. The GWP factors take into account the typical atmospheric impact (lifetime, radiation effects) of the six different categories of global warming gases. Carbon dioxide is assigned the lowest factor, the value of 1, considering that it has the least long-term impact per unit of mass. As indicated in Table 1, methane has a much higher factor of 28. The difference in these factors suggests that one pound of methane in the atmosphere has the same long term adverse impact as twenty-eight pounds of carbon dioxide.

Table 1. Global Warming Potential Factors[1]

Compound	Compound	Global Warming Potential Multiplier (100 year) Source; [IPPC AR5, 2014.[4]
Carbon Dioxide	CO_2	1
Methane	CH_4	28
Nitrous Oxide	N_2O	265
Nitrogen Trifluoride	NF_3	16,100
Hydrofluorocarbons	HFC-23	12,400
	HFC-32	677
	HFC-125	3,170
	HFC-134a	1,300
	HFC-143a	4,800
	HFC-152a	138
	HFC-227ea	3,320
	HFC-236fa	8,060
	HFC431mee	1,650
Perfluorocarbons	CF_4	6,630
	C_2F_6	11,100
	C_3F_8	8,900
	C_4F_{10}	9,200
	C_6F_{14}	7,910
Sulfur Hexafluoride	SF_6	23,500

1. GWP factors for refrigerant blends are provided in the NSSGA Excel® program.

It is apparent that researchers consider nitrous oxide and the various fluorinated compounds to have a much greater impact than carbon dioxide on a unit mass basis. Carbon dioxide dominates the greenhouse gas issue primarily because it is emitted in quantities that substantially exceed the emissions of the other known GHG compounds.

2.8 Direct and Indirect Emissions

The NSSGA GHG inventory program separately calculates the direct and indirect GHG emissions. Direct emissions come from sources which burn fuels, generating GHG compounds on-site. Sources of direct emissions include mobile source fuel combustion, stationary source fuel combustion, rotary driers, and fuel combustion through blasting. Indirect emissions are those created by the consumption of electrical power or other energy purchased from a non-owned and operated facility such as a power plant. The direct and indirect emissions are tabulated separately to avoid double counting emissions when evaluating total GHG emissions from many reporting entities.

3. INVENTORY BOUNDARIES

Prior to compiling a GHG emission inventory, NSSGA member companies should determine the most appropriate geographical and organizational boundaries for that inventory. The inventory is prepared for a logical group of facilities—not a specific facility. The most important considerations in setting the inventory boundaries include (1) protection of facility-specific production information, (2) compilation of data requested by various regulatory agencies, and (3) consistency with recordkeeping practices in the corporate organization.

3.1 Geographical Boundaries

It seems likely that GHG emission reporting on a state level will eventually be required so that each state can determine the inventory, reporting, and control programs that are appropriate.

While GHG emission inventory reports will preferably be on a corporate entity basis with state-by-state subtotals, it is possible that NSSGA member companies will often find it appropriate to release inventory data for a specific facility. This information may be requested by stakeholders reviewing permit applications for new or modified facilities. To provide for future obligations, the NSSGA procedures are designed to allow GHG emission data reporting on a national corporate level, a state corporate level, and a specific facility level.

3.2 Organizational Boundaries

The organizational boundary of the GHG emission inventories should be clearly stated when reporting GHG emissions. TCR [2], WRI, and CCAR have provided guidance on constructing logical organization boundaries for facilities owned or managed jointly by two or more corporations. CCAR presents two alternative approaches: (1) allocation of GHG emissions based on a fraction of management control and (2) allocation of GHG emissions based on an equity share of the joint facility. TCR [2] provides additional information concerning the distribution of GHG emissions for complex organizational forms.

All equipment on-site at aggregate, industrial, and pulverized mineral producing sources that are subject to a long-term lease agreement or a financing agreement is considered under the direct control of the facility. Emissions from the leased equipment are the responsibility of the source and should be included in the inventory. Short-term leases, such as rental cars and other off-site equipment, are not considered in compiling the GHG emission inventories.

4. EMISSION INVENTORY CALCULATION PROCEDURES

The emission inventory calculation procedures are based on the general structure of the TCR forms and emission factors. The NSSGA forms allow for increased emission inventory accuracy via the substitution of default emission factors with site-specific emission factors based on site specific fuel characteristics, vehicle model years, and vehicle emission reduction technology information.

The calculation procedures use data that can be readily obtained and verified for each facility and source included in the inventory. The types of information that serve as input information include (1) fuel purchase records, (2) fuel firing rate records, (3) electrical power bills, and (4) HFC and PFC purchase records. No additional emission tests or facility specific activity measurements are needed to support the emission inventory calculation procedures.

A set of Excel spreadsheets and calculation forms is provided as an attachment to this User's Guide. These calculations are part of a single file with multiple tabs that can be used to input data from the facilities included in an organization's boundaries and to calculate the carbon dioxide equivalent (CO_2e) emissions for each facility. Data such as fuel consumption and facility power bills that must be entered by the user are shown in white. Conversion factors and other standard data are provided in locked cells that are shaded yellow. Calculated values are shown in cells that are shaded grey. The GHG emissions in short tons CO_2e are totaled for each category of source at each facility. Each set of forms includes the year for which the inventory applies. The Attachment includes some notes and example calculations that should be deleted whenever appropriate.

The Excel file includes all the calculation sheets and supporting conversion factors and information needed to complete the inventory calculations. There are separate sheets for direct emissions from mobile source fuel combustion, direct emissions from stationary source fuel combustion, direct emissions from blasting, direct emissions from air conditioners and refrigerators, and indirect emissions from purchased power.

All the forms have information concerning the locations of records used in the calculations and references to notes concerning the calculation procedures. Contact information for each facility is provided on the summary report form and the facility information form. Facility and contact information is entered into the facility form (Facility Form 1) and the facility ID number is linked to the other spreadsheets for clarity. The direct and indirect GHG emissions are compiled on the summary report form (Report Form 2). The GHG emissions data are provided in short tons CO_2e and in metric tons CO_2e to facilitate reporting in the form required by the appropriate GHG registry.

4.1 Direct Emissions from Mobile Sources

The emissions of CO_2e from on-road and off-road vehicles, forklifts, locomotives, ships, and aircraft controlled by the facility are determined entirely from the fuel purchase records. For each facility, it is necessary to calculate the total gasoline, diesel, propane, and other fuel purchases for the calendar year and to subtract any inventory of these fuels in plant storage vessels and tanks. The calculation yields the total quantity of each fuel used at each facility for the calendar year.

The annual fuel consumption data are then entered into Column E of the Mobile Source Factors Form (GHG Form 3a). The CO_2e emissions for each type of fuel are strictly a function of the heating value and ultimate analysis (e.g., carbon, hydrogen, oxygen, sulfur, nitrogen) content of that fuel. TCR has provided default factors to calculate the gross heat content of the fuels. These default factors are included in Form 3b and are included in the calculations on Form 3. These CO_2 default emission factors are based on the 2021 TCR default emission factor document provided as Appendix A to this User's Guide.

TCR, CCAR, and WRI recommend the use of the higher heating value even though it is not practical to achieve this value. Some users of the emission inventory program may wish to enter a site-specific factor or a lower heating value in Form 3b Mobile Source Factors. Either the higher or lower heating values should then be multiplied by the total fuel consumption data to calculate the total heat input for each fuel shown in Column G.

The CO_2 emissions for each fuel depend strongly on the carbon content of the fuel. Fuels such as methane have a relatively low carbon content, while some types of coal, especially anthracite coal, have an extremely high carbon content. TCR default values for mass of carbon dioxide emitted per MMBTU of fuel are specified in Form 3b. These are based on average U.S. values. The CO_2 emissions calculated based on actual fuel data can be as much as 20% different from these values. Accordingly, site-specific fuel composition data should be used if they are representative of the fuels used throughout the year. If the site-specific fuel ultimate analysis data are limited to just a few spot measurements, TCR default values are probably as accurate.

The emissions of CO_2 (Form 3a Column G) are the product of TCR emission factor and the total heat input for each fuel source. In GHG Form 3a, the CO_2 emissions are expressed in units of short tons.

The NSSGA GHG inventory program includes the emissions of methane and nitrous oxide from mobile sources. These emissions are only weakly related to the fuel characteristics. Instead, the emissions of these two types of greenhouse gases are due primarily to the combustion conditions. To calculate emissions of CH_4 and N_2O, TCR default factors are listed in Form 3b. Emissions of the compounds are calculated based on the annual fuel use data and the emission factors provided in Form 3b. The emissions are converted to CO_{2e} by multiplying the short tons per year emitted by the global warming potential (GWP) value shown on the top of Form 3a and discussed earlier in this emission inventory program in Section 2.

The emissions of CO_2 from rail operations, ship/barge operations, and aircraft should be included only if these mobile sources are under the direct control of the facility. If so, the emissions are calculated using procedures parallel to those for on-road and off-road vehicles. As is the case with vehicle emissions, CO_2 is the only significant greenhouse gas. The emissions of CH_4 and N_2O are small for these other types of mobile sources.

Forklifts are another small mobile source present at many aggregate and pulverized mineral facilities. The emissions from these small sources can be calculated using the fuel purchase records for each calendar year. The calculations are essentially identical to those discussed with respect to gasoline and propane.

The records needed to estimate CO_2 emissions from mobile sources include (1) fuel purchase records and (2) fuel storage tank inventory records. Copies of these records should be maintained at a central location where the GHG inventory is compiled.

4.2 Direct Emissions from Stationary Source Combustion

Stationary combustion sources on-site at aggregate, industrial mineral, and pulverized mineral producing facilities include rotary driers, fluidized bed driers, natural gas-fired heaters for office buildings, shop heaters, and small space heaters. The only data needed to complete these calculations are (1) fuel purchase records and (2) fuel inventory records.

GHG emissions for these sources are calculated based on 2021 TCR default emission factors for CO_2, CH_4, and N_2O. TCR emission factors for CO_2 are based on the higher heating value of the fuel. Data on the higher heating content of common fuels are listed in GHG Form 4b Stationary Combustion Factors. It is important to note that many companies in the U.S. are accustomed to using data on a lower heating value basis because this is most closely related to the actual useful energy content of the fuel. Climate action registry organizations have taken a different approach by selecting the higher heating value. However, reporting entities may decide to enter lower heating values into Form 4b Stationary Combustion Factors and use these values to calculate the total energy input. Regardless of the type of fuel heating value used, the selected value is multiplied by the fuel consumption rate to calculate the total heat input for each combustion source as shown in Form 4a Stationary Combustion. The CO_2 emissions are calculated using an emission factor expressed in units of pounds of CO_2 per million BTU (Lbs. per MMBTU).

The emissions of methane and nitrous oxide from combustion systems are based on standard emission factors presented by TCR [1]. These standard emission factors are presented in the two lower tables included in Form 4b. Site-specific data are preferable to these default factors whenever possible; however, site-specific data are rare due to the cost and difficulty of testing for emissions of CH_4 and N_2O over a sufficient period to adequately characterize long-term emissions.

Several examples are imbedded in the copy of Form 4a presented in the appendix to this emission inventory program. As indicated in this form, the emissions of CO_2 substantially exceed the values for methane and nitrous oxide even considering the global warming potential impact multipliers shown at the bottom of the form. Methane and nitrous oxide contribute less than 2% of the CO_2e calculated for many common fuels and combustion systems.

4.3 Direct Emissions from Blasting

GHG emissions from blasting on-site at aggregate, industrial, and pulverized mineral producing facilities can be calculated using Form 5 Blasting. The only data needed to complete these calculations are (1) ANFO (ammonium nitrate and fuel oil) purchase records and (2) fuel oil content value of the ANFO used in blasting. The calculated CO_2e emissions from blasting in Form 5 are presented in tons per year.

4.4 Indirect Emissions from Purchased Energy

The indirect GHG emissions due to purchased energy are calculated using Form 6a Purchased Power. The only data needed for these calculations are the annual electrical power data provided on electrical bills for each separately monitored facility or subsection of a facility. The annual electrical use data in kilowatt hours (kWh) should be calculated for each facility.

Emission factors for carbon dioxide, methane, and nitrous oxide are provided by the EPA (Appendix C) based on the distribution of electrical generating sources used by each power company in each geographical area [6]. Regions where the electric utilities use more renewable energy sources, nuclear power, and/or hydroelectric sources have lower emission factors than those based primarily on fossil fuels. As electric utilities gradually convert to cleaner energy sources, these geographically oriented emission factors will decrease. Data for determining the geographical distribution of electrical generating sources can be found on Form 6b eGRID Map [6]. This information can then be used for selecting the appropriate emission factors.

The appropriate emission factors for CO_2, CH_4, and N_2O can be retrieved Form 6c eGRID2007 Data or on a zip code-specific basis from http://cfpub.epa.gov/ egridweb/reports.cfm. In the EPA eGRID databases, the emission factors are expressed in units of pounds per megawatt (lbs./MWh) or pounds per gigawatt (lbs./GWh.) In GHG Form 6a, the data are converted to pounds per kWh.

The emissions of CO_2, CH_4, and N_2O are calculated by multiplying the EPA-supplied emission factor by the electrical power consumption for the year. The emissions for all facilities included within the boundary of the emission inventory should be summed for each facility. The GWP multipliers are provided at the top of Form 6a to convert the emissions of CH_4 and N_2O into CO_2e emissions. It is apparent in the examples included in Form 6a, that the CH_4 and N_2O emissions do not exceed the 2% level.

4.5 Direct Emissions from Hydrofluorocarbons HFC and Perfluorocarbons PFC

GHG emissions from the use of HFCs and PFCs on-site at aggregate, industrial, and pulverized mineral producing facilities can be calculated using Forms 7a HFC, PFC and 7b HFC, PFC GWPs. The data needed to complete these calculations are (1) the refrigerant type or blend number, (2) the global warming potential factor, (3) the refrigerant purchase records, and (4) information concerning the on-site refrigeration equipment. The global warming potential factors can be found on Form 7b HFC, PFC

GWPs. The calculated CO_2e emissions from refrigerant use in Form 7a are presented in tons per year.

5. RECORDKEEPING AND INVENTORY VERIFICATION

NSSGA encourages member companies compiling GHG inventories to compile photocopies of all fuel purchase records, fuel storage inventory records, and electrical power bills in a central area. These records must be retrievable when the inventory is audited by an independent party. The TCR and CCAR require an independent audit once per year starting after the second year of reporting.

In addition to the records for each facility and source included in the boundary of the GHG inventory, NSSGA encourages member companies to retain electronic copies of all major references that provide default emission factors and other supporting information for the conversion factors. These files will be useful when checking the accuracy of calculations completed several years earlier.

6. VOLUNTARY REPORTING

Voluntary reporting of GHG emissions is required annually for participants in TCR and CCAR programs. For CCAR participants, these emissions are reported on an automated system termed “CARROT”. The NSSGA GHG inventory forms are designed to provide data compatible with the input fields of the CARROT system and other similar systems that might be developed in the future.

7. REFERENCES

1. The Climate Registry. May 2021 Default Emission Factors. Document available as Appendix A to the NSSGA User's Guide. 2021.

2. The Climate Registry. General Reporting Protocol, Version 3.0. May 2019. Document available as Appendix B to the NSSGA User's Guide 2021.

3. EPA Mandatory Reporting Rule, 40 CFR Part 98. October 30, 2009.

4. IPCC, Global Warming Potential Factors (100 Year) AR5 Values 2014. https://www.ipcc.ch/pdf/assessmentreport/ar5/wg1/WG1AR5_Chapter08_FINAL.

5. IPCC, Global Warming Potential Factors (100 Year) AR4 values: https://www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10-2.htm.

6. U.S. EPA. Emission Factor for Greenhouse Gas Inventories. April 2021. Document available as Appendix C to the NSSGA User's Guide 2021.

APPENDIX A
The Climate Registry 2021 Default Emission Factors

The Climate Registry

MAY 2021

The Climate Registry (TCR) is pleased to present its 2021 default emission factors. Each year, we update the default emission factors associated with our program because:

1. The components of energy (electricity, fuel, etc.) change over time, and;
2. Emission factor quantification methods are frequently refined.

Members that rely on these emission factors to measure and report base year inventories should assess whether changes in emissions factors over time materially impact their base year emissions, and consider adjusting accordingly. The default emission factors are incorporated into the Climate Registry Information System (CRIS) for use in emissions calculations. We publish these default factors to our website to advance best practices, consistency, and transparency in greenhouse gas (GHG) accounting.

Our default emission factors are compiled from publicly available data sources, which are cited at the bottom of each table. TCR is not responsible for the underlying data or methodology used to calculate these default emission factors, or for communicating any changes to the data sources that occur between our annual updates.

As detailed in TCR's General Reporting Protocol (GRP), you should apply the most up-to-date emission factor available in CRIS (or otherwise) when calculating emissions. To calculate indirect emissions associated with electricity using grid average emission factors, you should apply the emission factor that corresponds with the year being reported (or the most recent previous year), and may not apply a factor that post-dates the reporting year.

There are four important changes to note in the 2021 default emission factor update:

1. **Table 2.4 U.S Default Factors for Calculating CH_4 and N_20 Emissions from Highway Vehicles by Technology Type:** There is a new distinction between ARB LEV III and EPA Tier 3. This will not affect most members but TCR staff will contact reporters currently using this emission factor to determine which factor they wish to utilize going foward.
2. **Table 2.5 U.S Default Factors for Calculating CH_4 and N_20 Emissions from Highway Vehicles by Model Year:** The model year ranges for Diesel Passenger Cars, Diesel Light-Duty Trucks, Diesel Medium and Heavy-Duty Trucks and Busses, and Diesel Motorcycles have changed.
3. **Table 3.1 U.S Default Factors for Calculating Emissions from Grid Electricity by eGRID Subregion:** The U.S EPA published *The Emissions and Generation Resource Integrated Database (eGRID) Technical Guide with Year 2019 Data*. When these publications are released TCR updates electricity emission factors by EPA grid region for members to use in their reporting. This emission factor publication shows emission factors for electricity based on 2019 emissions data, published in 2021. The 2019 eGRID publication also added a new regional emission factor for Puerto Rico (PRMS).
4. **Table 3.9 U.S. Green-e® Residual Mix Emissions Rates by eGRID Subregion:** TCR members can now use Green-e® Residual Mix Emissions Rates to calculate emissions totals for their market-based electricity purchases. Green-e® Residual Mix emission factors correspond to the eGRID subregions. Organizations should use the most specific emission factors available in the hierarchy of contractual instruments for the market-based method.[1] In the absence of other contractual instruments (i.e., certificates or RECs, contracts, utility-specific emission factors), organizations should use residual mix emission factors to calculate emissions for market-based purchased electricity instead of the regional emission factor (e.g., eGRID).

TCR members are encouraged to contact help@theclimateregistry.org with questions or feedback on these default emission factors or citation information.

Sincerely,

The Climate Registry

[1] See GRP sections C-12 to C-14.

List of Tables

Table 1.1 U.S. Default Factors for Calculating CO_2 Emissions from Combustion of Fossil Fuel and Biomass

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	25.09	28.28	1	103.69	2602
Bituminous	24.93	25.44	1	93.28	2325
Subbituminous	17.25	26.50	1	97.17	1676
Lignite	14.21	26.65	1	97.72	1389
Coal Coke	24.80	31.00	1	113.67	2819
Mixed Electric Utility/Electric Power	19.73	26.05	1	95.52	1885
Unspecified Residential/Com*	19.09	26.09	1	95.66	1826
Mixed Commercial Sector	21.39	25.71	1	94.27	2016
Mixed Industrial Coking	26.28	25.61	1	93.90	2468
Mixed Industrial Sector	22.35	25.82	1	94.67	2116
Natural Gas	**Btu / scf**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / scf**
US Weighted Average**	1026.00	14.47	1	53.06	0.05444
Greater than 1,000 Btu**	>1000	14.47	1	53.06	varies
975 to 1,000 Btu**	975 – 1,000	14.73	1	54.01	varies
1,000 to 1,025 Btu**	1,000 – 1,025	14.43	1	52.91	varies
1,025 to 1,035 Btu**	1,025 – 1,035	14.45	1	52.98	varies
1,025 to 1,050 Btu**	1,025 – 1,050	14.47	1	53.06	varies
1,050 to 1,075 Btu**	1,050 – 1,075	14.58	1	53.46	varies
1,075 to 1,100 Btu**	1,075 – 1,100	14.65	1	53.72	varies
Greater than 1,100 Btu**	>1,100	14.92	1	54.71	varies
(EPA 2010) Full Sample**		14.48	1	53.09	n/a
(EPA 2010) <1.0% CO2**		14.43	1	52.91	n/a
(EPA 2010) <1.5% CO2**		14.47	1	53.06	n/a
(EPA 2010) <1.0% CO2 and <1,050 Btu/scf**	<1,050	14.42	1	52.87	n/a
(EPA 2010) <1.5% CO2 and <1,050 Btu/scf**	<1,050	14.47	1	53.06	n/a
(EPA 2010) Flare Gas**	>1,100	15.31	1	56.14	n/a

Petroleum Products	MMBtu / gallon	kg C / MMBtu		kg CO_2 / MMBtu	kg CO_2 / gallon
Distillate Fuel Oil No. 1	0.139	19.98	1	73.25	10.18
Distillate Fuel Oil No. 2	0.138	20.17	1	73.96	10.21
Distillate Fuel Oil No. 4	0.146	20.47	1	75.04	10.96
Residual Fuel Oil No. 5	0.140	19.89	1	72.93	10.21
Residual Fuel Oil No. 6	0.150	20.48	1	75.10	11.27
Still Gas	0.143	18.20	1	66.73	9.53
Used Oil	0.138	20.18	1	74.00	10.21
Kerosene	0.135	20.51	1	75.20	10.15
LPG	0.092	16.83	1	61.71	5.68
Propane (Liquid)	0.091	17.15	1	62.87	5.72
Propylene	0.091	18.48	1	67.77	6.17
Ethane	0.068	16.25	1	59.60	4.05
Ethylene	0.058	17.99	1	65.96	3.83
Isobutane	0.099	17.71	1	64.94	6.43
Isobutylene	0.103	18.78	1	68.86	7.09
Butane	0.103	17.66	1	64.77	6.67
Butylene	0.105	18.74	1	68.72	7.22
Naptha (<401 deg F)	0.125	18.55	1	68.02	8.50
Natural Gasoline	0.110	18.24	1	66.88	7.36
Other Oil (>401 deg F)	0.139	20.79	1	76.22	10.59
Pentanes Plus	0.110	19.10	1	70.02	7.70
Petrochemical Feedstocks	0.125	19.37	1	71.02	8.88
Petroleum Coke (Liquid)	0.143	27.93	1	102.41	14.64
Special Naptha	0.125	19.73	1	72.34	9.04
Unfinished Oils	0.139	20.33	1	74.54	10.36
Heavy Gas Oils	0.148	20.43	1	74.92	11.09
Lubricants	0.144	20.26	1	74.27	10.69
Motor Gasoline	0.125	19.15	1	70.22	8.78
Aviation Gasoline	0.120	18.89	1	69.25	8.31
Kerosene Type Jet Fuel	0.135	19.70	1	72.22	9.75
Asphalt and Road Oil	0.158	20.55	1	75.36	11.91
Crude Oil	0.138	20.33	1	74.54	10.29

Petroleum Waxes	0.132	19.80	1	72.60	9.57
Fossil Fuel-derived Fuels (gaseous)	**MMBtu / scf**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / scf**
Acetylene***	0.00147	19.53	1	71.61	0.11
Blast Furnace Gas	0.000092	74.81	1	274.32	0.02524
Coke Oven Gas	0.000599	12.78	1	46.85	0.02806
Propane (Gas)	0.002516	16.76	1	61.46	0.15463
Fuel Gas	0.001388	16.09	1	59.00	0.08189
Fossil Fuel-derived Fuels (solid)	**MMBtu / short ton**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / short ton**
Municipal Solid Waste	9.95	24.74	1	90.70	902
Tires	28.00	23.45	1	85.97	2407
Plastics	38.00	20.45	1	75.00	2850
Petroleum Coke (Solid)	30.00	27.93	1	102.41	3072
Biomass Fuels-Solid	**MMBtu / short ton**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / short ton**
Wood and Wood Residuals (12% moisture content)	17.48	25.58	1	93.80	1640
Agricultural Byproducts	8.25	32.23	1	118.17	975
Peat	8.00	30.50	1	111.84	895
Solid Byproducts	10.39	28.78	1	105.51	1096
Kraft Black Liquor (NA hardwood)		25.55	1	93.70	n/a
Kraft Black Liquor (NA softwood)		25.75	1	94.40	n/a
Kraft Black Liquor (Bagasse)		26.05	1	95.50	n/a
Kraft Black Liquor (Bamboo)		25.55	1	93.70	n/a
Kraft Black Liquor (Straw)		25.94	1	95.10	n/a
Municipal Solid Waste (Biomass)	9.95	24.74	1	90.70	902
Biomass Fuels-Gaseous	**MMBtu / scf**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / scf**
Biogas (Captured Methane)	0.000655	14.20	1	52.07	0.034106
Landfill Gas (50% CH_4/50%CO_2)	0.000485	14.20	1	52.07	0.025254
Wastewater Treatment Biogas****	varies	14.20	1	52.07	varies
Biomass Fuels - Liquid	**MMBtu / gallon**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / gallon**
Ethanol (100%)	0.084	18.67	1	68.44	5.75
Biodiesel (100%)	0.128	20.14	1	73.84	9.45
Rendered Animal Fat	0.125	19.38	1	71.06	8.88
Vegetable Oil	0.120	22.24	1	81.55	9.79

Source: Heat Content and CO_2 emission factors per unit energy are from EPA Final Mandatory Reporting of Greenhouse Gases Rule Tables C-1 and AA-1, and the associated eCFR database Title 40 Protection of the Environment, Part 98 Mandatory Greenhouse Gas Reporting as amended December 2016. Carbon Content is derived using the heat content and/or default emission factor. The source marked with * heat content factor for Unspecified Residential/Corn is derived from the U.S. Energy Information Administration, Monthly Energy Review (December 2020). Sources marked with ** are from US Inventory of Greenhouse Gas Emissions and Sinks 1990-2018 (April 2020) Annex 2, Tables A- 51, and A-61. Sources marked with *** are derived from the API Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry (August 2009), Section 3.6.3, Table 3-8. Sources marked with **** are derived from the EPA Climate Leaders Technical Guidance (2008) Table B-2. A fraction oxidized value of 1.00 is from the Intergovernmental Panel on Climate Change (IPCC), Guidelines for National Greenhouse Gas Inventories (2006). Sources marked as n/a = data not available.

Note: Where not provided from the EPA Final Mandatory Reporting of Greenhouse Gases Rule, 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 the equation: Heat Content × Carbon Content × Fraction Oxidized × 44/12 × Conversion Factor (if applicable).

Table 1.2 Canadian Default Factors for Calculating CO_2 Emissions from Combustion of Natural Gas, Petroleum Products, and Biomass

Fuel Type	Carbon Content (Per Unit Energy)	Heat Content	Fraction Oxidized	CO_2 Emission Factor (Per Unit Mass or Volume)
Natural Gas	kg C / GJ	GJ / megalitre		g CO_2 / m3
All Provinces				
Still gas (Upgrading Facilities)	n/a	43.24	1	2140
Still gas (Refineries & Others)	n/a	36.08	1	2183
Newfoundland and Labrador				
Marketable	n/a	39.03	1	1901
Non-Marketable	n/a	39.03	1	2494
Nova Scotia				
Marketable	n/a	39.03	1	1901
Non-Marketable	n/a	39.03	1	2494
New Brunswick				
Marketable	n/a	39.03	1	1901
Non-Marketable	n/a	39.03	1	n/o
Quebec				
Marketable	n/a	39.03	1	1887
Non-Marketable	n/a	39.03	1	n/o
Ontario				
Marketable	n/a	39.03	1	1888
Non-Marketable	n/a	39.03	1	n/o

Manitoba				
Marketable	n/a	39.03	1	1886
Non-Marketable	n/a	39.03	1	n/a
Saskatchewan				
Marketable	n/a	39.03	1	1829
Non-Marketable	n/a	39.03	1	2441
Alberta				
Marketable	n/a	39.03	1	1928
Non-Marketable	n/a	39.03	1	2392
British Columbia				
Marketable	n/a	39.03	1	1926
Non-Marketable	n/a	39.03	1	2162
Yukon				
Marketable	n/a	39.03	1	1901
Non-Marketable	n/a	39.03	1	2401
Northwest Territories				
Marketable	n/a	39.03	1	1901
Non-Marketable	n/a	39.03	1	2466
Natural Gas Liquids	**kg C / GJ**	**GJ / Kilolitre**		**g CO_2 / L**
Propane: Residential Propane	n/a	25.31	1	1515
Propane: Other Uses Propane	n/a	25.31	1	1515

Ethane	n/a	17.22	1	986
Butane	n/a	28.44	1	1747
Refinery LPGs (All Stationary)	n/a	n/a	1	1629
Petroleum Products	**kg C / GJ**	**GJ / Kilolitre**		**g CO_2 / L**
Light Fuel Oil Electric Utilities	n/a	38.80	1	2753
Light Fuel Oil Industrial	n/a	38.80	1	2753
Light Fuel Oil Producer Consumption	n/a	38.80	1	2670
Light Fuel Oil Residential	n/a	38.80	1	2753
Light Fuel Oil Forestry, Construction, Public Administration, Commercial/Institutional	n/a	38.80	1	2753
Heavy Fuel Oil (Electric Utility, Industrial, Forestry, Construction, Public Administration, Commercial/Institutional)	n/a	42.50	1	3156
Heavy Fuel Oil (Residential)	n/a	42.50	1	3156
Heavy Fuel Oil (Producer Consumption)	n/a	42.50	1	3190
Kerosene (Electric Utility, Industrial, Producer Consumption, Residential, Forestry, Construction, Public Administration, Commercial/Institutional)	n/a	37.68	1	2560
Diesel	n/a	38.30	1	2681
Petroleum Coke from Upgrading Facilities	n/a	40.57	1	3494
Petroleum Coke from Refineries & Others	n/a	46.35	1	3778
Motor Gasoline	n/a	35.00	1	2307
Biomass	**kg C / GJ**	**GJ / t**		**g CO2 / kg**
Wood Fuel/Wood Waste	n/a	18.00	1	1715

Spent Pulping Liquor	n/a	14.00	1	1250
Landfill Gas	n/a	n/a	1	2752
Stoves and Fireplaces	n/a	n/a	1	1539
Pellet Stove	n/a	n/a	1	1652
Other Wood-burning Equipment	n/a	n/a	1	1539

Source: Default CO_2 emission factors: Environment Canada, National Inventory Report, 1990-2018: Greenhouse Gas Sources and Sinks in Canada (April 2020), Annex 6: Emission Factors, Tables A6.1-1, A6.1-3, A6.1-4, A6.1-5, A6.6-1 and A6.6-2. The CO_2 emission factor for refinery LPGs is from: Environment Canada, National Inventory Report, 1990-2012: Greenhouse Gas Sources and Sinks in Canada (2015), Annex 8: Emission Factors, Table A8-5. Default Heat Content: Statistics Canada, Report on Energy Supply and Demand in Canada, 2016-Revision (April 2019), Energy conversion factors, p. 132; Default Carbon Content: Canada-specific carbon content coefficients are not available. If you cannot obtain measured carbon content values specific to your fuels, you should use the default emission factor; Default Fraction Oxidized: Intergovernmental Panel on Climate Change (IPCC), Guidelines for National Greenhouse Gas Inventories (2006). n/a=data not available. n/o=not occurring.

Note: Red text indicates a revised emission factor for Manitoba from the previous publication.

Table 1.3 Canadian Default Factors for Calculating CO_2 Emissions from Combustion of Coal

Province and Coal Type	Carbon Content	Heat Content	Fraction Oxidized	CO_2 Emission Factor
Newfoundland and Labrador	**kg C / GJ**	**GJ / t**		**g CO_2 / kg**
Canadian Bituminous	n/a	28.96	1	2211
Foreign Bituminous	n/a	29.82	1	2540
Foreign Sub-Bituminous	n/a	19.15	1	1865
Lignite	n/a	15.00	1	1469
Prince Edward Island	**kg C / GJ**	**GJ / t**		**g CO_2 / kg**
Canadian Bituminous	n/a	28.96	1	2211
Foreign Bituminous	n/a	29.82	1	2540
Foreign Sub-Bituminous	n/a	19.15	1	1865
Lignite	n/a	15.00	1	1469
Nova Scotia	**kg C / GJ**	**GJ / t**		**g CO_2 / kg**
Canadian Bituminous	n/a	28.96	1	2357
Foreign Bituminous	n/a	29.82	1	2540
Foreign Sub-Bituminous	n/a	19.15	1	1865
Lignite	n/a	15.00	1	1469
New Brunswick	**kg C / GJ**	**GJ / t**		**g CO_2 / kg**
Canadian Bituminous	n/a	26.80	1	2224

Foreign Bituminous	n/a	29.82	1	2540
Foreign Sub-Bituminous	n/a	19.15	1	1865
Lignite	n/a	15.00	1	1469
Quebec	**kg C / GJ**	**GJ / t**		**g CO_2 / kg**
Canadian Bituminous	n/a	28.96	1	2224
Foreign Bituminous	n/a	29.82	1	2662
Lignite	n/a	15.00	1	1469
Ontario	**kg C / GJ**	**GJ / t**		**g CO_2 / kg**
Canadian Bituminous	n/a	25.43	1	2224
Foreign Bituminous	n/a	29.82	1	2651
Foreign Sub-Bituminous	n/a	19.15	1	1865
Lignite	n/a	15.00	1	1469
Manitoba	**kg C / GJ**	**GJ / t**		**g CO_2 / kg**
Foreign Bituminous	n/a	29.82	1	2651
Foreign Sub-Bituminous	n/a	19.15	1	1865
Lignite	n/a	15.00	1	1469
Saskatchewan	**kg C / GJ**	**GJ / t**		**g CO_2 / kg**
Canadian Bituminous	n/a	25.43	1	2224
Canadian Sub-Bituminous	n/a	19.15	1	1774
Lignite	n/a	15.00	1	1464

Alberta	kg C / GJ	GJ / t		g CO_2 / kg
Canadian Bituminous	n/a	25.43	1	2224
Foreign Bituminous	n/a	n/a	1	2662
Canadian Sub-Bituminous	n/a	19.15	1	1774
Lignite	n/a	15.00	1	1469
British Columbia	**kg C / GJ**	**GJ / t**		**g CO_2 / kg**
Canadian Bituminous	n/a	26.02	1	2224
Canadian Sub-Bituminous	n/a	19.15	1	1774
Lignite	n/a	15.00	1	1469
All Provinces and Territories	**kg C / GJ**	**GJ / t**		**g CO_2 / kg**
Coke	n/a	28.83	1	3173
Anthracite	n/a	27.70	1	2411
Coke Oven Gas	n/a	19.14	1	687

Source: Default CO_2 Emission Factors: Environment Canada, National Inventory Report, 1990-2018: Greenhouse Gas Sources and Sinks in Canada (April 2020), Annex 6: Emission Factors, Tables A6.1-8 and A6.1-9; Default Heat Content: Statistics Canada, Report on Energy Supply and Demand in Canada, 2016-Revision (April 2019), Energy conversion factors, p. 132 (value for Foreign Bituminous uses heat content of "Imported bituminous" value, for Foreign Sub-Bituminous uses heat content of "Sub- bituminous"); Default Carbon Content: Canada-specific carbon content coefficients are not available. If you cannot obtain measured carbon content values specific to your fuels, you should use the default emission factor; Default Fraction Oxidized: Intergovernmental Panel on Climate Change (IPCC), Guidelines for National Greenhouse Gas Inventories (2006) and Environment Canada, National Inventory Report, 1990-2015: Greenhouse Gas Sources and Sinks in Canada (April 2017), Annex 4: Reference Approach Energy Conversion and Emission Factors for Canada. n/a=data not available.

Note: CO_2 emission factors from Environment Canada originally included fraction oxidized factors of less than 100% for Solid - Primary Fuels. Values were converted to include a 100% oxidation rate using 98.8% for Anthracite, 98.8% for Bituminous, 99.4% for Subbituminous, and 99.5% for Lignite based on the rates used to calculate the original factors.

