ALBERTANS & CLIMATE CHANGE

Taking ACTION

ALBERTA GREENHOUSE GAS REPORTING PROGRAM FOR 2003

ANALYSIS

Alberta
ENVIRONMENT

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Summary

Reporting of greenhouse gas (GHG) emissions from large industrial sources is a fundamental component of Alberta's action plan to address climate change. The development of a mandatory GHG reporting program was a commitment identified in *Albertans and Climate Change: Taking Action* released in October 2002. Information gathered under the provincial program is needed to assist both the province and industry in characterizing emission sources and identifying opportunities for reductions in GHG emissions.

Data gathered by the provincial GHG reporting program will be used to implement and monitor progress of specific Alberta emission reduction strategies, such as setting GHG emission targets, establishing emission trading systems, accelerating industry implementation of GHG-reduction technologies and promoting improvements in emissions intensity associated with the production of electricity and commodities. Implementation of reporting to Alberta Environment in 2004 fulfills the commitment made to the public by the Minister of Environment and enables the national system to benefit from lessons learned from the first year of reporting in Alberta.

The first phase of reporting was implemented for GHG emissions from large industrial facilities that annually emit a minimum of 100 kilotonnes (kt) of carbon dioxide equivalents (CO_2-e). For the first reporting year, industry was required to report emissions of carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O). Reports for the 2003 annual emissions were submitted to Alberta Environment by November 15, 2004 in accordance with the Specified Gas Reporting Regulation and the accompanying Specified Gas Reporting Standard.

Under the Specified Gas Reporting Regulation the reporter could request in writing that some of the information be kept confidential for up to five years to protect business interests. Of the 101 facilities that reported, 20 were granted confidentiality status for some portion of their GHG report. Facilities granted confidentiality included eight gas plants, four oil sands facilities, three petroleum refining facilities, three power plants, one heavy oil plant and one lime manufacturing plant. Care was taken to present the data so that confidential data cannot be identified.

For the 2003 reporting year, large industrial emitters of GHGs in Alberta reported 103.5 Mt (megatonnes) of CO_2-e from 101 facilities. This accounts for almost half (47%) of all GHG emissions in Alberta and two-thirds (66%) of all GHGs emitted by industry in the province based on Canada's Greenhouse Gas Inventory for 2002. Based on 2003 data reported to the Alberta system, power plants (46%), oil sands facilities (17%) and gas plants (9%) accounted for the highest percentages of total GHG emissions expressed as CO_2-e.

For the year 2003, the majority (94%) of the actual tonnes of reported emissions were CO_2. The remaining 6% were distributed evenly between CH_4 and N_2O. CH_4 contributed to significant percentages of total CO_2-e emissions for landfill (100%), coal-mining (68%) and pipeline facilities (19%). N_2O contributed to significant percentages of total CO_2-e emissions for fertilizer facilities (26%) and chemical production facilities (10%).

Total CO_2-e and CO_2 emissions are dominated by stationary fuel combustion sources. However, 78% of CH_4 emissions are from fugitive sources and 72% of N_2O emissions are from process-related sources. Stationary fuel combustion was the largest source of GHG emissions for most facility types, with the exception of the cement, landfill and coal-mining facilities.

A total of three gas plants reported geological injection. For two of these facilities, injected CO_2 accounted for greater than 30% of total CO_2 produced from that plant. Additionally, three oil sands and three pulp & paper and wood product facilities reported CO_2 biomass emissions. In the oil sands facilities, CO_2 biomass emissions only represented 1% of total CO_2-e emissions from both fossil fuel and biomass sources. However, for the forestry facility type, CO_2 biomass emissions represented 87% of total CO_2-e emissions from both fossil fuel and biomass sources.

A total of 17 facilities reported intensity data, with only nine of these facilities being outside the pipeline facility type. No facility reported the metric upon which the intensity measurement was based. Improved reporting of intensities and associated metrics in non-pipeline facility types would enable a detailed analysis of these parameters and comparison within specific industry facility types.

Emission factors were the most commonly used method of emission estimation. However, considerable variation existed in the methodology and reference documents used. Use of consistent emissions estimation methodologies would enable more defendable comparisons of emission estimates between individual industries, and especially facility types.

