The Climate Registry

08/18/10
General Reporting Protocol 1.1
Updates and Clarifications

The Climate Registry (The Registry) published its General Reporting Protocol (GRP v 1.1) in May 2008. While The Registry intends for the GRP v 1.1 to be a complete document, it recognizes that updates and clarifications will be necessary as the voluntary greenhouse gas (GHG) reporting program evolves. Therefore, The Registry created this document to track all modifications relating to GRP v 1.1. This document will be updated as new updates and clarifications are identified.

The updates and clarifications are presented in order of the chapters of GRP v 1.1 and not according to the dates issued. **"Issued"** is the date when the clarification was first issued and **"Effective"** is the effective date, meaning all emissions quantified on or after that date must follow these guidelines. The Registry releases the majority of technical updates at the beginning of each calendar year to help ensure consistency in reporting for all Members.

The updates and clarifications identified in this document will be incorporated into the next version of the GRP. Until the next version of the GRP is released, all Members and Verification Bodies should refer to the updates and clarifications listed below for the most current interpretation and explanation of GHG reporting policies, processes, and activities.

If you have any questions about the updates or clarifications in this document, please contact Peggy Foran at: peggy@theclimateregistry.org or (213) 542-0291.

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GRP v 1.1	**General Reporting Protocol Version 1.1**		**Issued: 11/24/08** **Effective: 11/24/08**
	The Registry has changed its nomenclature from "Reporters" to "Members" to reflect that its Members demonstrate leadership in reporting their footprint to The Registry and to highlight that its Members are participating in a GHG community. To ease this transition in terminology, all references in this document will refer to "Members." The next version of the GRP will reference the term "Members" rather than "Reporters."		

Mandatory Program Calculation Methodologies	**The Registry Accepts Mandatory Program Calculation Methodologies**		**Issued: 02/11/10** **Effective: 02/11/10**
	The Registry accepts all GHG emission calculation methodologies mandated by a State, Provincial, or Federal GHG Regulatory GHG reporting program. Like all information publically reported through The Registry, data calculated using mandatory methodologies must be included in the Verification Body's risk assessment in accordance with the guidelines of the General Verification Protocol.		

Emission Factors	**Updated Emission Factors**		**Issued: 01/5/10** **Effective: 01/5/10**
	Default emission factors sometimes change over time as the components of energy (electricity, fuel, etc.) change and as emission factor quantification methods are refined. The Registry updates emission factors on an annual basis in January to reflect the most up-to-date knowledge. New emission factors were released on The Registry's website on January 5, 2010 and are available here. These emission factors will be part of the CRIS 3.0 calculation tool (released Spring 2010) and must be used to calculate 2009 emissions. Members who choose to report emissions data from previous years can use the most up to date emission factors in the CRIS calculation tool at the time they report. Members do not have to change data already inputted in CRIS. If you are in the middle of reporting when the emissions factors change, you must make sure that across your inventory you use the same default emission factor for all occurrences of each emitting activity.		

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Member Developed Methodologies	**Member Developed Methodologies**		**Issued: 02/11/10** **Effective: 01/1/10**
	In rare instances, Members find it necessary to develop a unique methodology to complete their greenhouse gas inventory. The Climate Registry has developed a process to approve these member developed methodologies. Complete information and the necessary forms for this process can be found here. We encourage Members to complete this process prior to entering the verification stage. *Please note that **Members can only propose methodologies under three circumstances**: 1) the methodology is for an emissions source not covered under The Registry's guidance, 2) a member is unable to use any of the Registry-provided methodologies for a certain source or 3) a member is able to develop a methodology that is more accurate than The Registry's methodology for that source. To be approved, **the methodology must be at least as accurate as one of The Registry's methodologies*** <u>Evaluation Criteria</u> Member developed methodologies will be approved when they meet any one of the following two criteria: 1. The Registry does not provide guidance for the particular source 2. The Member is unable to use The Registry's current guidance And when: The methodology is deemed, by Registry staff, to be at least as accurate as one of The Registry's accepted methodologies.		

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Data Quality Tiers	**Elimination of Data Quality Tier Labels**		**Issued: 02/11/10** **Effective: 02/11/10**
	The Registry is eliminating the use of data quality tiers in its voluntary reporting program. This means that tier designations will not appear in CRIS 3.0 (launching Spring 2010) nor the GRP 2.0 (to be released in Fall 2010). The Registry is making this change to simplify and standardize the use of reporting methodologies. The General Reporting Protocol and the Industry-specific protocols contain many calculation methodologies. Each separate methodology provides a specific level of accuracy. In the forthcoming GRP 2.0, each calculation methodology will be assigned a unique reference identifier, rather than a general tier designation. Members will use these identifiers in reporting emission calculation methods. This will streamline reporting and some verification activities. Mandatory reporting programs that reference The Registry's reporting protocols may continue to designate which methodologies are acceptable and/or preferred under their program. *The Registry is not removing or altering the calculation methodologies in the GRP; only the Tier designations are being eliminated.* This change will not affect Member calculations for voluntary reporting. The Registry continues to encourage Members to use the most accurate methodologies possible. In general, the more site-specific information used when calculating emissions from an activity, the more accurate the outcome. Direct monitoring systems, such as Continuous Emissions Monitoring Systems (CEMS), provide the highest data accuracy, emission factors customized to reflect site-specific monitoring data provide the next level of accuracy, and default emission factors provide a lower, but still acceptable, level of accuracy.		

Utility Specific Metrics	**Utility Companies Can Report Electric Power Utility Sector Specific Metrics Starting with 2009 Data**		**Issued: 02/11/10** **Effective: 02/11/10**
	Starting with 2010 emissions data, utility companies will be required to report to The Registry using the Electric Power Sector (EPS) Protocol. Beginning with 2009 emissions data, utility companies can report EPS specific metrics as supplementary information. To do this, Members must contact The Registry and request the appropriate reporting form.		

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Chapter 2 Geographic Boundaries	Calculating Emissions from US Dependent Territories	**p. 11**	**Issued: 02/11/10 Effective: 02/11/10**

Scope 1 default emission factors for US dependent territories are not available at this time. Members should use default US emission factors to report Scope 1 emissions from US territories. For Scope 2 emissions, Members must use the emission factors below, taken from the Department of Energy guidance on Voluntary Reporting of Greenhouse Gases (http://www.eia.doe.gov/oiaf/1605/pdf/Appendix%20F_r071023.pdf):

	1999-2002 Emission Rates		
	lbs CO2/MWh	lb CH4/MWh	lbs N2O/MWH
U.S. Territories	1891.566208	0.075905157	0.017129918

Chapter 4	**Organizational Boundaries**		**Issued: 04/27/09 Effective: 04/27/09**

When reporting emissions to The Registry you must include emissions from all of the activities that are present within your organization's chosen consolidation methodology as of December 31st of the reporting year, unless you have closed a facility. In the case of a closure, you *must* report the emissions from the closed facility that occurred during the reporting year.