Table 1.4 Canadian Default Factors for Calculating CH_4 and N_2O Emissions from Combustion of Natural Gas, Petroleum Products, Coal, and Biomass

Fuel Type	CH_4 Emission Factor (Per Unit Mass or Volume)	N_2O Emission Factor (Per Unit Mass or Volume)
Natural Gas	**g CH_4 / m^3**	**g N_2O / m^3**
Electric Utilities	0.490	0.049
Industrial	0.037	0.033
Producer Consumption (NonMarketable)	6.4	0.060
Pipelines	1.900	0.050
Cement	0.037	0.034
Manufacturing Industries	0.037	0.033
Residential, Construction, Commercial/Institutional, Agriculture	0.037	0.035
Natural Gas Liquids	**g CH_4 / L**	**g N_2O / L**
Propane (Residential)	0.027	0.108
Propane (All Other Uses)	0.024	0.108
Ethane	0.024	0.108
Butane	0.024	0.108
Refinery LPGs	0.024	0.108
Refined Petroleum Products	**g CH_4 / L**	**g N_2O / L**
Light Fuel Oil (Electric Utilities)	0.18	0.031
Light Fuel Oil (Industrial and Producer Consumption)	0.006	0.031

Light Fuel Oil (Residential)	0.026	0.006
Light Fuel Oil (Forestry, Construction, Public Administration, and Commercial/Institutional)	0.026	0.031
Heavy Fuel Oil (Electric Utilities)	0.034	0.064
Heavy Fuel Oil (Industrial and Producer Consumption)	0.12	0.064
Heavy Fuel Oil (Residential, Forestry, Construction, Public Administration, and Commercial/Institutional)	0.057	0.064
Kerosene (Electric Utilities, Industrial, and Producer Consumption)	0.006	0.031
Kerosene (Residential)	0.026	0.006
Kerosene (Forestry, Construction, Public Administration, and Commercial/Institutional)	0.026	0.031
Diesel (Refineries and Others)	0.078	0.022
Diesel (Upgraders)	0.078	0.022
Still Gas (Refineries and Others)	0.0317	0.00002
Still Gas (Upgraders)	0.0389	0.00002
Motor Gasoline (Unspecified)	0.100	0.02
Petroleum Coke	**g CH_4 / L**	**g N_2O / L**
Upgrading Facilities	0.12	0.024
Refineries & Others	0.12	0.0275
Coal	**g CH_4 / kg**	**g N_2O / kg**
Coal (Electric Utilities)	0.02	0.03
Coal (Industry and Heat & Steam Plants)	0.03	0.02
Coal (Residential, Public Administration)	4.00	0.02

Coke	0.03	0.02
Coal (gas)	**g CH_4 / m^3**	**g N_2O / m^3**
Coke Oven Gas	0.04	0.04
Biomass	**g CH_4 / kg**	**g N_2O / kg**
Wood Fuel/Wood Waste (Industrial Combustion)	0.10	0.07
Spent Pulping Liquor (Industrial Combustion)	0.03	0.005
Stoves and Fireplaces (Advance Technology or Catalytic Control)	5.9	0.12
Stoves and Fireplaces (Conventional, Inserts)	12.9	0.12
Pellet Stove	4.12	0.059
Other Wood-burning Equipment	4.12	0.059
Landfill Gas	**kg CH_4 / t**	**kg N_2O / t**
Landfill Gas (Industrial Combustion)	0.05	0.005

Source: Environment Canada, National Inventory Report, 1990-2018: Greenhouse Gas Sources and Sinks in Canada (April 2020), Annex 6: Emission Factors, Tables A6.1-2, A6.1-3, A6.1-4, A6.1-6, A6.1-7, A6.1-10, A6.6-1, and A6.6-2. n/a=data not available.

Note: The CH_4 and the N_2O emission factors for refinery LPGs is from: Environment Canada, National Inventory Report, 1990-2012: Greenhouse Gas Sources and Sinks in Canada (2014), Annex 8: Emission Factors, Table A8-4.

Table 1.5 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
Residual Fuel Oil/Shale Oil Boilers	Tangential Firing	0.8	0.3
Gas/Diesel Oil Boilers	Normal Firing	0.9	0.4
Gas/Diesel Oil Boilers	Tangential Firing	0.9	0.4
Large Diesel Oil Engines >600hp (447kW)		4.0	n/a
Solid Fuels			
Pulverized Bituminous Combustion Boilers	Dry Bottom, wall fired	0.7	0.5
Pulverized Bituminous Combustion Boilers	Dry Bottom, tangentially fired	0.7	1.4
Pulverized Bituminous Combustion Boilers	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
Bituminous Fluidized Bed Combustor	Bubbling Bed	1.0	61.1
Bituminous Cyclone Furnace		0.2	1.6
Lignite Atmospheric Fluidized Bed		n/a	71.2
Natural Gas			

Fuel Type and Basic Technology	Configuration	CH_4 (g / MMBtu)	N_2O (g / MMBtu)
Boilers		0.9	0.9
Gas-Fired Gas Turbines >3MW		3.8	0.9
Large Dual-Fuel Engines		245.0	n/a
Combined Cycle		0.9	2.8
Peat			
Peat Fluidized Bed Combustor	Circulating Bed	3.0	7.0
Peat Fluidized Bed Combustor	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 five 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 used by the IPCC were used here to obtain the original values in units of HHV.) Values were converted from kg/TJ to g/MMBtu using 1 kg = 1000 g and 1 MMBtu = 0.001055 TJ. n/a=data not available.			

Table 1.6 Default Factors for Calculating CH_4 and N_2O Emission from Kilns, Ovens, and Dryers

Industry	Source	CH_4 (g / MMBtu)	N_2O (g / MMBtu)
Cement, Lime	Kilns - Natural Gas	1.04	n/a
Cement, Lime	Kilns – Oil	1.0	n/a
Cement, Lime	Kilns – Coal	1.0	n/a
Coking, Steel	Coke Oven	1.0	n/a
Chemical Processes, Wood, Asphalt, Copper, Phosphate	Dryer - Natural Gas	1.04	n/a
Chemical Processes, Wood, Asphalt, Copper, Phosphate	Dryer – Oil	1.0	n/a
Chemical Processes, Wood, Asphalt, Copper, Phosphate	Dryer – Coal	1.0	n/a

Source: IPCC, Guidelines for National Greenhouse Gas Inventories (2006), Chapter 2: Stationary Combustion, Table 2.8. Values were converted back from LHV to HHV using IPCC's assumption that LHV are five percent lower than HHV for coal and oil and 10 percent lower for natural gas. Values were converted from kg/TJ to g/MMBtu using 1 kg = 1000 g and 1 MMBtu = 0.001055 TJ. n/a=data not available.

Table 1.7 Default Factor for Calculating CH_4 and N_2O Emissions by Technology Type for the Industrial Sector

Fuel Type and Basic Technology	Configuration	CH_4 (g / MMBtu)	N_2O (g / MMBtu)
Liquid Fuels			
Residual Fuel Oil Boilers		3.0	0.3
Gas/Diesel Oil Boilers		0.2	0.4
Large Stationary Diesel Oil Engines >600hp (447 kW)		4.0	n/a
Liquefied Petroleum Gases Boilers		0.9	4.0
Solid Fuels			
Other Bituminous/Sub-bit. Overfeed Stoker Boilers		1.0	0.7
Other Bituminous/Sub-bit. Underfeed Stoker Boilers		14.0	0.7
Other Bituminous/Sub-bituminous Pulverized	Dry Bottom, wall fired	0.7	0.5
Other Bituminous/Sub-bituminous Pulverized	Dry Bottom, tangentially fired	0.7	1.4
Other Bituminous/Sub-bituminous Pulverized	Wet Bottom	0.9	1.4
Other Bituminous Spreader Stokers		1.0	0.7
Other Bituminous/Sub-bit. Fluidized Bed Combustor	Circulating Bed	1.0	61.1
Other Bituminous/Sub-bit. Fluidized Bed Combustor	Bubbling Bed	1.0	61.1
Natural Gas			
Boilers		0.9	0.9
Gas-Fired Gas Turbines >3MW		3.8	0.9
Natural Gas-fired Reciprocating Engines	2-Stroke Lean Burn	658.0	n/a
Natural Gas-fired Reciprocating Engines	4-Stroke Lean Burn	566.9	n/a

Fuel Type and Basic Technology	Configuration	CH_4 (g / MMBtu)	N_2O (g / MMBtu)
Natural Gas-fired Reciprocating Engines	4-Stroke Rich Burn	104.4	n/a
Biomass			
Wood/Wood Waste Boilers		9.3	5.9
Source: IPCC, Guidelines for National Greenhouse Gas Inventories (2006), Chapter 2: Stationary Combustion, Table 2.7. Values were converted from LHV to HHV assuming that LHV are five 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 used by the IPCC were used here to obtain the original values in units of HHV.) Values were converted from kg/TJ to g/MMBtu using 1 kg = 1000 g and 1 MMBtu = 0.001055 TJ. n/a=data not available.			

Table 1.8 Default Factors for Calculating CH_4 and N_2O Emissions by Technology Type for the Commercial Sector

Fuel Type and Basic Technology	Configuration	CH_4 (g / MMBtu)	N_2O (g / MMBtu)
Liquid Fuels			
Residual Fuel Oil Boilers		1.4	0.3
Gas/Diesel Oil Boilers		0.7	0.4
Liquefied Petroleum Gases Boilers		0.9	4.0
Solid Fuels			
Other Bituminous/Sub-bit. Overfeed Stoker Boilers		1.0	0.7
Other Bituminous/Sub-bit. Underfeed Stoker Boilers		14.0	0.7
Other Bituminous/Sub-bit. Hand-fed Units		87.2	0.7
Other Bituminous/Sub-bituminous Pulverized Boilers	Dry Bottom, wall fired	0.7	0.5
Other Bituminous/Sub-bituminous Pulverized Boilers	Dry Bottom, tangentially fired	0.7	1.4
Other Bituminous/Sub-bituminous Pulverized Boilers	Wet Bottom	0.9	1.4
Other Bituminous Spreader Stokers		1.0	0.7
Other Bituminous/Sub-bit. Fluidized Bed Combustor	Circulating Bed	1.0	61.1
Other Bituminous/Sub-bit. Fluidized Bed Combustor	Bubbling Bed	1.0	61.1
Natural Gas			
Boilers		0.9	0.9
Gas-Fired Gas Turbines >3MWa		3.8	1.3
Biomass			
Wood/Wood Waste Boilers		9.3	5.9
Source: IPCC, Guidelines for National Greenhouse Gas Inventories (2006), Chapter 2: Stationary Combustion, Table 2.10. Values were converted from LHV to HHV assuming that LHV are five 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 used by the IPCC were used here to obtain the original values in units of HHV.) Values were converted from kg/TJ to g/MMBtu using 1 kg = 1000 g and 1 MMBtu = 0.001055 TJ.			

Table 1.9 U.S. Default Factors for Calculating CH_4 and N_2O Emissions by Fuel Type Industrial and Energy Sectors

Fuel Type / End-Use Sector	CH_4 (kg / MMBtu)	N_2O (kg / MMBtu)
Coal		
Industrial	0.011	1.6E-3
Energy Industry	0.011	1.6E-3
Coke		
Industrial	0.011	1.6E-3
Energy Industry	0.011	1.6E-3
Petroleum Products		
Industrial	3.0E-3	6.0E-4
Energy Industry	3.0E-3	6.0E-4
Natural Gas		
Industrial	1.0E-3	1.0E-4
Energy Industry	1.0E-3	1.0E-4
Municipal Solid Waste		
Industrial	0.032	4.2E-3
Energy Industry	0.032	4.2E-3
Tires		
Industrial	0.032	4.2E-3
Energy Industry	0.032	4.2E-3
Blast Furnace Gas		
Industrial	2.2E-5	1.0E-4
Energy Industry	2.2E-5	1.0E-4
Coke Oven Gas		
Industrial	4.8E-4	1.0E-4
Energy Industry	4.8E-4	1.0E-4
Biomass Fuels Solid (except Wood and Wood Residuals)		
Industrial	0.032	4.2E-3
Energy Industry	0.032	4.2E-3
Wood and Wood Residuals		

Industrial	0.0072	3.6E-3
Energy Industry	0.0072	3.6E-3
Biogas		
Industrial	3.2E-3	6.3E-4
Energy Industry	3.2E-3	6.3E-4
Biomass Fuels Liquid		
Industrial	1.1E-3	1.1E-4
Energy Industry	1.1E-3	1.1E-4
Pulping Liquors		
Industrial*	1.9E-3	4.2E-4

Source: CH_4 and N_2O emission factors per unit energy are from EPA Final Mandatory Reporting of Greenhouse Gases Rule Table C-2. Except those marked with * are from Table AA-1.

Note: For coal combustion, organizations who fall within the IPCC "Energy Industry" category can employ a value of 1g of CH4/mmBtu.

Table 1.10 Default Factors for Calculating CH_4 and N_2O Emission by Fuel Type for the Residential and Commercial Sectors

Fuel Type / End-Use Sector	CH_4 (g / MMBtu)	N_2O (g / MMBtu)
Coal		
Residential	300.7	1.5
Commercial	10.0	1.5
Petroleum Products		
Residential	10.0	0.6
Commercial	10.0	0.6
Natural Gas		
Residential	4.7	0.1
Commercial	4.7	0.1
Wood		
Residential	253.2	3.4
Commercial	253.2	3.4

Source: IPCC, Guidelines for National Greenhouse Gas Inventories (2006), Chapter 2: Stationary Combustion, Tables 2.4 and 2.5. Values were converted from LHV to HHV assuming that LHV are five 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 used by the IPCC were used here to obtain the original values in units of HHV.) Values were converted from kg/TJ to g/MMBtu using 1 kg = 1000 g and 1 MMBtu = 0.001055 TJ.

Table 2.1 U.S. Default Factors for Calculating CO_2 Emissions from Combustion of 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**
Gasoline	19.2	5.25	1	8.78
Diesel Fuel	20.2	5.80	1	10.21
Aviation Gasoline	18.9	5.04	1	8.31
Jet Fuel (Jet A or A-1)	19.7	5.67	1	9.75
Kerosene	20.5	5.67	1	10.15
Residual Fuel Oil No. 5	19.9	5.88	1	10.21
Residual Fuel Oil No. 6	20.5	6.30	1	11.27
Crude Oil	20.3	5.80	1	10.29
Biodiesel (B100)	20.1	5.38	1	9.45
Ethanol (E100)	18.7	3.53	1	5.75
Methanol*	n/a	n/a	1	4.10
Liquefied Natural Gas (LNG)	n/a	n/a	1	4.50
Liquefied Petroleum Gas (LPG)	17.2	3.86	1	5.68
Propane (Liquid)	16.8	3.82	1	5.72
Ethane	16.3	2.86	1	4.05
Isobutane	17.7	4.16	1	6.43
Butane	17.7	4.33	1	6.67
Renewable Diesel (R100)**	20.2	5.80	1	10.21
Fuels Measured in Standard Cubic Feet	**kg C / MMBtu**	**Btu / Standard cubic foot**		**kg CO_2 / Standard cubic foot**
Compressed Natural Gas (CNG)	14.5	1026	1	0.05444
Propane (Gas)	16.8	2516	1	0.15463
Renewable Natural Gas***	14.5	1026	1	0.05444

Source: Heat content and default emission factors are from EPA Final Mandatory Reporting of Greenhouse Gases Rule Table C-1. Carbon content derived using the heat content and default emission factor. A fraction oxidized of 1.00 is from the IPCC, Guidelines for National Greenhouse Gas Inventories (2006). CNG and LNG CO_2 factors are from EPA Center for Corporate Climate Leadership GHG Emission Factors Hub (March 2018). *Methanol emission factor is calculated from the properties of the pure compounds. ** Renewable Diesel (R100) emission factor assumes that chemical properties of renewable diesel are indistinguishable from petroleum-based diesel according to CalEPA Fuels Guidance Document, Version 2.0, September 2015. *** Renewable Natural Gas (RNG) emission factor assumes that RNG is chemically identical to fossil natural gas according to U.S. Department of Energy Office of Energy Efficiency and Renewable Energy's Alternative Fuels Data Center information on Natural Gas Vehicle Emissions. n/a=data not available.

Note: Carbon contents are calculated using the following equation: (Emission Factor / (44/12) / Heat Content x Conversion Factor. Heat content factors are based on higher heating values (HHV).

Table 2.2 Canadian Default Factors for Calculating CO_2 Emissions from Combustion of Transport Fuels

Fuel Type	Carbon Content (kg C / GJ)	Heat Content	Fraction Oxidized	CO_2 Emission Factors
		GJ / kiloliter		g CO_2 / L
Motor Gasoline	n/a	35.00	1	2307
Diesel	n/a	38.30	1	2681
Light Fuel Oil	n/a	38.80	1	2753
Heavy Fuel Oil	n/a	42.50	1	3156
Aviation Gasoline	n/a	33.52	1	2365
Aviation Turbo Fuel	n/a	37.40	1	2560
Propane	n/a	25.31	1	1515
Ethanol	n/a	n/a	1	1508
Biodiesel	n/a	n/a	1	2472
Kerosene	n/a	n/a	1	2560
		GJ / megaliter		g CO_2 / L
Natural Gas	n/a	39.03	1	1.9

Source: Default CO_2 Emission Factors: Environment Canada, National Inventory Report, 1990-2018: Greenhouse Gas Sources and Sinks in Canada (April 2020) Annex 6: Emission Factors, Table A6.1-13; Default Heat Content: Statistics Canada, Report on Energy Supply and Demand in Canada, 2017-Revision (May 2019), Energy conversion factors, p. 132; Default Carbon Content: Not available for Canada. If you cannot obtain measured carbon content values specific to your fuels, you should use the default emission factor. Default Fraction Oxidized: A value of 1.00 is used following the Intergovernmental Panel on Climate Change (IPCC), Guidelines for National Greenhouse Gas Inventories (2006).

Table 2.3 Canadian Default Factors for Calculating CH_4 and N_2O Emissions from Mobile Combustion

Vehicle Type	CH_4 Emission Factor ($g\ CH_4/L$)	N_2O Emission Factor ($g\ N_2O/L$)
Light-Duty Gasoline Vehicles (LDGVs)		
Tier 2	0.14	0.022
Tier 1	0.23	0.47
Tier 0	0.32	0.66
Oxidation Catalyst	0.52	0.20
Non-Catalytic Controlled	0.46	0.028
Light-Duty Gasoline Trucks (LDGTs)		
Tier 2	0.14	0.022
Tier 1	0.24	0.58
Tier 0	0.21	0.66
Oxidation Catalyst	0.43	0.20
Non-Catalytic Controlled	0.56	0.028
Heavy-Duty Gasoline Vehicles (HDGVs)		
Three-Way Catalyst	0.068	0.2
Non-Catalytic Controlled	0.29	0.047
Uncontrolled	0.49	0.084
Gasoline Motorcycles		
Non-Catalytic Controlled	0.77	0.041
Uncontrolled	2.3	0.048
Light-Duty Diesel Vehicles (LDDVs)		
Advance Control*	0.051	0.22
Moderate Control	0.068	0.21
Uncontrolled	0.10	0.16
Light-Duty Diesel Trucks (LDDTs)		
Advance Control*	0.068	0.22
Moderate Control	0.068	0.21
Uncontrolled	0.085	0.16

Heavy-Duty Diesel Vehicles (HDDVs)		
Advance Control	0.11	0.151
Moderate Control	0.14	0.082
Uncontrolled	0.15	0.075
Gas Fueled Vehicles		
Natural Gas Vehicles	0.009	0.00006
Propane Vehicles	0.64	0.028
Railways		
Diesel Train	0.15	1.0
Marine		
Gasoline Boats	0.22	0.063
Diesel Ships	0.25	0.072
Light Fuel Oil Ships	0.26	0.073
Heavy Fuel Oil Ships	0.29	0.082
Kerosene	0.25	0.071
Aviation		
Aviation Gasoline	2.2	0.23
Aviation Turbo Fuel	0.029	0.071
Renewable Fuels		
Biodiesel	**	**
Ethanol	***	***
Off-Road Vehicles		
Off-road Gasoline 2-stroke	10.61	0.013
Off-road Gasoline 4-stroke	5.08	0.064
Off-road Diesel <19kW	0.073	0.022
Off-road Diesel >=19kW, Tier 1-3	0.073	0.022
Off-road Diesel >= 19kW, Tier 4	0.073	0.227
Off-road Natural Gas	0.0088	0.00006
Off-road Propane	0.64	0.087

Source: Environment Canada, National Inventory Report, 1990-2018: Greenhouse Gas Sources and Sinks in Canada (April 2020) Annex 6: Emission Factors, Table A6.1-13. *Advanced control diesel emission factors should be used for Tier 2 diesel vehicles. **Diesel CH4 and N2O emission factors (by mode and technology) shall be used to calculate biodiesel emissions. ***Gasoline CH_4 and N_2O emission factors (by mode and technology) shall be used to calculate ethanol emissions.

Table 2.4 U.S. Default Factors for Calculating CH_4 and N_2O Emissions from Highway Vehicles by Technology Type

Vehicle Type/Control Technology	CH_4 (g / mi)	N_2O (g / mi)
Gasoline Passenger Cars		
EPA Tier 3	0.0055	0.0015
ARB LEV III	0.0045	0.0012
EPA Tier 2	0.0072	0.0048
ARB LEV II	0.0070	0.0043
ARB LEV	0.0100	0.0205
EPA Tier 1	0.0271	0.0429
EPA Tier 0	0.0704	0.0647
Oxidation Catalyst	0.1355	0.0504
Non-Catalyst Control	0.1696	0.0197
Uncontrolled	0.1780	0.0197
Low Emission Vehicles*	0.0105	0.0150
Gasoline Light Trucks (Vans, Pickup Trucks, SUVs)		
EPA Tier 3	0.0092	0.0012
ARB LEV III	0.0065	0.0012
EPA Tier 2	0.0100	0.0025
ARB LEV II	0.0084	0.0057
ARB LEV	0.0148	0.0223
EPA Tier 1	0.0452	0.0871
EPA Tier 0	0.0776	0.1056
Oxidation Catalyst	0.1516	0.0639
Non-Catalyst Control	0.1908	0.0218
Uncontrolled	0.2024	0.0220
Low Emission Vehicles*	0.0148	0.0157
Gasoline Medium and Heavy-Duty Vehicles Trucks and Busses		
EPA Tier 3	0.0252	0.0063
ARB LEV III	0.0411	0.0136
EPA Tier 2	0.0297	0.0015
ARB LEV II	0.0391	0.0015

ARB LEV	0.0300	0.0466
EPA Tier 1	0.0655	0.1750
EPA Tier 0	0.2630	0.2135
Oxidation Catalyst	0.2356	0.1317
Non-Catalyst Control	0.4181	0.0473
Uncontrolled	0.4604	0.0497
Low Emission Vehicles*	0.0303	0.0320
Diesel Passenger Cars		
Aftertreatment	0.0302	0.0192
Advanced	0.0005	0.0010
Moderate	0.0005	0.0010
Uncontrolled	0.0006	0.0012
Diesel Light-Duty Trucks		
Aftertreatment	0.0290	0.0214
Advanced	0.0010	0.0015
Moderate	0.0009	0.0014
Uncontrolled	0.0011	0.0017
Diesel Medium and Heavy-Duty Vehicles (Trucks and Busses)		
Aftertreatment	0.0095	0.0431
Advanced	0.0051	0.0048
Moderate	0.0051	0.0048
Uncontrolled	0.0051	0.0048
Motorcycles		
Non-Catalyst Control	0.0672	0.0069
Uncontrolled	0.0899	0.0087
Source: US Inventory of Greenhouse Gas Emissions and Sinks 1990-2018 (April 2020) Annex 3, Table A-96. *The CH_4 and N_2O emissions from Low-Emission Vehicles are from: US Inventory of Greenhouse Gas Emissions and Sinks 1990-2015 (April 2017) Annex 3, Table A-108.		

Table 2.5 U.S. Default Factors for Calculating CH_4 and N_2O Emission from Highway Vehicles by Model Year

Vehicle Type and Year	CH_4 (g / mi)	N_2O (g / mi)
Gasoline Passenger Cars		
Model Years 1984-1993	0.0704	0.0647
Model Year 1994	0.0617	0.0603
Model Year 1995	0.0531	0.0560
Model Year 1996	0.0434	0.0503
Model Year 1997	0.0337	0.0446
Model Year 1998	0.0247	0.0395
Model Year 1999	0.0222	0.0362
Model Year 2000	0.0175	0.0304
Model Year 2001	0.0105	0.0212
Model Year 2002	0.0102	0.0207
Model Year 2003	0.0098	0.0185
Model Year 2004	0.0083	0.0089
Model Year 2005	0.0076	0.0067
Model Year 2006	0.0076	0.0075
Model Year 2007	0.0072	0.0052
Model Year 2008	0.0071	0.0049
Model Year 2009	0.0072	0.0048
Model Year 2010	0.0071	0.0046
Model Year 2011	0.0071	0.0046
Model Year 2012	0.0071	0.0046
Model Year 2013	0.0071	0.0046
Model Year 2014	0.0071	0.0046
Model Year 2015	0.0068	0.0042
Model Year 2016	0.0065	0.0038
Model Year 2017	0.0054	0.0018
Model Year 2018	0.0052	0.0016
Gasoline Light Trucks (Vans, Pickup Trucks, SUVs)		
Model Years 1987-1993	0.0813	0.1035

Model Year 1994	0.0646	0.0982
Model Year 1995	0.0517	0.0908
Model Year 1996	0.0452	0.0871
Model Year 1997	0.0452	0.0871
Model Year 1998	0.0412	0.0787
Model Year 1999	0.0333	0.0618
Model Year 2000	0.0340	0.0631
Model Year 2001	0.0221	0.0379
Model Year 2002	0.0242	0.0424
Model Year 2003	0.0221	0.0373
Model Year 2004	0.0115	0.0088
Model Year 2005	0.0105	0.0064
Model Year 2006	0.0108	0.0080
Model Year 2007	0.0103	0.0061
Model Year 2008	0.0096	0.0038
Model Year 2009	0.0095	0.0036
Model Year 2010	0.0095	0.0035
Model Year 2011	0.0096	0.0034
Model Year 2012	0.0096	0.0033
Model Year 2013	0.0095	0.0035
Model Year 2014	0.0095	0.0033
Model Year 2015	0.0094	0.0031
Model Year 2016	0.0091	0.0029
Model Year 2017	0.0084	0.0018
Model Year 2018	0.0081	0.0015
Gasoline Medium and Heavy-Duty Trucks and Busses		
Model Years 1985-1986	0.4090	0.0515
Model Year 1987	0.3675	0.0849
Model Years 1988-1989	0.3492	0.0933
Model Years 1990-1995	0.3246	0.1142
Model Year 1996	0.1278	0.1680
Model Year 1997	0.0924	0.1726

Model Year 1998	0.0655	0.1750
Model Year 1999	0.0648	0.1724
Model Year 2000	0.0630	0.1660
Model Year 2001	0.0577	0.1468
Model Year 2002	0.0634	0.1673
Model Year 2003	0.0602	0.1553
Model Year 2004	0.0298	0.0164
Model Year 2005	0.0297	0.0083
Model Year 2006	0.0299	0.0241
Model Year 2007	0.0322	0.0015
Model Year 2008	0.0340	0.0015
Model Year 2009	0.0339	0.0015
Model Year 2010	0.0320	0.0015
Model Year 2011	0.0304	0.0015
Model Year 2012	0.0313	0.0015
Model Year 2013	0.0313	0.0015
Model Year 2014	0.0315	0.0015
Model Year 2015	0.0332	0.0021
Model Year 2016	0.0321	0.0061
Model Year 2017	0.0329	0.0084
Model Year 2018	0.0326	0.0082
Diesel Passenger Cars		
Model Years 1960-1982	0.0006	0.0012
Model Years 1983-2006	0.0005	0.0010
Model Years 2007-2018	0.0302	0.0192
Diesel Light Duty Trucks		
Model Years 1960-1982	0.0011	0.0017
Model Years 1983-1995	0.0009	0.0014
Model Years 1996-2006	0.0010	0.0015
Model Years 2007-2018	0.0290	0.0214
Diesel Medium and Heavy-Duty Trucks and Busses		
Model Years 1960-2006	0.0051	0.0048

Model Years 2007-2018	0.0095	0.0431
Diesel Motorcycles		
Model Years 1960-1995	0.0899	0.0087
Model Years 1996-2018	0.0069	0.0672
Source: US Inventory of Greenhouse Gas Emissions and Sinks 1990-2018 (April 2020) Annex 3, Tables A-107 - A-111.		

Table 2.6 U.S. Default Factors for Calculating CH_4 and N_2O Emissions from Alternative Fuel Vehicles

Vehicle Type	CH_4 (g / mi)	N_2O (g / mi)
Light-Duty Cars		
Methanol-Flex Fuel ICE	0.008	0.006
Ethanol-Flex Fuel ICE	0.008	0.006
CNG ICE	0.082	0.006
CNG Bi-fuel	0.082	0.006
LPG ICE	0.008	0.006
LPG Bi-fuel	0.008	0.006
Biodiesel (BD100)	0.030	0.019
Light-Duty Trucks		
Ethanol-Flex Fuel ICE	0.012	0.011
CNG ICE	0.123	0.011
CNG Bi-fuel	0.123	0.011
LPG ICE	0.012	0.013
LPG Bi-fuel	0.012	0.013
LNG	0.123	0.011
Biodiesel (BD100)	0.029	0.021
Medium Duty Trucks		
CNG ICE	4.200	0.001
CNG Bi-fuel	4.200	0.034
LPG ICE	0.014	0.034
LPG Bi-fuel	0.014	0.001
LNG	4.200	0.043
Biodiesel (BD100)	0.009	0.001
Heavy-Duty Trucks		
Neat Methanol ICE	0.075	0.028
Neat Ethanol ICE	0.075	0.028
CNG ICE	3.700	0.001
LPG ICE	0.013	0.026

LPG Bi-fuel	0.013	0.026
LNG	3.700	0.001
Biodiesel (BD100)	0.009	0.043
Buses		
Neat Methanol ICE	0.022	0.032
Neat Ethanol ICE	0.022	0.032
CNG ICE	10.000	0.001
LPG ICE	0.034	0.017
LNG	10.000	0.001
Biodiesel (BD100)	0.009	0.043
Source: US Inventory of Greenhouse Gas Emissions and Sinks 1990-2018 (April 2020) Annex 3, Tables A-112 - A-113.		

Table 2.7 U.S. Default Factors for Calculating CH_4 and N_2O Emission from Non-Highway Vehicles

Vehicle Type / Fuel Type	CH_4 (g / gallon)	N_2O (g / gallon)
Ships and Boats		
Residual Fuel Oil	0.55	0.55
Gasoline 2 Stroke	9.54	0.06
Gasoline 4 Stroke	4.88	0.23
Distillate Fuel Oil (Diesel)	0.31	0.50
Rail		
Diesel Fuel	0.80	0.26
Aircraft		
Jet Fuel	0.00	0.30
Aviation Gasoline	7.06	0.11
Agricultural Equipment		
Gasoline-Equipment 2 Stroke	12.96	0.06
Gasoline-Equipment 4 Stroke	7.24	0.21
Gasoline-Off-road Trucks	7.24	0.21
Diesel-Equipment	0.28	0.49
Diesel-Off-Road Trucks	0.13	0.49
LPG	2.19	0.39
Construction/Mining Equipment		
Gasoline-Equipment 2 Stroke	12.42	0.07
Gasoline-Equipment 4 Stroke	5.59	0.20
Gasoline-Off-Road Trucks	5.59	0.20
Diesel-Equipment	0.20	0.47
Diesel-Off-Road Trucks	0.13	0.49
LPG	1.05	0.41
Lawn and Garden Equipment		
Gasoline-Residential 2 Stroke	16.49	0.05
Gasoline-Residential 4 Stroke	6.36	0.18

Gasoline-Commercial 2 Stroke	15.57	0.06
Gasoline-Commercial 4 Stroke	5.84	0.18
Diesel-Commercial	0.33	0.47
LPG	0.35	0.41
Airport Equipment		
Gasoline 4 Stroke	2.58	0.25
Diesel	0.17	0.49
LPG	0.33	0.41
Industrial/Commercial Equipment		
Gasoline 2 Stroke	15.14	0.06
Gasoline 4 Stroke	5.48	0.20
Diesel	0.23	0.47
LPG	0.44	0.41
Logging Equipment		
Gasoline 2 Stroke	12.03	0.08
Gasoline 4 Stroke	6.71	0.18
Diesel	0.10	0.49
Railroad Equipment		
Gasoline 4 Stroke	5.78	0.19
Diesel	0.44	0.42
LPG	1.20	0.41
Recreational Equipment		
Gasoline 2 Stroke	7.81	0.03
Gasoline 4 Stroke	8.45	0.19
Diesel	0.41	0.41
LPG	2.98	0.38
Source: US Inventory of Greenhouse Gas Emissions and Sinks 1990-2018 (April 2020) Annex 3, Table A-114 - A-115. Original factors converted to g/gallon fuel using fuel density defaults from US Inventory of Greenhouse Gas Emissions and Sinks 1990-2018 (April 2020) Annex 6.5.		

Table 2.8 Default Factors for Calculating LTO Emission for Typical Aircraft

Aircraft	CO_2 (kg / LTO)	CH_4 (kg / LTO)	N_2O (kg / LTO)
A300	5450	0.12	0.2
A310	4760	0.63	0.2
A319	2310	0.06	0.1
A320	2440	0.06	0.1
A321	3020	0.14	0.1
A330-200/300	7050	0.13	0.2
A340-200	5890	0.42	0.2
A340-300	6380	0.39	0.2
A340-500/600	10660	0.01	0.3
707	5890	9.75	0.2
717	2140	0.01	0.1
727-100	3970	0.69	0.1
727-200	4610	0.81	0.1
737-100/200	2740	0.45	0.1
737-300/400/500	2480	0.08	0.1
737-600	2280	0.10	0.1
737-700	2460	0.09	0.1
737-800/900	2780	0.07	0.1
747-100	10140	4.84	0.3
747-200	11370	1.82	0.4
747-300	11080	0.27	0.4
747-400	10240	0.22	0.3
757-200	4320	0.02	0.1
757-300	4630	0.01	0.1
767-200	4620	0.33	0.1
767-300	5610	0.12	0.2
767-400	5520	0.10	0.2
777-200/300	8100	0.07	0.3

Aircraft	CO_2 (kg / LTO)	CH_4 (kg / LTO)	N_2O (kg / LTO)
DC-10	7290	0.24	0.2
DC-8-50/60/70	5360	0.15	0.2
DC-9	2650	0.46	0.1
L-1011	7300	7.40	0.2
MD-11	7290	0.24	0.2
MD-80	3180	0.19	0.1
MD-90	2760	0.01	0.1
TU-134	2930	1.80	0.1
TU-154-M	5960	1.32	0.2
TU-154-B	7030	11.90	0.2
RJ-RJ85	1910	0.13	0.1
BAE 146	1800	0.14	0.1
CRJ-100ER	1060	0.06	0.03
ERJ-145	990	0.06	0.03
Fokker 100/70/28	2390	0.14	0.1
BAC111	2520	0.15	0.1
Dornier 328 Jet	870	0.06	0.03
Gulfstream IV	2160	0.14	0.1
Gulfstream V	1890	0.03	0.1
Yak-42M	2880	0.25	0.1
Cessna 525/560	1070	0.33	0.03
Beech King Air	230	0.06	0.01
DHC8-100	640	0.00	0.02
ATR72-500	620	0.03	0.02

Source: IPCC, Guidelines for National Greenhouse Gas Inventories (2006), Volume 2: Energy, Chapter 3: Mobile Combustion, Table 3.6.9. LTO = landing/take-off.

Table 2.9 Factors for Estimating CH_4 and N_2O Emissions from Gasoline and Diesel Vehicles (SEM)

GHG	MT GHG per MT of CO_2
CH_4	2.34E-05
N_2O	2.50E-05

Source: Derived from US Inventory of Greenhouse Gas Emissions and Sinks 1990-2018 (April 2020), Table 2-13. Only includes data for passenger cars and light-duty trucks.

Table 3.1 U.S. Default Factors for Calculating Emissions from Grid Electricity by eGRID Subregion

eGRID 2019 Subregion	eGRID 2019 Subregion Name	2019 Emission Rates		
		(lbs CO_2 / MWh)	(lbs CH_4 / GWh)	(lbs N_2O / GWh)
AKGD	ASCC Alaska Grid	1,114.40	98	13
AKMS	ASCC Miscellaneous	549.30	26	4
AZNM	WECC Southwest	952.30	68	10
CAMX	WECC California	453.20	33	4
ERCT	ERCOT All	868.60	57	8
FRCC	FRCC All	861.00	55	7
HIMS	HICC Miscellaneous	1,185.60	143	22
HIOA	HICC Oahu	1,694.50	185	28
MROE	MRO East	1,502.60	147	22
MROW	MRO West	1,098.40	119	17
NEWE	NPCC New England	488.90	77	10
NWPP	WECC Northwest	715.20	68	10
NYCW	NPCC NYC/Westchester	553.80	21	2
NYLI	NPCC Long Island	1,209.00	157	20
NYUP	NPCC Upstate NY	232.30	17	2
PRMS	Puerto Rico Miscellaneous	1,537.30	84	13
RFCE	RFC East	695.00	53	7
RFCM	RFC Michigan	1,189.30	114	16
RFCW	RFC West	1,067.70	99	14
RMPA	WECC Rockies	1,242.60	117	17
SPNO	SPP North	1,070.00	112	16

SPSO	SPP South	1,002.00	70	10
SRMV	SERC Mississippi Valley	806.80	43	6
SRMW	SERC Midwest	1,584.40	169	25
SRSO	SERC South	969.20	71	10
SRTV	SERC Tennessee Valley	949.70	87	13
SRVC	SERC Virginia/Carolina	675.40	58	8
US Territories (not an eGRID Region)*	N/A	1,891.57	75.91	17.13
Source: U.S. EPA Year 2019 eGRID 14th edition (February 2021: eGRID subregion annual total output emission rates). Except * from Department of Energy Guidance on Voluntary Reporting of Greenhouse Gases, Form EIA-1605 (2007), Appendix F, Electricity Emission Factors, Table F-1.				