The experiences from the first reporting year indicate that there are technical issues with the current reporting program that should be addressed in subsequent years. As the Alberta program harmonizes with the national program the following improvements should be considered:

- More detail in submitted supporting data or development of an auditing program.
- Increased disaggregation of data reported from complex industries such as oil sands, refining and chemicals.
- Use of standard emission estimation methodologies.

- A closer examination of gases and types of emissions that should be included in reporting thresholds.
- Clarification of definitions including ‘stationary fuel-combustion emissions’, ‘process-related emissions’, and ‘facility’ to harmonize with the national system.
- Determination of intensity metrics and requiring intensity reporting on a CO_2-e basis.
- Specification of which offsets or emission reduction equivalences are applicable for calculating net specified gases.
- Submission of more comprehensive rationale for confidentiality requests.

This report provides the results of the first year of GHG reporting in Alberta. In subsequent years, the Alberta program will be harmonized with the national GHG reporting program and will be expanded to include additional GHGs such as hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulphur hexafluoride (SF_6). Large emitters of GHGs in Alberta reported their 2004 GHGs emissions through the national program by June 1, 2005.

Other provinces, including Ontario and Quebec have also implemented mandatory and voluntary GHG reporting programs to assess emissions reduction progress in their respective jurisdictions. In order to better provide for the needs of varied jurisdictions while minimizing reporting burden on industry, federal, provincial/territorial and industry stakeholders have pursued the development of a national-level reporting system, which is being implemented in phases. The first two phases are: 2004-2005 (Phase I) and 2006 and beyond (Phase II).

Under the national reporting system, Alberta facilities will report to the Alberta government using an electronic reporting system managed by Statistics Canada. Alberta has signed an information sharing agreement that will allow Statistics Canada to share the Alberta information with the federal government.

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Abbreviations

AENV: Alberta Environment

CH_4: Methane

CO_2: Carbon Dioxide

CO_2-e: Carbon Dioxide Equivalent

EPEA: Environmental Protection and Enhancement Act

GHG: Greenhouse Gas

GWP: Global Warming Potential

HFCs: Hydrofluorocarbons

N_2O: Nitrous Oxide

PFCs: Perfluorocarbons

SF_6: Sulphur Hexafluoride

STP: Standard Temperature and Pressure

UNFCCC: United Nations Framework Convention on Climate Change

USEPA: United States Environmental Protection Agency

VCR: Voluntary Challenge and Registry

1.0 Overview of the Alberta GHG Reporting Program

1.1 Context

In October 2002, the Alberta government released Albertans and Climate Change: Taking Action[i]. This document identified a provincial greenhouse gas (GHG) reporting program as an important part of Alberta's action plan to address climate change. Information gathered under the provincial program is needed to assist both the province and industry in characterizing emission sources and identifying opportunities for emission reductions of the six key greenhouse gases identified under Canada's Greenhouse Gas Inventory[ii]. The provincial GHG reporting program will allow the Alberta government to monitor progress of specific Alberta emission reduction strategies, such as setting GHG emission targets, establishing emission trading systems, accelerating industry uptake of GHG-reduction technologies and promoting improvements in emissions intensity associated with the production of electricity and commodities.

In order to fulfill the objectives of Alberta's action plan to address climate change, the Alberta government is committed to negotiating agreements with specific sectors, including energy, manufacturing, transportation, municipalities, commercial and agriculture, to gain commitment for action to reduce GHG emissions. A reduction of GHG emissions by sector will require broader and more detailed GHG emission information than is currently available through voluntary programs and existing Environmental Protection and Enhancement Act (EPEA) approvals. To forward this initiative, a new regulation is currently being developed under the Climate Change and Emissions Management Act. This regulation will deal with definitions, specified gas emission targets, sectoral agreements, programs, agreements regarding inter-jurisdictional co-operation, climate change and emissions management fund, liability and vicarious responsibility, and emission offsets. The intent is to have the regulation come into force in January 2007 with emissions targets applied beginning in January 2008.