Example:
If ABC Corp. sold Facility A on June 15th to XYZ Inc. and closed Facility B on September 10th, ABC Corp. would only report the emissions from Facility B (those that were emitted between January 1st and September 15th). ABC Corp. would not report any emissions from Facility A. Instead, XYZ Inc. would be responsible for reporting emissions from Facility A for the entire reporting year, as Facility A would appear on XYZ Inc.'s facility inventory on Dec 31st of the reporting year.

The following paragraph and table should be inserted into the text after the fourth paragraph of the introduction to Chapter 4:

> When reporting to The Registry, you must include emissions from all activities that fall within your chosen consolidation methodology as of December 31st of the reporting year, unless your entity has closed a facility. In the case of a closure, you must report the emissions from the closed facility that occurred during the reporting year. The table below illustrates how to determine when

you are required to report emissions based on the following common scenarios:

Action	Reporting Requirement
Acquire Existing Facility	The acquiring entity must report emissions from the acquired facility for the entire reporting year.
Divest Existing Facility	The entity divesting itself of the facility must not report any Scope 1 or Scope 2 emissions from the divested facility during the reporting year. Emissions from the divested facility may optionally be reported by this entity as Scope 3 emissions.
Open New Facility	The entity with control of a new facility on December 31st must report all emissions emitted by the new facility during the reporting year.
Close Existing Facility	The entity that controlled the facility before it was closed must report the emissions emitted by the closed facility during the reporting year.

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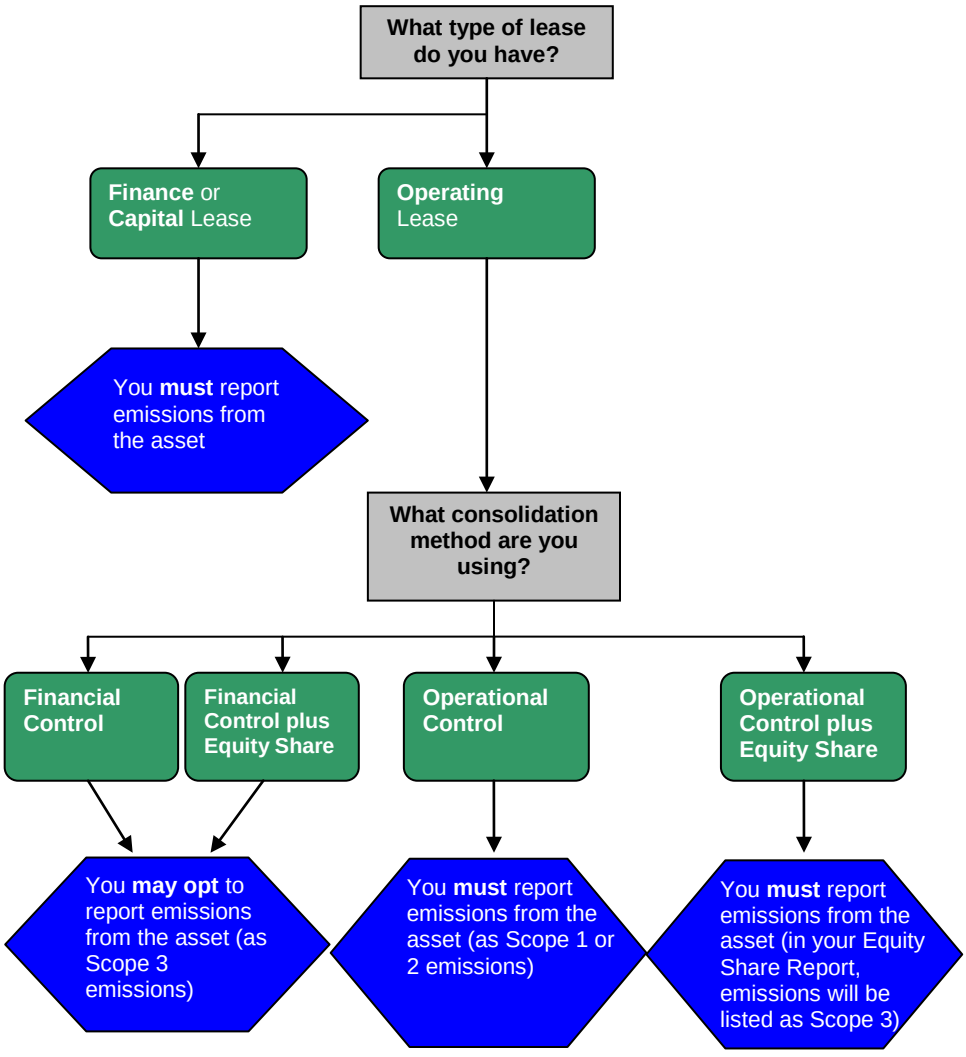
Figure 4.2	**Decision Tree for Determining the Lessee's Reporting Requirements for a Leased Asset**	**p.24**	**Issued: 03/02/09** **Effective: 03/02/09**

The decisions tree has been updated to clarify operational boundary issues around leased assets. The updated table is:



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Chapter 5.2	**Stationary Combustion**	**p.32**	**Issued: 03/02/09** **Effective: 03/02/09**
	The definition of stationary combustion in the GRP does not only apply to fuels combusted to produce electricity, steam, heat or power. It more accurately refers to combustion of any fuel in a fixed location. Therefore The Registry is clarifying that the definition of stationary combustion is: Combustion of fuels in any stationary equipment including boilers, furnaces, burners, turbines, heaters, incinerators, engines, flares, etc.		

Chapter 6	**Required Facility-Level Reporting**		**Issued: 08/18/10** **Effective: 08/18/10**
	In order to simplify the process of reporting very small sources, The Registry has updated its reporting policy for emissions estimated using simplified estimation methods. The following language will be added to Chapter 6 of the GRP: Facility-level reporting is not required for emissions quantified using simplified estimation methods (SEMs). SEMs sources may be reported as an aggregated facility at the state/province, national, North American, or non-North American levels. Aggregated SEMs emissions must be identified as SEMs. Please see Chapter 11 or the CRIS User's Guide for more information on reporting emissions estimated using SEMs.		

Chapter 7.1	**Verification Requirement for Historical Base Year**	**p.46**	**Issued: 03/02/09** **Effective: 03/02/09**
	This chapter indicates that you may set a historical base year if you submit complete data for the historical year and all subsequent years. In addition to the requirement to submit complete data, you must also have that historical base year and all subsequent reporting years verified with a Registry-recognized Verification Body. Therefore, the following sentence should be inserted into the text in the second to last paragraph of Section 7.1: Historical base years and all subsequent reporting years must be verified by a Registry-recognized Verification Body.		