Table 3.2 Canadian Default Factors for Calculating Emissions from Grid Electricity by Province

Province	2018 Emission Rates		
	g CO_2 / kWh	g CH_4 / kWh	g N_2O / kWh
Alberta	750	0.04	0.01
British Columbia	9.5	0.003	0.0007
Manitoba	1.9	0.0001	0.00
New Brunswick	260	0.02	0.004
Newfoundland and Labrador	40	0.0006	0.001
Northwest Territories	150	0.01	0.00
Nova Scotia	680	0.03	0.01
Nunavut	720	0.0	0.0
Ontario	20	0.004	0.001
Prince Edward Island	14	0.0005	0.0002
Quebec	1.2	0.0	0.00
Saskatchewan	660	0.05	0.02
Yukon	49	0.003	0.00

Source: Environment Canada, National Inventory Report, 1990-2018: Greenhouse Gas Sources and Sinks in Canada (April 2020) Annex 13: Emission Factors, Table A13-2 - A13-14.

Table 3.3 Mexican Default Factors for Calculating Emissions from Grid Electricity

Year	Emission Rates (kg CO_2e / MWh)
2000	604.1
2001	625
2002	600
2003	571.2
2004	549.6
2005	550.1
2014	454
2015	458
2016	458
2017	582
2018	527
2019	505

Source: Asociación de Técnicos y Profesionistas en Aplicación Energética (ATPAE), 2003, Metodologías para calcular el Coeficiente de Emisión Adecuado para Determinar las Reducciones de GEI Atribuibles a Proyectos de EE/ER – Justificación para la selección de la Metodología, versión final 4.1 (June 2003), proyecto auspiciado por la Agencia Internacional de Estados Unidos para el Desarrollo Internacional, México, D.F., México. Factors are a national average of all the power plants operating and delivering electricity to the National Electric System and do not include transmission and distribution losses. Factors for 2002 to 2005 were not calculated with actual data but instead estimated using the Electricity Outlooks published by Mexico's Ministry of Energy. Default emission factors for electricity in years 2014-2019 sourced from Gobierno De Mexico's Registro Nacional de Emisiones Aviso Sobre El Factor De Emisión Eléctrico reports.

Note: These emission rates are in units of CO_2 equivalent (CO_2e) and include emissions of CO_2, CH_4, and N_2O.

Table 3.4 Non-North American Default Factors for calculating Emissions from Electricity Generation

Region / Country / Economy	2010 Emission Rates ($g\ CO_2$ / kWh)	2011 Emission Rates ($g\ CO_2$ / kWh)
Albania	2	7
Algeria	548	556
Angola	440	390
Argentina	367	390
Armenia	92	123
Australia	841	823
Austria	188	215
Azerbaijan	439	455
Bahrain	640	601
Bangladesh	593	564
Belarus	449	441
Belgium	220	196
Benin	720	722
Bolivia	423	433
Bosnia and Herzegovina	723	794
Botswana	2517	1787
Brazil	87	68
Brunei Darussalam	717	717
Bulgaria	535	591
Cambodia	804	793
Cameroon	207	200

Region / Country / Economy	2010 Emission Rates ($g\ CO_2$ / kWh)	2011 Emission Rates ($g\ CO_2$ / kWh)
Chile	410	441
Chinese Taipei	624	601
Colombia	176	108
Congo	142	230
Costa Rica	56	64
Côte d'Ivoire	445	437
Croatia	236	334
Cuba	1012	955
Cyprus	697	732
Czech Republic	589	591
Dem. Rep. of Congo	3	3
Denmark	360	315
Dominican Republic	589	743
DPR of Korea	465	475
Ecuador	389	345
Egypt	450	457
El Salvador	223	243
Eritrea	646	849
Estonia	1014	1086
Ethiopia	7	7
Finland	229	191
France	79	61

Region / Country / Economy	2010 Emission Rates ($g\ CO_2$ / kWh)	2011 Emission Rates ($g\ CO_2$ / kWh)
FYR of Macedonia	685	811
Gabon	383	378
Georgia	69	102
Germany	461	477
Ghana	259	215
Gibraltar	762	752
Greece	718	720
Guatemala	286	286
Haiti	538	382
Honduras	332	371
Hong Kong, China	723	768
Hungary	317	317
Iceland	0	n/a
India	912	856
Indonesia	709	755
Iraq	1003	903
Ireland	458	427
Islamic Rep. of Iran	565	578
Israel	689	727
Italy	406	402
Jamaica	711	620
Japan	416	497

Region / Country / Economy	2010 Emission Rates ($g\ CO_2$ / kWh)	2011 Emission Rates ($g\ CO_2$ / kWh)
Jordan	566	637
Kazakhstan	403	431
Kenya	274	294
Korea	533	545
Kosovo	1287	1109
Kuwait	842	787
Kyrgyzstan	59	45
Latvia	120	133
Lebanon	709	707
Libya	885	636
Lithuania	337	270
Luxembourg	410	387
Malaysia	727	688
Malta	872	862
Mongolia	949	837
Montenegro	405	653
Morocco	718	729
Mozambique	1	1
Myanmar	262	255
Namibia	197	24
Nepal	1	1
Netherlands	415	404

Region / Country / Economy	2010 Emission Rates ($g\ CO_2$ / kWh)	2011 Emission Rates ($g\ CO_2$ / kWh)
Netherlands Antilles	707	708
New Zealand	150	141
Nicaragua	460	471
Nigeria	405	433
Norway	17	13
Oman	794	741
Pakistan	425	409
Panama	298	357
Paraguay	n/a	n/a
People's Rep. of China	766	764
Peru	289	297
Philippines	481	492
Poland	781	780
Portugal	255	303
Qatar	494	490
Republic of Moldova	517	486
Romania	413	499
Russian Federation	384	437
Saudi Arabia	737	754
Senegal	637	689
Serbia	718	784
Singapore	499	500

Region / Country / Economy	2010 Emission Rates ($g\ CO_2$ / kWh)	2011 Emission Rates ($g\ CO_2$ / kWh)
Slovak Republic	197	200
Slovenia	325	338
South Africa	927	869
Spain	238	291
Sri Lanka	379	469
Sudan	344	204
Sweden	30	17
Switzerland	27	30
Syrian Arab Republic	594	602
Tajikistan	14	12
Thailand	513	522
Togo	195	206
Trinidad and Tobago	700	506
Tunisia	463	455
Turkey	460	472
Turkmenistan	954	983
Ukraine	392	450
United Arab Emirates	598	600
United Kingdom	457	441
United Rep. of Tanzania	329	288
Uruguay	81	197
Uzbekistan	550	559

Region / Country / Economy	2010 Emission Rates ($g\ CO_2$ / kWh)	2011 Emission Rates ($g\ CO_2$ / kWh)
Venezuela	264	234
Vietnam	432	429
Yemen	655	633
Zambia	3	3
Zimbabwe	660	358

Source: 2010 emission rates from *CO_2 Emissions from Fuel Combustion Highlights* (2012) © OECD/IEA, 2012, CO_2 emissions per kWh from electricity and heat generation. 2011 emission rates from *CO_2 Emissions from Fuel Combustion Highlights* (2013) © OECD/IEA, 2013, CO_2 emissions per kWh from electricity and heat generation. Values were converted from tonnes/tWh to g/kWh using 1 tonne = 1,000,000 g and 1 tWh = 1,000,000,000 kWh. n/a=data not available.
Note: Emission rates more recent than 2011 are not publicly available, but are available for purchase from the International Energy Agency.

Table 3.5 Average Cost per Kilowatt Hour by U.S. State

State	2019 Average Retail Price Residential (¢/kWh)	2019 Average Retail Price Commercial (¢/kWh)	2019 Average Retail Price Industrial (¢/kWh)
AK Total	22.92	19.80	16.94
AL Total	12.53	11.52	5.95
AR Total	9.80	8.78	6.13
AZ Total	12.43	10.25	6.28
CA Total	19.15	16.67	13.40
CO Total	12.18	10.43	7.40
CT Total	21.87	16.75	13.44
DC Total	12.98	12.26	8.22
DE Total	12.55	9.53	7.70
FL Total	11.70	9.27	7.65
GA Total	11.76	10.02	6.17
HI Total	32.06	29.23	25.76
IA Total	12.46	9.99	6.60
ID Total	9.89	7.67	6.08
IL Total	13.03	9.08	6.52
IN Total	12.58	11.03	7.36
KS Total	12.71	10.29	7.35
KY Total	10.80	10.15	5.57
LA Total	9.80	8.91	5.23
MA Total	21.92	16.80	14.76

MD Total	13.12	9.97	7.80
ME Total	17.89	12.83	9.22
MI Total	15.74	11.39	7.07
MN Total	13.04	10.34	7.53
MO Total	11.14	9.07	7.11
MS Total	11.27	10.52	5.85
MT Total	11.13	10.41	5.45
NC Total	11.42	8.81	6.30
ND Total	10.30	9.01	7.94
NE Total	10.77	8.85	7.65
NH Total	20.05	15.93	13.09
NJ Total	15.85	12.23	10.16
NM Total	12.51	9.79	5.48
NV Total	12.00	8.04	6.14
NY Total	17.94	14.06	5.61
OH Total	12.38	9.72	6.55
OK Total	10.21	7.98	5.07
OR Total	11.01	8.85	5.86
PA Total	13.80	8.71	6.41
RI Total	21.73	16.38	15.59
SC Total	12.99	10.58	6.11
SD Total	11.55	9.59	7.81
TN Total	10.87	10.65	5.68
TX Total	11.76	8.06	5.45

UT Total	10.40	8.26	5.98
VA Total	12.07	8.18	6.85
VT Total	17.71	15.98	11.05
WA Total	9.71	8.75	4.80
WI Total	14.18	10.72	7.31
WV Total	11.25	9.16	6.02
WY Total	11.18	9.64	6.73

Source: Energy Information Administration: Electric Power Annual, Table 2.10: Average Price of Electricity to Ultimate Customers by End-Use Sector, by State, in cents per kilowatt-hour (October 2020).

Table 3.6 Canadian Energy Intensity by Building Activity

Principal Building Activity	GJ / m^2	Electricity / Natural gas split (%)
Office building (non-medical)	1.13	58/42
Medical office building	1.28	49/51
Elementary or secondary school	0.88	37/63
Assisted daily or residential care	1.3	45/55
Warehouse	0.82	40/60
Hotel, motel, or lodge	1.24	43/57
Hospital	2.45	32/68
Food or beverage store	1.87	70/30
Non-food retail store	1.12	46/54
Other activity or function*	1.19	43/57

Source: Statistics Canada, Survey of Commercial and Institutional Energy Use, 2014 (September 2016), Tables 2 and 7. Energy intensity values in Canada include both electricity (49%) and natural gas (51%) consumption (a small subset of other fuel types is included in the natural gas portion). Members should apportion their consumption totals between activities accordingly.

Table 3.7 U.S. Electricity and Natural Gas Intensity by Building Activity

Principal Building Activity Annual Intensy	Electricity Intensity (kWh / ft^2)	Natural Gas Intensity (ft^3 NG/ft^2)
Education	11.0	29.8
Food Sales	48.7	61.3
Food Service	44.9	159.2
Health Care	25.8	78.5
Inpatient	31.0	101.1
Outpatient	18.7	38.0
Lodging	15.3	43.8
Mercantile	18.3	33.5
Retail (other than mall)	15.2	21.5
Enclosed and strip malls	21.1	41.3
Office	15.9	26.8
Public Assembly	14.5	33.9
Public Order and Safety	14.9	39.5
Religious Worship	5.2	28.1
Service	8.3	42.7
Warehouse and Storage	6.6	19.4
Other	28.3	57.2
Vacant	4.5	13.9

Source: 2012 Commercial Buildings Energy Consumption Survey, Energy Information Administration (http://www.eia.doe.gov/emeu/cbecs), Tables E6 (Electricity) and E8 (Natural Gas).

Table 3.8 U.S. Utility-Specific CO_2 Emission Factors for Purchased Electricity

Utility	Factor Type	CO_2 Emission Factor lbs / MWh
2005		
Northern States Power Company (Xcel Energy)	System Average	1236.79
Public Service Company of Colorado (Xcel Energy)	System Average	1847.47
Southwestern Public Service Company (Xcel Energy)	System Average	1693.15
2006		
Northern States Power Company (Xcel Energy)	System Average	1225.77
Public Service Company of Colorado (Xcel Energy)	System Average	1834.24
Southwestern Public Service Company (Xcel Energy)	System Average	1615.99
2007		
Northern States Power Company (Xcel Energy)	System Average	1234.59
Public Service Company of Colorado (Xcel Energy)	System Average	1752.67
Southwestern Public Service Company (Xcel Energy)	System Average	1638.03
2009		
Bonneville Power Administration	System Average	93.17
Modesto Irrigation District	Retail Power	1036.17
	Special Power	0.00
	Wholesale Power	2048.09
Northern States Power Company (Xcel Energy)	System Average	1104.51
Public Service Company of Colorado (Xcel Energy)	System Average	1611.58
Southwestern Public Service Company (Xcel Energy)	System Average	1574.10
Pacific Gas & Electric	System Average	575.38
2010		
Bonneville Power Administration	System Average	134.70
City of Vernon, Light and Power	System Average	775.83
Modesto Irrigation District	Retail Power	942.99
	Special Power	0.00
	Wholesale Power	2026.12
Newmont Nevada Energy Investment	Wholesale Power	2055.79
Northern States Power Company (Xcel Energy)	System Average	1033.97
Public Service Company of Colorado (Xcel Energy)	System Average	1660.08
Southwestern Public Service Company (Xcel Energy)	System Average	1558.67
Sacramento Municipal Utility District	Retail Power	526.47
	Special Power	0.00
	Wholesale Power	828.58

Seattle City Light	Retail Power	45.57
	Special Power	0.00
	Wholesale Power	537.64
Pacific Gas & Electric	System Average	444.64
2011		
Bonneville Power Administration	System Average	47.86
City of Vernon, Light and Power	System Average	731.49
Northern States Power Company (Xcel Energy)	System Average	1071.45
Public Service Company of Colorado (Xcel Energy)	System Average	1618.19
Southwestern Public Service Company (Xcel Energy)	System Average	1472.69
Pacific Gas & Electric	System Average	392.87
Sacramento Municipal Utility District	Retail Power	429.29
	Special Power	0.00
	Wholesale Power	795.14
Seattle City Light	Retail Power	13.77
	Special Power	0.00
	Wholesale Power	218.75
2012		
Bonneville Power Administration	System Average	36.91
City of Vernon, Light and Power	System Average	765.97
Metropolitan Water District of Southern California	Wholesale Power	658.73
	Self-consumed Power	157.87
Northern States Power Company (Xcel Energy)	System Average	930.35
Public Service Company of Colorado (Xcel Energy)	System Average	1547.64
Southwestern Public Service Company (Xcel Energy)	System Average	1558.67
Pacific Gas & Electric	System Average	444.62
Sacramento Municipal Utility District	Retail Power	521.73
	Special Power	0.00
	Wholesale Power	799.77
Seattle City Light	Retail Power	25.62
	Special Power	0.00
	Wholesale Power	362.85
2013		
Bonneville Power Administration	System Average	43.65
City of Palo Alto	System Average	0.00
City of Vernon, Light and Power	System Average	760.86
Metropolitan Water District of Southern California	Wholesale Power	610.82
	Self-consumed Power	239.10

Northern States Power Company (Xcel Energy)	System Average	950.19
Public Service Company of Colorado (Xcel Energy)	System Average	1371.27
Southwestern Public Service Company (Xcel Energy)	System Average	1512.37
Pacific Gas & Electric (Corrected)	System Average	427.27
Sacrameto Municipal Utility District	Retail Power	559.86
	Special Power	0.00
	Wholesale Power	816.02
Seattle City Light	Retail Power	33.23
	Special Power	0.00
	Wholesale Power	491.61
2014		
Bonneville Power Administration	System Average	36.82
City of Palo Alto	System Average	0.00
Metropolitan Water District of Southern California	Wholesale Power	610.82
	Self-consumed Power	458.55
Northern States Power Company (Xcel Energy)	System Average	961.21
Public Service Company of Colorado (Xcel Energy)	System Average	1472.69
Southwestern Public Service Company (Xcel Energy)	System Average	1485.91
Pacific Gas & Electric	System Average	434.92
Sacrameto Municipal Utility District	Retail Power	561.08
	Special Power	0.00
	Wholesale Power	803.58
Seattle City Light	Retail Power	20.08
	Special Power	0.00
	Wholesale Power	376.25
Sonoma Clean Power	Special Power - EverGreen	51.00
	Retail Power - CleanStart	224.38
2015		
Bonneville Power Administration	System Average	36.44
City of Palo Alto	System Average	0.00
Imperial Irrigation District	System Average	1037.52
Metropolitan Water District of Southern California	Wholesale Power	650.32
	Self-consumed Power	358.60
Northern States Power Company (Xcel Energy)	System Average	877.44
Public Service Company of Colorado (Xcel Energy)	System Average	1468.28
Southwestern Public Service Company (Xcel Energy)	System Average	1375.68
Pacific Gas & Electric	System Average	404.51
Sacrameto Municipal Utility District	Retail Power	590.84
	Special Power	0.00

	Wholesale Power	667.34
Seattle City Light	Retail Power	52.44
	Special Power	0.00
	Wholesale Power	319.31
Sonoma Clean Power	Special Power - EverGreen	57.00
	Retail Power - CleanStart	217.57
University of California, Office of the President	System Average	719.06
2016		
Metropolitan Water District of Southern California	Wholesale Power	568.65
	Self-consumed Power	239.56
Northern States Power Company (Xcel Energy)	System Average	817.91
Public Service Company of Colorado (Xcel Energy)	System Average	1342.61
Southwestern Public Service Company (Xcel Energy)	System Average	1287.50
Pacific Gas & Electric	System Average	293.67
Sonoma Clean Power	Special Power - EverGreen	57.00
	Retail Power - CleanStart	97.76
Bonneville Power Administration	System Average	35.76
Seattle City Light	Retail Power	31.12
	Special Power	0.00
	Wholesale Power	216.67
Sacramento Municipal Utility District	Retail Power	492.95
	Special Power	0.00
	Wholesale Power	852.75
University of California, Office of the President	System Average	493.61
CleanPowerSF	Special Power - Green	186.74
	Special Power - SuperGreen	0.00
Hetch Hetchy	Wholesale Power	0.12
	Retail Power	0.00
2017		
Metropolitan Water District of Southern California	Wholesale Power	526.90
	Self-consumed Power	293.21
Sonoma Clean Power	Special Power - EverGreen	53.00
	Retail Power - CleanStart	127.98
University of California, Office of the President	System Average	208.50
Pacific Gas & Electric	System Average	210.44
Sacramento Municipal Utility District	Retail Power	383.60
	Special Power	0.00
	Wholesale Power	645.95
	Retail Power	46.37

Seattle City Light	Special Power	0.00
	Wholesale Power	106.12
Northern States Power Company (Xcel Energy)	System Average	822.32
Public Service Company of Colorado (Xcel Energy)	System Average	1302.93
Southwestern Public Service Company (Xcel Energy)	System Average	1239.00
CleanPowerSF	Special Power - Green	0.00
	Special Power - SuperGreen	0.00
Hetch Hetchy	Wholesale Power	0.12
	Retail Power	0.00
Bonneville Power Administration	System Average	27.21
2018		
East Bay Community Energy	Special Power - Renewable 100	0.00
	Special Power - Brilliant 100	0.00
	Special Power - Bright Choice	100.75
Northern States Power Company	Wholesale Power	806.89
	Special Power- Wind Source	0.00
	Special Power- Renewable Connect	0.00
	Retail Power	820.12
Public Service Company of Colorado	Wholesale Power	1210.34
	Special Power	0.00
	Retail Power	1307.34
Southwestern Public Service Company	Wholesale Power	1170.65
	Special Power	0.00
	Retail Power	1170.65
Sonoma Clean Power	Special Power - EverGreen	46.02
	Retail Power - CleanStart	98.81
University of California, Office of the President	System Average	138.17
Sacramento Municipal Utility District	Retail Power	465.17
	Special Power	0.00
	Wholesale Power	590.84
Seattle City Light	Wholesale Power	192.46
	Special Power	0.00
	Retail Power	32.05
CleanPowerSF	Special Power- Green	110.38
	Special Power- SuperGreen	0.00
Clean Power Alliance	Special Power- 100% Green Power	0.00
	Special Power- 65% Renewable Power	6.01
	Special Power- Clean Power	1.64

	Special Power- Lean Power	10.59
Pacific Gas & Electric	System Average	206.29
2019		
Pacific Gas & Electric	System Average	2.68
Clean Power Alliance	Special Power- 100% Green Power	0.00
	Special Power- Clean Power	359.28
	Special Power- Lean Power	594.97
East Bay Community Energy	Special Power- Brilliant 100	0.00
	Special Power- Bright Choice	135.10
University of California, Office of the President	System Average	0.00
Bonneville Power Administration	System Average	34.42
Sonoma Clean Power	Special Power- EverGreen	40.90
	Retail Power- CleanStart	39.51

Source: These emission factors have been reported by TCR members using the Electric Power Sector (EPS) Protocol and the option to develop utility-specific electricity delivery metrics. TCR members who are customers of these utilities can use these verified emission factors when quantifying market-based Scope 2 emissions. Utility-specific emission factors have been converted from tonnes/MWh to lbs/MWh in order to streamline reporting in CRIS.

Note: The emission factors in this table are updated once per year based on the verified emission factors available at the time of publication. More recent utility-specific emission factors may be available on TCR's website: https://www.theclimateregistry.org/our-members/cris-public-reports/.

Table 3.9 U.S. Green-e® Residual Mix Emissions Rates by eGRID Subregion

eGRID 2018 Subregion	eGRID 2018 Subregion Name	2018 Emission Rates		
		(lbs CO_2 / MWh)	(lbs CH_4 / GWh)	(lbs N_2O / GWh)
AKGD	ASCC Alaska Grid	1049.44	82.77	11.10
AKMS	ASCC Miscellaneous	525.08	24.00	4.00
AZNM	WECC Southwest	1023.92	77.12	11.02
CAMX	WECC California	498.00	34.10	4.01
ERCT	ERCOT All	984.90	69.77	9.51
FRCC	FRCC All	936.82	66.35	9.05
HIMS	HICC Miscellaneous	1110.69	118.00	18.00
HIOA	HICC Oahu	1669.94	180.00	27.00
MROE	MRO East	1678.53	169.05	25.01
MROW	MRO West	1290.18	143.60	20.81
NEWE	NPCC New England	522.34	82.00	11.00
NWPP	WECC Northwest	650.03	65.10	9.15
NYCW	NPCC NYC/Westchester	596.41	22.00	3.00
NYLI	NPCC Long Island	1184.24	139.00	18.00
NYUP	NPCC Upstate NY	253.15	18.00	2.00
RFCE	RFC East	716.22	61.02	8.00
RFCM	RFC Michigan	1313.32	129.07	18.01
RFCW	RFC West	1166.59	117.05	17.01
RMPA	WECC Rockies	1284.13	124.02	18.15
SPNO	SPP North	1241.98	132.40	19.22
SPSO	SPP South	1318.00	102.81	14.69

SRMV	SERC Mississippi Valley	855.88	55.08	8.01
SRMW	SERC Midwest	1680.73	186.84	27.27
SRSO	SERC South	1032.97	81.40	12.06
SRTV	SERC Tennessee Valley	1031.92	97.04	14.01
SRVC	SERC Virginia/Carolina	745.19	67.17	9.02

Source: 2020 Green-e® Residual Mix Emissions Rates (2018 Data). CH_4 and N_2O are from U.S. EPA Year 2018 eGRID 13th edition (March 2020: eGRID subregion annual total output emission rates).

Table 4.1 Default Factors for Calculating Emissions from Refrigeration/Air Conditioning Equipment

Type of Equipment	Refrigerant Capacity (kg)	Installation Emission Factor k (% of capacity)	Operating Emission Factor w (% of capacity/year)	Refrigerant Remaining at Disposal y (% of capacity)	Recovery Efficiency z (% of remaining)
Domestic Refrigeration	0.05 - 0.5	1%	0.50%	80%	70%
Stand-alone Commercial Applications	0.2 - 6	3%	15%	80%	70%
Medium & Large Commercial Refrigeration	50 - 2,000	3%	35%	100%	70%
Transport Refrigeration	3 - 8	1%	50%	50%	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%
Mobile Air Conditioning - Maritime	5.0 - 6,500	0.50%	40%	50%	50%
Mobile Air Conditioning - Railway	10 - 30	0.50%	20%	50%	50%
Mobile Air Conditioning - Buses	4 - 18	0.50%	20%	50%	50%
Mobile Air Conditioning - Other Mobile	0.5 - 2	0.50%	20%	50%	50%

Source: IPCC, 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (2019), 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).

Table 4.2 Default Composition of Refrigerant Blends that Contain HFCs and PFCs

Blend	Constituents	Composition (%)
R-405A	HCFC-22/HFC-152a/HCFC-142b/PFC-318	(45.0/7.0/5.5/42.5)
R-413A	PFC-218/HFC-134a/HC-600a	(9.0/88.0/3.0)
R-508A	HFC-23/PFC-116	(39.0/61.0)
R-508B	HFC-23/PFC-116	(46.0/54.0)
Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 3, Table 7.8, page 7.44.		

Table 4.3 U.S. Default Factors for Calculating CO_2 Emissions from Geothermal Energy Production

Fuel Type	Carbon Content (Per Unit Energy)	CO_2 Emission Factor (Per Unit Energy)
Geothermal	**kg C / MMBtu**	**kg CO_2 / MMBtu**
Flash Steam	2.18	7.99
Dry Steam	3.22	11.81
Binary	0.00	0.00
Binary/Flash Steam	0.00	0.00
Source: US Inventory of Greenhouse Gas Emissions and Sinks 1990-2018 (April 2020) Annex 2, Table A-41.		

Table 5.1 Global Warming Potential Factors for Required Greenhouse Gases

Common Name	Formula	Chemical Name	SAR	TAR	AR4	AR5
Carbon dioxide	CO_2		1	1	1	1
Methane	CH_4		21	23	25	28
Nitrous oxide	N_2O		310	296	298	265
Nitrogen trifluoride	NF_3		n/a	10,800	17,200	16,100
Sulfur hexafluoride	SF_6		23,900	22,200	22,800	23,500
Hydrofluorocarbons (HFCs)						
HFC-23 (R-23)	CHF_3	trifluoromethane	11,700	12,000	14,800	12,400
HFC-32 (R-32)	CH_2F_2	difluoromethane	650	550	675	677
HFC-41 (R-41)	CH_3F	fluoromethane	150	97	92	116
HFC-125 (R-125)	C_2HF_5	pentafluoroethane	2,800	3,400	3,500	3,170
HFC-134 (R-134)	$C_2H_2F_4$	1,1,2,2-tetrafluoroethane	1,000	1,100	1,100	1,120
HFC-134a (R-134a)	$C_2H_2F_4$	1,1,1,2-tetrafluoroethane	1,300	1,300	1,430	1,300
HFC-143 (R-143)	$C_2H_3F_3$	1,1,2-trifluoroethane	300	330	353	328
HFC-143a (R-143a)	$C_2H_3F_3$	1,1,1-trifluoroethane	3,800	4,300	4,470	4,800
HFC-152 (R-152)	$C_2H_4F_2$	1,2-difluoroethane	n/a	43	53	16
HFC-152a (R-152a)	$C_2H_4F_2$	1,1-difluoroethane	140	120	124	138
HFC-161 (R-161)	C_2H_5F	fluoroethane	n/a	12	12	4
HFC-227ea (R-227ea)	C_3HF_7	1,1,1,2,3,3,3-heptafluoropropane	2,900	3,500	3,220	3,350
HFC-236cb (R-236cb)	$C_3H_2F_6$	1,1,1,2,2,3-hexafluoropropane	n/a	1,300	1,340	1,210

HFC-236ea (R-236ea)	$C_3H_2F_6$	1,1,1,2,3,3-hexafluoropropane	n/a	1,200	1,370	1,330
HFC-236fa (R-236fa)	$C_3H_2F_6$	1,1,1,3,3,3-hexafluoropropane	6,300	9,400	9,810	8,060
HFC-245ca (R-245ca)	$C_3H_3F_5$	1,1,2,2,3-pentafluoropropane	560	640	693	716
HFC-245fa (R-245fa)	$C_3H_3F_5$	1,1,1,3,3-pentafluoropropane	n/a	950	1,030	858
HFC-365mfc	$C_4H_5F_5$	1,1,1,3,3-pentafluorobutane	n/a	890	794	804
HFC-43-10mee (R- 4310)	$C_5H_2F_{10}$	1,1,1,2,3,4,4,5,5,5-decafluoropentane	1,300	1,500	1,640	1,650
Perfluorocarbons (PFCs)						
PFC-14 (Perfluoromethane)	CF_4	tetrafluoromethane	6,500	5,700	7,390	6,630
PFC-116 (Perfluoroethane)	C_2F_6	hexafluoroethane	9,200	11,900	12,200	11,100
PFC-218 (Perfluoropropane)	C_3F_8	octafluoropropane	7,000	8,600	8,830	8,900
PFC-318 (Perfluorocyclobutane)	c-C_4F_8	octafluorocyclobutane	8,700	10,000	10,300	9,540
PFC-3-1-10 (Perfluorobutane)	C_4F_{10}	decafluorobutane	7,000	8,600	8,860	9,200
PFC-4-1-12 (Perfluoropentane)	C_5F_{12}	dodecafluoropentane	n/a	8,900	9,160	8,550
PFC-5-1-14 (Perfluorohexane)	C_6F_{14}	tetradecafluorohexane	7,400	9,000	9,300	7,910
PFC-9-1-18 (Perfluorodecalin)	$C_{10}F_{18}$		n/a	n/a	>7,500	7,190

Source: Intergovernmental Panel on Climate Change (IPCC) Second Assessment Report (SAR) published in 1995, Third Assessment Report (TAR) published in 2001, Fourth Assessment Report (AR4) published in 2007, and Fifth Assessment Report published in 2013. All defaults 100-year GWP values. For any defaults provided as a range, use exact value provided for the purpose of reporting to TCR. n/a=data not available.

Note: Complete reporters must include emissions of all Kyoto-defined GHGs (including all HFCs and PFCs) in inventory reports. If HFCs or PFCs are emitted that are not listed above, complete reporters must use industry best practices to calculate CO_2e from those gases.

Table 5.2 Global Warming Potentials of Refrigerant Blends

Refrigerant Blend	Gas	SAR	TAR	AR4	AR5
R-401A	HFC	18.2	15.6	16.12	17.94
R-401B	HFC	15	13	14	15
R-401C	HFC	21	18	18.6	20.7
R-402A	HFC	1680	2040	2100	1902
R-402B	HFC	1064	1292	1330	1205
R-403A	PFC	1400	1720	1766	1780
R-403B	PFC	2730	3354	3444	3471
R-404A	HFC	3260	3784	3922	3943
R-407A	HFC	1770	1990	2107	1923
R-407B	HFC	2285	2695	2804	2547
R-407C	HFC	1526	1653	1774	1624
R-407D	HFC	1428	1503	1627	1487
R-407E	HFC	1363	1428	1552	1425
R-407F	HFC	1555	1705	1825	1674
R-407G	HFC	1321	1334	1463	1331
R-407H	HFC	1314	1371	1495	1378
R-407I	HFC	1301	1332	1459	1337
R-408A	HFC	1944	2216	2301	2430
R-410A	HFC	1725	1975	2088	1924
R-410B	HFC	1833	2118	2229	2048
R-411A	HFC	15	13	14	15

R-411B	HFC	4.2	3.6	3.72	4.14
R-412A	PFC	350	430	442	445
R-415A	HFC	25.2	21.6	22.32	24.84
R-415B	HFC	105	90	93	104
R-416A	HFC	767	767	843.7	767
R-417A	HFC	1955	2234	2346	2127
R-417B	HFC	2450	2924	3027	2742
R-417C	HFC	1570	1687	1809	1643
R-418A	HFC	3.5	3	3.1	3.45
R-419A	HFC	2403	2865	2967	2688
R-419B	HFC	1982	2273	2384	2161
R-420A	HFC	1144	1144	1258	1144
R-421A	HFC	2170	2518	2631	2385
R-421B	HFC	2575	3085	3190	2890
R-422A	HFC	2532	3043	3143	2847
R-422B	HFC	2086	2416	2526	2290
R-422C	HFC	2491	2983	3085	2794
R-422D	HFC	2232	2623	2729	2473
R-422E	HFC	2135	2483	2592	2350
R-423A	HFC	2060	2345	2280	2274
R-424A	HFC	2025	2328	2440	2212
R-425A	HFC	1372	1425	1505	1431
R-426A	HFC	1352	1382	1508	1371
R-427A	HFC	1828	2013	2138	2024

R-428A	HFC	2930	3495	3607	3417
R-429A	HFC	14	12	12	14
R-430A	HFC	106.4	91.2	94.24	104.88
R-431A	HFC	41	35	36	40
R-434A	HFC	2662	3131	3245	3075
R-435A	HFC	28	24	25	28
R-437A	HFC	1567	1684	1805	1639
R-438A	HFC	1890	2151	2264	2059
R-439A	HFC	1641	1873	1983	1828
R-440A	HFC	158	139	144	156
R-442A	HFC	1609	1793	1888	1754
R-444A	HFC	85	72	87	88
R-444B	HFC	284	240	293	295
R-445A	HFC	117	117	128.7	117
R-446A	HFC	442	374	459	460
R-447A	HFC	540	493	582	571
R-447B	HFC	666	646	739	714
R-448A	HFC	1170	1300	1386	1273
R-449A	HFC	1184	1308	1396	1282
R-449B	HFC	1199	1320	1411	1296
R-449C	HFC	1067	1167	1250	1146
R-450A	HFC	546	546	600.6	546
R-451A	HFC	132.6	132.6	145.86	132.6
R-451B	HFC	145.6	145.6	160.16	145.6

R-452A	HFC	1724	2067	2139	1945
R-452B	HFC	632	607	697	675
R-452C	HFC	1789	2143	2219	2018
R-453A	HFC	1534	1664	1765	1636
R-454A	HFC	228	193	236	237
R-454B	HFC	448	379	465	466
R-454C	HFC	140	118	145	146
R-456A	HFC	624	618	684	626
R-457A	HFC	131	113	136	138
R-458A	HFC	1457	1576	1650	1564
R-460C	HFC	684	697	762	694
R-461A	HFC	2291	2676	2767	2567
R-462A	HFC	1883	2136	2249	2060
R-463A	HFC	1256	1400	1493	1377
R-464A	HFC	1106	1277	1321	1240
R-465A	HFC	137	116	142	142
R-500	HFC	37	31	32	36
R-503	HFC	4692	4812	5935	4972
R-504	HFC	313	265	325	326
R-507 or R-507A	HFC	3300	3850	3985	3985
R-509 or R-509A	PFC	3920	4816	4945	4984
R-512A	HFC	198	179	189.3	196.1
R-513A	HFC	572	572	629.2	572
R-513B	HFC	540	539.5	593	539.5

R-515A	HFC	348	420	386	402
R-516A	HFC	130	127	139	130
Source: Refrigerant blend GWPs are calculated using a weighted average from the blend composition and the IPCC GWP values. The blend compositions are from ASHRAE Standard 34-2019. The GWP values are 100- year values from the Intergovernmental Panel on Climate Change (IPCC) Second Assessment Report (SAR) published in 1995, Third Assessment Report (TAR) published in 2001, Fourth Assessment Report (AR4) published in 2007, and Fifth Assessment Report (AR5) published in 2013.					

Conversion Factors

Mass			
1 pound (lb) =	453.6 grams (g)	0.4536 kilograms (kg)	0.0004536 metric tons
1 kilogram (kg) =	1,000 grams (g)	2.2046 pounds (lb)	0.001 metric tons
1 short ton (ton) =	2,000 pounds (lb)	907.18 kilograms (kg)	0.9072 metric tons
1 metric ton =	2,204.62 pounds (lb)	1,000 kilograms (kg)	1.1023 short tons
Volume			
1 cubic foot (ft^3) =	7.4805 U.S. gallons (gal)	0.1781 barrels (bbl)	
1 cubic foot (ft^3) =	28.32 liters (L)	0.02832 cubic meters (m^3)	
1 U.S. gallon (gal) =	0.0238 barrels (bbl)	3.785 liters (L)	0.003785 cubic meters (m^3)
1 barrel (bbl) =	42 U.S. gallons (gal)	158.99 liters (L)	0.1589 cubic meters (m^3)
1 liter (L) =	0.001 cubic meters (m^3)	0.2642 U.S. gallons (gal)	0.0063 barrels (bbl)
1 cubic meter (m^3) =	6.2897 barrels (bbl)	264.17 U.S. 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		

APPENDIX B
The Climate Registry General Reporting Protocol, Version 3.0

The Climate Registry

GENERAL REPORTING PROTOCOL

VERSION 3.0

MAY 2019

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TABLE OF CONTENTS

A. INTRODUCTION

ABOUT THE CLIMATE REGISTRY

The Climate Registry (TCR) designs and operates voluntary and compliance greenhouse gas (GHG) reporting programs globally, and assists organizations in measuring, reporting, and verifying (MRV) the carbon in their operations in order to manage and reduce it. TCR also consults with governments nationally and internationally on all aspects of GHG measurement, reporting, and verification.

TCR's Carbon Footprint Registry is aligned with international standards and provides a nexus between business, government, and non-governmental organizations to share policy information and exchange best practices.

For more information, please visit: www.theclimateregistry.org.

About This Document

The Climate Registry's General Reporting Protocol (GRP) Version 3.0 outlines GHG accounting policies and calculation methods for reporting an organizational carbon footprint, or GHG inventory. The GRP was developed through a comprehensive public stakeholder process that included over 1,275 individual comments from 124 respondents representing industry, environmental non-governmental organizations, regulatory agencies, and consulting firms.