To facilitate management of GHG emissions, all Albertans, represented by industry, municipalities and consumer organizations require accurate and timely emissions data provided by a provincial reporting program. For this reason, comprehensive emission data, including direct emissions and indirect emissions (associated with electricity and steam imports), are required from all sectors. To monitor the progress of emission intensity reductions by sector, the necessary data needs to be made available. This requires that significant sources of the six greenhouse gases (CO_2, CH_4, N_2O, HFCs, PFCs and SF_6) identified in Canada's Greenhouse Gas Inventory[ii] be reported accordingly. Reports also need to include sufficient detail for report verification.

In coordination with the national reporting program, reporting of GHGs will be implemented in phases, with subsequent years possibly involving an increasing detailed level and scope of reporting. In the first year of the Alberta program, all large industrial emitters from the energy and manufacturing facilities were required to report direct emissions and geologically-injected CO_2 at the facility level. Reporting of geologically-injected CO_2 was required for tracking purposes. Reporting of emissions intensity enables the government to manage greenhouse gas emissions using an intensity-based approach that integrates both environmental and economic objectives.

In the first year of reporting, large emitters reported their preceding year's emissions to Alberta Environment. Beginning in June 2005 large emitters will report to a national reporting system, of which Alberta is a part. Implementation of reporting to Alberta Environment in 2004 fulfills the commitment made to the public by the Minister of Environment and enables the national system to benefit from lessons learned from the first year of reporting in Alberta.

1.2 History of Development of the Alberta GHG Reporting Program

1.2.1 Phase I Reporting

In the first phase of reporting, the Alberta GHG reporting program required Alberta facilities emitting 100,000 tonnes or more of carbon dioxide equivalent (CO_2-e) per year (based on the sum of direct emissions of carbon dioxide, methane, and nitrous oxide) to report their greenhouse gas emissions. Emissions were estimated and reported according to the November 2004 version of the Specified Gas Reporting Standard[iii]. Reportable emissions included combustion, manufacturing process, and fugitive sources. The Alberta GHG reporting program has been developed in consultation with industry and is based on Alberta's climate change action plan and legislation. Standardized reporting protocols used in this program are based on existing industry and international guidelines and practices. The deadline for reporting 2003 GHG emissions was November 15, 2004.

Major industry facilities involved in reporting included power plants, oil sands, gas plants, heavy oil plants, petroleum refining, chemical, coal-mining, cement, pulp & paper and wood products, fertilizer plants, natural gas pipelines and landfills.

The Alberta Specified Gas Reporting Standard was modified in March of 2005 to harmonize with the national electronic data reporting system. One of the modifications included mandatory reporting of all six GHGs (CO_2, CH_4, N_2O, HFCs, PFCs and SF_6) instead of only CO_2, CH_4 and N_2O. Reporting of HFCs, PFCs and SF_6 was optional in the previous version of the Standard. Alberta industries will be reported in accordance with the new Standard to the national system for the 2004 reporting year.

1.2.2 Legal Components

The three important components detailing the legalities and expectations of industrial emitters under this new program are the Specified Gas Reporting Standard[iii], the Specified Gas Reporting Regulation[iv], and the *Climate Change and Emissions Management Act*[v]. A reporting template was developed for the 2003 reporting program. Its use for the Specified Gas Reporting program was not mandatory, but provided a useful tool for reporting.

Under the *Climate Change and Emissions Management Act*[v] (2003) section 6(1) every person who releases greenhouse gases at or exceeding levels in the regulations is required to report their emissions. The Specified Gas Reporting Regulation further specifies that the responsible person for the facility meeting or exceeding established levels during a calendar year, commencing with the 2003 calendar year, must submit a specified gas report (section 3(1)). The specified gas report must include information respecting the specified gas reporter, the facility to which the specified gas report relates, the release of specified gases from the facility, and geologically injected CO_2 (section (2)).

Under the Specified Gas Reporting Standard section 2(1), the threshold level for submission of a specified gas report is the release of 100-kt CO_2-e based on the sum of direct emissions of CO_2, CH_4 and N_2O, not including CO_2 emissions arising from biomass combustion[iii]. Under section 5(1), the specified gas report of the preceding calendar year shall contain the following information in summary tabular form:

(a) The direct emissions in tonnes, of CO_2, CH_4 and N_2O for each of the following emission source types: stationary fuel combustion, industrial process, fugitive and other.