Chapter 9	**Reporting Historical Data**	**p.54**	**Issued: 04/27/09** **Effective: 04/27/09**
	To clarify The Registry's intent to permit Members to consolidate multiple years of reported emissions data in a centralized location, The Registry is providing the following clarifications regarding historical data:		

	Historical data is data that has been previously calculated but may not meet The Registry's reporting and verification requirements. Instead, historical data must meet the following minimum requirements: • Entity-level emissions of CO_2 from stationary combustion for all operations in at least one state or province • Third party verified If historical data was verified by an independent third party as part of another GHG program, The Registry does not require this data to be re-verified, however, a formal written attestation of verified data by a credible third party verification body must be submitted to The Registry along with the historical data emission report. If a Member's historical data is calculated, but has not previously been verified, The Registry recommends that Members use an ANSI-accredited, Registry-recognized Verification Body to verify this data. All historical data emissions reports will be titled "Historical Data." Members must indicate the name of the GHG program the data was originally reported to, which will appear on the historical data emissions report. If historical data was calculated, but not reported to another program, Members must indicate that their data is "Self Reported." Members must always report consecutive years of data to The Registry. Consequently, while Members may report historical data for as many past years as they like, this data must immediately precede a Member's earliest reported emissions such that a data gap does not exist. Members also have the option of reporting historical data that adheres to The Registry's reporting and verification requirements. Data reported in this manner will not be labeled "Historical Data" as it is guaranteed to be completely consisted with non-historical Registry data.

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Chapter 10	**Reporting Data Quality Tiers for Pre-calculated Data**	**p.56 & 57**	**Issued: 03/02/09** **Effective: 03/02/09**
	When entering pre-calculated data into CRIS at the facility-level, you are not required to identify the data quality tier you used to calculate your emissions. The sentence on page 56 of the GRP V1.1 that reads: "You must disclose the tiers and quantification approaches used for the various sources within each of your facilities." should be amended to read: "When reporting activity-level data into CRIS you must disclose the tiers and quantification approaches used for the various sources within each of your facilities. When entering pre-calculated data at the facility-level you are not required to indicate in CRIS which data tier you used to calculate your emissions."		

Chapter 11	**Reporting Emissions Estimated using Simplified Methods**		**Issued: 08/18/10** **Effective: 08/18/10**
	In order to simplify the process of reporting very small sources, The Registry has updated its reporting policy for emissions estimated using simplified estimation methods. The following language will be added to Chapter 11 of the GRP: Members have two options when reporting emissions estimated using simplified estimation methods (SEMs): 1. Emissions can be included in the facilities where the emissions occurred, either as part of the facility total or as emitting activities within facilities, or 2. Members can choose to report aggregated SEMs across facilities at the state/province, national, North American or non-North American levels as long as these emissions are reported in facilities made up exclusively of emissions estimated using SEMs within the appropriate geographic boundary. Emissions reported in this way can use methodologies that aggregate or extrapolate activity data across multiple facilities. Both reporting options can be used within a corporate inventory provided the total emissions estimated using SEMs do not exceed five percent of your entity's total emissions (scope 1, scope 2 and direct biogenic emissions from stationary and mobile combustion) within North America and separately either for non-North American or worldwide emissions (depending on the scope of your verification activities; See GVP v. 2.0 Section 2.7.4 discussion on Options 1 and 2 for more information).		

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Chapter 11 Simplified Estimation Methodologies	**Simplified Estimation Methodologies**	**p.58**	**Issued: 02/11/10 Effective: 02/11/10**
	In GRP 1.1, Biogenic emissions from stationary and mobile combustion were inadvertently left out of the description of how to calculate the five percent threshold for the use of simplified estimation methods. The document is updated to read: Simplified estimation methodologies can be used for up to five percent of the sum of an entity's Scope 1, Scope 2, and **biogenic emissions from stationary and mobile combustion**.		

Chapter 12	**Stationary Combustion**	**p.61**	**Issued: 03/02/09 Effective: 03/02/09**
	Members should use Chapter 12 if they combust fuel in any stationary equipment, not only if fuel is combusted to provide electricity, steam, heat or power.		

Chapter 12	**Stationary Combustion**	**p.61**	**Issued: 03/02/09 Effective: 03/02/09**
	Stationary combustion in the GRP does not consist only of fuels combusted to produce electricity, steam, heat or power. It more specifically refers to combustion of any fuel in a fixed location. Therefore, The Registry is clarifying that stationary combustion refers to the combustion of fuels in any stationary equipment including boilers, furnaces, burners, turbines, heaters, incinerators, engines, flares, etc.		

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Chapter 12.4	**Default Stationary Combustion Emission Factors for Acetylene**	**p.72**	**Issued: 11/24/08** **Effective: 11/24/08**

The default carbon dioxide emission factors for acetylene were not published in the GRP 1.1. The appropriate factors to use in reporting acetylene use to The Registry are listed below. These factors were derived by the California Climate Action Registry from information published in the 2004 API Compendium.

	Tier B Method			Tier C Method	
	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)
	MMBtu / standard cubic foot	kg C / MMBtu		kg CO_2 / MMBtu	kg CO_2 / standard cubic foot
Acetylene (C_2H_2)	1,476	19.48	1	71.42	0.1043

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Table 12.3	**Canadian Default Factors for Calculating CO_2 Emissions from Combustion of Natural Gas, Petroleum Products, and Biomass**	**p.76**	**Issued: 04/27/09** **Effective: 04/27/09**

Updated emission factors for calculating CO_2 emissions from combustion of natural gas, petroleum products and biomass for operations in Canada are provided below:

Fuel Type	Tier B Method			Tier C Method
	Carbon Content (Per Unit Energy)	Heat Content	Fraction Oxidized(*)	CO_2 Emission Factor (Per Unit Mass or Volume)
Natural Gas	**kg C / GJ**	**TJ / GL**		**g CO_2 / m^3**
Electric Utilities, Industrial, Pipelines, Cement, Manufacturing Industries, Residential, Construction, Commercial/Institutional, Agriculture	n/a	38.32	1	1900.50
Producer Consumption	n/a	n/a	1	2401.01
Natural Gas Liquids	**kg C / GJ**	**TJ / ML**		**g CO_2 / L**
Propane	n/a	25.31	1	1517.59
Ethane	n/a	17.22	1	980.90
Butane	n/a	28.44	1	1738.69
Refined Petroleum Products	**kg C / GJ**	**TJ / ML**		**g CO_2 / L**
Light Fuel Oil	n/a	38.80	1	2752.53
Light Fuel Oil (Producer Consumption)	n/a	n/a	n/a	2669.70
Heavy Fuel Oil	n/a	42.50	1	3155.56
Heavy Fuel Oil (Producer Consumption)	n/a	n/a	n/a	3189.90
Kerosene	n/a	37.68	1	2559.60
Diesel	n/a	38.30	1	2689.90
Petroleum Coke	**kg C / GJ**	**TJ / ML**		**g CO_2 / L**
Upgrading Facilities	n/a	40.57	1	3529.29
Refineries & Others	n/a	46.35	1	3864.65
Still Gas	**kg C / GJ**	**TJ / GL**		**g CO_2 / m^3**
Upgrading Facilities (*)	n/a	43.24	1	2161.62
Refineries & Others (*)	n/a	36.08	1	1767.68
Biomass	**kg C / GJ**	**TJ / Kton**		**g CO_2 / kg**