TCR's GRP embodies GHG accounting best practices drawn from the following existing GHG standards and guidance:

- The World Resources Institute and the World Business Council for Sustainable Development (WRI/WBCSD) GHG Protocol Corporate Accounting and Reporting Standard (Revised Edition);
  - The GHG Protocol Scope 2 Guidance: An amendment to the GHG Protocol Corporate Standard; and,
  - The GHG Protocol Corporate Value Chain (Scope 3) Accounting and Reporting Standard: Supplement to the GHG Protocol Corporate Accounting and Reporting Standard.
- International Organization for Standardization (ISO) 14064-1:2018, Greenhouse Gases – Part 1: Specification with guidance at the organization level for quantification and reporting of greenhouse gas emissions and removals; and,
- U.S. Environmental Protection Agency Center for Corporate Climate Leadership Greenhouse Gas Inventory Guidance.

GHG Accounting and Reporting Principles

The GRP adheres to five overarching accounting and reporting principles that are intended to help ensure that GHG data represent a faithful, true, and fair account of an organization's GHG emissions. These principles are the basis for the requirements and guidance in the GRP.

- **Relevance:** Ensure that the GHG inventory appropriately reflects an organization's GHG emissions and serves the decision-making needs of users—both internal and external to the organization.
- **Completeness:** Account for and report all relevant GHG emissions and activities within the defined inventory boundary.
- **Consistency:** Use consistent methods to allow for meaningful comparisons of emissions over time. Clearly document any changes to the data, inventory boundary, methods, or any other relevant factors.
- **Transparency:** Address all relevant issues in a factual and coherent manner, based on a clear audit trail. Disclose any relevant assumptions and make appropriate references to the quantification methods and data sources used to allow intended users to make decisions with reasonable confidence.
- **Accuracy:** Ensure that the quantification of GHG emissions is neither systematically overstating nor understating true emissions, and that uncertainties are reduced as much as practicable. Achieve sufficient accuracy to enable users of the data to make decisions with reasonable assurance of the integrity of the reported information.

GRP Structure

The GRP is presented as a series of individual topic-specific modules, which may be viewed separately or downloaded together as a combined document. The GRP modules provide the key reporting requirements for TCR's Carbon Footprint Registry and are designed to be used as a set.

The GRP is comprised of the following modules, which mirror the chronology of the reporting process:

MODULE	DESCRIPTION
A. Introduction (this module)	» Provides an overview of the GRP.
B. Inventory Boundaries	» Outlines the GHGs and types of GHG sources that may be included in the inventory, provides requirements for defining organizational and reporting boundaries, and describes various levels of granularity at which emissions data may be publicly reported.
C. GHG Emissions Quantification Methods	» Provides methods for quantifying emissions for the following source categories: » Direct emissions from stationary combustion; » Direct emissions from mobile combustion; » Indirect emissions from non-electric energy use; and, » Direct fugitive emissions.
D. Advanced Methods	» Provides advanced methods for quantifying emissions. References to advanced methods are available throughout the GHG Emissions Quantification Methods Module.
E. Reporting an Inventory	» Provides additional required and optional information to include alongside GHG emissions quantification to complete and report a GHG inventory.

All GRP modules are available to download at www.theclimateregistry.org.

Additional sector-specific protocols and metrics are available for certain sectors at www.theclimateregistry.org and contain additional methods and requirements to the GRP. Supplemental guidance documents will provide further examples, background material, or tips for reporting. Members should report emissions to the Carbon Footprint Registry following a step-wise reporting process, starting with the GRP, progressing to sector-specific protocols and metrics if relevant, and referring to guidance documents as needed.

Updates to the GRP

TCR may update this document in the future to reflect changes in international best practices and to provide additional clarity and guidance.

Updates to the GRP will be incorporated into the relevant GRP module(s) as needed. TCR will inform stakeholders of changes to the GRP in a timely manner, and will provide explicit direction for when new reporting and verification policies or procedures will be required.

B. INVENTORY BOUNDARIES

DEFINING OPERATIONS

The greenhouse gas (GHG) emitting activities within an inventory are based on the intersection of the selected organizational boundary and reporting boundary as defined below. While an organizational boundary encompasses all of an organization's business activities, organizations may define their own reporting boundary to include all activities (matching the organizational boundary), or a subset of activities.

Organizational Boundaries

Businesses, government agencies and non-profits can utilize a range of organizational structures to define the degree of ownership or control they exert over different activities. Some examples of these structures include wholly owned operations, divisions, subsidiaries and joint ventures. When added together, the activities within these structures define the organizational boundary.

GHG emissions inventories can be constructed to reflect three different views of an organizational boundary: operational control, financial control, or equity share.

Operational Control: Reflects the activities where the organization or its subsidiaries has the full authority to introduce and implement operating policies. The organization that holds the operating license for an activity typically has operational control.

Financial Control: Reflects activities where the organization has the ability to direct the financial policies of the activity with an interest in gaining economic benefits from the activity. An organization has financial control over an activity if the activity is fully consolidated in the organization's financial accounts.

Equity Share: Reflects activities that are wholly owned and partially owned according to the organization's equity share in each.

Organizations must apply the same organizational boundary approach consistently to all activities. If an organization wholly owns and controls all of its activities, its organizational boundary will be the same using each approach.

Organizations with more complex owner or operator structures should take into account their individual situation and select an approach that best reflects the actual level of control and the standard practice within the industry. Organizations may also elect to compile separate inventory reports reflecting different approaches.

Operational Control

Operational control is the authority to develop and carry out the operating or health, safety and environmental (HSE) policies of an activity. One or more of the following conditions establishes operational control:

» Wholly owning and controlling an activity, operation, facility, or source; or,

» Having the full authority to introduce and implement operational and HSE (including both GHG- and non-GHG related policies). The authority to introduce and implement operational and HSE policies is often explicitly conveyed in the contractual or legal structure of the partnership or joint venture. In most cases, holding an operating license is an indication of the organization's authority to implement operational and HSE policies. If an organization holds an operating license and believes it does not have operational control, it must explicitly demonstrate that the organization's authority to introduce operational and HSE policies is significantly limited or vested with a separate entity.

It should be noted that an organization need not control all aspects of an activity to have operational control. For instance, an organization with operational control may not have the authority to make decisions on major capital investments without the approval of other parties in a joint venture.

Financial Control

Financial control is the ability to dictate or direct the financial policies of an activity with the ability to gain the economic rewards from the activity. One or more of the following conditions establishes financial control:

» Wholly owning an activity, operation, facility, or source;

» Considering an activity to be, for the purposes of financial accounting, a group company or subsidiary, and consolidating its financial accounts in an organization's financial statements;

» Governing the financial policies of a joint venture under a statute, agreement or contract; or,

» Retaining the rights to the majority of the economic benefits and/or financial risks from an activity or facility that is part of a joint venture or partnership (incorporated or unincorporated), however these rights are conveyed.[1]

Equity Share

Under the equity share approach, an organization accounts for GHG emissions from activities according to its share of equity in each activity.[2]

The equity share reflects economic interest, which is the extent of rights an organization has to the risks and rewards flowing from an activity. Typically, the share of economic risks and rewards in an activity is aligned with the organization's ownership percentage of that activity, and equity share will normally be the same as the ownership percentage. Where this is not the case, the economic substance of the relationship the organization has with the activity always overrides the legal ownership form to ensure that equity share reflects the percentage of economic interest.

Reporting Boundaries

Organizations may define their own reporting boundary to include the GHG sources that are relevant to their operational and sustainability goals in accordance with the principles of GHG accounting. The reporting boundary may match the organizational boundary (i.e., all the emission sources within the organizational boundary are included), or may be a subset of the organizational boundary.

Organizations must publicly define and disclose their own inventory reporting boundary using the following parameters, which are described in the following sections:

» GHGs;

» GHG Sources;

» Reporting Period; and,

» Geography/business units.

1 These rights may be evident through the traditional conveyance of equity interest or working/participating interest or through nontraditional arrangements. The latter could include an 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.

2 Organizations need not include emissions from fixed asset investments, where the parent company has neither significant influence nor financial control.

RELEVANT GHG SOURCES

To fulfill the GHG accounting principle of completeness, the inventory must include all relevant direct and indirect emissions within the defined reporting boundary. For the purposes of reporting to The Climate Registry (TCR), all Scope 1 and Scope 2 emissions, combustion-based direct biogenic emissions, and combustion-based indirect biogenic emissions associated with the consumption of energy are relevant[3], and must be included within the reporting boundary for TCR to consider the inventory "complete."

However, all members reporting to TCR have the flexibility to define their reporting boundary to report specific GHG sources that they deem relevant to their individual business and sustainability goals. Thus, members may decide that some sources deemed relevant by TCR are not relevant for their organization, or that additional sources beyond TCR's criteria are relevant for their organization. Members reporting in conformance with TCR's program that exclude GHG sources that TCR has defined as relevant from the reporting boundary must identify the excluded sources and explain the reason for their exclusion.[4]

Members may also refer to TCR's guidance on conforming to ISO 14064-1: 2018 and the GHG Protocol if they are seeking to conform to these standards.

GEOGRAPHY

Organizations may use geography as a parameter in defining their reporting boundary. For example, organizations can choose to include specific countries, states, provinces or territories in their reporting boundary. Similarly, parameters can include specific business units or facilities. When organizations are defining their reporting boundary to include a subset of facilities in their operational boundary, they must disclose any facilities that are excluded from the reporting boundary. Members will make this disclosure in the *Self-Defined Boundary Form*.

GREENHOUSE GASES (GHGs)

Organizations may define their reporting boundary to include all internationally-recognized GHGs regulated under the Kyoto Protocol, or a subset of these gases. These are:

» Carbon dioxide (CO_2);

» Methane (CH_4);

» Nitrous oxide (N_2O);

» Hydrofluorocarbons (HFCs);

» Perfluorocarbons (PFCs);

» Sulfur hexafluoride (SF_6); and,

» Nitrogen trifluoride (NF_3).

Organizations must disclose whether they are excluding any of the gases above from the reporting boundary. Members will make this disclosure in the *Self-Defined Boundary Form*.

A complete list of the Kyoto GHGs, including individual HFCs and PFCs, is provided in Tables 5.1 and 5.2.[5]

Organizations must account for emissions of each gas separately, in metric tons of each gas.[6]

3 TCR does not consider the following emission sources relevant: approved miniscule sources, biogenic emissions other than those associated with the combustion of biomass, and emission sources identified as optional in the protocols.

4 TCR provides an explanation for the exclusion of miniscule sources included on the *Exclude Miniscule Sources Form*.

5 Emission factor tables are available at www.theclimateregistry.org.

6 Emissions totals of the HFC and PFC categories are reported in metric tons of carbon dioxide equivalents (CO_2e) of each respective category.

Reporting Emissions in Carbon Dioxide Equivalent (CO_2e)

In addition to reporting GHG emissions by gas, organizations must also report emissions from non-CO_2 gases in units of carbon dioxide equivalent (CO_2e). Converting emissions of non-CO_2 gases to units of CO_2e allows the ability of each GHG to trap heat in the atmosphere to be compared on a common basis.

Tables 5.1 and 5.2 include the Global Warming Potential (GWP) of each GHG, which is used to calculate the carbon dioxide equivalent of the individual gases.[7,8] GWP factors represent how much heat each GHG is able to trap in the atmosphere relative to the heat-trapping ability of CO_2.

GWP defaults are published by the Intergovernmental Panel on Climate Change (IPCC.) As part of its activities, the IPCC revisits and updates these defaults in periodic Assessment Reports. Organizations may use GWPs from the Assessment Report that is most relevant to their operations providing the following conditions are met:

1. All GWPs must be 100 year values;
2. Where possible within an inventory, all GWPs must come from a single Assessment Report. If a GWP for a particular gas is not provided in the chosen Assessment Report, organizations must select the more recent GWP for that gas; and,
3. The source of all GWP values must be disclosed publicly.[9]

It is best practice to use GWP values from the most recent Assessment Report.[10] However, when a base year has been set, it is best practice to use the same GWP values for the current inventory and the base year inventory.

GHG SOURCES

Direct and indirect emissions are categorized as follows: [11]

- **Scope 1:** Direct anthropogenic GHG emissions.
- **Scope 2:** Indirect anthropogenic GHG emissions associated with the consumption of purchased or acquired electricity, steam, heating, or cooling (collectively referred to as consumed energy).
- **Scope 3:** All other (non-Scope 2) indirect anthropogenic GHG emissions that occur in the value chain.[12]
- **Additional GHGs:** Biogenic GHG emissions are excluded from the scope categories and are reported separately. Non-Kyoto GHG emissions are also outside of the scopes.

Together these categories provide a comprehensive accounting framework for managing and reducing direct and indirect emissions.

Figure 1 below provides an overview of the relationship between the scopes and the activities that generate direct and indirect emissions along the value chain. An organization reports anthropogenic emissions within its organizational boundary directly in Scope 1, and anthropogenic emissions that result indirectly from its activities in Scope 2 and Scope 3.

7 Ibid.

8 Emission factor tables are available at www.theclimateregistry.org.

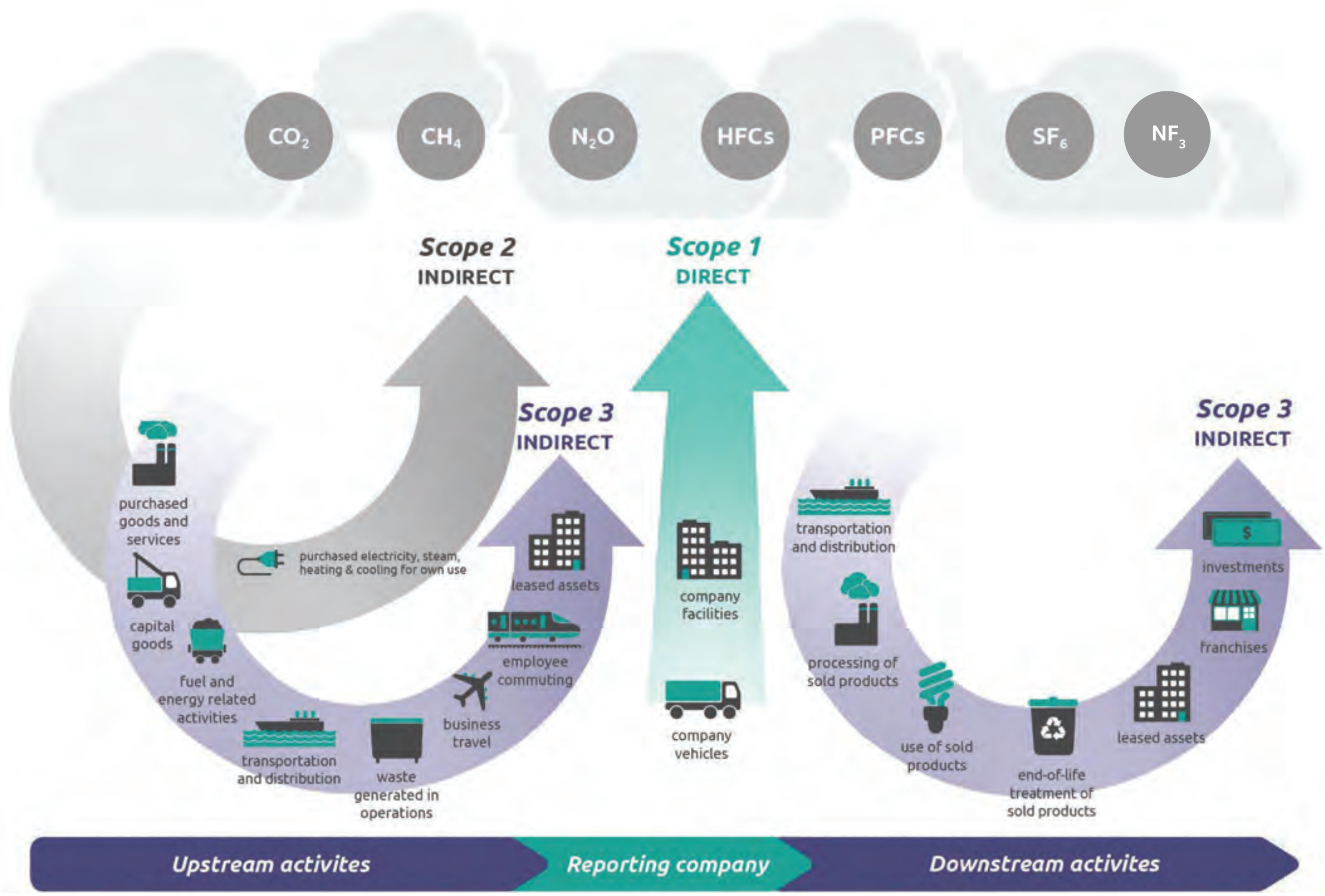
9 Organizations must also publicly disclose whether GWPs from multiple Assessment Reports have been used.

10 Organizations that select a GWP that is not from the most recent Assessment Report must justify their selection in order to conform with ISO 14064-1: 2018.

11 Scopes 1, 2, and 3 align with WRI/WBCSD's GHG Protocol Corporate Standard. ISO 14064-1: 2018 categorizes emissions into direct and indirect emissions.

12 Examples of Scope 3 emissions include emissions resulting from employee commuting and business travel, use of sold products and services, and waste disposal.

Figure 1: Overview of Scopes and Emissions throughout an Organization's Operations



Source: Adapted from WRI / WBCSD *GHG Protocol Corporate Value Chain (Scope 3) Accounting and Reporting Standard*.

Direct Emissions: Scope 1

Direct GHG emissions are emissions from sources within the organizational boundary.

Scope 1 emissions are all direct emissions resulting from the impact of human beings on nature. These generally result from the use of fossil fuels or other man-made chemicals and must be subdivided within the inventory into the four types of sources they result from:

» **Stationary combustion** of fuels in any stationary equipment including boilers, furnaces, burners, turbines, heaters, incinerators, engines, flares, etc.;

» **Mobile combustion** of fuels in transportation sources (e.g., cars, trucks, marine vessels and planes) and emissions from non-road equipment such as those in construction, agriculture and forestry;

» **Physical and chemical processes** other than fuel combustion (e.g., for the manufacturing of cement, aluminum, adipic acid, ammonia, etc.); and,

» **Fugitive sources,** i.e., intentional or unintentional releases from the production, processing, transmission, storage, and use of fuels and other substances, that do not pass through a stack, chimney, vent, exhaust pipe or other functionally-equivalent opening (such as releases of SF_6 from electrical equipment; HFC releases during the use of refrigeration and air conditioning equipment; and CH_4 leakage from natural gas transport or landfills).

Indirect Emissions: Scope 2

Indirect GHG emissions are a consequence of activities that take place within the organizational boundary of the reporting organization, but occur at sources owned or controlled by another organization. For example, emissions that occur at a natural gas power plant as a result of providing electricity to a local manufacturing company contribute to the manufacturer's indirect emissions. Scope 2 is a special category of indirect emissions and refers only to indirect anthropogenic emissions associated with consumed energy.

Scope 2 emissions are reported in two ways, using the location-based method and the market-based method.

- The **location-based method** reflects the GHG emissions from locally-generated energy delivered through the grid. It transparently demonstrates local conditions and the impacts of energy conservation.
- The **market-based method** reflects the GHG emissions associated with choices an organization makes about its energy supply or product. It allows organizations to claim the specific emission rate associated with their energy purchases, as well demonstrate the impacts of energy conservation.[13]

Indirect emissions reported by one organization may also be reported as direct emissions by another. For example, the company that owns and operates the power plant described above would report the emissions resulting from the generation of the electricity it provided to the manufacturing company as its own direct emissions. This dual reporting does not constitute double counting because the organizations report the emissions associated with the electricity production and its consumption in different scopes (Scope 1 for the power provider and Scope 2 for the manufacturing organization). The scope framework allows for a broader assessment of an organization's GHG emissions impact within an inventory, but emissions can only be aggregated meaningfully across organizations *within* a single scope.[14]

Indirect Emissions: Scope 3

Scope 3 is a broad category of indirect emissions that includes all anthropogenic indirect emissions other than emissions associated with consumed energy. Reporting Scope 3 emissions provides opportunities for identifying and reducing emissions across the value chain, and communicating innovation in GHG management. Members are encouraged to report Scope 3 emissions in accordance with the *GHG Protocol Corporate Value Chain (Scope 3) Accounting and Reporting Standard*. TCR provides guidance for calculating sources of Scope 3 emissions in many of our sector-specific resources.

Additional Gases

Emissions from Biomass

Biogenic CO_2 emissions are generated during the combustion or decomposition of biologically-based material. Organizations must track and report biogenic CO_2 emissions separately from other emissions because the carbon in biomass was recently contained in living organic matter. This sets it apart from the carbon in fossil fuels that has been trapped in geologic formations for millennia, the release of which can be attributed directly to human activities.[15]

Only combustion-based direct biogenic emissions and combustion-based indirect biogenic emissions associated with the consumption of energy are relevant for the purposes of reporting to TCR, and must be included within the reporting boundary for TCR to consider the inventory "complete." TCR does not include other biogenic emissions in its definition for relevance due to a lack of scientific consensus around the methods used to quantify these emissions.

The separate reporting of CO_2 emissions from biomass combustion applies only to CO_2 and not to CH_4 and N_2O, which are also emitted during biomass combustion. Unlike CO_2 emissions, the CH_4 and N_2O emitted from biomass combustion are not of a biogenic origin and are therefore classified as Scope 1 or Scope 2 emissions. When biomass is combined with fossil fuel combustion, the biomass-based CH_4 and N_2O emissions should be reported together with fossil-fuel based CH_4 and N_2O emissions.

Non-Kyoto GHGs

Non-Kyoto GHG emissions may be disclosed alongside the inventory, outside the scopes, as part of a separate public document.[16]

13 Refer to the GHG Emissions Quantification Module, Indirect Emissions from Electricity Use section for more information about using the location-based and market-based methods.

14 Reporting of direct and indirect biogenic emissions mirrors the scopes framework (e.g., emissions from the combustion of biogas to produce electricity would be reported as direct biogenic emissions for the power generator and indirect biogenic emissions for the power consumer).

15 Because of this difference, the *IPCC Guidelines for National Greenhouse Gas Inventories* requires that CO_2 emissions from biogenic sources be reported separately.

16 Organizations seeking to conform with the Greenhouse Gas Protocol Corporate Standard may report non-Kyoto GHGs outside of the inventory provided that the organization includes a list of these gases, and provided that 100-year Global Warming Potential (GWP) values for these GHGs have been defined in IPCC Assessment Reports.

REPORTING PERIOD

Organizations must disclose the period for which emissions are reported. Members must report emissions on an ***annual basis*** (i.e., calendar year or fiscal year).[17]

The year in which the emissions occurred is known as the reporting year (RY). For example, if an inventory is reported in 2019 for an organization's 2018 emissions, the reporting year is 2018.

Organizations must include emissions from the activities within their organizational boundary for the part of the year each activity is within its control. For most activities, this will be the total annual emissions from the operation.

MINISCULE SOURCES

Miniscule sources are very small sources of emissions in a member's inventory that represent a high reporting burden, such as hand-held fire extinguishers, refrigerant in office water coolers, or CO_2 from soda fountains. Miniscule sources should not:

» Compromise the relevance of the reported inventory;

» Significantly reduce the combined quantity of Scope 1, Scope 2,[18] and biogenic CO_2e emissions reported;

» Impact the ability to identify the member's viable opportunities for emissions reduction projects;

» Impact the ability to ascertain whether the member has achieved a reduction (of five percent or greater) in total entity emissions from one year to the next;

» Impact the ability to assess the member's climate change-related risk exposure; or,

» Impact the decision-making needs of users (i.e., is not expected to be deemed critical by key stakeholders).

Whenever possible, members are encouraged to report emissions from miniscule sources using TCR approved methods or Simplified Estimation Methods (SEMs). However, members may opt to exclude miniscule sources from their inventory by completing and publicly disclosing TCR's *Exclude Miniscule Sources Form* for each reporting year.

Sources identified on the form can be excluded without further action. Information on how to request the exclusion of a new miniscule source is available at www.theclimateregistry.org.

CRITERIA ICON

The Criteria Icon identifies criteria that must be met to use a particular quantification method or reporting option.

SEMS ICON

The SEMs Icon identifies emission sources commonly calculated with SEMs and methods that must be reported as SEMs.

17 The fiscal year may be defined by the member.

18 The higher Scope 2 total.

DATA GRANULARITY FOR REPORTING TO TCR

Members may enter their GHG data at the source, facility, or entity level in the Climate Registry Information System (CRIS), and choose whether to report publicly at the facility-level or entity-level.[19]

Source-Level Reporting

Members are encouraged to report emissions data at the source level, if data is available. Reporting data at this level of granularity is valuable for internal data management and can help streamline verification. Source-level data is not made available publicly through TCR, but members will have access to this information in private reports.

Facility-Level Reporting

Reporting of facility-level information enables tracking of GHG emissions at a disaggregated level, including emission changes associated with discrete business operations or facilities. It is also typically the required reporting boundary for mandatory GHG reporting programs. Emissions information will be presented in public reports at the facility-level by GHG type and source category.[20]

Entity-Level Reporting

Entity-level reporting provides a public summary of the inventory emissions totals by GHG type and source category. Members may choose to enter pre-calculated entity-wide emissions totals, or may enter facility-level or source-level data, which will be available to the member in private reports.

19 In public reports, source-level data is aggregated to the facility-level. Members seeking verification must be prepared to provide source-level information for each sampled facility to their verification body upon request.

20 Source categories include stationary combustion, mobile combustion, process emissions, fugitive emissions, Scope 1 purchased electricity, Scope 2 purchased heating, direct combustion-based biogenic emissions, and indirect combustion-based biogenic emissions associated with consumed energy.

C. GHG EMISSIONS QUANTIFICATION METHODS

INTRODUCTION TO QUANTIFYING EMISSIONS

Greenhouse gas (GHG) emissions are quantified using either direct measurement or calculation methods. The selection of a quantification method will depend on the information that is available for each source. Once a method has been chosen, it is best practice to use it year after year to ensure the comparability of emissions data over time.[1]

This module provides step-by-step methods to calculate emissions from common activities within the following source categories:[2]

- Stationary combustion;[3]
- Mobile combustion;
- Electricity use;
- Non-electric energy use; and,
- Fugitive emissions.

Within each section, the most commonly used methods are listed first.

Guidelines for using Simplified Estimation Methods (SEMs) to conservatively calculate emissions from small sources are provided in this module. Additional quantification methods for less common sources are provided in the Advanced Methods Module and TCR's sector specific protocols. If TCR has not provided guidelines for quantifying emissions from a particular emission source, organizations may use existing international or industry best practice methods, which are published, peer reviewed methods or emission factors.[4]

1 A change in the employed method could trigger a base year recalculation. View the Tracking Emissions Over Time Guidance for more information on base year recalculation.

2 Refer to the Inventory Boundaries Module section on GHG sources for descriptions of the types of direct and indirect emissions.

3 Direct measurement methods for stationary combustion are available in the Advanced Methods Module.

4 Emission factors must be gas-specific (i.e., not in units of carbon dioxide equivalent (CO_2e)).

TCR also accepts GHG emission quantification methods mandated by a state, provincial, or federal GHG reporting program that conform to the principles of corporate GHG accounting.[5]

Calculation-Based Methods

Most organizations will use calculation methods to quantify their GHG emissions. Calculation methods use activity data and emission factors to estimate GHG emissions. Activity data is a measure of a level of activity that results in GHG emissions (e.g., gallons of fuel or kWh of electricity consumed). Emission factors reflect the average GHG intensity per unit of activity data for a given source. Most organizations will use default emission factors to estimate emissions. Organizations may also develop their own site-specific emission factors based on the specific characteristics of the GHG source and fuel or unit of energy consumption.

Calculating emissions from GHG sources generally involves the following six steps:[6]

1. Determine annual consumption of each combusted fuel or annual energy consumption;
2. Determine the CO_2 emission factor for each fuel or unit of energy consumption;
3. Determine CH_4 and N_2O emission factors for each fuel or unit of energy consumption;[7]
4. Calculate CO_2 emissions by multiplying the emission factor by annual fuel or energy consumption;
5. Calculate CH_4 and N_2O emissions by multiplying emission factors by annual fuel or energy consumption;[8] and,
6. Convert CH_4 and N_2O emissions to CO_2e.

DEFAULT EMISSION FACTORS

Default emission factors may be updated when the attributes of energy (electricity, fuel, etc.) change and as emission factor quantification methods are refined. TCR publishes up-to-date emission factors on an annual basis. Organizations reporting emissions data from previous years must use the most recent emission factors available[9] when the inventory is being reported, except when quantifying emissions associated with electricity use. For electricity, organizations must use the factor corresponding to the reporting year, or when unavailable, the most recent previous year.[10,11]

Measurement-Based Methods

Emissions may be measured directly through systems that monitor the concentration of the GHGs and output flow rate. Direct measurement may be relevant to entities with facilities using Continuous Emissions Monitoring System (CEMS), such as power plants, industrial facilities with large stationary combustion units, or landfills with landfill gas collection systems.

ADVANCED METHOD

» Quantifying direct CO_2 emissions with site-specific data

5 Please note: where mandatory requirements exclude certain emission sources, members may quantify emissions from those sources in accordance with TCR's reporting requirements, or may exclude them from the reporting boundary, provided the exclusion is documented and justified.

6 Different processes are used to calculate fugitive and process emissions. Guidance on calculating emissions from refrigeration systems is outlined in the section on fugitive emissions.

7 CH_4 and N_2O emissions from mobile combustion are calculated using mileage data rather than fuel consumption data.

8 Ibid.

9 From TCR's annual update or a more recent peer-reviewed publication.

10 The most recent supplier-specific emission factor (meeting TCR's eligibility criteria for electricity) may be used in lieu of a more recent residual mix or grid-average emission factor to calculate market-based Scope 2 emissions, provided the supplier-specific emission factor is no more than five years older than the most recent residual mix or grid-average emission factor.

11 Members may elect to use eGRID2012 or eGRID2014 for EY 2014 through EY 2016.

Simplified Estimation Methods

Organizations must quantify emissions using TCR-accepted methods. However, in some cases organizations may have difficulty applying these methods to every source within their boundaries—either because it is not possible or not efficient to use them.

Therefore, TCR accepts emissions estimated using simplified methods in certain cases. Members may use Simplified Estimation Methods (SEMs) for any combination of emission sources and/or gases, provided that corresponding emissions do not exceed 10% of the CO_2e sum of reported Scope 1, Scope 2,[12] combustion-based direct biogenic emissions and combustion-based indirect biogenic emissions associated with consumed energy[13] (hereafter referred to as the 10% SEMs threshold). In developing SEMs, members should follow the principle of conservativeness (i.e., erring on the side of overestimating rather than underestimating emissions). Members must document emissions that have been estimated using SEMs for verification. Refer to the Accounting for Small Emission Sources Guidance for more information.

SEMS ICON

The SEMs Icon identifies emission sources commonly calculated with SEMs and methods that must be reported as SEMs.

10% SEMS THRESHOLD

Emissions calculated with SEMs must not exceed 10% of the CO_2e sum of reported Scope 1, Scope 2, combustion-based direct biogenic emissions and combustion-based indirect biogenic emissions associated with consumed energy.

DIRECT EMISSIONS FROM STATIONARY COMBUSTION

Stationary combustion refers to the combustion of anthropogenic or biogenic-based fuels or biomass in any stationary equipment.[14] Common large stationary sources exist in power plants, refineries, and manufacturing facilities. Examples of stationary combustion units include boilers, burners, turbines, furnaces, and internal combustion engines.

ADVANCED METHODS

- Quantifying CO_2 emissions with direct measurement systems
- Quantifying biogenic emissions from co-firing units
- Quantifying direct CO_2 emissions with measured fuel characteristics
- Optional: Allocating emissions from combined heat and power
- Eligibility of contractual instruments for renewable fuels

12 The higher Scope 2 total must be used to total Scope 1, Scope 2, combustion-based direct biogenic emissions and combustion-based indirect biogenic emissions associated with consumed energy. See the section on Indirect Emissions from Electricity Use for more information on the location-based and market-based methods.

13 Consumed energy refers to purchased or acquired electricity, steam, heating, or cooling.

14 Due to their biogenic origin, organizations must report CO_2 emissions from the combustion of biomass or biogenic-based fuels separately from fossil fuel CO_2 emissions. Refer to the advanced method for determining the eligibility of contractual instruments for renewable fuels.

Emissions may be quantified through direct measurement, or calculated based on fuel use data. This section provides a calculation method using fuel use data. The Advanced Methods Module provides methods for quantifying emissions with direct measurement systems and using measured fuel characteristics. It also includes methods for allocating biogenic emissions from co-firing units, an optional method to allocate emissions from combined heat and power, and guidance on determining eligibility of contractual instruments for renewable fuels.

Calculating Emissions from Stationary Combustion Using Fuel Use Data

To calculate emissions from stationary combustion using fuel use data, organizations will need to:

1. Determine annual consumption of each fuel combusted at the facility, and
2. Determine the CO_2, CH_4, and N_2O emission factors for each fuel.

1. Determine Annual Consumption of Each Fuel Combusted at the Facility

For each type of fuel,[15] determine the actual annual consumption, measured in units of energy, mass, or volume. The most accurate method is to read individual meters located at the fuel input point of each combustion unit. For solid fuels, fuel use may be back calculated from steam generation rates.[16] If self-producing fuels, such as biomass, organizations may rely on internal records that identify the site-specific methods used, the measurements made, and the calculations performed to quantify fuel usage. Alternatively, organizations may use fuel receipts, or purchase and storage records.

Use the equation below to estimate annual fuel consumption based on fuel purchase and storage data.

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*

2.a. Determine the CO_2 Emission Factor for Each Fuel

Use the default CO_2 emission factors provided by fuel type in Tables 1.1 to 1.3.[17] Emission factors are provided in units of CO_2 per unit energy and CO_2 per unit mass or volume. For fuels that are combusted in small quantities, it may be acceptable to use SEMs.

If heat content and/or carbon content is known or can be directly measured, organizations may use an advanced method to derive an emission factor for CO_2 based on that information. If combusting a fuel that is not listed in the tables, organizations may use a relevant published, peer-reviewed emission factor.

Organizations that have purchased a contractual instrument that includes the environmental attributes of a biofuel (e.g., biogas for thermal use) should refer to the advanced method to determine eligibility for claiming the emission attributes of the contractual instrument.

2.b. Determine the CH_4 and N_2O Emission Factors for Each Fuel

Estimating CH_4 and N_2O emissions from fuel combustion depends not only on fuel characteristics, but also on technology type and combustion characteristics; usage of pollution control equipment; and maintenance and operational practices.

15 Examples of common fuels used for stationary combustion include natural gas, diesel, and wood.

16 For example, as indicated in U.S. Greenhouse Gas Reporting Program §98.33(a)(2)(iii) corresponding to Tier 2 methodology, EquationC-2c.

17 Emission factor tables are available at www.theclimateregistry.org.

Facilities that use direct monitoring to obtain specific emission factors based on periodic exhaust sampling should use these emission factors. If either the specific type of combustion equipment used at a facility or a facility's specific sector can be determined, use factors from Tables 1.4 to 1.8.[18] If only the type of fuel is known, use Tables 1.9 and 1.10 to obtain emission factors by fuel type and sector.[19] For example, emission factors for natural gas-fired turbines greater than 3 MW for the electricity sector are available in Table 1.5. Less specific emission factors for natural gas used in the energy sector are available in Table 1.9.

DIRECT EMISSIONS FROM MOBILE COMBUSTION

Mobile emissions come from sources capable of emitting GHGs while moving from one location to another. These include both on-road and non-road vehicles such as automobiles, trucks, buses, trains, ships and other marine vessels, airplanes, tractors, construction equipment, forklifts, ride-on lawn mowers, snowmobiles, snow blowers, chainsaws, and lawn care equipment. The combustion of fuels in mobile sources emits CO_2, CH_4 and N_2O.

CO_2 emissions, which account for the majority of emissions from mobile sources, 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 the distance traveled. Mobile sources may also emit HFCs and PFCs from mobile air conditioning and transport refrigeration leaks. See the fugitive emissions section for guidance on estimating these refrigerant emissions.

ADVANCED METHOD

» Eligibility of contractual instruments for renewable fuels

REPORTING EMISSIONS FROM BIOFUELS

Biofuels such as ethanol, biodiesel, and various blends of biofuels and fossil fuels are frequently combusted in mobile sources. Due to their biogenic origin, organizations must report CO_2 emissions from the combustion of biofuels separately from fossil fuel CO_2 emissions. For biofuel blends such as E85 (85% ethanol and 15% gasoline), E10 (10% ethanol and 90% gasoline) and B20 (20% biodiesel and 80% diesel), organizations must apportion emissions as fossil CO_2 and biogenic CO_2 based on the blend composition.

In many cases, standard gasoline is blended with some biofuel. However, fuel mixes can vary with location and the time of year. When using default emission factors to quantify CO_2 emissions, unless documentation of specific information about the particular gasoline blend is available, organizations should use TCR's default emission factor for motor gasoline. This will result in all CO_2 emissions being reported in Scope 1.

Refer to the advanced method for determining the eligibility of contractual instruments for renewable fuels.

Calculating CO_2 Emissions from Mobile Combustion

To calculate CO_2 emissions from mobile combustion, organizations will need to:

1. Determine annual fuel consumption for each type of fuel used, and
2. Select the appropriate CO_2 emission factor.

1. Determine Annual Fuel Consumption by Fuel Type

For each type of fuel, determine actual annual consumption, or estimate the annual consumption based on distance traveled.

18 Ibid.

19 Ibid.

Method A: Actual Fuel Use

Using data on actual fuel consumption for each type of fuel will result in the most accurate emissions quantifications. These data include direct measurements of fuel use (e.g., official logs of vehicle fuel gauges or storage tanks); collected fuel receipts; and purchase records for bulk fuel purchases.

Method B: Estimation Based on Distance

Organizations that cannot obtain fuel use data, but have information on annual mileage and fuel economy, may estimate fuel consumption using the following procedure:

1. Identify the vehicle make, model, fuel type, and model year for all operated vehicles;
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 using the equation below.

ESTIMATING FUEL USE BASED ON DISTANCE

$$\text{Fuel Use (gallons)} = \frac{Distance\ (miles)}{(City\ FE\ x\ City\ percentage)\ (mpg) + (Highway\ FE\ x\ Highway\ percentage)\ (mpg)}$$

FE = Fuel Economy
City percentage = percentage a vehicle's annual mileage that is city driving
Hwy percentage = percentage of a vehicle's annual mileage that is highway driving

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

The most accurate method for estimating fuel economy is to use company records by specific vehicle, such as the miles per gallon (mpg) values listed on the sticker when the vehicle was purchased, vehicle manufacturer documentation, or other company records.[20]

For heavy-duty trucks, fuel economy data may be available from vehicle suppliers, manufacturers, or in company records. If no specific information is available, organizations should assume fuel economy factors of 8.0 mpg for medium trucks (10,000-26,000 pounds (lb)) and 5.8 mpg for heavy trucks (more than 26,000 lbs).[21]

Organizations must calculate the fuel use for each vehicle type separately and then sum them together by fuel.

USING DEFAULT FUEL ECONOMY EMISSION FACTORS

If direct access to fuel economy information for vehicles is unavailable, organizations may obtain fuel economy factors for passenger cars and light trucks from the U.S. EPA website www.fueleconomy.gov, which lists city, highway, and combined fuel economy factors by make, model, model year, and specific engine type. If accurate information about the driving patterns of the fleet is available, organizations should apply a specific mix of city and highway driving, using the equation above. Otherwise use the combined fuel economy factor, which assumes 45% of a vehicle's mileage is highway driving and 55% is city driving.

ADVANCED METHOD

» Quantifying direct CO_2 emission factors for mobile combustion based on actual fuel characteristics, fuel density and heat content

20 This method should be used to determine fuel economy for non-road vehicles, since default fuel economy information for non-road vehicles is not available.

21 Source: U.S. Department of Energy, *Transportation Energy Data Book*, Ed. 36, 2018, Table 5.4

2. Select CO_2 Emission Factor

Most organizations will use the default CO_2 emission factors by fuel type in Table 2.1 (U.S.) and Table 2.2 (Canada).[22] If information on actual fuel characteristics is available, organizations may use an advanced method based on heat content or fuel density.

Calculating CH_4 and N_2O Emissions from Mobile Combustion

To calculate emissions of CH_4 and N_2O from mobile sources, organizations will need to:

1. Identify the vehicle type, fuel type, and technology type or model year of each operated vehicle;
2. Identify the annual mileage by vehicle type;
3. Select the emission factor for each vehicle type; and,
4. For each vehicle type, multiply the annual mileage by the emission factor for CH_4 and N_2O to estimate CH_4 and N_2O emissions.

There are several possible methods to complete the steps above, based on available information. Emissions calculations will be most accurate if there is data on the type of emissions control technology actually used for each vehicle, but organizations can also use the vehicle's make and model year to determine which control technology is typically used. Organizations will also need mileage data for each vehicle type, but if this is not available, mileage can be estimated based on fuel consumption. Default emission factors are provided in Tables 2.4 to 2.7 based on the available data (e.g., specific control technologies or model years).[23]

When mobile emissions of CH_4 and N_2O are sufficiently small, organizations may consider using a SEM to estimate those emissions based on annual fuel consumption.

SEM FOR MOBILE CH_4 AND N_2O EMISSIONS FROM GASOLINE AND DIESEL PASSENGER CARS AND LIGHT DUTY TRUCKS

This SEM estimates CH_4 and N_2O emissions by applying an emission factor that describes a default ratio of CH_4 or N_2O to corresponding CO_2 emissions.[24]

1. Determine the total annual quantity of gasoline and diesel fuel gallons consumed, by fuel-type;
2. Calculate the CO_2 emissions using the methods above;
3. To calculate the CH_4 and N_2O emissions, multiply the metric tons of CO_2 by the CH_4 and N_2O emission factor from Table 2.9.[25]

CALCULATING CH_4 AND N_2O FOR NON-HIGHWAY VEHICLES

The procedure described in this section applies to highway vehicles and alternative fuel vehicles, but not to non-highway vehicles such as ships, locomotives, aircraft, and agricultural equipment. For these types of vehicles, use the same fuel consumption data used to estimate CO_2 emissions in the previous section, along with default emission factors for CH_4 and N_2O provided in Table 2.7.[26] Organizations reporting emissions from jet fuel combustion in jet aircraft can also quantify CH_4 and N_2O emissions using the number of landing and takeoff (LTO) cycles by aircraft type provided in Table 2.8.[27]

22 Emission factor tables are available at www.theclimateregistry.org.

23 Ibid.

24 The default ratio is based on GHG emission trend data reported as part of the *U.S. National Inventory of Greenhouse Gas Emissions and Sinks* every year to estimate CH_4 and N_2O emissions.

25 Emission factor tables are available at www.theclimateregistry.org.

26 Ibid.

27 Ibid.

1. Identify the Vehicle Type, Fuel Type, and Technology Type or Model Year of All Owned and Operated Vehicles

Organizations must identify all owned and operated vehicles, their vehicle type (e.g., passenger car or heavy-duty truck), their fuel type (e.g., gasoline or diesel), and either the emission control technology or model year for each vehicle.

The most accurate approach is to determine the actual control technology employed in each vehicle. Table 2.4 provides the names of control technologies for each vehicle type.[28] Information on the control technology type for each vehicle is posted on an under-the-hood label.

ESTIMATING VEHICLE CONTROL TECHNOLOGY

If it is not feasible to check each vehicle's under-the-hood label, organizations can estimate vehicle control technologies using each vehicle's model year. Table 2.5 provides emission factors for highway vehicles by model year and vehicle type based on a weighted average of available control technologies for each model year.[29]

2. Determine Annual Mileage for Each Vehicle Type

Unlike CO_2 emissions, CH_4 and N_2O emissions depend more on distance traveled than volume of fuel combusted. Therefore, organizations will need to identify vehicle miles traveled by vehicle type.

If mileage data is unavailable, but fuel consumption data for each highway vehicle type is available, organizations can estimate the vehicle miles traveled using fuel economy factors by vehicle type. (This is the reverse of the method to estimate fuel consumption based on mileage data to quantify CO_2 emissions.) If more than one type of vehicle is operated, organizations must separately calculate the fuel use for each vehicle type. If only bulk fuel purchase data is available, organizations should allocate consumption across vehicle types and model years based on usage data. Then use the equation below to estimate distance.

ESTIMATING DISTANCE BASED ON FUEL USE

Distance (miles)	=	$Fuel\,use\ (gallons) \times [(City\,FE \times City\,percentage)(mpg) + (Highway\,FE \times Highway\,percentage)(mpg)]$

FE = Fuel Economy
City percentage = percentage a vehicle's annual mileage that is city driving
Hwy percentage = percentage of a vehicle's annual mileage that is highway driving

3. Select the Emission Factor for Each Vehicle Type

Next, select an emission factor for each vehicle type based on the vehicle's model year or control technology.

If data on vehicles' model years is available, obtain emission factors for highway vehicles from Table 2.5. Use Tables 2.6 and 2.7 for alternative fuel and non-highway vehicles.[30]

If data on vehicles' specific control technologies is available, obtain emission factors for highway vehicles from Table 2.4. Use Tables 2.6 and 2.7 for alternative fuel and non-highway vehicles.[31]

28 Ibid.
29 Ibid.
30 Ibid.
31 Ibid.

Organizations reporting emissions associated with jet fuel combustion in jet aircraft can use the emission factors based on LTO cycles by aircraft type in Table 2.8 to quantify CH_4 and N_2O emissions.[32]

4. Calculate CH_4 and N_2O Emissions by Vehicle Type

For each vehicle type, multiply the total annual mileage by the emission factors for CH_4 and N_2O to calculate CH_4 and N_2O emissions.

Please note: When calculating Scope 1 or direct biogenic emissions from mobile combustion, organizations must only account for emissions resulting from their own activities (e.g., tailpipe emissions from fuel combustion) rather than taking into account the indirect emissions that are part of a fuel's life cycle, 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 are Scope 3 emissions.

INDIRECT EMISSIONS FROM ELECTRICITY USE

The generation of electricity through the combustion of fossil fuels typically yields CO_2, and to a smaller extent, CH_4 and N_2O. To calculate indirect emissions from electricity use, organizations will determine annual electricity consumption and calculate a location-based Scope 2 total and a market-based Scope 2 total for electricity.

Emissions from purchased or imported energy are reported in two ways as follows:

- **Location-based method:** The location-based method quantifies the average emissions from electricity generated and consumed in an organization's geographic region(s) of operations within the organization's defined boundaries, primarily using grid-average emission factors. This method reflects the GHG emissions from locally-generated electricity delivered through the grid and transparently demonstrates local conditions and the impacts of energy conservation. It does not reflect any purchasing choice(s) made by an organization.
- **Market-based method:** The market-based method quantifies emissions from electricity generated and consumed that organizations have purposefully purchased, using emission factors conveyed through contractual instruments between the organization and the electricity or product provider.[33] This method reflects the GHG emissions associated with the choices an organization makes about its electricity supply or product. It allows organizations to claim the specific emission rate associated with these purchases, for instance, a utility-specific emission factor from TCR's Electric Power Sector (EPS) delivery metrics. Energy conservation (i.e., reduced energy consumption) also impacts the GHG emissions reflected in the market-based method.

These two methods are referred to throughout the GRP as the Scope 2 methods.[34]

1. Determine Annual Electricity Consumption

There are several methods to determine electricity consumption depending on available information:

- Known electricity use method;
- Area method;
- Cost method; or,
- Average intensity method.

ADVANCED METHODS

- Sample data method
- Proxy data method

Method A: Known Electricity Use

Monthly electric bills or electric meter records provide the number of kilowatt-hours (kWh) or megawatt-hours (MWh) of electricity consumed. 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.[35]

32 Ibid.

33 Examples of markets with contractual instruments include the U.S., the European Union, Australia, most Latin American countries, Japan, and India. The market-based method is applicable when contractual instruments are present in the market.

34 The Scope 2 methods also apply to combustion-based indirect biogenic emissions that are reported outside the scopes.

35 When an electric bill does not begin exactly on the first day of the reporting year and end on the last day of the reporting year, members must prorate utility data in the first and last month's electricity bills (for those two months only) to determine annual electricity use.

Method B: Area

The area method allows organizations to estimate energy use based on their share of the building's floor space and total electricity consumption. This method is less accurate than the known electricity use method.

Organizations will need to collect the following information from the building's property manager:

» Total building area (square feet);

» Area of organization's space (square feet);

» Total building annual electricity use (kWh); and,

» Building occupancy rate (e.g., if 75% of the building is occupied, use 0.75).

Use this information and the equation below to estimate the organization's share of the building's electricity use.

ADVANCED METHOD

» [Using energy audit data to estimate electricity consumption]

ESTIMATING ELECTRICITY CONSUMPTION USING THE AREA METHOD

Electricity Use (kWh) =

$$\frac{Organization's\ Area\ (ft^2) \times Building\ Electricity\ Use\ (kWh)}{Building\ Area\ (ft^2) \times Occupancy\ Rate}$$

Method C: Cost (U.S. Commercial Facilities and Warehouses Only)

If it is not feasible to obtain kWh data for commercial facilities and warehouses,[36] organizations can estimate electricity consumption using electricity expenditures and average kWh costs.[37]

To use this method, first determine annual electricity expenditures for each facility. This data is often found in utility bills or financial records. Then, to estimate annual kWh, divide the annual facility-level electricity expenditures by the average electricity cost by U.S. state from Table 3.5, as shown in the equation below.[38]

ESTIMATING ELECTRICITY CONSUMPTION USING THE EXPENDITURE RECORDS

Electricity Use (kWh) =

$$\frac{Facility\ Expenditures\ (dollars) \times 100}{Average\ Kilowatt\ Hour\ \left(\frac{cents}{kWh}\right)}$$

Method D: Average Intensity

Organizations may need to use the average intensity method for calculating indirect emissions from leased space if they do not receive information about electricity use from an electric utility and they are unable to obtain information about the building's electricity use from the landlord/property manager. The average intensity method is less accurate than methods A-C.

This method involves the following steps:

1. Determine the leased space's square footage;

ADVANCED METHOD

» [Developing an operation-specific electricity use model to estimate electricity use]

36 This method is accepted for commercial facilities and warehouses only. It is not accepted for industrial facilities.

37 The cost method may not be used to calculate indirect emissions for on-site generation in which energy attributes are sold to another organization.

38 Emission factor tables are available at www.theclimateregistry.org.

2. Determine the average annual electricity intensity for the building space; and,
3. Estimate electricity consumption.

1. Determine the Leased Space's Square Footage

First, review the lease to determine the leased space's usable square footage. Usable square footage is the space contained within the walls of the leased space, including storage space. It does not include other 'rentable' areas such as building bathrooms, common areas, etc.

2. Determine the Average Annual Electricity Intensity for Building Space

Next, select the most appropriate average electricity intensity according to the operations of the building space using Table 3.6 (Canada) and Table 3.7 (U.S).[39,40]

3. Calculate Electricity Consumption

Use the equation below to estimate the electricity consumption for each leased space.

ESTIMATING ANNUAL ELECTRICITY CONSUMPTION				
Annual Electricity Consumption	=	*Leased Space (useable space) (ft^2) (from landlord)*	X	*Annual Electricity Intensity (kWh/ft^2) (from table)*

Select Emission Factor to Calculate Location-Based Emissions

An electricity emission factor represents the amount of GHGs emitted per unit of electricity consumed. Emission factors for the location-based method reflect the GHG emissions intensity from locally-generated electricity delivered either through the grid or through a direct line transfer.

Organizations must select an emission factor for each unit of electricity consumed. Three categories of location-based emission factors are listed in order from most specific to least specific in the location-based hierarchy and are described in the sections that follow. Organizations should use the most specific emission factors available.[41]

GUIDANCE

- » Alternative accounting methods if certificates are transferred to a third party
- » Choosing a default emission factor when the generator does not provide an emissions rate
- » Prorating emissions when power is received from both a direct line generation source and the electric grid

LOCATION-BASED EMISSION FACTOR HIERARCHY
1. Location-A: Direct line emission factors (if available)
2. Location-B: Regional or subnational emission factors
3. Location-C: National production emission factors

Please note: When a standalone biogenic CO_2 emission factor is not available for combustion-based indirect biogenic emissions (e.g., when relying on grid average factors), the member must publicly disclose that indirect biogenic emissions are or may have been excluded.[42]

39 Ibid.

40 Members with facilities in another country may submit a Member-Developed Methodology Approval Request Form to TCR for review if they are able to find a similar default electricity intensity.

41 Location-based emission factor hierarchy is from WRI's GHG Protocol Scope 2 Guidance, Table 6.2.

42 Members that demonstrate that no biomass was combusted to generate consumed electricity are not subject to this requirement.

Location-A: Direct Line Emission Factors (If Applicable)

Direct line emission factors represent emissions from electricity purchased directly from a generation source with no grid transfers. The emissions factor is ineligible to be claimed when energy attribute certificates are transferred to a third-party.

Examples:

» Landfill waste-to-energy generator that sends power to nearby organization without connecting to the grid; and,

» Solar or wind generator that sends power to organization without connecting to the grid.

Location-B: Regional or Subnational Emission Factors

Regional or subnational emission factors represent average emissions from all electricity produced in a defined grid distribution region. These emission factors should reflect net physical energy imports and exports across the grid boundary.[43]

To find the appropriate emission factors for a facility in the U.S., use the U.S. EPA Power Profiler tool, available at: www.epa.gov/cleanenergy/powerprofiler.html to determine the facility's Emissions & Generation Resource Integrated Database (eGRID) subregion. Then, based on the subregion, find the emission factors for each gas in Table 3.1.[44]

For Canadian facilities, use emission factors for each province from Tables 3.2.[45]

Location-C: National Production Emission Factors

National production emission factors represent average emissions from all energy produced within state or national borders.

If applying national production emission factors, use the value for the reporting year, or the most recent year available.

For Mexican facilities, use emission factors from Table 3.3.[46]

Country-specific Scope 2 emission factors can be obtained from the International Energy Agency (IEA) for operations outside of North America.[47, 48]

Select Emission Factor to Calculate Market-Based Emissions

Emission factors for the market-based method reflect the emission factor from electricity that organizations have purposefully purchased, through the use of contractual instruments between the organization and the electricity or product provider.

Types of contractual instruments that convey specific emissions factors for the market-based method are listed in order from most specific to least specific in the hierarchy below and are described in the sections that follow. Organizations should select the most specific emission factor available to them given their eligible contractual instruments for each unit of electricity that they consume.[49, 50, 51]

Organizations must publicly disclose the category or categories of contractual instruments used to calculate emissions using the market-based method (e.g., energy attribute certificates, contracts, utility-specific emission factors). Organizations are encouraged to specify the energy generation technologies (e.g., coal, solar, nuclear).

Please note: As with the location-based method, when a standalone biogenic CO_2 emission factor is not available for combustion-based indirect biogenic emissions (e.g.,

43 Members with facilities in the U.S. using this approach should use emission factors specific to each facility's regional power pool rather than the state it is located in, because transmission and distribution grids do not adhere to state boundaries. However, state-specific emission factors that reflect net imports and exports across the grid boundary are acceptable.

44 Emission factor tables are available at www.theclimateregistry.org.

45 Ibid.

46 Ibid.

47 See: http://www.iea.org/statistics/onlinedataservice/.

48 International Energy Agency (IEA) emission factors do not adjust for imports/exports of energy across national boundaries.

49 Organizations centrally purchasing energy attribute certificates on behalf of all their operations in a single country or region should indicate how they match these purchases to individual site consumption.

50 Organizations must ensure that any contractual instrument from which an emission factor is derived meets the TCR Eligibility Criteria outlined in the next section. Where contractual instruments do not meet these criteria, emission factors from either Market-D or Market-E must be used.

51 Market-based method emission factor hierarchy adapted from WRI's GHG Protocol Scope 2 Guidance, Table 6.3

when relying on grid average factors), the member must publicly disclose that indirect biogenic emissions are or may have been excluded.[52]

Contractual instruments for electricity, such as renewable energy certificates (RECs), can only be used to calculate Scope 2 emissions or combustion-based indirect biogenic emissions associated with consumed energy, and not Scope 1 or 3 emissions.[53]

MARKET-BASED EMISSION FACTOR HIERARCHY
1. Market-A: Energy attribute certificates (or equivalent instruments)
2. Market-B: Contracts
3. Market-C: Supplier/utility-specific emission factors
4. Market-D: Residual mix
5. Market-E: Other grid-average emission factors

Market-A: Energy Attribute Certificates (or Equivalent Instruments)

Energy attribute certificates convey information about energy generation to organizations involved in the sale, distribution, consumption, or regulation of electricity. They provide proof of electricity generation from a specific energy source and represent the rights to claim the environmental, social, and low or zero emissions characteristics resulting from the use of that electricity generation. Certificates can be unbundled, bundled with electricity, conveyed in a contract, or delivered by a utility. Where energy attribute certificates are issued, the certificates themselves serve as the emission factor for the market-based method.[54]

Examples include:

- Renewable Energy Certificates (RECs) (U.S., Canada, Australia, others);
- Electricity contracts that convey RECs;
- Certificates for non-renewable generation in regions where all-generation tracking systems are in operation;[55] and,
- Any other energy certificates that meet the TCR Eligibility Criteria.

GUIDANCE

- Role of energy attribute certificates in the market-based method
- Renewable Energy Certificates in the market-based method

Market-B: Contracts

Contracts can convey electricity generation attributes where energy attribute certificates do not exist or where attributes or certificates are not required to claim use.[56] These may apply to specified sources of electricity, from both renewable and fossil fuels.

Contracts are also commonly present when electricity is conveyed from a specific source through a direct line transfer. The guidance on direct line emission factors for the location-based method also applies to the market-based method.

Examples:

- Power purchase agreements (PPAs) or contracts for electricity from specific nonrenewable sources (e.g., coal, nuclear) outside of regions where all-generation tracking systems are in operation;
- Direct line transfers;[57]

52 Members that demonstrate that no biomass was combusted to generate consumed electricity are not subject to this requirement.

53 With the exception of Scope 3 or biogenic end-use electricity consumption.

54 Most contractual instruments for renewable energy will have an emission factor of zero. However, depending on the renewable resource employed, some may have non-biogenic emissions that must be reflected in Scope 2 or indirect biogenic emissions totals. In cases where a contractual instrument employs a biomass fuel type but does not provide a corresponding emission factor for biogenic CO_2, members must publicly disclose that indirect biogenic emissions are or may have been excluded from their emissions inventory.

55 In the U.S., the New England Power Pool Generation Information System (NEPOOL GIS), New York Generation Attribute Tracking System (NYGATS), and the Pennsylvania, Jersey, Maryland (PJM) regional transmission organization have all-attribute tracking systems. Therefore, in these regions, certificates are needed to convey the attributes (emission rates) of all specified purchases. If certificates that meet the TCR eligibility criteria are not available for specified purchases, organizations must use emission factors from either Market-D or Market-E.

56 This may also refer to cases where attribute ownership is not explicit but where the contract can nevertheless serve as a proxy for attributes due to reasonable certainty that the attributes are not otherwise conveyed.

57 See Location-A in the location-based method section for more information on direct line transfers.

- Contracts that convey attributes to the power consumer where certificates do not exist; and,
- Contracts for power that are silent on attributes, but where attributes are not otherwise tracked or claimed.

Market-C: Supplier/Utility-Specific Emission Factors

ADVANCED METHOD

- Using supplier-specific delivery metrics that are publicly disclosed or certified

Supplier/utility-specific emission factors quantify indirect emissions associated with a standard product offer, green power program, or a customized power product.

Organizations may use electric delivery metrics reported and verified in accordance with TCR's EPS Protocol,[58] or other publicly certified delivery metrics developed by a supplier or utility as described in the advanced methods.

Examples:

- Retail emission factor, representing a delivered energy product (e.g., TCR EPS delivery metrics, Table 3.8);[59]
- Special power product (SPP, also known as green power products or green energy tariffs); and,
- Voluntary renewable electricity program or product.

Market-D: Residual Mix

ADVANCED METHOD

- Validating residual mix emission factors

Residual mix emission factors quantify subnational or national energy production, factoring out voluntary purchases to prevent double counting of these claims.

Many organizations will either be unable to obtain supplier-specific or utility-specific emission factors and/or will purchase some electricity exclusively from the grid. In these cases, organizations should use a residual mix emission factor, or must publicly disclose if a residual mix emission factor is not available.[60]

Refer to the advanced method for requirements for use of residual mix emission factors.

Market-E: Other Grid-Average Emission Factors

Refer to the location-based emission factor hierarchy for the subnational/regional or national production emission factors. Organizations using a grid-average emission factor in the market-based method must publicly disclose the lack of an available residual mix emission factor if one is not available.

Examples:

- Regional or subnational emission factors (Tables 3.1, 3.2).[61]
- National production emission factors (Table 3.3).[62]

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58 Emission factor tables are available at www.theclimateregistry.org.

59 Ibid.

60 Members may contact TCR at help@theclimateregistry.org to assess the applicability of a residual mix emission factor.

61 Emission factor tables are available at www.theclimateregistry.org.

62 Ibid.

ENSURE CONTRACTUAL INSTRUMENTS MEET TCR ELIGIBILITY CRITERIA FOR ELECTRICITY

TCR defines certain eligibility criteria that are designed to ensure that emission factors used to calculate the market-based method Scope 2 total are consistent with GHG accounting best practices. Only emission factors that meet the criteria in the table below are eligible to be claimed. Where contractual instruments do not meet these criteria, emission factors from either Market-D or Market-E must be used.

Members must upload a public document identifying the contractual instrument certification program(s) or other documentation that demonstrates clear and explicit ownership and TCR eligibility in CRIS (e.g., REC certification document, self-attestation form).

TCR Eligibility Criteria for Electricity[63]

CRITERIA	DESCRIPTION
CONTRACTUAL INSTRUMENTS MUST:	
1. Convey GHG information	» Convey the direct GHG emission rate attribute associated with produced electricity.
2. Prevent double counting	» Be the only instrument that carries the GHG emission rate attribute claim associated with that quantity of electricity generation. Clear and explicit ownership must be demonstrated by either third-party verification that includes a chain of custody audit, or documentation of permanent retirement in an electronic tracking system in a dedicated, named retirement subaccount for a particular TCR reporting year. » Be distinct from offsets. A MWh generated by a renewable energy project and claimed as an offset cannot also be claimed as a contractual instrument (e.g., REC).
3. Be retired	» Be tracked, redeemed, retired, or canceled by or on behalf of the reporting organization.
4. Be of recent vintage	» Have been generated within a period of six months before the reporting year to up to three months after the reporting year.
5. Be sourced from same market as operations	» Be sourced from the same market in which the reporting organization's electricity consuming operations are located and to which the instrument is applied. Market boundaries are assumed to match national boundaries, except where international grids are closely tied.
UTILITY-SPECIFIC EMISSION FACTORS MUST BE:	
6. Calculated based on delivered electricity	» Calculated based on contractually-delivered electricity, incorporating RECs or other instruments sourced and retired on behalf of customers.
DIRECT LINE GENERATION OR ORGANIZATIONS CONSUMING ON-SITE GENERATION MUST:	
7. Convey GHG claims to the organization	» Ensure that all emission claims are transferred to the reporting organization only.
ALL CONTRACTUAL INSTRUMENTS MUST OPERATE IN MARKETS WITH A:	
8. Residual mix	» Adjusted, residual mix emission factor characterizing the GHG intensity of unclaimed or publicly shared electricity. Organizations must disclose the lack of an available residual mix emission factor if one is not available.

63 TCR's Eligibility Criteria are based on the Scope 2 Quality Criteria in the *GHG Protocol Scope 2 Guidance* and additional international best practices.

INDIRECT EMISSIONS FROM NON-ELECTRIC ENERGY USE

The consumption of non-electric energy such as imported steam, heat, and cooling is another category of Scope 2 emission sources and is reported similarly to electricity consumption. Emissions from non-electric energy consumption are calculated in two ways, using the location-based and market-based methods.

Some facilities purchase steam or heating, for example, to provide space heating in the commercial sector or process heating in the industrial sector. An advanced method is provided for calculating emissions from imported steam or heating transferred on a direct line from a conventional boiler plant.

An advanced method is also provided for estimating indirect emissions from heat and power produced at a combined heat and power (CHP) plant. 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.

Some facilities purchase cooling, such as chilled water, for either cooling or refrigeration when they do not operate cooling compressors on-site. 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 organizations purchase cooling, the compressor system that produces the cooling is driven by either electricity, fossil fuel, or biofuel combustion. An advanced method is provided for calculating emissions from imported cooling.

In many cases, organizations that lease space (such as office space) use heat, steam, or cooling that is generated within the facility in which they are located, where the heat or cooling generation unit is outside of their organizational boundary. The rest of the methods in this section estimate indirect emissions resulting from non-electric energy consumption in leased spaces.

ADVANCED METHODS

- Calculating indirect emissions from imported steam or heating from a conventional boiler plant
- Calculating indirect emissions from heat and power produced at a CHP facility
- Calculating indirect emissions from cooling

Calculating Indirect Energy Use from Imported Steam, Heating, or Cooling in Leased Spaces

Imported Heating or Steam

Organizations who lease space that is heated by units located outside of their organizational boundaries must report anthropogenic emissions associated with consumed energy in Scope 2 (imported heat). Combustion-based indirect biogenic emissions associated with consumed energy must be reported separately outside of the scopes.[64] In both cases, organizations must use the area method or average intensity method to calculate emissions.

Organizations with operational control of heating units in leased space (typically those with heating units located within the leased space, or organizations who pay their own gas bill directly to the utility) are required to report the emissions from such heating units as Scope 1 (stationary combustion) emissions.

Often in leased spaces, tenants do not separately contract for imported heat and are unable to obtain that information from their landlords. In these cases, organizations can utilize default consumption rates such as the natural gas consumption defaults from the U.S. Energy Information Administration Commercial Building Energy Consumption Survey or the Natural Resources Canada Commercial and Institutional Building Energy Use Survey to determine the energy used to generate the heat they consume and use the average intensity method to calculate emissions.

64 When a standalone biogenic CO_2 emission factor is not available for combustion-based indirect biogenic emissions (e.g., when relying on grid average factors), the member must publicly disclose that indirect biogenic emissions are or may have been excluded. Members that demonstrate that no biomass was combusted to generate consumed electricity are not subject to this requirement.

Imported Cooling

Organizations who lease space with air conditioning or cooling units that are located within their organizational boundaries are required to report the emissions from such cooling units as Scope 1 (fugitive) emissions and Scope 2 (electricity use). Anthropogenic emissions associated with consumed energy must be reported in Scope 2. Combustion-based indirect biogenic emissions associated with consumed energy must be reported separately outside of the scopes.[65]

DIRECT FUGITIVE EMISSIONS

This section provides guidance on calculating direct fugitive emissions of HFCs and PFCs from refrigeration and air conditioning systems. Refrigeration and air conditioning systems include motor vehicle air conditioning, chillers, retail food refrigeration, cold storage warehouses, refrigerated transport, industrial process refrigeration, commercial air conditioning systems, household refrigeration, and domestic air conditioning and heat pumps.

Emissions of HFCs and PFCs from refrigeration and air conditioning equipment result from the manufacturing process, leakage over the operational life of the equipment, and disposal at the end of the useful life of the equipment. This section addresses emissions from the use of refrigeration and air conditioning equipment only (including installation, use, and disposal).

Two methods for estimating emissions of HFCs and PFCs from refrigeration and air conditioning equipment are provided in this section:

- Simplified mass balance method; and,
- Screening method, which may be used as a SEM provided that total emissions estimated with SEMs fall below the 10% SEMs threshold.

An advanced mass balance method is provided for organizations that have access to detailed data on refrigerant purchases, sales, storage, and changes in total equipment capacity.

ADVANCED METHOD

- Quantification of direct fugitive emissions using the advanced mass balance method

REPORTING HFC AND PFC BLENDS

Please note: some refrigerant blends include both HFCs and PFCs. When reporting emissions associated with these blends, the HFC and PFC components must be reported by gas. To report the emissions from these blends, organizations must multiply the amount of each refrigerant used by the percent composition of each HFC and PFC listed in Table 5.2. Use the equation below and the GWP factors from Table 5.2 to convert each HFC and PFC to units of CO_2e.[66]

CONVERTING HFC AND PFC EMISSIONS TO CO_2e		
HFC Type A Emissions (mt CO_2e)	=	$HFC\ Type\ A\ Emissions\ (mt\ HFC\ Type\ A) \times GWP\ (HFC\ A)$
PFC Type A Emissions (mt CO_2e)	=	$PFC\ Type\ A\ Emissions\ (mt\ PFC\ Type\ A) \times GWP\ (PFC\ A)$

65 Ibid.

66 Emission factor tables are available at www.theclimateregistry.org.

REPORTING MONTREAL PROTOCOL REFRIGERANTS

Common refrigerants R-2, R-12, and R-11 are not part of the GHGs required to be reported to TCR because they are either HCFCs or chlorofluorocarbons (CFCs). The production of HCFCs and CFCs is being phased out under the Montreal Protocol and as a result, HCFCs and CFCs are not defined as GHGs under the Kyoto Protocol. Emissions of non-Kyoto-defined GHGs must not be reported as emission sources in the inventory, regardless of the GWP of the gas. Members that opt to disclose emissions of these refrigerants must include that information in a supplemental document.

Method A: Simplified Mass Balance

If the necessary data to use the advanced mass balance method is not available, organizations should use the simplified mass balance method. This method may be used either by organizations that service their own equipment or by organizations that have contractors service their equipment.

1. Determine the Types and Quantities of Refrigerants Used

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

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

Organizations who have contractors that service refrigeration equipment should obtain the required information from the contractor. Always track and maintain the required information carefully in order to obtain accurate emissions data.

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" in the advanced mass balance method.

2. Calculate Annual Emissions of Each HFC and PFC Gas

Use the equation below to calculate emissions for each refrigerant used.

CALCULATING EMISSIONS OF EACH REFRIGERANT USING THE SIMPLIFIED MASS BALANCE METHOD		
Total Annual Emissions (mt)	=	$\frac{(P_N - C_N + P_S - P_R + C_D - R_D)(kg)}{1,000\,(\frac{kg}{mt})}$

Where:
P_N = Purchases of refrigerant used to charge new equipment*
C_N = Total full charge (capacity) of the new equipment*
P_S = Quantity of refrigerant used to service equipment
P_R = Quantity of refrigerant recycled
C_D = Total full charge (capacity) of retiring equipment
R_D = Refrigerant recovered from retiring equipment

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

Method C: Screening

The screening method is a SEM which may be used to estimate HFC and PFC emissions from refrigeration and air conditioning systems by multiplying the quantity of refrigerants used by default emission factors. Because default emission factors are highly uncertain, the resulting emissions estimates are not considered accurate.

Organizations may only use the screening method if total, entity-wide emissions estimated with SEMs do not exceed 10% of the CO_2e sum of reported Scope 1, Scope 2, combustion-based direct biogenic emissions and combustion-based indirect biogenic emissions associated with consumed energy (i.e., the 10% SEMs threshold).

1. Determine the Types and Quantities of Refrigerants Used

To estimate emissions, organizations 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 4.1).[67] If the refrigerant charge capacity of each piece of equipment is unknown, use the upper bound of the range provided by equipment type in Table 4.1.[68]

2. Estimate Annual Emissions of Each Refrigerant

For each refrigerant, use the equation below to estimate annual emissions. Default emission factors are provided in Table 4.1 by equipment type.[69] The equation includes emissions from installation, operation, and disposal of equipment. If an organization did not install or dispose of equipment during the reporting year, it should not include emissions from these activities in the estimation.

ESTIMATING EMISSIONS OF EACH REFRIGERANT USING THE SCREENING METHOD

For each refrigerant:
Total Annual Emissions (mt) =

$$\frac{(C_N \times k) + (C \times w \times T) + [C_D \times y \times (1 - z)]\,(kg)}{1,000\,(\frac{kg}{mt})}$$

Where:
C_N = Quantity of refrigerant charged into the new equipment*
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**
k = Installation emission factor*
w = Operating emission factor
y = Refrigerant remaining at disposal**
z = Recovery efficiency**

*Omitted if no equipment was installed during the reporting year or the installed equipment was pre-charged by the manufacturer
**Omitted if no equipment was disposed of during the reporting year

If the sum of HFC and PFC emissions, in units of CO_2e, plus any other emissions estimated with SEMs, do not exceed the 10% SEMs threshold, organizations may use these estimates to report HFC and PFC emissions from the use of refrigeration and air conditioning equipment. Members must mark these emissions as SEMs in CRIS.

67 Emission factor tables are available at www.theclimateregistry.org.
68 Ibid.
69 Ibid.

D. ADVANCED METHODS FOR QUANTIFYING EMISSIONS

This module provides advanced methods to measure or calculate greenhouse gas (GHG) emissions from less common emission sources and calculation methods that use measured or site-specific data. Advanced methods for calculating the following categories of emissions are provided:

- Direct carbon dioxide (CO_2) emissions from stationary combustion using site-specific data or measured fuel characteristics;
- Direct CO_2 emissions from mobile combustion using actual fuel characteristics;
- Indirect emissions from electricity use using sample, proxy, or energy audit data or an operation-specific electricity use model;
- Indirect emissions from heat and power produced at a combined heat and power (CHP) system;
- Indirect emissions from imported heat, steam, and cooling; and,
- Direct fugitive emissions from refrigeration using purchase, retirement, and storage data.

The module also provides a method to allocate biogenic and anthropogenic emissions from co-firing stationary combustion units, and an optional method to allocate emissions from CHP. Detailed guidance is provided for selecting emission factors to calculate market-based Scope 2 emissions, and determining the eligibility of contractual instruments for renewable fuels combusted in stationary and mobile equipment.

More common quantification methods for many sources are available in the [GHG Emissions Quantification Methods Module](). If TCR has not provided guidelines for quantifying emissions from a particular emission source, organizations may use existing international or industry best practice methods, which are published, peer-reviewed calculation and measurement methods or emission factors.[1]

1 Emission factors must be gas-specific (i.e., not in units of carbon dioxide equivalent (CO_2e)).

QUANTIFYING DIRECT CO_2 EMISSIONS WITH SITE-SPECIFIC DATA

GHG emissions are quantified using either direct measurement or calculation methods. Direct measurement systems monitor GHG concentration and flow rates. Calculation-based methods use activity data and emission factors to estimate GHG emissions. Most organizations will use default emission factors, but organizations with more specific data available may also develop their own site-specific emission factors based on the specific characteristics of the GHG source and fuel.

This section provides instruction for measuring direct emissions using the following advanced methods:

» Direct measurement of CO_2 emissions;

» Allocating anthropogenic and biogenic CO_2 emissions from co-firing units;

» Developing site-specific CO_2 emission factors to quantify emissions with calculation-based methods; and,

» Optionally allocating emissions from combined heat and power.