Wood Fuel/Wood Waste (Industrial Combustion)	n/a	18.00	1	n/a
Landfill Gas (Industrial Combustion)	n/a	n/a	n/a	n/a
Spent Pulping Liquor (Industrial Combustion)	n/a	14	1	n/a
Stoves and Fireplaces (Residential Combustion)	n/a	n/a	n/a	n/a

Source: Default CO_2 emission factors: Environment Canada, *National Inventory Report, 1990-2006: Greenhouse Gas Sources and Sinks in Canada* (May 2008), Annex 12: Emission Factors, Tables A12-1, A12-2, A12-3 (2006 data) and A12-19; Default Heat Content: Statistics Canada, *Report on Energy Supply-demand in Canada, 2005* (2007), Energy conversion factors, p. 116; 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 Tier C Method (default CO_2 emission factor). Default Fraction Oxidized: Intergovernmental Panel on Climate Change (IPCC), *Guidelines for National Greenhouse Gas Inventories* (2006).
(*) Since the fraction not oxidized is usually very small, presented emission factors assume complete oxidation of the carbon contained in the fuel. However, other oxidation fractions should be used if country-specific values, based on measurements or other well documented data are available, or specific if values are required for reporting to mandatory programs.
(**)Source document [Environment Canada, National Inventory Report, 1990-2006: Greenhouse Gas Sources and Sinks in Canada (May 2008), Annex 12: Emission Factors, Table A12-3: CO2 Emission Factors for Petroleum, Coke and Still Gas] contains specific values for years 1990 to 2005. These values must be used when calculating year 1990 through 2005 emissions.
Note: CO_2 emission factors from Environment Canada originally assumed an oxidized fraction of less than 100 percent. Values were converted to reflect a 100 percent oxidation rate from the original assumptions of 99.5 percent for natural gas and NGLs; 99 percent for petroleum products and still gas; and 95 percent for spent pulping liquor.

Table 12.4 | **Canadian Default Factors for Calculating CO_2 Emissions from Combustion of Coal** | **p.77** | **Issued: 04/27/09 Effective: 04/27/09**

Updated emission factors for calculating CO_2 emissions from combustion of coal for operations in Canada are provided below:

Province and Coal Type	Tier B Method			Tier C Method
	Carbon Content	Heat Content	Fraction Oxidized (*)	CO_2 Emission Factor (Per Unit Mass)
Newfoundland and Labrador	**kg C/GJ**	**GJ / metric ton**		**g CO_2 / kg**
Canadian Bituminous	n/a	28.96	1	2272.73
Anthracite	n/a	27.7	1	2414.14
Prince Edward Island				
Canadian Bituminous	n/a	28.96	1	2272.73
Nova Scotia				

	Canadian Bituminous	n/a	28.96	1	2272.73
	U.S. Bituminous	n/a	28.99	1	2313.13
	Sub-bituminous	n/a	19.15	1	1747.47
	New Brunswick				
	Canadian Bituminous	n/a	26.8	1	2020.20
	U.S. Bituminous	n/a	28.99	1	2333.33
	Quebec				
	Canadian Bituminous	n/a	28.96	1	2272.73
	U.S. Bituminous	n/a	28.99	1	2363.64
	Anthracite	n/a	27.7	1	2414.14
	Ontario				
	Canadian Bituminous	n/a	25.43	1	2272.73
	U.S. Bituminous	n/a	28.99	1	2454.55
	Sub-bituminous	n/a	19.15	1	1747.47
	Lignite	n/a	15	1	1494.95
	Anthracite	n/a	27.7	1	2414.14
	Manitoba				
	Canadian Bituminous	n/a	26.02	1	2272.73
	U.S. Bituminous	n/a	28.99	1	2454.55
	Sub-bituminous	n/a	19.15	1	1747.47
	Lignite	n/a	15	1	1434.34
	Anthracite	n/a	27.7	1	2414.14
	Saskatchewan				
	Canadian Bituminous	n/a	25.43	1	1868.69
	Lignite	n/a	15	1	1444.44
	Alberta				
	Canadian Bituminous	n/a	25.43	1	1868.69
	Sub-bituminous	n/a	19.15	1	1787.88
	Anthracite	n/a	27.7	1	2414.14
	British Columbia				
	Canadian Bituminous	n/a	26.02	1	2090.91
	U.S. Bituminous	n/a	28.99	1	2454.55
	Sub-bituminous	n/a	19.15	1	1787.88
	All Provinces				
	Coke	n/a	28.83	1	n/a
		kg C/GJ	**GJ / megalitre**		**g/m^3**
	Coke Oven Gas	n/a	19.14	1	n/a

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Source: Default CO_2 Emission Factors: Environment Canada, *National Inventory Report, 1990-2006: Greenhouse Gas Sources and Sinks in Canada* (May 2008), Annex 12: Emission Factors, Table A12-5 (1998-2006 data); Default Heat Content: Statistics Canada, *Report on Energy Supply-demand in Canada, 2005* (2007), Energy conversion factors, p. 116, except value for U.S. Bituminous which was taken from Appendix C of this Protocol; 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 Tier C Method. Default Fraction Oxidized: Intergovernmental Panel on Climate Change (IPCC), *Guidelines for National Greenhouse Gas Inventories* (2006).
(*) Since the fraction not oxidized is usually very small, presented emission factors assume complete oxidation of the carbon contained in the fuel. However, other oxidation fractions should be used if country-specific values, based on measurements or other well documented data are available, or specific if values are required for reporting to mandatory programs.
Note: CO_2 emission factors from Environment Canada originally assumed an oxidized fraction of 99 percent. Values were converted to reflect a 100 percent oxidation rate.

New Table 12.X

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

Issued: 04/27/09
Effective: 04/27/09

Updated emission factors for calculating CH_4 and N_2O emissions from combustion of natural gas, petroleum products, coal, and biomass for operations in Canada are provided below:

Fuel Type	Tier C Method	
	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	0.49	0.049
Industrial	0.037	0.033
Producer Consumption	6.5	0.06
Pipelines	1.9	0.05
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	n/a	n/a
Butane	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	0.133	0.4
Still Gas	n/a	0.00002
Petroleum Coke	**g CH_4 / L**	**g N_2O / L**
Upgrading Facilities	0.12	0.0231(*)
Refineries & Others	0.12	0.0265(*)
Coal	**g CH_4 / kg**	**g N_2O / kg**
Coal (Electric Utilities)	0.022	0.032
Coal (Industry and Heat & Steam Plants)	0.030	0.020
Coal (Residential, Public Administration)	4.000	0.020
Coke	0.030	0.020
Coal (gas)	**g CH_4 / m^3**	**g N_2O / m^3**
Coke Oven Gas	0.037	0.035
Biomass	**g CH_4 / kg**	**g N_2O / kg**
Wood Fuel/Wood Waste (Industrial Combustion)	0.05	0.02
Landfill Gas (Industrial Combustion)	0.60	0.06
Spent Pulping Liquor (Industrial Combustion)	0.05	0.02
Stoves and Fireplaces (Advance Technology or Catalytic Control)	6.9	0.16
Stoves and Fireplaces (Conventional, Inserts, and Other Wood-Burning Equipment)	15	0.16

Source: Environment Canada, *National Inventory Report, 1990-2006: Greenhouse Gas Sources and Sinks in Canada* (May 2008), Annex 12: Emission Factors, Tables A12-1, A12-2, A12-4 (1998-2006 data), A12-6, and A12-19.