Quantifying CO_2 Emissions with Direct Measurement Systems

CO_2 emissions may be measured directly with Continuous Emissions Monitoring Systems (CEMS), that monitor GHG concentration and flow rates based on periodic exhaust sampling. CEMS can be found in facilities such as power plants,[2] industrial facilities with large stationary combustion units, or landfills with sensors to monitor emissions from landfill gas collection systems.

Organizations may use either of the two following CEMS methods to measure and calculate annual CO_2 emissions:[3]

1. 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 then determined based on the operating time of the unit.
2. 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, 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 then determined based on the operating time of the unit.

Direct measurement may be used to quantify and report both anthropogenic and biogenic emissions, depending on the activity being monitored.

Quantifying Biogenic Emissions from Co-Firing Units

For facilities that combust blended fuels, such as municipal solid waste (MSW) treatment facilities, organizations must calculate or monitor 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). CO_2 emissions from combusting the biomass portion of the fuel or feedstock (e.g., yard waste or paper products for MSW) must be separately calculated and reported as biogenic CO_2 emissions (reported separately from the scopes). Methods are provided for the allocation of emissions from blended fuels in units without CEMS and in units with CEMS below.

Allocating Emissions from Blended Fuels in Units Without Cems

Information on the biomass portion of fuels and feedstocks are often site-specific. MSW facilities without CEMS should obtain biomass/fossil fuel breakdown information from a local waste characterization study. Organizations may also use the method 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 CARB *Regulation for the Mandatory Reporting of Greenhouse Gas Emissions*, Section 95125(h)(2).

2 For organizations in the electric power sector, additional specifications on using CEMS can be found in TCR's EPS Protocol.

3 All methods of direct monitoring using CEMS pursuant to 40 CFR Parts 60, 75, 98 or Environment Canada's Report EPS 1/PG/7 (Revised) are consistent with the method in this section.

Allocating Emissions from Blended Fuels in Units with Cems

Where biomass and fossil fuels are co-fired and emissions are monitored through a CEMS, the emissions associated with each combustion activity may be mixed in the exhaust stack and measured collectively by the same CEMS device. To determine the share of biogenic CO_2 emissions measured by the CEMS, calculate the CO_2 emissions from fossil fuel or biomass combustion by using a fuel-specific emission factor applied to the amount of fuel or biomass combusted.[4] After calculating these CO_2 emissions from either fossil fuel or biomass combustion, subtract the calculated value from the total CEMS measured CO_2 value to identify the remaining (anthropogenic or biogenic) CO_2 emissions.

Alternatively, organizations may use the method described in ASTM D6866-06a (see above for more information).

Quantifying Direct CO_2 Emissions with Measured Fuel Characteristics

Organizations that have access to measured characteristics of combusted fuels may derive an emission factor for CO_2. 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). Organizations 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 Parts 86, 87, 89 et al. *Mandatory Reporting of Greenhouse Gases;*

» 40 CFR Part 75, Appendix G *Continuous Emissions Monitoring, Determination of CO_2 Emissions;*

» *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;" and,

» WRI/WBCSD *GHG Protocol Guidance: Direct Emissions from Stationary Combustion,* Version 3.0 (July 2005), Annex D (www.ghgprotocol.org).

The carbon content of each fuel can be expressed in mass of carbon per mass of fuel (e.g., kilogram (kg) C/short ton), mass of carbon per volume of fuel (e.g., kg C/gallon), or mass of carbon per unit energy of fuel (e.g., 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).[5]

If carbon content is expressed in mass of carbon per unit energy (e.g., kg C/Btu), multiply by the heat content of that fuel per unit mass or volume (such as Btu/ton or Btu/gallon) to determine the mass of carbon per physical unit of fuel (such as kg C/ton or kg C/gallon).[6]

4 Emission factors may be derived using measured fuel characteristics or default values from Tables 1.1 to 1.3. Emission factor tables are available at www.theclimateregistry.org.

5 Outside of the U.S. and Canada, lower heating values (LHV) are more commonly used. Refer to TCR's guidance on converting from LHV to HHV.

6 If carbon content data is expressed in mass of carbon per mass or volume of fuel, skip this step.

To account for the small fraction of carbon that may not be oxidized during combustion, multiply the carbon content in physical units of fuel by the fraction of carbon oxidized. Organizations may use a site-specific oxidation factor, or where site-specific data is not available, apply a default oxidation factor of 1.00 (100% oxidation). Then convert from units of carbon to units of CO_2 by applying the molecular weight ratio of CO_2 to carbon (44/12) as shown in the equation below.

CALCULATING CO_2 EMISSION FACTORS USING MEASURED FUEL CHARACTERISTICS		
Emission Factor	=	$\mathit{Heat\ Content} \times \mathit{Carbon\ Content} \times \mathit{Percent\ Oxidized} \times \frac{44}{12}$

Combining Measured Data and Default Factors

Organizations should use measured fuel characteristics of combusted fuels to quantify emissions whenever possible. In some cases, heat content information may be available (for example, from the fuel supplier), while measured carbon content data is not, and vice versa. In these cases, organizations should combine the more specific data with default emission factors from Tables 1.1 to 1.3.[7]

Optional: Allocating Emissions from Combined Heat and Power

Accounting for the GHG emissions from a Combined Heat and Power (CHP) system that captures the waste heat from the primary electricity generating pathway and uses it for non-electricity purposes is unique because the system produces more than one useful product from the same amount of fuel combusted, namely, electricity and heat or steam.[8] As such, apportionment of the GHG emissions between the two different energy streams may be useful.

Please note: While allocating the emissions generated by a CHP system between the two energy product streams is optional, absolute emissions from CHP systems included within the reporting boundary must be reported.

The most consistent approach for allocating GHG emissions from CHP systems is the efficiency method, which allocates emissions of CHP systems 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, the organization must know the total emissions from the CHP system, the total steam (or heat) and electricity production, and the steam (or heat) and electricity production efficiency of the system.

Use the following steps to determine the share of emissions attributable to steam (or heat) and electricity production.

1. Determine the total direct emissions from the CHP system;
2. Determine the total steam (or heat) and electricity output for the CHP system;
3. Determine the efficiencies of steam (or heat) and electricity production; and,
4. Determine the fraction of total emissions allocated to steam (or heat) and electricity production.

7 Emission factor tables are available at www.theclimateregistry.org.

8 Note that a combined cycle (or bottoming cycle) system that uses waste heat to generate electricity should be treated no differently from stationary combustion emissions as described in the previous section.

1. Determine the Total Direct Emissions from the CHP System

Calculate total direct GHG emissions using the methods for quantifying direct emissions from stationary combustion. Like the guidance for non-CHP stationary combustion, calculating total emissions from CHP systems is based on either CEMS or fuel input data.

2. Determine the Total Steam and Electricity Output for the CHP System

To determine the total energy output of the CHP system attributable to steam production, use published tables that provide energy content (enthalpy) values for steam at different temperature and pressure conditions.[9] Energy content values multiplied by the quantity of steam produced at the temperature and pressure of the CHP system 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.

3. Determine the Efficiencies of Steam and Electricity Production

Identify steam (or heat) and electricity production efficiencies. If actual efficiencies of the CHP system are not known, use a default value of 80% for steam and a default value of 35% 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.

4. Determine the Fraction of Total Emissions Allocated to Steam and Electricity Production

Allocate the emissions from the CHP system to the steam (or heat) and electricity product streams by using the equation below.

ALLOCATING CHP EMISSIONS TO STEAM AND ELECTRICITY	
STEP 1:	$E_H = \dfrac{\frac{H}{e_H} \times E_T}{\frac{H}{e_H} + \frac{P}{e_P}}$
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

E_P = Emissions allocated to electricity production

9 E.g., 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).

QUANTIFYING CO_2 EMISSION FACTORS FOR MOBILE COMBUSTION BASED ON ACTUAL FUEL CHARACTERISTICS, FUEL DENSITY, AND HEAT CONTENT

To calculate CO_2 emissions from mobile combustion, organizations will need to determine annual fuel consumption for each type of fuel used in the fleet and select the appropriate CO_2 emission factor. Most organizations will use the default CO_2 emission factors by fuel type in Table 2.1 (U.S.) and Table 2.2 (Canada) to calculate emissions from mobile combustion.[10] More accurate CO_2 emission factors can be derived by measuring the fuel characteristics of the specific fuel consumed, or obtaining this data from the fuel supplier. Specific emission factors can be determined from data on either the fuel density and carbon content of fuels, or heat content and carbon content per unit of energy of fuels.

If only measured heat content data is available and measured carbon content data is missing (or vice versa), organizations may use a combination of their own data and a default heat content or carbon content factor from Table 2.1 (U.S.) or Table 2.2 (Canada).[11]

Fuel Density Method

Multiply the fuel density (mass/volume) by the carbon content per unit mass (mass C/mass fuel) to determine the mass of carbon per unit of volume of fuel (such as kg C/gallon). To account for the small fraction of carbon that may not be oxidized during combustion, multiply the carbon content by the fraction of carbon oxidized. If oxidation factors specific to the combustion source are not available, use a default oxidation factor of 1.00 (100% oxidation). To convert from units of carbon to CO_2, multiply by 44/12. Refer to the equation below.

CALCULATING CO_2 EMISSION FACTORS USING THE FUEL DENSITY APPROACH		
Emission Factor (kg CO_2/gallon)	=	$Fuel\ Density\ (kg/gallon) \times CarbonContent\ (kg\ C/kg\ fuel) \times\ Percent\ Oxidized \times \frac{44}{12}(CO_2/C)$

Heat Content Method

If the heat content and carbon content of each fuel can be obtained from the fuel supplier, multiply the heat content per unit volume (e.g., Btu/gallon) by the carbon content per unit energy (e.g., kg C/Btu) to determine the mass of carbon per unit volume (e.g., kg C/gallon). To account for the small fraction of carbon that may not be oxidized during combustion, multiply the carbon content by the fraction of carbon oxidized. If oxidation factors specific to the combustion source are not available, use a default oxidation factor of 1.00 (100% oxidation). To convert from units of carbon to CO_2, multiply by 44/12. Refer to the equation below.

CALCULATING CO_2 EMISSION FACTORS USING THE HEAT CONTENT APPROACH		
Emission Factor (kg CO_2/gallon)	=	$Heat\ Content\ (Btu/gallon) \times Carbon\ Content\ (kg\ C/Btu) \times\ Percent\ Oxidized \times \frac{44}{12}(CO_2/C)$

10 Emission factor tables are available at www.theclimateregistry.org.

11 Ibid.

ELIGIBILITY OF CONTRACTUAL INSTRUMENTS FOR RENEWABLE FUELS COMBUSTED IN STATIONARY OR MOBILE EQUIPMENT

Organizations that have purchased a contractual instrument that includes the environmental attributes of a biofuel (e.g., biogas) should consult the TCR Eligibility Criteria for Steam and Heating in the advanced method for Calculating Indirect Emissions from Imported Steam or Heating from a Conventional Boiler Plant to evaluate if the instrument may be claimed in the inventory.[12] If eligible, the most specific market-based emission factors available should be used to report biogenic CO_2 and Scope 1 methane (CH_4) and nitrous oxide (N_2O) emissions. If the contractual instrument is ineligible, organizations should report using the appropriate default emission factor of the fuel consumed.[13]

QUANTIFYING INDIRECT EMISSIONS FROM ELECTRICITY USE

To calculate indirect emissions from electricity use, organizations will determine annual electricity consumption and calculate a location-based Scope 2 total and a market-based Scope 2 total for electricity.

Determining Electricity Consumption

There are several advanced methods to determine electricity consumption depending on available information. These methods involve the following types of information:

» Sample data;

» Proxy data;

» Energy Audit data; and,

» Operation-specific electricity use data to develop a model.

Sample Data Method

Organizations can use sample data to estimate total electricity consumption if they can demonstrate that:

» Hours of use of the equipment have been metered or tracked; and,

» The equipment is operating continuously (or on a schedule that they can account for) at a constant rate.

To use the sample data method to estimate electricity consumption, multiply the sample by the amount of time the equipment was in use.

Proxy Data Method

Organizations can use existing data on equipment operations as a proxy for unavailable data at another site as long as they can demonstrate that:

» The equipment is identical;

» Equipment operations where site-specific data is unavailable consume the same amount of energy as identical equipment where site-specific data is available;

» The equipment operates on the same schedule; and,

» The same maintenance procedures are followed.

12 The Eligibility Criteria for Steam and Heating also apply to contractual instruments for other renewable technologies, such as solar thermal and geothermal.

13 If TCR does not provide a default emission factor for the consumed fuel, organizations may use existing international or industry best practice methods, which are published, peer-reviewed calculation and measurement methods or emission factors. Emission factors must be gas-specific (i.e., not in units of carbon dioxide equivalent (CO_2e).

Organizations may use make and model information, manufacturer specifications, or testing to determine that both pieces of equipment consume the same amount of electricity.

Using Energy Audit Data to Estimate Electricity Consumption

As an alternative to the area method to estimate electricity use (see the GHG Emissions Quantification Methods Module, Indirect Emissions from Electricity Use section), organizations with access to a comprehensive energy audit can use the audit findings to apportion total building electricity use to the organization's space, provided electricity use has been consistent since the date of the audit. Organizations may also use a combination of energy audit findings and the area method to allocate total emissions to different operations.

Developing an Operation-Specific Electricity Use Model to Estimate Electricity Use

In certain circumstances, organizations may have sufficient information to develop operation-specific electricity use models for their operations. For example, if an organization has several retail stores where they use a consistent lighting design and lighting makes up the majority of the electricity load, they may develop a member-specific electricity consumption model to estimate electricity use based on square footage. Members should contact TCR if they are interested in developing their own operation-specific electricity use model to estimate electricity use.

Emissions estimated using these approaches will not contribute to the Simplified Estimation Methods (SEMs) threshold.

Selecting Emission Factors to Calculate Market-Based Emissions

Emission factors for the market-based method reflect the emission rate from electricity that organizations have purposefully purchased, through the use of contractual instruments between the organization and the electricity or product provider.

The GHG Emissions Quantification Methods Module, Indirect Emissions from Electricity Use section describes five categories of emission factors that could be applied to each unit of electricity consumed to calculate market-based emissions. In this section, advanced methods are provided for organizations that use supplier-specific emission factors that are publicly disclosed and certified (from the Market-C: Supplier/utility-specific emissions rate category), and for validating residual mix emission factors (from the Market-D: Residual mix category).

Using Supplier-Specific Delivery Metrics That Are Publicly Disclosed or Certified

Supplier-specific and utility-specific emission factors quantify indirect emissions associated with a standard product offer, green power program, or a customized power product.

Organizations may use electric delivery metrics reported and verified in accordance with TCR's EPS Protocol,[14] or other publicly certified delivery metrics developed by a supplier or utility. To demonstrate the validity of factors that are not reported and verified through TCR, members must upload a public document in CRIS that identifies where the emission factor is publicly disclosed or the utility's certification of the emission factor. The utility's certification must describe the methodology used to develop the emission factor and, as applicable, include references to publicly available data used in its development.[15]

Validating Residual Mix Emission Factors

Residual mix emission factors quantify subnational or national energy production, factoring out voluntary purchases to prevent double counting of these claims.

TCR accepts residual mix emission factors that are publicly documented and are industry expert-developed or have been through a regulatory or peer review process. To validate these emission factors, members must upload public documentation of the source data in CRIS. This should include the methodology used to calculate the residual mix and where the data is publicly available.

14 Emission factor tables are available at www.theclimateregistry.org.

15 These emission factors are expected to be compiled in a manner comparable to TCR's requirements in the EPS Protocol. Specifically, these factors must reflect purchased power delivered to customers and treatment of RECs should be consistent with the TCR Eligibility Criteria.

QUANTIFYING INDIRECT EMISSIONS FROM IMPORTED STEAM, HEATING, COOLING, AND A CHP SYSTEM

This section provides advanced methods for quantifying indirect emissions from imported steam, heating, cooling, and a CHP system.

Calculating Indirect Emissions from Imported Steam or Heating from a Conventional Boiler Plant

Some facilities purchase steam or heating, for example, to provide space heating in the commercial sector or process heating in the industrial sector. This section provides guidance on calculating emissions from imported steam or heating that is produced with a conventional boiler.[16]

To estimate a facility's GHG emissions from imported steam or heating, follow these steps:

1. Determine energy obtained from steam or heating;
2. Calculate location-based Scope 2 total for steam or heating; and,
3. Calculate market-based Scope 2 total for steam or heating.

1. Determine Energy Obtained from Steam or Heating

First, determine the quantity of acquired steam or heating. 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 obtain annual consumption.

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

CONVERTING STEAM CONSUMPTION FROM THERMS TO MMBTU		
Energy Consumption (MMBtu)	=	$Energy\ Consumption\,(therms) \times 0.1\,(MMBtu/therm)$

If steam consumption is measured in pounds, either monitor the temperature and pressure of the steam received, or request this data 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.[17] 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.

16 If heating is generated using electricity, refer to the advanced method on Calculating Indirect Emissions from Cooling to calculate emissions from heating.

17 Source: American Petroleum Institute, Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry, 2001.

The enthalpy of the steam can be found in standard steam tables.[18] The enthalpy of saturated water at the reference conditions is 180 Btus/lb. The thermal energy consumption for the steam can then be calculated as shown in the equation below.

CONVERTING STEAM CONSUMPTION FROM POUNDS TO MMBTU		
Energy Consumption (MMBtu)	=	$\frac{[Enthalpy\ of\ Delivered\ Steam - 180](\frac{Btu}{lb}) \times Steam\ consumed\ (lb)}{1,000,000\ (\frac{Btu}{MMBtu})}$

2. Calculate Location-Based Scope 2 Total for Steam or Heating

Organizations must publicly report Scope 2 emissions for imported steam or heating in two ways, using both the location-based method and the market-based method.

A. Select a Location-Based Emission Factor

First, select the emission factors that apply to the location-based method. For steam or heating, an emission factor represents the amount of GHGs emitted per unit of energy consumed. It is usually reported in amount of GHG (in metric tons or pounds) per MMBtu of heat generated.

Location-based Emission Factor Hierarchy
1. Location-A: Direct line emission factors (if available)
2. Location-B: Regional or subnational emission factors

Organizations must select an emission factor for each unit of energy consumption, as identified in step one. Two categories of location-based emission factors are listed in order from most specific to least specific in the location-based emission factor hierarchy. Organizations should use the most specific emission factors available.[19] A description of each category is described in the sections that follow.

Anthropogenic emissions associated with consumed energy must be reported in Scope 2. Combustion-based indirect biogenic emissions associated with consumed energy must be reported separately outside of the scopes.[20]

Location-A: Direct Line Emission Factors

Direct line emission factors represent emissions from steam or heat purchased directly from a generation source, from direct line transfers where the organization receives energy directly from a generator with no grid transfers. Emission factors may be obtained directly by the supplier, or may be estimated based on boiler efficiency, fuel mix, heat content, and carbon content.

Examples include:

» Connected facilities where one facility creates heat or steam and transfers it directly to a facility owned or operated by an organization; and,

» Heat or steam produced by a central boiler within a multi-tenant leased building and sold to organizations that are tenants who do not own or operate the building or equipment.[21]

Direct line emission factors should be in units of mass per unit of energy (e.g., metric tons of CO_2 emitted per MMBtu of heat generated). See the advanced method for [Quantifying Direct CO_2 Emissions with Measured Fuel Characteristics] for information on deriving CO_2 emission factors.

18 E.g., Industrial Formulation 1997 for the Thermodynamic Properties of Water and Steam published by IAPWS.

19 Location-based emission factor hierarchy is adapted from WRI's GHG Protocol Scope 2 Guidance, Table 6.2.

20 When a standalone biogenic CO_2 emission factor is not available for combustion-based indirect biogenic emissions (e.g., when relying on grid average factors), the member must publicly disclose that indirect biogenic emissions are or may have been excluded. Members that demonstrate that no biomass was combusted to generate consumed electricity are not subject to this requirement.

21 The GHG Emissions Quantification Methods Module, Indirect Emissions from Non-Electric Energy Use section provides methods for calculating indirect energy use from imported steam, heating, and cooling in leased spaces.

Refer to the GHG Emissions Quantification Module, Indirect Emissions from Electricity Use section and the Accounting for Renewable Energy Guidance for more detail on direct line emission factors and for guidance on their applicability to the location-based Scope 2 total.

If emission factors are not available from suppliers of heat or steam, organizations can estimate an emission factor based on boiler efficiency, fuel mix, and emission factors specific to the fuel type using a source-specific efficiency factor. Organizations should proceed to Location-B if they cannot obtain heat and carbon content from the supplier and are not able to estimate the emission factor.

Efficiency Approach Using a Source-Specific Efficiency Factor

Because emissions vary with fuel type, organizations must know the type of fuels that are burned in the plant supplying the steam or hot water or, for leased spaces, in the boiler supplying the natural gas. This information can be obtained from the plant's energy supplier. Once the fuels combusted to generate the steam or hot water are known, determine the appropriate emission factors for each fuel combusted. The most accurate approach, assuming a direct line, is to obtain CO_2 emission factors based on measured characteristics of the fuels combusted, including measured heat content and measured carbon content, from the supplier.

Next, 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 the equation below. Boiler efficiency is the ratio of steam output to fuel input, in units of energy, which should be obtained from the 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.

CALCULATING SYSTEM EFFICIENCY		
Total Efficiency Factor (percentage)	=	$\mathit{Boiler\ Efficiency} \times (100\ \mathit{Percent} \times \mathit{Transport\ Losses})$

Calculate CO_2, CH_4, and N_2O emission factors that reflect the efficiency and fuel mix of the boiler employed to generate the steam or hot water or, for leased spaces, in the boiler supplying the natural gas, using the equation below.

CALCULATING EMISSION FACTORS		
CO_2 Emission Factor (kg CO_2 / MMBtu)	=	$\dfrac{\mathit{Fuel\ Specific\ Emission\ Factor}\ \left(\frac{kg\ CO_2}{MMBtu}\right)}{\mathit{Total\ Efficiency\ Factor}\ (\mathit{percent})}$
CH_4 Emission Factor (kg CH_4 / MMBtu)	=	$\dfrac{\mathit{Fuel\ Specific\ Emission\ Factor}\ \left(\frac{kg\ CH_4}{MMBtu}\right)}{\mathit{Total\ Efficiency\ Factor}\ (\mathit{percent})}$
N_2O Emission Factor (kg N_2O / MMBtu)	=	$\dfrac{\mathit{Fuel\ Specific\ Emission\ Factor}\ \left(\frac{kg\ N_2O}{MMBtu}\right)}{\mathit{Total\ Efficiency\ Factor}\ (\mathit{percent})}$

Efficiency approach using a default efficiency factor

If the specific system efficiency of the boiler that generated the steam or heat is unavailable, apply a default total efficiency factor—boiler efficiency and transport losses combined—of 75% in the equation above.[22]

Location-B: Fuel-Specific Emission Factors

If measured heat content and measured carbon content from the supplier is not available, use the appropriate default fuel-specific emission factors for CO_2, CH_4, and N_2O from Tables 1.1 to 1.9.[23] Refer to Location-A above and use the equations in that section to calculate emission factors.

22 When using the CRIS calculator to report emissions from heating in leased spaces in CRIS, the default efficiency factor will automatically be applied.

23 Ibid.

B. Calculate Emissions from Imported Steam and Heating Using the Location-Based Method

Next, use the equation below to calculate GHG emissions from imported steam or hot water or, for leased spaces, from the natural gas supplying the boiler, for the location-based method.

CALCULATING EMISSIONS FROM IMPORTED STEAM OR HEAT						
Total CO_2 Emissions (mt)	=	*Energy Consumed (MMBtu)*	X	*Emission Factor (kg CO_2 / MMBtu)*	X	*0.001 (mt/kg)*
Total CH_4 Emissions (mt)	=	*Energy Consumed (MMBtu)*	X	*Emission Factor (kg CH_4 / MMBtu)*	X	*0.001 (mt/kg)*
Total N_2O Emissions (mt)	=	*Energy Consumed (MMBtu)*	X	*Emission Factor (kg N_2O / MMBtu)*	X	*0.001 (mt/kg)*

3. Calculate Market-Based Scope 2 Total for Imported Steam or Heating

A. Select the Appropriate Emission Factors that Apply to the Market-Based Method

If only direct line transfers are used for steam or heating, the location-based and market-based Scope 2 totals will be the same. In this case, report the location-based Scope 2 total for the market-based method.

Each unit of energy consumption must be matched with an emission factor appropriate for each facility's market.[24] Four types of contractual instruments that convey specific emissions rates for steam or heating are listed in order from most specific to least specific in the hierarchy below and are described in the sections that follow. Organizations should use the most specific emission factor available given the contractual instruments in their inventory.[25,26]

Market Based Emission Factor Hierarchy
1. Market-A: Energy attribute certificates (or equivalent instruments)
2. Market-B: Contracts
3. Market-C: Residual mix
4. Market-D: Fuel-specific emission factors

These contractual instruments can only be used to calculate market-based Scope 2 emissions, and not Scope 1 or Scope 3 emissions.

Anthropogenic emissions associated with consumed energy must be reported in Scope 2. Combustion-based indirect biogenic emissions associated with consumed energy must be reported separately outside of the scopes.[27]

Organizations must publicly disclose the category or categories of contractual instruments used to calculate

24 Organizations centrally purchasing energy attribute certificates on behalf of all their operations in a single country or region should indicate how they match these purchases to individual site consumption.

25 Organizations must ensure that any contractual instrument from which an emission factor is derived meets the TCR Eligibility Criteria. Where contractual instruments do not meet these criteria, emission factors from either Market-C or Market-D must be used.

26 Market-based method emission factor hierarchy adapted from WRI's *GHG Protocol Scope 2 Guidance,* Table 6.3.

27 When a standalone biogenic CO_2 emission factor is not available for combustion-based indirect biogenic emissions (e.g., when relying on grid average factors), the member must publicly disclose that indirect biogenic emissions are or may have been excluded. Members that demonstrate that no biomass was combusted to generate consumed electricity are not subject to this requirement.

emissions under the market-based method (e.g., energy attribute certificates, contracts), where possible specifying the energy generation technologies (e.g., natural gas, coal, solar, nuclear).

Market-A: Energy Attribute Certificates (or Equivalent Instruments)

Energy attribute certificates convey information about energy generation to organizations involved in the sale, distribution, consumption, or regulation of steam or heating. Refer to the GHG Emissions Quantification Module, Indirect Emissions from Electricity Use section for more detail on energy attribute certificates and for guidance on their applicability to the market-based Scope 2 total.

Examples include:

- Heat or steam contracts that convey attributes, or certificates for non-renewable generation in regions where all-generation tracking systems are in operation; and,
- Any other energy certificates that meet the TCR Eligibility Criteria for steam or heating.

Market-B: Contracts

Contracts include direct contracts between two parties for steam or heating as well as contracts from specific sources, where energy attribute certificates do not exist or are not required for a usage claim and are not transacted or claimed in any other way, either for that resource or in that market.

Contracts are also commonly present when steam or heat is conveyed from a specific source through a direct line transfer. Organizations that have a direct line transfer for a portion of their emissions from steam or heating should refer to the location-based emission factor categories.

Refer to the GHG Emissions Quantification Module, Indirect Emissions from Electricity Use section for more detail on contracts and for guidance on their applicability to the market-based Scope 2 total.

Examples include:

- Direct line transfers; and,
- PPAs or contracts for energy from specific non-renewable sources (e.g., coal, nuclear) outside of regions where all-generation tracking systems are in operation.

Market-C: Residual Mix

Residual mix emission factors quantify subnational or national energy production, factoring out voluntary purchases to prevent double counting of these claims.[28]

Organizations must publicly disclose the lack of an available residual mix emission factor if one is not available. Refer to the GHG Emissions Quantification Module, Indirect Emissions from Electricity Use section for more detail on residual mix emission factors and for guidance on their applicability to the market-based Scope 2 total.

Market-D: Fuel-Specific Emission Factors

If none of the preferred market-based emission factors are available, refer to the location-based emission factor categories for steam or heating. Examples of fuel-specific emission factors include:

- U.S. fuel-specific default emission factors (Tables 1.1, 1.9);[29]
- Canadian fuel-specific default emission factors (Tables 1.2-1.4); and,[30]
- International sector-specific default emission factors by fuel type (Tables 2.5-2.8, 1.10).[31]

28 No annual, grid-average third-party developed residual mix emission factors were available at the time GRP v. 3.0 was published. Members may contact TCR at help@theclimateregistry.org for updated information or to assess the applicability of a regional residual mix emission factor.

29 Emission factor tables are available at www.theclimateregistry.org.

30 Ibid.

31 Ibid.

B. Ensure Contractual Instruments Meet TCR Eligibility Criteria for Steam and Heating

TCR defines certain eligibility criteria that are designed to ensure that emission factors used to calculate the market-based Scope 2 total for steam and heating are consistent with GHG accounting best practices.

Members must upload a public document identifying the contractual instrument certification program(s) or other documentation that demonstrates clear and explicit ownership and TCR eligibility in CRIS (e.g., self-attestation form).

TCR Eligibility Criteria for Steam and Heating[32]

CRITERIA	DESCRIPTION
CONTRACTUAL INSTRUMENTS MUST:	
1. Convey GHG information	» Convey the direct GHG emission rate attribute associated with produced steam or heat, to be calculated based on its characteristics.
2. Prevent double counting	» Be the only instrument that carries the GHG emission rate attribute claim associated with that quantity of produced steam or heat. Clear and explicit ownership must be demonstrated by either third-party verification that includes a chain of custody audit, or documentation of permanent retirement in an electronic tracking system in a dedicated, named retirement subaccount for a particular TCR reporting year. » Be distinct from offsets. A MWh generated by a renewable energy project and claimed as an offset cannot also be claimed as a contractual instrument.
3. Be retired	» Be tracked, redeemed, retired, or canceled by or on behalf of the reporting organization.
4. Be of recent vintage	» Have been generated within a period of six months before the reporting year to up to three months after the reporting year.
5. Be sourced from same market as operations	» Be sourced from the same market in which the reporting organization's steam or heat consuming operations are located and to which the instrument is applied. Market boundaries are assumed to match national boundaries, except where international grids are closely tied.
DIRECT LINE GENERATION OR ORGANIZATIONS CONSUMING ON-SITE GENERATION MUST:	
6. Convey GHG claims to the member	» Ensure that all emission claims are transferred to the reporting organization only.
ALL CONTRACTUAL INSTRUMENTS MUST:	
7. Residual mix	» Operate in markets with an adjusted, residual mix emission factor characterizing the GHG intensity of unclaimed energy. Organizations must disclose the lack of an available residual mix emission factor if one is not available.

32 TCR's Eligibility Criteria for steam and heating are based on the Scope 2 Quality Criteria in the *GHG Protocol Scope 2 Guidance* and have been adapted for steam, heating, and gas transactions. They may also reflect additional requirements from international best practice.

C. Calculate Emissions from Imported Steam or Heating for the Market-Based Method

Refer to the location-based method for guidance on calculating emissions using total energy consumed and the appropriate emission factors.

Calculating Indirect Emissions from Heat and Power Produced at a CHP Facility

Combined heat and power (CHP) systems simultaneously produce electricity and heat (or steam). When two or more parties receive the energy streams from CHP systems, indirect GHG emissions must be determined and allocated separately for heat production and electricity production. Allocation avoids double counting of the same GHG emissions in each product stream.

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

The process for estimating indirect emissions from heat and power produced by a CHP system involves the following three steps:

1. Obtain total emissions and power and heat generation information from CHP system;
2. Determine emissions attributable to net heat production and electricity production; and,
3. Calculate emissions attributable to the portion of heat and electricity consumed according to the location-and market-based methods.

1. Obtain Emissions and Power and Heat Information from the CHP System

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

» Total emissions of CO_2, CH_4, and N_2O from the CHP system, based on fuel input information;

» Total electricity production from the CHP system, based on generation meter readings; and,

» Net heat production from the CHP system.

Net heat production refers to the useful heat that is produced in the CHP system, minus whatever heat returns to the boiler as steam condensate, as shown in the equation below. (Alternatively, refer to Step 2 of the advanced method for Allocating Emissions from Combined Heat and Power for guidance on determining net heat production from steam temperature and pressure data.)

CALCULATING NET HEAT PRODUCTION		
Net Heat Production (MMBtu)	=	*Heat of Steam Export (MMBtu) – Heat of Return Condensate (MMBtu)*

2. Determine Emissions Attributable to Net Heat Production and Electricity Production

Refer to the GHG Emissions Quantification Module, Direct Emissions from Stationary Combustion section and the advanced method for Quantifying Direct CO_2 Emissions with Site-specific Data.

Refer to the advanced method for Allocating Emissions from Combined Heat and Power to calculate emissions attributable to net heat and electricity production.

3. Calculate Emissions Attributable to the Portion of Heat and Electricity Consumed According to the Location-Based and Market-Based Methods

Once the total emissions attributable to heat (or steam) and electricity production have been determined, organizations will need to determine the portion of heat or electricity they have consumed, and thus their indirect GHG emissions associated with heat or electricity use. Indirect emissions associated with this heat or electricity use must be reported according to both the location-based and market-based methods (refer to the GHG Emissions Quantification Module, Indirect Emissions from Electricity Use section).

This section assumes there is a direct line transfer between the generator and the user. When this is the case, methods in the GHG Emissions Quantification Module, Direct Emissions from Stationary Combustion section or the advanced methods for Quantifying Direct CO_2 Emissions with Site-specific Data section in this module will be sufficient for calculating indirect emissions associated with the generation according to both the location-based and market-based methods. In the case of grid-connected CHP, refer to the location-based and market-based emission factor categories for electricity in the GHG Emissions Quantification Module, Indirect Emissions from Electricity Use section.

First, obtain electricity and heat (or steam) consumption information, and then use the equations below to calculate the share of emissions according to both the location-based and market-based methods, as appropriate.

CALCULATING INDIRECT EMISSIONS ATTRIBUTABLE TO ELECTRICITY CONSUMPTION		
Indirect Emissions Attributable to Electricity Consumption (mt)	=	$\frac{\text{Total CHP Emissions Attributable to Electricity Production}\,(mt) \times \text{Your Electricity Consumption}\,(kWh)}{\text{Total CHP Electricity Production}\,(kWh)}$
CALCULATING INDIRECT EMISSIONS ATTRIBUTABLE TO HEAT (OR STEAM) CONSUMPTION		
Indirect Emissions Attributable to Heat Consumption (mt)	=	$\frac{\text{Total CHP Emissions Attributable to Heat Production}\,(mt) \times \text{Your Heat Consumption}\,(MMBtu)}{\text{CHP Net Heat Production}\,(MMBtu)}$

If contractual instruments are purchased and eligible to be claimed, these may only be applied to the portion of the facility's emissions that are consumed by the organization.

Calculating Indirect Emissions from Cooling

Some facilities purchase cooling, such as chilled water, for either cooling or refrigeration when they do not operate cooling compressors on-site. 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 organizations purchase cooling services using cooling, the compressor system that produces the cooling is driven by either electricity, fossil fuel combustion, or biofuel combustion.

Organizations reporting emissions from purchased cooling must report Scope 2 emissions in two ways, using both the location-based and market-based methods.

Anthropogenic emissions associated with consumed energy must be reported in Scope 2. Combustion-based indirect biogenic emissions associated with consumed energy must be reported separately outside of the scopes.[33]

33 When a standalone biogenic CO_2 emission factor is not available for combustion-based indirect biogenic emissions (e.g., when relying on grid average factors), the member must publicly disclose that indirect biogenic emissions are or may have been excluded. Members that demonstrate that no biomass was combusted to generate consumed electricity are not subject to this requirement.

Organizations must first determine the total cooling use by summing the total cooling from monthly cooling bills. Then, use either the detailed approach or simplified approach to estimate GHG emissions from cooling based on the data that is available.

Detailed Approach to Calculate Indirect Emissions from Cooling

The detailed approach allows organizations to determine the total cooling-related emissions from the cooling plant and the facility's fraction of total cooling demand.

Cooling plants take a variety of forms and may produce electricity, hot water, or steam for sale in addition to cooling.

The process for calculating combustion emissions from cooling plants is described in the GHG Emissions Quantification Module, Direct Emissions from Stationary Combustion section and the advanced methods for Quantifying Direct CO_2 Emissions with Site-specific Data in this module. Organizations will need to obtain the emission values from the cooling plant, or calculate the emissions based on the fuel consumption or any contractual instruments using emission factors from the location-based and market-based emission factor categories (refer to the GHG Emissions Quantification Methods Module, Indirect Emissions from Electricity Use section. If only direct line transfers are used for cooling and any certificates are retained, the location-based and market-based Scope 2 totals will be the same.

In the simplest case, all of the fuel consumed by the plant is used to provide cooling. In that case, organizations will be able to determine Scope 2 cooling emissions based on total direct emissions from cooling plant fuel combustion (metric tons).

Simplified Approach to Calculating Indirect Emissions from Cooling

The simplified approach uses an estimated value for the ratio of cooling demand to energy input for the cooling plant, known as the "coefficient of performance" (COP).[34] This approach allows organizations to estimate the portion of energy used at the cooling plant directly attributable to the organization's cooling. This involves the following steps:

1. Determine annual cooling demand;
2. Estimate COP for the plant's cooling system;
3. Determine energy input; and,
4. Calculate GHG emissions resulting from cooling.

1. Determine Annual Cooling Demand

Cooling demand is typically reported in ton-hours. Convert ton-hours of cooling demand to MMBtu using the equation below. If billed monthly, sum together monthly cooling demand to yield an annual total.

CALCULATING ANNUAL COOLING DEMAND		
Cooling Demand (MMBtu)	=	$\dfrac{Cooling\ Demand\ (ton-hour) \times 12,000\ (\frac{Btu}{ton-hour})}{1,000,000\ (\frac{MMBtu}{Btu})}$

34 Note that this approach is not considered a Simplified Estimation Method (SEM).

2. Determine COP for the Plant's Cooling System

The most accurate approach is to obtain the source-specific COP for the cooling plant. Organizations that can obtain the COP for the cooling plant should proceed to Step 3. If organizations cannot obtain the COP for the plant itself, determine the type of chiller used by the cooling plant. With that information, a rough estimate of the COP may be selected from the default values shown in Table 1.

Table 1. Typical Chiller Coefficients of Performance

CHILLER TYPE	COP	ENERGY SOURCE
Absorption Chiller	0.8	Natural Gas
Engine-Driven Compressor	1.2	Natural Gas

Source: California Climate Action Registry General Reporting Protocol Version 3.1, January 2009.

3. Determine Energy Input

To determine the energy input to the system resulting from cooling demand, use the equation below.

CALCULATING ENERGY INPUT

Energy Input (MMBtu) =

$$\frac{Cooling\ Demand\ (MMBtu)}{COP}$$

4. Calculate GHG Emissions Resulting from Cooling

To calculate the location-based and market-based Scope 2 totals for indirect emissions using the simplified approaches, refer to GHG Emissions Quantification Module, Indirect Emissions from Electricity Use section.

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 the GHG Emissions Quantification Module, Direct Emissions from Stationary Combustion section and the advanced methods for Quantifying Direct CO_2 Emissions with Site-specific Data. If the type of fuel used is known, multiply the energy input by source-specific or default emission factors for CO_2, CH_4, and N_2O from Tables 1.1 to 1.9.[35] If the fuel type cannot be determined, assume the fuel used is natural gas. Use the equation below to calculate emissions.

CALCULATING TOTAL COOLING EMISSIONS

Total CO_2 Emissions (mt)	=	*Energy Input (MMBtu)*	X	*Emission Factor (kg CO_2 / MMBtu)*	X	*0.001 (mt/kg)*
Total CH_4 Emissions (mt)	=	*Energy Input (MMBtu)*	X	*Emission Factor (kg CH_4 / MMBtu)*	X	*0.001 (mt/kg)*
Total N_2O Emissions (mt)	=	*Energy Input (MMBtu)*	X	*Emission Factor (kg N_2O / MMBtu)*	X	*0.001 (mt/kg)*

35 Emission factor tables are available at www.theclimateregistry.org.

QUANTIFICATION OF DIRECT FUGITIVE EMISSIONS USING THE ADVANCED MASS BALANCE METHOD

The advanced mass balance method is the most accurate method for determining HFC and PFC emissions. To calculate HFC and PFC emissions using this method, organizations will need to determine the amount of refrigerant in storage at the beginning of the year, and account for any changes based on refrigerant purchases and sales and changes in total equipment capacity. Table 2 is a template that lists various aspects of changes to the base year inventory.

Table 2. 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 equipment)	
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 equipment	
7	Total full charge of retiring equipment	
E	Change to nameplate capacity (6-7)	

1. Determine the Base Inventory for Each HFC and PFC

For each facility, 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 2. 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.

2. Calculate Any 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 2). Purchases and other acquisitions may include refrigerant:

» Purchased from producers or distributors;

» Provided by manufactures or inside equipment;

» Added to equipment by contractors or other service personnel (but not if that refrigerant is from the organization's 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 equipment (item *D* in Table 2). Sales and disbursements may include refrigerant:

» 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 refrigerant during the year (item *E* in Table 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 refrigerant 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 refrigerant 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 refrigerant in question) minus the full charge of equipment that is retired or sold (including full charge of refrigerant in question from equipment that is retrofit to use a different refrigerant) also provides the change in total capacity.

3. Calculate Annual Emissions of Each HFC and PFC Gas

For each refrigerant or refrigerant blend, use the equation below and data from Table 2 to calculate total annual emissions of each HFC and PFC gas at each facility.

CALCULATING EMISSIONS OF EACH OF HFC OR PFC GAS USING THE ADVANCED MASS BALANCE METHOD

Total Annual Emissions (mt of HFC or PFC)	=	$\frac{[A - B + C - D - E]\,(kg)}{1,000\ \frac{kg}{mt}}$

E. REPORTING AN INVENTORY

This module describes additional information that members must include with their emissions to complete their greenhouse gas (GHG) inventory. Members may also report optional information to better illustrate their emissions management strategy, goals and achievements. Optional information can include purchased offsets, a net inventory, performance metrics, or other supplemental information.

Members interested in publicly disclosing their inventory must have their inventories third-party verified. Members can choose which optional information to disclose to stakeholders and which they would like to keep private to use for internal purposes, and can choose to report with different levels of granularity in The Climate Registry Reporting System (CRIS).

ADDITIONAL REPORTING REQUIREMENTS

GHG emissions data is the primary information that members report to the Carbon Footprint Registry. However, TCR also requires members to publicly disclose the following additional information:

» Information about the entity (address, key contacts, etc.);

» Any member-defined criteria for defining relevant indirect emissions, if different from TCR's criteria for relevance;[1,2]

» A description of the reporting boundary, including any excluded emissions and explanation of the reason for their exclusion;[3]

1 For the purposes of reporting to TCR, all Scope 1 and Scope 2 emissions as well as combustion-based biogenic direct emissions and combustion-based biogenic indirect CO_2 emissions associated with energy consumption are relevant. The following emission sources are not relevant: approved miniscule sources, biogenic emissions other than those associated with the combustion of biomass, and emission sources identified as optional in the protocols.

2 Members seeking to conform to ISO 14064-1:2018 should refer to TCR's guidance on the meeting additional requirements of the ISO standard, since ISO 14064-1: 2018 criteria for relevant emissions includes significant Scope 3 emissions.

3 Members are not required to include a description of the reporting boundary and/or an explanation of why TCR-approved miniscule sources are excluded for inventories that include all relevant emissions.

- If combustion-based indirect biogenic emissions associated with energy consumption are included in the reporting boundary but are not reported, a statement that a standalone biogenic CO_2 emission factor is not available;
- The reporting year (e.g., calendar year or fiscal year);
- The set of Global Warming Potential (GWPs) applied;[4]
- The consolidation approach(es) employed (e.g., operational control, financial control, equity share);
- Industry type based on North American Industry Classification System (NAIC) Code;
- If the member is reporting as a subsidiary and the parent company is also reporting, the identity of the parent company as it appears in CRIS; and,
- Explanation of any change to or recalculation of a base-year or previous GHG inventory.[5]

OPTIONAL REPORTING

TCR encourages members to exceed reporting requirements by providing optional data in addition to the required data in the Additional Reporting Requirements section. Reporting optional data enhances the value of the inventory to stakeholders and the transparency of the emission report and the member's environmental leadership.

Offsets

Offsets represent the reduction, removal, or avoidance of GHG emissions from a specific project that is used to compensate for (i.e., offset) GHG emissions occurring elsewhere, for example, to meet a voluntary GHG target. A carbon offset represents one ton of carbon dioxide equivalent. Some regulatory and voluntary programs generate carbon credits from certified carbon offsets projects, which can then be tracked, traded and retired for compliance or voluntary purposes. The purchase and retirement of offset credits may be disclosed as additional information items.[6] Offsets may be applied to Scope 1, Scope 2, Scope 3 or biogenic emissions in a net inventory, separately from the primary inventory totals. If offsets are applied to Scope 2 emissions, the same offsets must be applied to both the location-based emissions and market-based emissions totals.

Offset credits applied to an adjusted inventory must meet TCR's offset requirements, below:

- **Real:** GHG reductions must represent actual emission reductions quantified using comprehensive accounting methods.
- **Additional:** GHG reductions or removals must be surplus to regulation and beyond what would have happened in the absence of the incentive provided by the offset credit.[7]
- **Permanent:** GHG reductions must be permanent or have guarantees to ensure that any losses are replaced in the future.
- **Transparent:** Offset projects must be publicly and transparently registered to clearly document offset generation, transfers and ownership.
- **Verified:** GHG reductions must result from projects whose performance has been appropriately validated and verified to a standard that ensures reproducible results by an independent third-party that is subject to a viable and trustworthy accreditation system.
- **Owned Unambiguously:** No parties other than the project developer, must be able to reasonably claim ownership of the GHG reductions represented by the offset credits.

Offset credits that are applied to a net inventory total or disclosed as additional information can only be used once and must be retired prior to the date they are reported to TCR. Members that wish to apply offset credits to a net inventory total or disclose offsets as additional information must also disclose the offset program or GHG scheme under which the offsets were generated.

TCR recognizes offset credits that have been issued or recognized by the following offset programs:

- State, province, territorial, or federal regulatory agencies in North America;

4 Members seeking to conform to ISO 14064-1:2018 must provide justification for the GWP selected if the latest IPCC GWP is not used.

5 Members seeking to conform to ISO 14064-1:2018 must also document any limitations to comparability resulting from a recalculation of a base year or previous GHG inventory.

6 Members seeking to report in accordance with ISO 14064-1 should refer to TCR's guidance on the treatment of offsets in ISO 14064-1:2018.

7 Offsets quantified using a project vs. performance standard methodology may establish slightly different requirements for demonstrating additionally.

» American Carbon Registry;

» Clean Development Mechanism;

» Climate Action Reserve;

» The Gold Standard;

» Joint Implementation;

» Verified Carbon Standard; and,

» Other programs meeting equivalent standards upon TCR staff evaluation.[8]

Members purchasing carbon offsets in the retail market can gain assurance about the validity of their purchases by seeking out retail offset certification. One such certification program is Green-e.

Performance Metrics

Performance metrics provide information about an organization's direct and indirect emissions relative to a unit of business activity, input, or output. Members may use performance metrics to serve a range of objectives, including:

» Evaluating emissions over time in relation to targets or industry benchmarks;

» Facilitating comparisons between similar organizations, process or products; and,

» Improving public understanding of the emissions profile over time, even as an organization's activity changes.

Many organizations track environmental performance with GHG intensity metrics, which measure GHG emissions per economic unit or unit of physical activity.

TCR currently has standards for several performance metrics specific to different sectors. These metrics can sometimes be used as inputs to the GHG inventories of other organizations in the supply chain, including customers or suppliers. For example, an electric utility customer may use a power delivery metric from their utility (e.g., emissions per megawatt hour of electricity product sold) as the emission factor to calculate and report market-based Scope 2 emissions.

Electric Power Generation and Deliveries Metrics

The Electric Power Sector (EPS) Protocol contains requirements for developing both electricity generation and delivery metrics, which provide helpful information for other members working to better quantify market-based Scope 2 emissions. Load serving entities (e.g., electric power utilities) publicly reporting to TCR are required to quantify and report generation metrics and may opt to develop delivery metrics. Published delivery metrics are available at www.theclimateregistry.org, and published generation metrics are available in the Public Reports section of https://www.cris4.org within supporting documents.

Transit Agency Performance Metrics

TCR has developed a set of performance metrics that provide transit agencies with a reliable, transparent, and clear communication tool that can be used to explain carbon efficiency to policymakers, the public and other stakeholders. Reporting of these metrics are optional. For more information on the transit agency performance metrics, visit www.theclimateregistry.org.

Water and Wastewater Agency Performance Metrics

TCR has developed two sets of reporting guidance for members of the water sector in California. The Water-Energy Nexus Registry (WEN Registry) Protocol includes standards and guidance for WEN Registry participants to report their entity-wide carbon footprint and water-related performance metrics. *Water-Energy GHG (WEG) Metrics: Performance Metrics for Water Managers in Southern California* provides additional guidance to water managers with operations in Southern California. These documents define system average and product-specific metrics that measure the GHG intensity of water-related operations or deliveries. Product-specific metrics may be used to communicate the emissions associated with water-related products purchased by distinct customer groups, while the system average reflects the total emissions related to water management across the system. Members may elect to report some or all of the water-related performance metrics alongside their GHG inventory.

8 Contact TCR at help@theclimateregistry.org to request evaluation of additional offset programs.

Optional Data

Members may include supplemental data or information with the emissions report. Among a wide array of optional data, TCR encourages members to consider including the following:

- Unit-level emissions (for stationary combustion units);
- Emissions based on more than one of the consolidation approaches described in the [Inventory Boundaries Module]() (i.e., report emissions on both an equity share and operational control basis, or both an equity share and financial control basis);
- Scope 2 disclosure;
    - Key features of contractual instruments, such as instrument certification labels, characteristics of energy generation facilities, GHG type reported that does not have a specific emission rate under a contractual instrument (e.g., CH_4 or N_2O), and policy context;
    - Total annual energy consumption reported separately from the scopes (e.g., in kWh, BTU), including any energy consumed from owned/operated energy producing facilities;
    - Percentage of overall electricity consumption reported in the market-based method that reflects markets *without* contractual information available;
    - Scope 2 totals for each method disaggregated by country;
    - Estimation of avoided emissions from contractual instrument purchases, reported separately from the scopes;
    - Advanced grid studies or real-time information if it is available, reported separately from the Scope 2 totals as a comparison to the location-based method;
    - Contractual instrument purchases that do not meet TCR Eligibility Criteria, including details on which criteria were not met and why;
    - Relationship to emission trading programs (e.g., cap-and-trade or emission rate trading), if applicable, and Scope 2 totals calculated by other regulatory methods;
    - Additional certificate or other instrument retirements performed in conjunction with a member's voluntary claim (e.g., certificate multipliers or pairing undertaken for regulatory or voluntary purposes);
    - Scope 2 method used to calculate Scope 3 emissions from fuel- and energy-related emissions not included in Scopes 1 and 2 (if this is reported); and,
    - Role of member's procurement practices in driving new projects.
- Scope 3 emissions and description of relevant Scope 3 calculation methods;
- Information on any GHG management or reduction programs or strategies, such as purchases of offsets (including information on whether they are verified or certified); and,
- Descriptions of unique environmental practices.

THIRD-PARTY VERIFICATION

Third-party verification is defined as an independent expert assessment of the accuracy and conformity of an emissions inventory based on the reporting requirements contained in the GRP, and the verification requirements described in TCR's [General Verification Protocol]().

Third-party verification provides confidence to users that the emission report represents a faithful, true, and fair account of emissions—free of material misstatements and conforming to the accounting and reporting rules in the documents listed above. Verification ensures that all data published by The Climate Registry is accurate, consistent and transparent.

Verification is optional for members, but is required for publication of emissions inventories in CRIS.

Members can refer to TCR's guidance for more information on the member's role in the verification process.

REPORTING DATA IN CRIS

CRIS is TCR's proprietary online platform for members to calculate, report, verify, and disclose GHG emissions. CRIS provides multiple options to calculate and report GHG emissions on an annual basis, and produces user-friendly reports for both TCR members and the public. Since organizations have different approaches for collecting and tracking GHG emissions data, CRIS provides a number of data entry options to allow organizations to easily report GHG data in a way that aligns with their own internal processes.

Getting Started in CRIS

User Accounts

TCR members are able to create two different types of user accounts with distinct permissions, an Entity Editor or an Entity Administrator account. More information on the features and permission levels for each user type can be found in the CRIS User Guide available in CRIS.

Inventory Details

Each year, members will update information about their organization and the annual emission inventory being reported. These updates include selection of the Global Warming Potentials (GWPs) used to calculate carbon dioxide equivalents, the public base year or period used for tracking emissions over time, addresses and contact information, and the TCR-recognized verification body that will review the inventory.

Global Warming Potential

Members may choose which IPCC Assessment Report and associated GWP set will be applied to each inventory reported in CRIS. The default GWP standard at the time of publication is "AR5," the IPCC's Fifth Assessment Report. The GWP standard will have a direct impact on the calculations that are completed in CRIS and members may update the standard at any time.

Data Entry

Members can report data at three different levels of granularity in CRIS: entity level, facility level and source level. Entity-level reporting refers to total organization-wide emissions. Facility-level emissions are total emissions for a given facility. Members may report emissions for individual sources within a facility (e.g., electricity and natural gas for offices or gasoline and diesel for vehicles) at the source level. Members have the option to report pre-calculated data or enter raw activity data in the emissions calculator, or a combination of each. The sections that follow describe the different approaches that organizations can take when reporting emissions in CRIS.

Entity-Level Reporting

Members that decide to report emissions at the entity level submit either raw activity data or pre-calculated data for one or more facilities in CRIS. If the inventory is reported according to both a control and entity share consolidation methodology, the member must report additional facilities to accurately reflect the equity share. Public reports contain only aggregated entity-level data.

Facility-Level Reporting

Members also have the option to report pre-calculated data at the individual facility level, or by aggregating like facilities. This provides more transparency to public stakeholders than entity-level reporting. Public reports will display the emissions totals of each emission source category for each facility.[9]

Source-Level Reporting

Members may choose from the following options to report GHG emissions at the source-level:

» Use the CRIS emissions calculator to perform GHG emissions calculations. This involves inputting activity data (e.g., kWh of electricity consumed or gallons of fuel combusted) and selecting the appropriate default emission factor supplied by the CRIS calculator to calculate emissions. TCR compiles default emission factors from publicly available sources and updates the factors in CRIS annually. Emission factors can also be customized in the emissions calculator if a more specific factor is available.

» Perform emissions calculations offline and submit pre-calculated data at the source level.

» Submit emissions from sources monitored with CEMS, PART 70 CEMS, and PART 60 CEMS as pre-calculated data.

Public reports will only display the emissions totals by emission source category for each facility, not raw activity data.

9 Emission source categories include stationary combustion; mobile combustion; process emissions; fugitive emissions; indirect emissions from consumed energy; combustion-based direct biogenic emissions and combustion-based indirect biogenic emissions associated with consumed energy.

Forms and Documents

CRIS contains built-in forms designed to disclose supplemental information and provide more context about an inventory. Depending upon a member's inventory, certain forms will be required and made public after verification. Members can submit optional forms for internal tracking purposes, which will remain private.

Self-Defined Boundary Form

Members that choose to define their own reporting boundary (i.e., define a reporting boundary that does not meet TCR's criteria for relevance[10]) must document the activities included in their inventory by completing the *Self-Defined Boundary Form*. Members can disclose the selected geographic boundary of the inventory, the GHGs included, and which activity types are included or excluded from the inventory. Once the inventory has been verified, this form will be made publicly available.

Exclude Miniscule Sources Form

TCR has designated a list of small sources of emissions that represent a high reporting burden for particular sectors. Members may exclude miniscule emission sources relevant to their sector by disclosing that the sources exist, but are not quantified and reported, using the *Exclude Miniscule Sources Form.* Once the inventory has been verified, this form will be publicly available.

Apply Purchased Offsets Form

Members may apply purchased carbon offset credits to Scope 1, Scope 2, Scope 3 and biogenic emissions in an adjusted inventory by using the *Apply Purchased Offsets Form*. When reported, offsets will appear as a line item in the member's entity emissions summary grids (mt CO_2e) on both public and private reports. Adjusted emissions totals for each scope are displayed separately from the primary emissions totals.

Indirect Emissions Disclosure Form

The *Indirect Emissions Disclosure Form* is required for members undergoing verification and communicates additional information about the contractual instruments associated with specific facilities and sources, the availability of residual mix emission factors, and the inclusion or exclusion of indirect biogenic emissions in an inventory. The form also allows members to disclose either the market-based or location-based Scope 2 total for an inventory if they have chosen exclude either category of emissions from the public emissions report. Once the inventory has been verified, this form will be publicly available.

Supporting Documents

Members may upload additional required and optional documentation to CRIS, such as sector-specific reports (e.g., EPS report, LGO standard inventory report, transit agency metrics), spreadsheets of calculations performed offline, energy attribute certificates or contracts for contractual instruments (e.g., power purchase agreements), and inventory management plans. Documents should be marked as public if they provide supporting information for the public emissions inventory, or marked as private if they are for internal tracking and verification body review only.

Submitting an Inventory

Once a member has finished reporting an inventory, they may submit it to a verification body to complete verification and make the emissions report public. The following tools are available to assist members prior to submitting inventories for verification.

Inventory Submission Checklist

The Inventory Submission Checklist is a tool that members can use to check that they have completed all of the required steps in the reporting process and uploaded all necessary supporting documentation. Completing the checklist is optional, and is only intended to assist members in preparing their submission. Verification bodies can review this list, but will not make any assessments about the accuracy of an inventory based on the member's responses on the checklist.

Activity History Log

The Activity History Log contains information on each step of the inventory submission process, including who changed the workflow and when, and the date that the inventory reporting process initially began.

10 For the purposes of reporting to TCR, all Scope 1 and Scope 2 emissions as well as combustion-based direct biogenic emissions and combustion-based indirect biogenic emissions associated with consumed energy are relevant. The following emission sources are not relevant for reporting to TCR: approved miniscule sources, biogenic emissions other than those associated with the combustion of biomass, and emission sources identified as optional in the protocols.

Quality Assurance Check

As a part of the inventory submission process, CRIS runs a number of checks on an inventory to identify any potential issues with the reported data. CRIS checks whether or not a member has:

- » reported emissions for each of the active sources and facilities;
- » included all of the sources from the previous reporting year in the current inventory;
- » added any new facilities;
- » reported CH_4 and N_2O for all of the combustion sources;
- » exceeded the 10% limit for estimating emissions using simplified estimation methods (SEMs); and/or,
- » selected a verification body.

There are two types of notifications that the Quality Assurance Check may generate: warnings and errors. Warnings are non-critical messages notifying a member that there may be potential issues with the inventory. Members are advised to address the warnings before submitting an inventory, but they will not prevent members from moving to the verification process. Errors are critical issues that must be addressed before members can submit an inventory to the verification body.

Verification

Once a member has selected a verification body and submitted an inventory, the verification body is automatically notified of the submission. Verification bodies have access to all reported data, supporting documentation and forms, and are able to submit requests for members to make corrections directly in CRIS.

Generating Reports

CRIS allows both members and the general public to generate reports on emissions data. Members can view their own reported emissions data in CRIS at any time by running private reports. Any member of the public with a CRIS login can access reports that have been verified and published.

Please view the CRIS Terms of Use for more information on the storage of reported data in CRIS (public and private). The Terms of Use can be viewed by selecting "Register for a new account" on the CRIS home page.

Public Reports

After an emissions inventory is successfully verified by a third-party verification body, it is published in CRIS. Verified reports are available to the general public and display emissions totals at either the entity- or facility-level. CRIS users can customize the information included in public reports by selecting a specific Region (Global or North America Only), Level of Detail (Detail or Summary), and the Organizational Boundary (Control, Equity Share and Control, or Equity Share Only).

Private Reports

Members have the ability to generate reports containing more information about an inventory than the public reports. The Detail Report—Control (Private) and the Data Extract Report are the most comprehensive reports available. Members can customize the information included in reports by selecting a specific Region (Global or North America Only), Level of Detail (Detail or Summary), and the Organizational Boundary (Control, Equity Share and Control, or Equity Share Only).

Detail Report—Control (Private)

The Private Detail Report provides a summary of entity-level emissions totals, as well as emissions at the facility- and source-levels if that level of data granularity is reported in CRIS. It is best to download this report from CRIS as a PDF file.

Data Extract

A Data Extract provides a line-by-line spreadsheet of all of the data a member has entered into CRIS, which can then be filtered and sorted using Excel. It is best to download this report from CRIS as an Excel file.

ABBREVIATIONS AND ACRONYMS

AR5	Intergovernmental Panel on Climate Change Fifth Assessment Report
Btu	British thermal unit(s)
C	Carbon
CARB	California Air Resources Board
CEMS	Continuous Emissions Monitoring System
CFC	Chlorofluorocarbon
CHP	Combined heat and power
CH_4	Methane
COP	Coefficient of performance
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
CRIS	Climate Registry Information System
eGRID	Emissions and Generation Resource Integrated Database
EPS	Electric Power Sector
EU ETS	European Union Emission Trading Scheme
FE	Fuel economy
GCV	Gross caloric value
GHG	Greenhouse gas
GPP	Green Power Product
GRP	General Reporting Protocol
GVP	General Verification Protocol
GWP	Global warming potential
HCFC	Hydrochlorofluorocarbon
HFC	Hydrofluorocarbon
HHV	Higher heating value

HSE	Health, safety, and environmental
HVAC	Heating, ventilation, and air conditioning
IAPWS	International Association for the Properties of Water and Steam
ICLEI	International Council for Local Environmental Initiatives
IPCC	Intergovernmental Panel on Climate Change
IEA	International Energy Agency
ISO	International Organization for Standardization
kg	Kilogram(s)
kWh	Kilowatt-hour(s)
lb	Pound
LGO	Local Government Operations
LHV	Lower heating value
LPG	Liquefied petroleum gas
LTO	Landing and takeoff
MMBtu	One million British thermal units
mpg	Miles per gallon
MRV	Measurement, reporting and verification
MSW	Municipal solid waste
mt	Metric ton
MWh	Megawatt-hour(s)
NAIC	North American Industry Classification System
NCV	Net calorific value
NEPOOL GIS	New England Power Pool Generation Information System
NERC	North American Electric Reliability Corporation
NF_3	Nitrogen trifluoride
N_2O	Nitrous oxide
NYGATS	New York Generation Attribute Tracking System

PFC	Perfluorocarbon
PPA	Power purchase agreement
PJM GATS	Pennsylvania, Jersey, Maryland Generation Attribute Tracking System
RECs	Renewable energy certificates
RY	Reporting year
scf	Standard cubic foot
SEM	Simplified Estimation Method
SF_6	Sulfur hexafluoride
T&D	Transmission & distribution
TCR	The Climate Registry
U.S.	United States
U.S. EPA	United States Environmental Protection Agency
VB	Verification Body
WBCSD	World Business Council for Sustainable Development
WEG	Water-Energy Greenhouse Gas
WEN	Water-Energy Nexus
WRI	World Resources Institute

GLOSSARY OF TERMS

Activity Data	Measure of a level of activity that results in greenhouse gas (GHG) emissions (e.g., gallons of fuel or kWh of electricity consumed).
Anthropogenic Emissions	GHGs emitted into the atmosphere as a direct result of human activities (i.e., the burning of fossil fuels).
Base Year (or base period)	A benchmark against which an organization's current or future emissions are compared. A base period is referred to as a base year for simplicity.
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. Biomass also includes the plant or animal fraction of flotsam from water body management, mixed residues from food and beverage production, composites containing wood, textile wastes, paper, cardboard and pasteboard, municipal and industrial waste, and processed municipal and industrial wastes.
Biogenic Emissions	Carbon dioxide (CO_2) generated during the combustion or decomposition of biologically-based material.
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.
Calculation-Based	Emission quantification methods that involve the calculation of emissions based on emission factors and activity data such as input material flow, fuel consumption, or product output.
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 Equivalent	(CO_2e) The universal unit for comparing emissions of different GHGs expressed in terms of the global warming potential (GWP) of one unit of carbon dioxide.
Combined Heat and Power	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.

Consumed Energy	Purchased or acquired electricity, steam, heating, or cooling.
Continuous Emission Monitoring System (CEMS)	Monitors installed in energy and industrial operations to continuously collect, record and report emissions data.
Contractual Instrument	Any type of contract between two parties for the sale and purchase of energy bundled with energy generation attributes, or for unbundled attribute claims. Contractual instruments applied to an inventory must meet the TCR Eligibility Criteria.
Control Approach	An emissions accounting approach for defining organizational boundaries in which an organization reports the GHG emissions from operations under its financial or operational control.
Direct Emissions	Emissions from sources within the reporting organization's organizational boundaries that are owned or controlled by the reporting organization, including stationary combustion emissions, mobile combustion emissions, process emissions, and fugitive emissions.
Direct Line	Energy purchased and received directly from a generation source, with no grid transfers.
Emission Factor	GHG emissions expressed on a per unit activity basis (e.g., metric tons of CO_2 emitted per million Btus of coal combusted, or metric tons of CO_2 emitted per kWh of electricity consumed).
Energy Attribute Certificate	A category of contractual instruments that conveys information about energy generation to organizations involved in the sale, distribution, consumption, or regulation of electricity (e.g., renewable energy certificates).
Equity Share Approach	An emissions accounting approach for defining organizational boundaries that reflects activities that are wholly owned and partially owned according to the organization's equity share in each.
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. Financial control is one of two ways to define the control approach.
Fugitive Emissions	Intentional or unintentional releases from the production, processing, transmission, storage, and use of fuels and other substances, that do not pass through a stack, chimney, vent, exhaust pipe or other functionally equivalent opening (such as releases of sulfur hexafluoride from electrical equipment; hydrofluorocarbon releases during the use of refrigeration and air conditioning equipment; landfill gas emissions; and CH_4 leakage from natural gas transport).
Geography	A physical parameter that is used to define the reporting boundary.

Global Warming Potential (GWP)	The ratio of radiative forcing (degree of warming to the atmosphere) that would result from the emission of one unit of a given GHG compared to one unit of carbon dioxide (CO_2).
Greenhouse Gases	(GHG) For the purposes of TCR, GHGs are the internationally recognized gases identified in the Kyoto Protocol: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF_6) and nitrogen trifluoride (NF_3).
Hydrofluorocarbons	(HFC) 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 organization, but that occur at sources owned or controlled by another organization. For example, emissions of electricity used by a manufacturing company that occur at a power plant represent the manufacturer's indirect emissions.
Industry Best Practice	Existing international or industry best practice methods, which are published, peer reviewed calculation and measurement methods or emission factors.
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 Report	The summary of emissions and related information reported as part of an inventory.
Location-Based Method	Scope 2 method that quantifies the average emissions from energy generated and consumed in an organization's geographic region(s) of operations within the organization's defined boundaries, primarily using grid average emission factors.
Market-Based Method	Scope 2 method that quantifies emissions from energy generated and consumed within the organization's defined boundaries, that the organization has purposefully purchased, using emission factors conveyed through contractual instruments between the organization and the electricity or product provider.
Measurement-Based	Emission quantification methods that involve the determination of emissions by means of direct measurement of the flue gas flow, as well as the concentration of the relevant GHG(s) in the flue gas.
Member	An organization that submits an emissions inventory based on the requirements in the General Reporting Protocol to TCR.

Miniscule Sources	Emissions sources listed on TCR's Exclude Miniscule Sources Form which TCR has deemed may be excluded from an inventory without: » Compromising the relevance of the reported inventory; » Significantly reducing the combined quantity of Scope 1, Scope 2, and biogenic CO_2e emissions reported; » Impacting ability to identify the member's viable opportunities for emissions reductions projects; » Impacting the ability to ascertain whether the member has achieved a reduction (of five percent or greater) in total entity-wide emissions from one year to the next; » Impacting ability to assess the member's climate change related risk exposure; or, » Impacting the decision-making needs of users.
Mobile Emissions	Emissions from the combustion of fuels in transportation sources (e.g., cars, trucks, buses, trains, airplanes, and marine vessels), emissions from non-road equipment such as equipment used in construction, agriculture, and forestry and other mobile sources.
Mobile Source	Emissions sources designed and capable of emitting GHGs while moving from one location to another. An emissions source is not a mobile source if it is a piece of equipment that is designed and capable of being moved from one location to another but does not combust fuel while it is being moved (e.g., an emergency generator).
Nitrogen Trifluoride	NF_3 is used as a replacement for PFCs (mostly C_2F_6) and SF_6 in the electronics industry. It is typically used in plasma etching and chamber cleaning during the manufacture of semi-conductors and LCD panels (Liquid Crystal Display). NF_3 is broken down into nitrogen and fluorine gases in situ, and the resulting fluorine radicals are the active cleaning agents that attack the poly-silicon. NF_3 is also used in the photovoltaic industry (thin-film solar cells) for "texturing, phosphorus silicate glass (PSG) removal, edge isolation and reactor cleaning after deposition of silicon nitrate or film silicon." NF_3 is further used in hydrogen fluoride and deuterium fluoride lasers, which are types of chemical lasers.
Non-Electric Energy Use	Consumption of energy other than electricity (i.e., steam, heat, cooling).
Offsets	Represent the reduction, removal, or avoidance of GHG emissions from a specific project that is used to compensate for (i.e., offset) GHG emissions occurring elsewhere.
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.
Operational Control	Full authority to introduce and implement operating policies at an operation. Operational control is one of two ways to define the control approach.

Organization	A business, corporation, institution, organization, government agency, etc., recognized under national law. A reporting organization is comprised of all the facilities and emission sources delimited by the organizational boundary developed by the organization, taken in their entirety.
Organizational Boundaries	The boundaries that determine the operations owned or controlled by the reporting organization, depending on the consolidation approach taken (either the equity share or control approach).
Perfluorocarbons	(PFC) A group of man-made chemicals composed of one or two carbon atoms and four to six fluorine atoms, containing no chlorine. PFCs have no commercial uses and are emitted as a byproduct of aluminum smelting and semiconductor manufacturing. PFCs have very high GWPs and are very long-lived in the atmosphere.
Process Emissions	Emissions resulting from physical or chemical processes other than from fuel combustion. Examples include emissions from manufacturing cement, aluminum, adipic acid, ammonia, etc.
Purchase Power Agreement	(PPA) A type of contract that allows a consumer, typically a large industrial or commercial entity, to form an agreement with a specific energy generating unit. The contract itself specifies the commercial terms including delivery, price, payment, etc. In many markets, these contracts secure a long-term stream of revenue for an energy project. In order for the consumers to say they are buying the electricity of the specific generator, attributes must be contractually transferred to the consumer with the electricity.
Relevant GHG Sources	Categories of emission sources that must be included within the reporting boundary for TCR to consider the inventory "complete" for the purposes of reporting to TCR. Relevant emissions consist of Scope 1 and Scope 2 emissions, combustion-based direct biogenic emissions, and combustion-based indirect biogenic emissions associated with the consumption of energy. Approved miniscule sources, biogenic emissions other than those associated with the combustion of biomass, and emission sources identified as optional in the protocols are not considered relevant.
Renewable Energy Certificate	(REC) A type of energy attribute certificate. In the U.S. a REC represents the property rights to the environmental, social and other non-power qualities of renewable electricity generation.
Reporting Boundary	The boundary that determines the direct and indirect emissions associated with activities within the inventory.
Reporting Year	The year in which the emissions occurred. Members must report emissions on an annual basis (i.e., calendar year or fiscal year).
Residual Mix	Subnational or national emission factor that uses energy production data and factors out voluntary purchases.
Scope 1 Emissions	Direct anthropogenic GHG emissions.

Scope 2 Emissions	Indirect anthropogenic GHG emissions associated with the consumption of purchased or acquired electricity, steam, heating, or cooling (collectively referred to as consumed energy).
Scope 3 Emissions	All other (non-Scope 2) indirect anthropogenic GHG emissions that occur in the value chain. 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 organization, use of sold products and services, outsourced activities, recycling of used products, and waste disposal.
Simplified Estimation Methods	(SEMs) Rough, upper-bound methods for estimating emissions. Members may use SEMs for any combination of emission sources and/or gases, provided that corresponding emissions do not exceed 10% of the CO_2e sum of reported Scope 1, Scope 2, combustion-based direct biogenic emissions and combustion-based indirect biogenic emissions associated with consumed energy. The higher Scope 2 total must be used to total Scope 1, Scope 2, combustion-based direct biogenic emissions and combustion-based indirect biogenic emissions associated with consumed energy.
Special Power Product	(SPP) A consumer option offered by an energy supplier distinct from the standard offering. The electricity associated with SPPs is often derived from renewable or other low-carbon energy sources, demonstrated by energy attribute certificates or other contracts.
Stationary Combustion Emissions	Emissions from the combustion of fuels in any stationary equipment including boilers, furnaces, burners, turbines, heaters, incinerators, engines, flares, etc.
Stationary Source	An emissions source that is confined to a distinct geographic location and is not designed to operate while in motion.
Verification	The process used to ensure that an organization's greenhouse gas emissions inventory has met a minimum quality standard and complied with TCR's procedures and protocols for calculating and reporting GHG emissions.

The Climate Registry

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APPENDIX C
U.S. EPA Emission Factors for Greenhouse Gas Inventories, 2018

Emission Factors for Greenhouse Gas Inventories

Last Modified: 1 April 2021

Red text indicates an update from the 2020 version of this document.

Typically, greenhouse gas emissions are reported in units of carbon dioxide equivalent (CO_2e). Gases are converted to CO_2e by multiplying by their global warming potential (GWP). The emission factors listed in this document have not been converted to CO_2e. To do so, multiply the emissions by the corresponding GWP listed in the table below.

Gas	100-Year GWP
CH_4	25
N_2O	298

Source: Intergovernmental Panel on Climate Change (IPCC), Fourth Assessment Report (AR4), 2007. See the source note to Table 11 for further explanation.