(*) 1998-2006 data. Please refer to the source document for prior years' data.

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Chapter 13 Direct Emissions from Mobile Combustion	**Calculating Emissions from Vehicles that Use Compressed Natural Gas (CNG)**	**p.88**	**Issued: 02/11/10** **Effective: 02/11/10**

Formula 13e Calculating CO_2 Emissions From Mobile Combustion in GRP 1.1 is updated below to demonstrate the quantification of CO_2 emissions from vehicles that operate using compressed natural gas (CNG) based on standard cubic feet (scf). The additions to the formula are in **bold italics**.

Formula 13e Calculating CO_2 Emissions From Mobile Combustion:

Fuel A CO_2 Emissions (metric tons) =
Fuel Consumed x Emission Factor ÷ 1,000
(gallons ***or scf***) (kg CO_2/gallon ***or*** ***kg CO_2/scf***) (kg/metric ton)

Fuel B CO_2 Emissions (metric tons) =
Fuel Consumed x Emission Factor ÷ 1,000
(gallons ***or scf***) (kg CO_2/gallon ***or*** ***kg CO_2/scf***) (kg/metric ton)

Total CO2 Emissions (metric tons) =
CO_2 from Fuel A + CO_2 from Fuel B + …
(metric tons) (metric tons) (metric tons)

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Table 13.2	**Canadian Default CO_2 Emission Factors for Transport Fuels**	**p.94**	**Issued: 04/27/09** **Effective: 04/27/09**

Updated emission factors for calculating CO_2 emissions from transportation fuels for operations in Canada are provided below:

Fuel Type	Tier A2 Method			Tier B/C Method
	Carbon Content	Heat Content	Fraction Oxidized (*)	CO_2 Emission Factors
	GJ / kiloliter			g CO_2 / L
Gasoline	n/a	35.00	1	2312.12
Diesel	n/a	38.30	1	2689.90
Light Fuel Oil	n/a	38.80	1	2752.53
Heavy Fuel Oil	n/a	42.50	1	3155.56
Aviation Gasoline	n/a	33.52	1	2365.66
Aviation Turbo Fuel	n/a	37.40	1	2559.60
Propane	n/a	25.31	1	1517.59
Ethanol	n/a	n/a	1	1509.09
	GJ / megaliter			g CO_2 / L
Natural Gas	n/a	38.26	1	1.90

Source: Default CO_2 Emission Factors: Environment Canada, *National Inventory Report, 1990-2006: Greenhouse Gas Sources and Sinks in Canada* (May 2008), Annex 12: Emission Factors, Table A12-7. Default Heat Content: Statistics Canada, *Report on Energy Supply-demand in Canada, 2005* (2007), Energy conversion factors, p. 116; 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 Tier C Method. 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).

(*) Since the fraction not oxidized is usually very small, presented emission factors assume complete oxidation of the carbon contained in the fuel. However, other oxidation fractions should be used if country-specific values, based on measurements or other well documented data are available, or specific if values are required for reporting to mandatory programs.
Note: CO_2 emission factors from Environment Canada originally assumed 99 percent oxidation rate for all values except for Natural Gas and Propane where the oxidation rate was 99.5 percent. All emission factor values have been adjusted to reflect 100 percent oxidation rate.

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New Table 13.X	**Canadian Default Factors for Calculating CO_2, CH_4, and N_2O Emissions from Mobile Combustion**		**Issued: 04/27/09** **Effective: 04/27/09**

Updated emission factors for calculating CO_2 CH_4, and N_2O emissions from mobile combustion for operations in Canada are provided below:

Vehicle Type	Tier C Method	
	CH_4 Emission Factor (g CH_4 / L)	N_2O Emission Factor (g N_2O / L)
Light-Duty Gasoline Vehicles (LDGVs)		
Tier 1	0.120	0.160
Tier 0	0.320	0.660
Oxidation Catalyst	0.520	0.200
Non-Catalytic Controlled	0.460	0.028
Light-Duty Gasoline Trucks (LDGTs)		
Tier 1	0.130	0.250
Tier 0	0.210	0.660
Oxidation Catalyst	0.430	0.200
Non-Catalytic Controlled	0.560	0.028
Heavy-Duty Gasoline Vehicles (HDGVs)		
Three-Way Catalyst	0.068	0.200
Non-Catalytic Controlled	0.290	0.047
Uncontrolled	0.490	0.084
Gasoline Motorcycles		
Non-Catalytic Controlled	1.400	0.045
Uncontrolled	2.300	0.048
Light-Duty Diesel Vehicles (LDDVs)		
Advance Control	0.051	0.220
Moderate Control	0.068	0.210
Uncontrolled	0.100	0.160
Light-Duty Diesel Trucks (LDDTs)		
Advance Control	0.068	0.220
Moderate Control	0.068	0.210
Uncontrolled	0.085	0.160
Heavy-Duty Diesel Vehicles (HDDVs)		

	Advance Control	0.120	0.082
	Moderate Control	0.140	0.082
	Uncontrolled	0.150	0.075
	Gas Fueled Vehicles		
	Natural Gas Vehicles	9×10^{-3}	6×10^{-5}
	Propane Vehicles	0.640	0.028
	Off-Road Vehicles		
	Off-Road Gasoline	2.700	0.050
	Off-Road Diesel	0.150	1.100
	Railways		
	Diesel Train	0.150	1.100
	Marine		
	Gasoline Boats	1.300	0.066
	Diesel Ships	0.150	1.1
	Light Fuel Oil Ships	0.260	0.073
	Heavy Fuel Oil Ships	0.280	0.079
	Aviation		
	Aviation Gasoline	2.200	0.230
	Aviation Turbo Fuel	0.080	0.230
	Renewable Fuels		
	Ethanol	**	**
	Source: Environment Canada, *National Inventory Report, 1990-2006: Greenhouse Gas Sources and Sinks in Canada* (May 2008), Annex 12: Emission Factors, Table A12-7. * Tier 1 or advanced control emission factors shall be used for Tier 2 Vehicles. ** Gasoline CH_4 and N_2O emission factors shall be used to calculate ethanol emissions.		

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Chapter 14.1 Indirect Emissions from Electricity	**Utility-Specific Emission Factors Accepted by The Registry**		**Issued: 02/11/10** **Effective: 01/1/10**

Registry Members may choose to use the following emission factors when calculating CO_2 emissions from the use of purchased electricity:

- Generator-Specific Emission Factors
- Default Emission Factors
- Registry-Approved Utility-Specific Emission Factors

Generator-specific and default emission factors are described in Chapter 14 of the GRP v.1.1.

Registry-Approved Utility-Specific Emission Factors

The Registry has approved two classes of utility-specific emission factors that may be used to calculate CO_2 emissions from the use of purchased electricity. These are:

1. Utility-specific emission factors reported and verified in accordance with the California Climate Action Registry's (CCAR) Power/Utility Reporting Protocol. (View the complete list here.)
2. Utility-specific retail electric or special power electric delivery metrics reported and verified in accordance with The Registry's Electric Power Sector (EPS) Protocol. (As they become available these will be listed on our website.)

Utility-specific emission factors may only be used for operations located within the service territories of electric utilities that have reported and verified their utility-specific CO_2 emission factors in accordance with CCAR or The Registry's sector-specific reporting requirements.

Members that choose to use utility-specific electric delivery metrics must use the most up to date metric available at the time they are reporting to The Registry. If the default U.S. eGRID emission factor or Registry approved Canadian provincial emission factor for purchased electricity is more recent than the approved utility-specific electric delivery metric previously used to report to The Registry, the default emission factor must be used instead.

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	With implementation of The Registry's EPS Protocol, utility-specific electric delivery metrics will be reflected in Members' reports in a separate category that will be displayed alongside a default Scope 2 emissions total. Emissions in the default total will be calculated using the U.S. eGRID, or Registry-approved Canadian provincial emission factors for purchased electricity. After the implementation of the EPS Protocol, emission reports of all Members that reported to The Registry using utility-specific electric delivery metrics prior to the implementation of the EPS Protocol will include a note to explain the shift back to the U.S. eGRID or Registry-approved Canadian Provincial emission factors in the default Scope 2 total.

Chapter 14.1 Calculating Indirect Emissions from Electricity Use	**New Methodology- Using Cost Data to Calculate Emission from Electricity Use in commercial facilities in the U.S.**	**p 97-99**	**Issued: 05/12/10 Effective: 05/12/10**

The most accurate way to calculate scope 2 emissions from electricity is to use kilowatt hour data provided by your utility company. Furthermore, site-specific kilowatt hour data greatly enhances the ability to accurately capture the benefits of energy efficiency initiatives. For these reasons, The Registry recommends using kilowatt hour data to calculate scope 2 emissions whenever feasible. Some Members, however, may find it unfeasible to obtain kilowatt hour data due to issues such as a lack of robust data management systems or an overwhelming number of utility accounts.

If it is not feasible to obtain kilowatt hour data for your commercial facilities and warehouses in the U.S., you can estimate electricity consumption using electricity expenditures and average kilowatt hour costs. If you have average kilowatt hour cost information from your utility provider(s), you should use that in Step 2 of the methodology outlined below. If you do not have this information you can use the average cost figures in Table 14.x which are provided by the U.S. Energy Information Administration (EIA).

Please Note: This method only qualifies as a Registry-accepted methodology when used to estimate electricity use for commercial facilities and/or warehouses in the U.S. where you do not have feasible access to kilowatt hour data. This methodology is not accepted for industrial facilities or for facilities located outside of the U.S.

Step 1: Determine annual electricity expenditures for each facility using utility bills or financial records.

Step 2: Estimate annual kilowatt hours by dividing the annual facility-level electricity expenditures by the average electricity cost (Table 14.x) for the appropriate state using Equation 14.x.

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Equation 14x	Estimating Electricity Consumption Using the Expenditure Records				
Electricity Use (kWh)	= Facility Expenditures ($)	x 100	÷	Average Kilowatt Hour Cost (¢/kWh)	

Step 3: Calculate the GHG emissions by multiplying the estimated kilowatt hours by the appropriate eGRID factor or Registry-approved utility-specific emissions factor.

Table 14.x Average Cost per Kilowatt Hour by State

State	Average Retail Price Residential (¢/kWh)	Average Retail Price Commercial (¢/kWh)	Average Retail Price Industrial (¢/kWh)
AK Total	15.18	12.19	12.63
AL Total	9.32	8.70	5.27
AR Total	8.73	6.91	5.25
AZ Total	9.66	8.27	6.05
CA Total	14.42	12.82	9.98
CO Total	9.25	7.62	5.97
CT Total	19.11	15.39	12.92
DC Total	11.18	12.01	9.32
DE Total	13.16	11.21	8.93
FL Total	11.22	9.75	7.76
GA Total	9.10	8.07	5.53
HI Total	24.12	21.91	18.38
IA Total	9.45	7.11	4.74
ID Total	6.36	5.14	3.87
IL Total	10.12	8.57	6.61
IN Total	8.26	7.29	4.89
KS Total	8.19	6.83	5.13
KY Total	7.34	6.76	4.47
LA Total	9.37	9.13	6.77
MA Total	16.23	15.20	13.03
MD Total	11.89	11.58	9.41
ME Total	16.52	12.94	14.11
MI Total	10.21	8.77	6.47
MN Total	9.18	7.48	5.69
MO Total	7.69	6.34	4.76
MS Total	9.36	8.92	5.75
MT Total	8.77	8.10	5.16
NC Total	9.40	7.43	5.47
ND Total	7.30	6.58	5.24
NE Total	7.59	6.39	4.78
NH Total	14.88	13.91	12.27
NJ Total	14.14	12.99	10.08
NM Total	9.12	7.66	5.60
NV Total	11.82	10.09	8.28
NY Total	17.10	15.92	8.71
OH Total	9.57	8.67	5.76

		OK Total	8.58	7.33	5.41
		OR Total	8.19	7.20	5.06
		PA Total	10.95	9.20	6.87
		RI Total	14.05	12.67	12.04
		SC Total	9.19	7.74	4.83
		SD Total	8.07	6.61	5.09
		TN Total	7.84	8.09	5.19
		TX Total	12.34	9.87	7.79
		UT Total	8.15	6.54	4.52
		VA Total	8.74	6.38	5.07
		VT Total	14.15	12.29	8.92
		WA Total	7.26	6.55	4.57
		WI Total	10.87	8.71	6.16
		WV Total	6.73	5.85	3.95
		WY Total	7.75	6.25	4.10
		Source Energy Information Administration: Current and Historical Monthly Retail Sales, Revenues and Average Revenue per Kilowatt hour by State and by Sector. Form EIA-826(based on 2007 data). http://www.eia.doe.gov/cneaf/electricity/epm/table5_6_a.html NOTE: There is generally a two year lag between data collection and the publishing of finalized figures. As of February 2010, the finalized figures were from 2007. Registry Members should always use the most up to date factor that is available when reporting for the current year and the most accurate factor available when reporting past years.			