Table 1 Stationary Combustion

Fuel Type	Heat Content (HHV)	CO_2 Factor	CH_4 Factor	N_2O Factor	CO_2 Factor	CH_4 Factor	N_2O Factor
	mmBtu per short ton	kg CO_2 per mmBtu	g CH_4 per mmBtu	g N_2O per mmBtu	kg CO_2 per short ton	g CH_4 per short ton	g N_2O per short ton
Coal and Coke							
Anthracite Coal	25.09	103.69	11	1.6	2,602	276	40
Bituminous Coal	24.93	93.28	11	1.6	2,325	274	40
Sub-bituminous Coal	17.25	97.17	11	1.6	1,676	190	28
Lignite Coal	14.21	97.72	11	1.6	1,389	156	23
Mixed (Commercial Sector)	21.39	94.27	11	1.6	2,016	235	34
Mixed (Electric Power Sector)	19.73	95.52	11	1.6	1,885	217	32
Mixed (Industrial Coking)	26.28	93.90	11	1.6	2,468	289	42
Mixed (Industrial Sector)	22.35	94.67	11	1.6	2,116	246	36
Coal Coke	24.80	113.67	11	1.6	2,819	273	40
Other Fuels - Solid							
Municipal Solid Waste	9.95	90.70	32	4.2	902	318	42
Petroleum Coke (Solid)	30.00	102.41	32	4.2	3,072	960	126
Plastics	38.00	75.00	32	4.2	2,850	1,216	160
Tires	28.00	85.97	32	4.2	2,407	896	118
Biomass Fuels - Solid							
Agricultural Byproducts	8.25	118.17	32	4.2	975	264	35
Peat	8.00	111.84	32	4.2	895	256	34
Solid Byproducts	10.39	105.51	32	4.2	1,096	332	44
Wood and Wood Residuals	17.48	93.80	7.2	3.6	1,640	126	63
	mmBtu per scf	kg CO_2 per mmBtu	g CH_4 per mmBtu	g N_2O per mmBtu	kg CO_2 per scf	g CH_4 per scf	g N_2O per scf
Natural Gas							
Natural Gas	0.001026	53.06	1.0	0.10	0.05444	0.00103	0.00010
Other Fuels - Gaseous							
Blast Furnace Gas	0.000092	274.32	0.022	0.10	0.02524	0.000002	0.000009
Coke Oven Gas	0.000599	46.85	0.48	0.10	0.02806	0.000288	0.000060
Fuel Gas	0.001388	59.00	3.0	0.60	0.08189	0.004164	0.000833
Propane Gas	0.002516	61.46	3.0	0.60	0.15463	0.007548	0.001510
Biomass Fuels - Gaseous							
Landfill Gas	0.000485	52.07	3.2	0.63	0.025254	0.001552	0.000306
Other Biomass Gases	0.000655	52.07	3.2	0.63	0.034106	0.002096	0.000413
	mmBtu per gallon	kg CO_2 per mmBtu	g CH_4 per mmBtu	g N_2O per mmBtu	kg CO_2 per gallon	g CH_4 per gallon	g N_2O per gallon
Petroleum Products							
Asphalt and Road Oil	0.158	75.36	3.0	0.60	11.91	0.47	0.09
Aviation Gasoline	0.120	69.25	3.0	0.60	8.31	0.36	0.07
Butane	0.103	64.77	3.0	0.60	6.67	0.31	0.06
Butylene	0.105	68.72	3.0	0.60	7.22	0.32	0.06
Crude Oil	0.138	74.54	3.0	0.60	10.29	0.41	0.08
Distillate Fuel Oil No. 1	0.139	73.25	3.0	0.60	10.18	0.42	0.08
Distillate Fuel Oil No. 2	0.138	73.96	3.0	0.60	10.21	0.41	0.08
Distillate Fuel Oil No. 4	0.146	75.04	3.0	0.60	10.96	0.44	0.09
Ethane	0.068	59.60	3.0	0.60	4.05	0.20	0.04
Ethylene	0.058	65.96	3.0	0.60	3.83	0.17	0.03
Heavy Gas Oils	0.148	74.92	3.0	0.60	11.09	0.44	0.09
Isobutane	0.099	64.94	3.0	0.60	6.43	0.30	0.06
Isobutylene	0.103	68.86	3.0	0.60	7.09	0.31	0.06
Kerosene	0.135	75.20	3.0	0.60	10.15	0.41	0.08
Kerosene-Type Jet Fuel	0.135	72.22	3.0	0.60	9.75	0.41	0.08
Liquefied Petroleum Gases (LPG)	0.092	61.71	3.0	0.60	5.68	0.28	0.06
Lubricants	0.144	74.27	3.0	0.60	10.69	0.43	0.09
Motor Gasoline	0.125	70.22	3.0	0.60	8.78	0.38	0.08
Naphtha (<401 deg F)	0.125	68.02	3.0	0.60	8.50	0.38	0.08
Natural Gasoline	0.110	66.88	3.0	0.60	7.36	0.33	0.07
Other Oil (>401 deg F)	0.139	76.22	3.0	0.60	10.59	0.42	0.08
Pentanes Plus	0.110	70.02	3.0	0.60	7.70	0.33	0.07
Petrochemical Feedstocks	0.125	71.02	3.0	0.60	8.88	0.38	0.08
Propane	0.091	62.87	3.0	0.60	5.72	0.27	0.05
Propylene	0.091	67.77	3.0	0.60	6.17	0.27	0.05
Residual Fuel Oil No. 5	0.140	72.93	3.0	0.60	10.21	0.42	0.08
Residual Fuel Oil No. 6	0.150	75.10	3.0	0.60	11.27	0.45	0.09
Special Naphtha	0.125	72.34	3.0	0.60	9.04	0.38	0.08
Unfinished Oils	0.139	74.54	3.0	0.60	10.36	0.42	0.08
Used Oil	0.138	74.00	3.0	0.60	10.21	0.41	0.08
Biomass Fuels - Liquid							
Biodiesel (100%)	0.128	73.84	1.1	0.11	9.45	0.14	0.01
Ethanol (100%)	0.084	68.44	1.1	0.11	5.75	0.09	0.01
Rendered Animal Fat	0.125	71.06	1.1	0.11	8.88	0.14	0.01
Vegetable Oil	0.120	81.55	1.1	0.11	9.79	0.13	0.01
Biomass Fuels - Kraft Pulping Liquor, by Wood Furnish							
North American Softwood		94.4	1.9	0.42			
North American Hardwood		93.7	1.9	0.42			
Bagasse		95.5	1.9	0.42			
Bamboo		93.7	1.9	0.42			
Straw		95.1	1.9	0.42			

Source:
Federal Register EPA; 40 CFR Part 98; e-CFR, (see link below). Table C-1, Table C-2 (as amended at 81 FR 89252, Dec. 9, 2016), Table AA-1 (78 FR 71965, Nov. 29, 2013).
https://www.ecfr.gov/cgi-bin/text-idx?SID=ae265d7d6f98ec86fcd8640b9793a3f6&mc=true&node=pt40.23.98&rgn=div5#ap40.23.98_19.1

Note: Emission factors are per unit of heat content using higher heating values (HHV). If heat content is available from the fuel supplier, it is preferable to use that value. If not, default heat contents are provided.

Table 2 Mobile Combustion CO_2

Fuel Type	kg CO_2 per unit	Unit
Aviation Gasoline	8.31	gallon
Biodiesel (100%)	9.45	gallon
Compressed Natural Gas (CNG)	0.05444	scf
Diesel Fuel	10.21	gallon
Ethanol (100%)	5.75	gallon
Kerosene-Type Jet Fuel	9.75	gallon
Liquefied Natural Gas (LNG)	4.50	gallon
Liquefied Petroleum Gases (LPG)	5.68	gallon
Motor Gasoline	8.78	gallon
Residual Fuel Oil	11.27	gallon

Source:
Federal Register EPA; 40 CFR Part 98; e-CFR, (see link below). Table C-1 (as amended at 81 FR 89252, Dec. 9, 2016).
https://www.ecfr.gov/cgi-bin/text-idx?SID=ae265d7d6f98ec86fcd8640b9793a3f6&mc=true&node=pt40.23.98&rgn=div5#ap40.23.98_19.1
LNG: The factor was developed based on the CO_2 factor for Natural Gas factor and LNG fuel density from GREET1_2020.xlsx Model, Argonne National Laboratory.

Table 3 Mobile Combustion CH_4 and N_2O for On-Road Gasoline Vehicles

Vehicle Type	Year	CH_4 Factor (g / mile)	N_2O Factor (g / mile)
Gasoline Passenger Cars	1973-74	0.1696	0.0197
	1975	0.1423	0.0443
	1976-77	0.1406	0.0458
	1978-79	0.1389	0.0473
	1980	0.1326	0.0499
	1981	0.0802	0.0626
	1982	0.0795	0.0627
	1983	0.0782	0.0630
	1984-93	0.0704	0.0647
	1994	0.0617	0.0603
	1995	0.0531	0.0560
	1996	0.0434	0.0503
	1997	0.0337	0.0446
	1998	0.0240	0.0389
	1999	0.0215	0.0355
	2000	0.0175	0.0304
	2001	0.0105	0.0212
	2002	0.0102	0.0207
	2003	0.0095	0.0181
	2004	0.0078	0.0085
	2005	0.0075	0.0067
	2006	0.0076	0.0075
	2007	0.0072	0.0052
	2008	0.0072	0.0049
	2009	0.0071	0.0046
	2010	0.0071	0.0046
	2011	0.0071	0.0046
	2012	0.0071	0.0046
	2013	0.0071	0.0046
	2014	0.0071	0.0046
	2015	0.0068	0.0042
	2016	0.0065	0.0038
	2017	0.0054	0.0018
	2018	0.0052	0.0016
Gasoline Light-Duty Trucks (Vans, Pickup Trucks, SUVs)	1973-74	0.1908	0.0218
	1975	0.1634	0.0513
	1976	0.1594	0.0555
	1977-78	0.1614	0.0534
	1979-80	0.1594	0.0555
	1981	0.1479	0.0660
	1982	0.1442	0.0681
	1983	0.1368	0.0722
	1984	0.1294	0.0764
	1985	0.1220	0.0806
	1986	0.1146	0.0848
	1987-93	0.0813	0.1035
	1994	0.0646	0.0982
	1995	0.0517	0.0908
	1996	0.0452	0.0871
	1997	0.0452	0.0871
	1998	0.0412	0.0787
	1999	0.0333	0.0618
	2000	0.0340	0.0631
	2001	0.0221	0.0379
	2002	0.0242	0.0424
	2003	0.0221	0.0373
	2004	0.0115	0.0088
	2005	0.0105	0.0064
	2006	0.0108	0.0080
	2007	0.0103	0.0061
	2008	0.0095	0.0036
	2009	0.0095	0.0036
	2010	0.0095	0.0035
	2011	0.0096	0.0034
	2012	0.0096	0.0033
	2013	0.0095	0.0035
	2014	0.0095	0.0033
	2015	0.0094	0.0031
	2016	0.0091	0.0029
	2017	0.0084	0.0018
	2018	0.0081	0.0015
Gasoline Heavy-Duty Vehicles	<1981	0.4604	0.0497
	1982-84	0.4492	0.0538
	1985-86	0.4090	0.0515
	1987	0.3675	0.0849
	1988-1989	0.3492	0.0933
	1990-1995	0.3246	0.1142
	1996	0.1278	0.1680
	1997	0.0924	0.1726
	1998	0.0655	0.1750
	1999	0.0648	0.1724
	2000	0.0630	0.1660
	2001	0.0577	0.1468
	2002	0.0634	0.1673
	2003	0.0602	0.1553
	2004	0.0298	0.0164
	2005	0.0297	0.0083
	2006	0.0299	0.0241
	2007	0.0322	0.0015
	2008	0.0340	0.0015
	2009	0.0339	0.0015
	2010	0.0320	0.0015
	2011	0.0304	0.0015
	2012	0.0313	0.0015
	2013	0.0313	0.0015
	2014	0.0315	0.0015
	2015	0.0332	0.0021
	2016	0.0321	0.0061
	2017	0.0329	0.0084
	2018	0.0326	0.0082
Gasoline Motorcycles	1960-1995	0.0899	0.0087
	1996-2018	0.0672	0.0069

Source: EPA (2020) Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2018. All values are calculated from Tables A-106 through A-110.

Table 4 **Mobile Combustion CH_4 and N_2O for On-Road Diesel and Alternative Fuel Vehicles**

Vehicle Type	Fuel Type	Vehicle Year	CH_4 Factor (g / mile)	N_2O Factor (g / mile)
Passenger Cars	Diesel	1960-1982	0.0006	0.0012
		1983-1995	0.0005	0.0010
		1996-2006	0.0005	0.0010
		2007-2018	0.0302	0.0192
Light-Duty Trucks	Diesel	1960-1982	0.0011	0.0017
		1983-1995	0.0009	0.0014
		1996-2006	0.0010	0.0015
		2007-2018	0.0290	0.0214
Medium- and Heavy-Duty Vehicles	Diesel	1960-2006	0.0051	0.0048
		2007-2018	0.0095	0.0431
Light-Duty Cars	Methanol		0.0080	0.0060
	Ethanol		0.0080	0.0060
	CNG		0.0820	0.0060
	LPG		0.0080	0.0060
	Biodiesel		0.0300	0.0190
Light-Duty Trucks	Ethanol		0.0120	0.0110
	CNG		0.1230	0.0110
	LPG		0.0120	0.0130
	LNG		0.1230	0.0110
	Biodiesel		0.0290	0.0210
Medium-Duty Trucks	CNG		4.2000	0.0010
	LPG		0.0140	0.0340
	LNG		4.2000	0.0430
	Biodiesel		0.0090	0.0010
Heavy-Duty Trucks	Methanol		0.0750	0.0280
	Ethanol		0.0750	0.0280
	CNG		3.7000	0.0010
	LPG		0.0130	0.0260
	LNG		3.7000	0.0010
	Biodiesel		0.0090	0.0430
Buses	Methanol		0.0220	0.0320
	Ethanol		0.0220	0.0320
	CNG		10.0000	0.0010
	LPG		0.0340	0.0170
	LNG		10.0000	0.0010
	Biodiesel		0.0090	0.0430

Source: EPA (2020) Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2018. All values are calculated from Tables A-109 through A-112.

Table 5 **Mobile Combustion CH_4 and N_2O for Non-Road Vehicles**

Vehicle Type	Fuel Type	CH_4 Factor (g / gallon)	N_2O Factor (g / gallon)
Ships and Boats	Residual Fuel Oil	0.55	0.55
	Gasoline (2 stroke)	9.54	0.06
	Gasoline (4 stroke)	4.88	0.23
	Diesel	0.31	0.50
Locomotives	Diesel	0.80	0.26
Aircraft	Jet Fuel	0	0.30
	Aviation Gasoline	7.06	0.11
Agricultural Equipment[A]	Gasoline (2 stroke)	12.96	0.06
	Gasoline (4 stroke)	7.24	0.21
	Diesel	0.28	0.49
	LPG	2.19	0.39
Agricultural Offroad Trucks	Gasoline	7.24	0.21
	Diesel	0.13	0.49
Construction/Mining Equipment[B]	Gasoline (2 stroke)	12.42	0.07
	Gasoline (4 stroke)	5.58	0.20
	Diesel	0.20	0.47
	LPG	1.05	0.41
Construction/Mining Offroad Trucks	Gasoline	5.58	0.20
	Diesel	0.13	0.49
Lawn and Garden Equipment	Gasoline (2 stroke)	15.57	0.06
	Gasoline (4 stroke)	5.84	0.18
	Diesel	0.33	0.47
	LPG	0.35	0.41
Airport Equipment	Gasoline	2.58	0.25
	Diesel	0.17	0.49
	LPG	0.33	0.41
Industrial/Commercial Equipment	Gasoline (2 stroke)	15.14	0.06
	Gasoline (4 stroke)	5.48	0.20
	Diesel	0.23	0.47
	LPG	0.44	0.41
Logging Equipment	Gasoline (2 stroke)	12.03	0.08
	Gasoline (4 stroke)	6.71	0.18
	Diesel	0.10	0.49
Railroad Equipment	Gasoline	5.78	0.19
	Diesel	0.44	0.42
	LPG	1.20	0.41
Recreational Equipment	Gasoline (2 stroke)	7.81	0.03
	Gasoline (4 stroke)	8.45	0.19
	Diesel	0.41	0.41
	LPG	2.98	0.38

Source: EPA (2020) Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2018. All values are calculated from Tables A-113 through A-114.

Notes:

[A] Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.

[B] Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.

Table 6 **Electricity**

	eGRID Subregion	Total Output Emission Factors			Non-Baseload Emission Factors		
		CO_2 Factor (lb / MWh)	CH_4 Factor (lb / MWh)	N_2O Factor (lb / MWh)	CO_2 Factor (lb / MWh)	CH_4 Factor (lb / MWh)	N_2O Factor (lb / MWh)
	AKGD (ASCC Alaska Grid)	1,114.4	0.098	0.013	1,333.0	0.123	0.017
	AKMS (ASCC Miscellaneous)	549.3	0.026	0.004	1,520.2	0.067	0.012
	AZNM (WECC Southwest)	952.3	0.068	0.010	1,445.3	0.100	0.014
	CAMX (WECC California)	453.2	0.033	0.004	964.0	0.058	0.007
	ERCT (ERCOT All)	868.6	0.057	0.008	1,277.2	0.083	0.012
	FRCC (FRCC All)	861.0	0.055	0.007	1,029.5	0.054	0.007
	HIMS (HICC Miscellaneous)	1,185.6	0.143	0.022	1,549.5	0.107	0.018
	HIOA (HICC Oahu)	1,694.5	0.185	0.028	1,704.1	0.158	0.025
	MROE (MRO East)	1,502.6	0.147	0.022	1,577.7	0.145	0.021
	MROW (MRO West)	1,098.4	0.119	0.017	1,806.8	0.188	0.027
	NEWE (NPCC New England)	488.9	0.077	0.010	839.9	0.089	0.012
	NWPP (WECC Northwest)	715.2	0.068	0.010	1,617.5	0.156	0.022
	NYCW (NPCC NYC/Westchester)	553.8	0.021	0.002	1,016.2	0.022	0.002
	NYLI (NPCC Long Island)	1,209.0	0.157	0.020	1,300.6	0.044	0.005
	NYUP (NPCC Upstate NY)	232.3	0.017	0.002	890.2	0.047	0.006
New Region	PRMS (Puerto Rico Miscellaneous)	1,537.3	0.084	0.013	1,587.9	0.055	0.010
	RFCE (RFC East)	695.0	0.053	0.007	1,237.9	0.089	0.012
	RFCM (RFC Michigan)	1,189.3	0.114	0.016	1,766.9	0.177	0.025
	RFCW (RFC West)	1,067.7	0.099	0.014	1,831.6	0.178	0.026
	RMPA (WECC Rockies)	1,242.6	0.117	0.017	1,578.8	0.126	0.018
	SPNO (SPP North)	1,070.0	0.112	0.016	1,958.6	0.200	0.029
	SPSO (SPP South)	1,002.0	0.070	0.010	1,543.7	0.108	0.015
	SRMV (SERC Mississippi Valley)	806.8	0.043	0.006	1,200.1	0.068	0.010
	SRMW (SERC Midwest)	1,584.4	0.169	0.025	1,960.9	0.216	0.031
	SRSO (SERC South)	969.2	0.071	0.010	1,389.5	0.101	0.015
	SRTV (SERC Tennessee Valley)	949.7	0.087	0.013	1,565.2	0.139	0.020
	SRVC (SERC Virginia/Carolina)	675.4	0.058	0.008	1,349.2	0.118	0.017
	US Average	884.2	0.075	0.011	1,420.2	0.114	0.016

Source: EPA eGRID2019, February 2021

Note: Total output emission factors can be used as default factors for estimating GHG emissions from electricity use when developing a carbon footprint or emissions inventory. Annual non-baseload output emission factors should not be used for those purposes, but can be used to estimate GHG emissions reductions from reductions in electricity use.

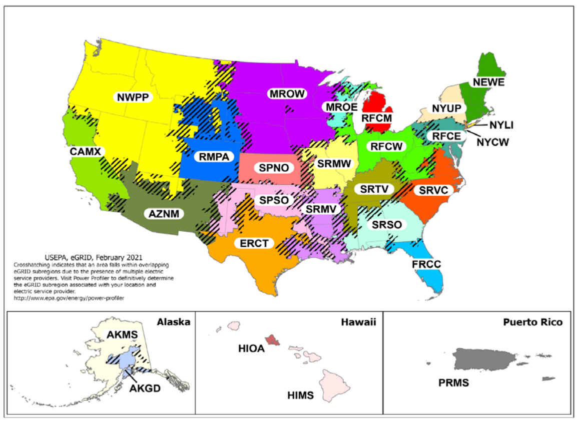

Table 7 **Steam and Heat**

	CO_2 Factor (kg / mmBtu)	CH_4 Factor (g / mmBtu)	N_2O Factor (g / mmBtu)
Steam and Heat	66.33	1.250	0.125

Note: Emission factors are per mmBtu of steam or heat purchased. These factors assume natural gas fuel is used to generate steam or heat at 80 percent thermal efficiency.

Scope 3 Emission Factors

Scope 3 emission factors provided below are aligned with the Greenhouse Gas Protocol Technical Guidance for Calculating Scope 3 Emissions, version 1.0 (Scope 3 Calculation Guidance). Where applicable, the specific calculation method is referenced. Refer to the Scope 3 Calculation Guidance for more information (http://www.ghgprotocol.org/scope-3-technical-calculation-guidance).

Table 8 Scope 3 Category 4: Upstream Transportation and Distribution and Category 9: Downstream Transportation and Distribution

These factors are intended for use in the distance-based method defined in the Scope 3 Calculation Guidance. If fuel data are available, then the fuel-based method should be used, with factors from Tables 2 through 5.

Vehicle Type	CO_2 Factor (kg / unit)	CH_4 Factor (g / unit)	N_2O Factor (g / unit)	Units
Medium- and Heavy-Duty Truck	1.407	0.013	0.033	vehicle-mile
Passenger Car [A]	0.341	0.009	0.008	vehicle-mile
Light-Duty Truck [B]	0.464	0.012	0.010	vehicle-mile
Medium- and Heavy-Duty Truck	0.211	0.0020	0.0049	ton-mile
Rail	0.022	0.0017	0.0005	ton-mile
Waterborne Craft	0.036	0.0116	0.0016	ton-mile
Aircraft[C]	1.160	0.0000	0.0357	ton-mile

Source:
CO_2, CH_4, and N_2O emissions data for road vehicles are from Table 2-13 of the EPA (2020) Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2018.
Vehicle-miles and passenger-miles data for road vehicles are from Table VM-1 of the Federal Highway Administration Highway Statistics 2018.
CO2e emissions data for non-road vehicles are based on Table A-124 of the EPA (2020) Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2018, which are distributed into CO2, CH4, and N2O emissions based on fuel/vehicle emission factors.
Freight ton-mile data for non-road vehicles are from Table 1-50 of the Bureau of Transportation Statistics, National Transportation Statistics for 2020 (Data based on 2018).

Notes:
Vehicle-mile factors are appropriate to use when the entire vehicle is dedicated to transporting the reporting company's product. Ton-mile factors are appropriate when the vehicle is shared with products from other companies.
[A] Passenger car: includes passenger cars, minivans, SUVs, and small pickup trucks (vehicles with wheelbase less than 121 inches).
[B] Light-duty truck: includes full-size pickup trucks, full-size vans, and extended-length SUVs (vehicles with wheelbase greater than 121 inches).
[C] Aircraft: updates due to a methodology change.

Table 9 **Scope 3 Category 5: Waste Generated in Operations and Category 12: End-of-Life Treatment of Sold Products**

These factors are intended for use in the waste-type-specific method or the average-data method defined in the Scope 3 Calculation Guidance for category 5 and category 12. Choose the appropriate material and disposal method from the table below. For the average-data method, use one of the mixed material types, such as mixed MSW.

	Metric Tons CO_2e / Short Ton Material					
Material	**Recycled**[A]	**Landfilled**[B]	**Combusted**[C]	**Composted**[D]	**Anaerobically Digested (Dry Digestate with Curing)**	**Anaerobically Digested (Wet Digestate with Curing)**
Aluminum Cans	0.06	0.02	0.01	NA	NA	NA
Aluminum Ingot	0.04	0.02	0.01	NA	NA	NA
Steel Cans	0.32	0.02	0.01	NA	NA	NA
Copper Wire	0.18	0.02	0.01	NA	NA	NA
Glass	0.05	0.02	0.01	NA	NA	NA
HDPE	0.21	0.02	2.80	NA	NA	NA
LDPE	NA	0.02	2.80	NA	NA	NA
PET	0.23	0.02	2.05	NA	NA	NA
LLDPE	NA	0.02	2.80	NA	NA	NA
PP	NA	0.02	2.80	NA	NA	NA
PS	NA	0.02	3.02	NA	NA	NA
PVC	NA	0.02	1.26	NA	NA	NA
PLA	NA	0.02	0.01	0.17	NA	NA
Corrugated Containers	0.11	0.90	0.05	NA	NA	NA
Magazines/Third-class mail	0.02	0.42	0.05	NA	NA	NA
Newspaper	0.02	0.35	0.05	NA	NA	NA
Office Paper	0.02	1.25	0.05	NA	NA	NA
Phonebooks	0.04	0.35	0.05	NA	NA	NA
Textbooks	0.04	1.25	0.05	NA	NA	NA
Dimensional Lumber	0.09	0.17	0.05	NA	NA	NA
Medium-density Fiberboard	0.15	0.07	0.05	NA	NA	NA
Food Waste (non-meat)	NA	0.58	0.05	0.15	0.14	0.11
Food Waste (meat only)	NA	0.58	0.05	NA	0.14	0.11
Beef	NA	0.58	0.05	0.15	0.14	0.11
Poultry	NA	0.58	0.05	0.15	0.14	0.11
Grains	NA	0.58	0.05	0.15	0.14	0.11
Bread	NA	0.58	0.05	0.15	0.14	0.11
Fruits and Vegetables	NA	0.58	0.05	0.15	0.14	0.11
Dairy Products	NA	0.58	0.05	0.15	0.14	0.11
Yard Trimmings	NA	0.33	0.05	0.19	0.11	NA
Grass	NA	0.26	0.05	0.19	0.09	NA
Leaves	NA	0.26	0.05	0.19	0.13	NA
Branches	NA	0.53	0.05	0.19	0.16	NA
Mixed Paper (general)	0.07	0.80	0.05	NA	NA	NA
Mixed Paper (primarily residential)	0.07	0.77	0.05	NA	NA	NA
Mixed Paper (primarily from offices)	0.03	0.75	0.05	NA	NA	NA
Mixed Metals	0.23	0.02	0.01	NA	NA	NA
Mixed Plastics	0.22	0.02	2.34	NA	NA	NA
Mixed Recyclables	0.09	0.68	0.11	NA	NA	NA
Food Waste	NA	0.58	0.05	0.15	NA	NA
Mixed Organics	NA	0.48	0.05	0.17	NA	NA
Mixed MSW	NA	0.52	0.43	NA	NA	NA
Carpet	NA	0.02	1.68	NA	NA	NA
Desktop CPUs	NA	0.02	0.40	NA	NA	NA
Portable Electronic Devices	NA	0.02	0.89	NA	NA	NA
Flat-panel Displays	NA	0.02	0.74	NA	NA	NA
CRT Displays	NA	0.02	0.64	NA	NA	NA
Electronic Peripherals	NA	0.02	2.23	NA	NA	NA
Hard-copy Devices	NA	0.02	1.92	NA	NA	NA
Mixed Electronics	NA	0.02	0.87	NA	NA	NA
Clay Bricks	NA	0.02	NA	NA	NA	NA
Concrete	0.01	0.02	NA	NA	NA	NA
Fly Ash	0.01	0.02	NA	NA	NA	NA
Tires	0.10	0.02	2.21	NA	NA	NA
Asphalt Concrete	-	0.02	NA	NA	NA	NA
Asphalt Shingles	0.03	0.02	0.70	NA	NA	NA
Drywall	NA	0.02	NA	NA	NA	NA
Fiberglass Insulation	0.05	0.02	NA	NA	NA	NA
Vinyl Flooring	NA	0.02	0.29	NA	NA	NA
Wood Flooring	NA	0.18	0.08	NA	NA	NA

Source: EPA, Office of Resource Conservation and Recovery (February 2016) Documentation for Greenhouse Gas Emission and Energy Factors used in the Waste Reduction Model (WARM). Factors from tables provided in the Management Practices Chapters and Background Chapters. WARM Version 15, November 2020 Update. Additional data provided by EPA, WARM-15 Background Data.

Notes: These factors do not include any avoided emissions impact from any of the disposal methods. All the factors presented here include transportation emissions, which are optional in the Scope 3 Calculation Guidance, with an assumed average distance traveled to the processing facility. AR4 GWPs are used to convert all waste emission factors into CO_2e.

[A] Recycling emissions include transport to recycling facility and sorting of recycled materials at material recovery facility.

[B] Landfilling emissions include transport to landfill, equipment use at landfill and fugitive landfill CH_4 emissions. Landfill CH_4 is based on typical landfill gas collection practices and average landfill moisture conditions.

[C] Combustion emissions include transport to combustion facility and combustion-related non-biogenic CO_2 and N_2O

[D] Composting emissions include transport to composting facility, equipment use at composting facility and CH_4 and N_2O emissions during composting.

Table 10 **Scope 3 Category 6: Business Travel and Category 7: Employee Commuting**

These factors are intended for use in the distance-based method defined in the Scope 3 Calculation Guidance. If fuel data are available, then the fuel-based method should be used, with factors from Tables 2 through 5.

Vehicle Type	CO_2 Factor (kg / unit)	CH_4 Factor (g / unit)	N_2O Factor (g / unit)	Units
Passenger Car [A]	0.341	0.009	0.008	vehicle-mile
Light-Duty Truck [B]	0.464	0.012	0.010	vehicle-mile
Motorcycle	0.189	0.070	0.007	vehicle-mile
Intercity Rail - Northeast Corridor [C]	0.058	0.0055	0.0007	passenger-mile
Intercity Rail - Other Routes [C]	0.150	0.0117	0.0038	passenger-mile
Intercity Rail - National Average [C]	0.113	0.0092	0.0026	passenger-mile
Commuter Rail [D]	0.143	0.0119	0.0029	passenger-mile
Transit Rail (i.e. Subway, Tram) [E]	0.106	0.0095	0.0013	passenger-mile
Bus	0.054	0.0206	0.0009	passenger-mile
Air Travel - Short Haul (< 300 miles)	0.206	0.0071	0.0065	passenger-mile
Air Travel - Medium Haul (>= 300 miles, < 2300 miles)	0.131	0.0006	0.0042	passenger-mile
Air Travel - Long Haul (>= 2300 miles)	0.161	0.0006	0.0051	passenger-mile

Source:
CO_2, CH_4, and N_2O emissions data for highway vehicles are from Table 2-13 of the EPA (2020) Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2018.
Vehicle-miles and passenger-miles data for highway vehicles are from Table VM-1 of the Federal Highway Administration Highway Statistics 2018.
Fuel consumption data and passenger-miles data for rail are from Tables A.14 to A.16 and C.9 to C.11 of the Transportation Energy Data Book: Edition 39. Fuel consumption was converted to emissions by using fuel and electricity emission factors presented in the tables above.
Intercity Rail factors from personal communication with Amtrak (Laura Fotiou), March 2020. These are based on 2019 values.
Air Travel factors from 2020 Guidelines to Defra / DECC's GHG Conversion Factors for Company Reporting. Version 1.0 July 2020.

Notes:
[A] Passenger car: includes passenger cars, minivans, SUVs, and small pickup trucks (vehicles with wheelbase less than 121 inches).
[B] Light-duty truck: includes full-size pickup trucks, full-size vans, and extended-length SUVs (vehicles with wheelbase greater than 121 inches).
[C] Intercity rail: Amtrak long-distance rail between major cities. Northeast Corridor extends from Boston to Washington D.C. Other Routes are all routes outside the Northeast Corridor.
[D] Commuter rail: rail service between a central city and adjacent suburbs (also called regional rail or suburban rail).
[E] Transit rail: rail typically within an urban center, such as subways, elevated railways, metropolitan railways (metro), streetcars, trolley cars, and tramways.

Global Warming Potentials

Table 11 Global Warming Potentials (GWPs)

Gas	100-Year GWP
CO_2	1
CH_4	25
N_2O	298
HFC-23	14,800
HFC-32	675
HFC-41	92
HFC-125	3,500
HFC-134	1,100
HFC-134a	1,430
HFC-143	353
HFC-143a	4,470
HFC-152	53
HFC-152a	124
HFC-161	12
HFC-227ea	3,220
HFC-236cb	1,340
HFC-236ea	1,370
HFC-236fa	9,810
HFC-245ca	693
HFC-245fa	1,030
HFC-365mfc	794
HFC-43-10mee	1,640
SF_6	22,800
NF_3	17,200
CF_4	7,390
C_2F_6	12,200
C_3F_8	8,830
c-C_4F_8	10,300
C_4F_{10}	8,860
C_5F_{12}	9,160
C_6F_{14}	9,300
$C_{10}F_{18}$	>7,500

Source:
100-year GWPs from IPCC Fourth Assessment Report (AR4), 2007. IPCC AR4 was published in 2007 and is among the most current and comprehensive peer-reviewed assessments of climate change. AR4 provides revised GWPs of several GHGs relative to the values provided in previous assessment reports, following advances in scientific knowledge on the radiative efficiencies and atmospheric lifetimes of these GHGs and of CO_2. Because the GWPs provided in AR4 reflect an improved scientific understanding of the radiative effects of these gases in the atmosphere, the values provided are more appropriate for supporting the overall goal of organizational GHG reporting than the Second Assessment Report (SAR) GWP values previously used in the Emission Factors Hub.
While EPA recognizes that Fifth Assessment Report (AR5) GWPs have been published, in an effort to ensure consistency and comparability of GHG data between EPA's voluntary and non-voluntary GHG reporting programs (e.g. GHG Reporting Program and National Inventory), EPA recommends the use of AR4 GWPs. The United States and other developed countries to the UNFCCC have agreed to submit annual inventories in 2015 and future years to the UNFCCC using GWP values from AR4, which will replace the current use of SAR GWP values. Utilizing AR4 GWPs improves EPA's ability to analyze corporate, national, and sub-national GHG data consistently, enhances communication of GHG information between programs, and gives outside stakeholders a consistent, predictable set of GWPs to avoid confusion and additional burden.

Table 12 Global Warming Potentials (GWPs) for Blended Refrigerants

ASHRAE #	100-year GWP	Blend Composition
R-401A	16	53% HCFC-22 , 34% HCFC-124 , 13% HFC-152a
R-401B	14	61% HCFC-22 , 28% HCFC-124 , 11% HFC-152a
R-401C	19	33% HCFC-22 , 52% HCFC-124 , 15% HFC-152a
R-402A	2,100	38% HCFC-22 , 6% HFC-125 , 2% propane
R-402B	1,330	6% HCFC-22 , 38% HFC-125 , 2% propane
R-403B	3,444	56% HCFC-22 , 39% PFC-218 , 5% propane
R-404A	3,922	44% HFC-125 , 4% HFC-134a , 52% HFC 143a
R-406A	0	55% HCFC-22 , 41% HCFC-142b , 4% isobutane
R-407A	2,107	20% HFC-32 , 40% HFC-125 , 40% HFC-134a
R-407B	2,804	10% HFC-32 , 70% HFC-125 , 20% HFC-134a
R-407C	1,774	23% HFC-32 , 25% HFC-125 , 52% HFC-134a
R-407D	1,627	15% HFC-32 , 15% HFC-125 , 70% HFC-134a
R-407E	1,552	25% HFC-32 , 15% HFC-125 , 60% HFC-134a
R-408A	2,301	47% HCFC-22 , 7% HFC-125 , 46% HFC 143a
R-409A	0	60% HCFC-22 , 25% HCFC-124 , 15% HCFC-142b
R-410A	2,088	50% HFC-32 , 50% HFC-125
R-410B	2,229	45% HFC-32 , 55% HFC-125
R-411A	14	87.5% HCFC-22 , 11 HFC-152a , 1.5% propylene
R-411B	4	94% HCFC-22 , 3% HFC-152a , 3% propylene
R-413A	2,053	88% HFC-134a , 9% PFC-218 , 3% isobutane
R-414A	0	51% HCFC-22 , 28.5% HCFC-124 , 16.5% HCFC-142b
R-414B	0	5% HCFC-22 , 39% HCFC-124 , 9.5% HCFC-142b
R-417A	2,346	46.6% HFC-125 , 5% HFC-134a , 3.4% butane
R-422A	3,143	85.1% HFC-125 , 11.5% HFC-134a , 3.4% isobutane
R-422D	2,729	65.1% HFC-125 , 31.5% HFC-134a , 3.4% isobutane
R-423A	2,280	47.5% HFC-227ea , 52.5% HFC-134a ,
R-424A	2,440	50.5% HFC-125, 47% HFC-134a, 2.5% butane/pentane
R-426A	1,508	5.1% HFC-125, 93% HFC-134a, 1.9% butane/pentane
R-428A	3,607	77.5% HFC-125 , 2% HFC-143a , 1.9% isobutane
R-434A	3,245	63.2% HFC-125, 16% HFC-134a, 18% HFC-143a, 2.8% isobutane
R-500	32	73.8% CFC-12 , 26.2% HFC-152a , 48.8% HCFC-22
R-502	0	48.8% HCFC-22 , 51.2% CFC-115
R-504	325	48.2% HFC-32 , 51.8% CFC-115
R-507	3,985	5% HFC-125 , 5% HFC143a
R-508A	13,214	39% HFC-23 , 61% PFC-116
R-508B	13,396	46% HFC-23 , 54% PFC-116

Source:
100-year GWPs from IPCC Fourth Assessment Report (AR4), 2007. See the source note to Table 11 for further explanation. GWPs of blended refrigerants are based on their HFC and PFC constituents, which are based on data from http://www.epa.gov/ozone/snap/refrigerants/refblend.html.