Chapter 14.1	**Alternative Methodology for Estimating Electricity in Leased Spaces**	**p. 99**	**Issued: 01/01/10 Effective: 02/11/10**

An alternative method for estimating electricity in leased spaces was introduced through the GRP Updates and Clarifications dated April 27, 2009. This alternative method can be used by lessees to determine the emissions they should report and by lessors to determine the emissions they should subtract when calculating their inventory.

Two changes have been made since that update.

1) A table with average electricity intensity for Canada was added.
2) Step 4 now includes language that corresponds to updates in The Registry's reporting software, Climate Registry Information System (CRIS).

Members with facilities in Mexico who wish to use this methodology should contact The Registry for guidance. Please note that the text in ***bold italics*** indicates a revision of the originally released update.

The following alternative methodology may be used by Members reporting emissions from leased spaces:

You may use the following estimation methodology to calculate indirect

emissions from leased space in the U.S. **or Canada** if:

- You do not receive information about electricity usage directly,
- You are unable to obtain information about your building's electricity usage from your landlord/property owner/property manager, and
- You indicate in your emission report that you have used an estimation methodology to determine your electricity usage.

STEP 1: Determine the office space's square footage.
To do this, you will need to review your lease which should have your exact usable square footage. Be sure to include square footage for any storage space, if applicable. NOTE: Usable square footage is the space contained within the walls of your office. It does not include other 'rentable' areas such as building bathrooms, common areas, etc.

STEP 2: Determine the average annual electricity intensity for building space.
Select the most appropriate average electricity intensity according the operations of your building space***. Use the Canadian Electricity Intensity table if you are reporting for Canadian facilities and the US Electricity Intensity table if you are reporting for US facilities.***

Canadian Electricity Intensity

Principal Building Activity Annual Electricity Intensity	**GJ/m^2**
Commercial and institutional accommodation	0.53
Entertainment and recreation	0.93
Office	0.97
Food retails	1.86
Non food retails	0.52
Food service	1.34
Non food service	0.58
Shopping malls	0.72
Warehouse/wholesale	0.79
Administration	0.82
Education	0.4
Health care	0.93
Public assembly	0.55
Other	0.58

Source: Natural Resources Canada, Commercial and Institutional Building Energy Use Survey 2000 Table 11.1 *Total electricity consumption and electricity intensity by building characteristics, occupancy characteristics, energy efficiency features, heating energy sources and equipment, cooling energy sources and equipment, and water heating energy sources*
http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/data_e/cibeus/section_11.cfm?attr=0

US Electricity Intensity

Principal Building Activity Annual Electricity Intensity	**kWh/ft^2**
Education	11.0
Food Sales	49.4
Food Service	38.4
Health Care	22.9
Inpatient	27.5
Outpatient	16.1
Lodging	13.5
Retail (other than mall)	14.3
Office	17.3
Public Assembly	12.5
Public Order and Safety	15.3
Religious Worship	4.9
Service	11
Warehouse and Storage	7.6
Other	22.5
Vacant	2.4
Source: 2003 Commercial Buildings Energy Consumption Survey, Energy Information Administration (http://www.eia.doe.gov/emeu/cbecs/)	

STEP 3: Calculate your office's electricity consumption.

Office Space (useable space) (ft^2) (from landlord)	**X**	Annual Electricity Intensity (kWh/ft^2) (from table)	**=**	Your Estimated Annual Electricity Consumption

STEP 4: Calculate the GHG emissions associated with your estimated annual electricity consumption.

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	You can now use the Climate Registry Information System (CRIS) to report the GHG emissions associated with your estimated electricity use. In order to specify that the emissions are simplified estimation methods you will need to create an emitting activity, indicate that you are entering in pre-calculated values and then enter the amount of CO_2, CH_4 and N_2O based on your calculations. You must also upload back up documentation in CRIS to explain your calculations. **METHODOLOGY DISCLOSURE** You must disclose your use of this estimation methodology in your CRIS report. We have supplied Members with the following standard disclosure language to enter in the comment field: • *"[Some or all] of the indirect emissions from purchased electricity disclosed in this report were estimated based on a Registry-accepted alternate methodology for estimating electricity use, not calculated based on metered data."*

Table 14.1	**U.S. Emission Factors for Grid Electricity by eGRID Subregion**	**p. 104**	**Issued: 03/02/09 Effective: 03/02/09**

Updated emission factors for electricity use in the U.S. are provided below:

Table 14.1 U.S. Emission Factors for Grid Electricity by eGRID subregion

eGRID 2007 Subregion	eGRID 2007 Subregion Name	2005 Emission Rates		
		lbs CO_2/ MWh	lbs CH_4/ GWh	lbs N_2O/ GWh
AKGD	ASCC Alaska Grid	1,232.3571	25.6003	6.5074
AKMS	ASCC Miscellaneous	498.8588	20.7521	4.0770
ERCT	ERCOT All	1,324.3497	18.6460	15.1147
FRCC	FRCC All	1,318.5715	45.9238	16.9412
HIMS	HICC Miscellaneous	1,514.9249	314.6817	46.8831
HIOA	HICC Oahu	1,811.9758	109.4696	23.6171
MROE	MRO East	1,834.7194	27.5921	30.3627
MROW	MRO West	1,821.8448	27.9997	30.7055
NYLI	NPCC Long Island	1,536.8038	115.4147	18.0922
NEWE	NPCC New England	927.6814	86.4947	17.0075
NYCW	NPCC NYC/Westchester	815.4518	36.0243	5.4565
NYUP	NPCC Upstate NY	720.7984	24.8200	11.1931

RFCE	RFC East	1,139.0746	30.2721	18.7146
RFCM	RFC Michigan	1,563.2804	33.9326	27.1702
RFCW	RFC West	1,537.8249	18.2348	25.7088
SRMW	SERC Midwest	1,830.5105	21.1464	30.5014
SRMV	SERC Mississippi Valley	1,019.7374	24.3143	11.7060
SRSO	SERC South	1,489.5393	26.2724	25.4715
SRTV	SERC Tennessee Valley	1,510.4430	20.0465	25.6400
SRVC	SERC Virginia/Carolina	1,134.8788	23.7698	19.7888
SPNO	SPP North	1,960.9435	23.8170	32.0851
SPSO	SPP South	1,658.1362	24.9785	22.6051
CAMX	WECC California	724.1201	30.2365	8.0758
NWPP	WECC Northwest	902.2403	19.1299	14.8998
RMPA	WECC Rockies	1,883.0808	22.8842	28.7507
AZNM	WECC Southwest	1,311.0503	17.4544	17.9360

Source: U.S. EPA eGRID2007 Version 1.1 (2005 data: eGRID subregion annual CO_2 output emission rate). Factors do not include emissions from transmission and distribution losses. January 28th, 2009.
The calculation tool within The Registry's reporting software, CRIS, accepts electricity use in multiple units (i.e. MWh, kWh).

Table 14.2 | **Canadian Emission Factors for Grid Electricity by Province** | **p. 105** | **Issued: 04/27/09 Effective: 04/27/09**

Updated emission factors for electricity use in Canadian provinces are provided below:

Table 14.2 Canadian Emission Factors for Grid Electricity by Province

Province	2006 Emission Rates		
	g $C0_2$ / kWh	g CH_4 / MWh	g N_2O / MWh
Newfoundland	10	0.00	0.29
Prince Edward Island	150	1.90	3.06
Nova Scotia	730	14.76	9.71
New Brunswick	350	17.14	6.71
Quebec	10	1.43	0.16
Ontario	180	9.05	3.19
Manitoba	10	0.48	0.26
Saskatchewan	800	36.19	18.58
Alberta	920	27.62	17.23

British Columbia	20	4.29	0.48	
Yukon, Northwest Territories & Nunavut	80	3.81	11.39	
Source: Greenhouse Gas Division, Environment Canada (2006 data). Factors do not include emissions from transmission and distribution losses.				

Chapter 15.2	**Calculating Indirect GHG Emissions from Imported Steam or District Heating from a Conventional Boiler in Leased Spaces**	**p. 114**	**Issued: 04/27/09** **Effective: 04/27/09**
	In many cases, organizations that lease space (such as office space) use heat or steam that is generated within the facility they are located in where the heat generation unit is outside of their organizational boundary. For example, if a firm leases office space on the third floor of a 24 story building with a central heating system consisting of a series of boilers in the basement, the boilers are in the same facility but outside of the firm's organizational boundary. Members who lease space with heating units that are located within their organizational boundaries are required to report the emissions from such heating units as Scope 1 (stationary combustion) emissions. Members who lease space that is heated by units located in the building they occupy but that are outside of their organizational boundaries may report emissions from the resulting heating unit(s) as optional Scope 2 emissions (imported heat).		

Chapter 15.3	**Calculating Indirect GHG Emissions from District Cooling in Leased Spaces**	**p. 115**	**Issued: 04/27/09** **Effective: 04/27/09**
	In many cases, organizations that lease space (such as office space) use cooling that is generated within the facility they are located in where the cooling generation unit is outside of their organizational boundary. Members who lease space with cooling units that are located within their organizational boundaries are required to report the emissions from such cooling units as Scope 1 (fugitive) emissions. Members who lease space that is cooled by units located in the building they occupy but that are outside of their organizational boundaries may report emissions from the resulting cooling unit(s) as optional Scope 2 emissions (imported cooling).		

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Chapter 16 Direct Fugitive Emissions from the Use of Refrigeration and Air Conditioning Equipment	**Guidance for Subtracting Recycled Refrigerant from Mass Balance Methodology**	**p.127**	**Issued: 02/11/10** **Effective: 02/11/10**
	Formula 16d Calculating Emissions of Each Type of Refrigerant has been updated to address the treatment of refrigerant removed for recycling by a contractor. The additions to the formula are in ***bold italics***. **Total Annual Emissions** (metric tons) **=** **(** PN - CN + PS - ***PR*** + CD - RD) ÷ 1,000 (kg) (kg) (kg) (kg) (kg) (kg) (kg/metric tons) Where: PN = quantity of refrigerant used to charge new equipment * CN = total full charge of the new equipment * PS = quantity of refrigerant used to service equipment ***PR = quantity of refrigerant recycled*** CD = total full charge of retiring equipment RD = refrigerant recovered from retiring equipment, not previously accounted for under P_R * Omitted if no equipment was installed during the emissions year or if the installed equipment was pre-charged by the manufacturer		

Chapter 16.1	**HFC and PFC content of Refrigerant Blends for Reporting to CRIS**	**p. 124 & 127**	**Issued: 11/24/08** **Effective: 11/24/08**
	In order to eliminate confusion regarding the reporting of refrigerant blends that are blends of HFCs and PFCs, The Registry developed the following reporting guidance: To report the emissions from these blends, Members must multiply the amount of each refrigerant used by the percent composition of HFC and PFC listed below. Then Members must enter that refrigerant into CRIS twice; once to report the HFCs present in the blend and once to report the PFCs present in the blend. The only refrigerants that must be reported to The Registry that are blends of HFCs and PFCs are listed in the table below. **NOTE:** The Registry has developed an excel tool that will automatically calculate the appropriate amounts of HFC and PFC from the refrigerant blends listed below. This tool can be downloaded from: The Registry's website.		

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	REFRIGERANT BLENDS (CONTAIN HFC AND PFC)		
	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.		

Chapter 16.2	**Example: Calculating Emissions of Each Type of HFC and PFC**	**p.131**	**Issued: 03/02/09** **Effective: 03/02/09**
	Equation 16a in the example on page 131 contains an error. The example should be corrected to subtract 90 kg instead of add 90 kg. The equation should therefore read as follows: HFC-23 Emissions = (412.6 – 405.1 + 197.5 – 53.3 – 90) ÷ 1,000 = 0.062 (metric tons of HFC-23) (kg) (kg) (kg) (kg) (kg) (kg/metric ton)		

Chapter 20.2	**Confidential Business Information**	**p.151**	**Issued: 11/24/08** **Effective: 11/24/08**
	To affirm the permanent nature of The Registry's confidentiality policy regarding confidential business information (CBI) exemptions, The Registry has provided the following clarifications: • All Members that submit the Public Disclosure Exemption Request Form for reasons of CBI will be granted an exemption unless their form is incomplete. • The Registry will honor any CBI classification granted by a regulatory agency. However, the Member must communicate such classification to The Registry on the Public Disclosure Exemption Request Form. • Each Member must submit the Public Disclosure Exemption Request Form for each year of data they want to remain confidential.		

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Glossary of Terms	**Industry Best Practices**	**p.156**	**Issued: 03/02/09** **Effective: 03/02/09**
	The term "Industry Best Practices" will be added to the Glossary of Terms with the following definition: Calculation and measurement methodologies or factors that are documented and have been through a reasonable peer review process conducted by industry experts.		

Glossary of Terms	**Mobile Combustion Emissions**	**p.156**	**Issued: 04/27/09** **Effective: 04/27/09**
	The definition of mobile combustion in the GRP is clarified to be: 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 sources that are designed and capable of emitting GHGs while moving from one location to another. A emissions source is not a mobile combustion 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).		

Glossary of Terms	**Stationary Combustion Emissions**	**p.158**	**Issued: 03/02/09** **Effective: 03/02/09**
	The definition of stationary combustion in the GRP does not only apply to fuels combusted to produce electricity, steam, heat or power. It more accurately refers to combustion of any fuel in a fixed location. Therefore The Registry is clarifying that the definition of stationary combustion is: Combustion of fuels in any stationary equipment including boilers, furnaces, burners, turbines, heaters, incinerators, engines, flares, etc.		