(b) CO_2 emissions from biomass combustion.

(c) The amount (tonnes) and location of geologically injected CO_2.

(d) A listing of the methodology type (monitoring/direct measurement, mass balance, emission factors, engineering estimate) and a citation of applicable methodology reference publications (listed under section 7) used in calculating emissions.

Under section 6(1), the specified gas report may also contain the following additional information:

(a) The amount, in tonnes, of biologically sequestrated CO_2.

(b) The amount, in tonnes, of indirect emissions of CO_2, CH_4 and N_2O associated with the generation of imported/purchased electricity, steam or heat for the facility.

(c) A calculation and description of net specified gas emissions, in tonnes of CO_2e; based on the total direct emissions less offsets or emission reduction equivalences.

(d) A calculation of the specified gas intensity expressed in tonnes, and associated calculation.

(e) Actual equations, calculations, emission factors, and emission estimation models used to determine emissions.

(f) The amount of HFCs, PFCs, and SF_6 released and captured at the facility, aggregated and combined, and expressed as tonnes of CO_2e.

1.2.3 Stakeholder Involvement

Over the last two years, the Alberta government has worked with provincial stakeholders to develop an efficient and effective greenhouse gas (GHG) reporting program. In December 2002, Alberta Environment released a *Framework Proposal for an Alberta Greenhouse Gas Reporting Program*[vi], which highlighted issues needing to be addressed for development of an effective program. During presentations held February 2003, stakeholders were asked to comment on the following issues highlighted in the proposal:

- program administration,
- reporting boundaries,
- reporting industries,
- reportable emission sources and parameters,
- emission estimation methodologies,
- required supporting information and emission thresholds.

Feedback and comments were received and compiled in: *Summary of Comments on Alberta's Proposed Greenhouse Gas Reporting Program*[vii]. The feedback and comments identified and prioritized issues requiring resolution during the succeeding consultative process.

The external reference group (ERG) and a technical working group (TWG) formed an integral part of the consultative process, which is described in more detail in *Alberta's Greenhouse Gas Reporting Program Development Plan 2003-04*[viii]. Alberta Environment encouraged stakeholders to be involved in the ERG. This group served as a forum to initiate discussions and forward concerns from a wide spectrum of industry, government and environmental organization perspectives. Concerns from the ERG were referred to the smaller TWG. This group provided expertise to resolve specific reporting issues necessary for the program implementation.

In late June 2003, members of the ERG and TWG met in a joint session to review the *Alberta Greenhouse Gas Reporting Program Guidance 1st Draft*[ix], which was based on earlier stakeholder input compiled in the *Summary of Comments on Alberta's Proposed Greenhouse Gas Reporting Program*[vii]. A facilitator's report on this joint session was made available to participants in mid-July 2003[x]. Stakeholder input was used as a basis for subsequent revisions to the 1st draft. Unresolved issues were referred to the TWG, which began working on targeted issues in late July 2003.

After the TWG made their recommendations, Alberta Environment hosted a workshop in the fall of 2003 to seek further input from stakeholders on finalization of the *Alberta Greenhouse Gas Reporting Program Guidance 1st Draft*[ix]. The proceedings of this workshop were captured in a facilitator's report.

In May of 2004, Alberta Environment hosted final consultation workshops held in Edmonton and Calgary. The discussions centered on the drafts of the Specified Gas

Reporting Regulation[iv] and Specified Gas Reporting Standard[iii]. A facilitator's report[xi] was generated as a result of the workshops encompassing industry's concerns and questions, with Alberta Environment's responses to them. A news release of the Specified Gas Reporting Regulation was issued on October 21, 2004 with the regulation coming into effect November 1. An Alberta Gazette notice in November contained a reference to the Specified Gas Reporting Standard. The consultative approach resulted in a GHG reporting program that allowed optimum flexibility for reporters.

1.3 Future National GHG Reporting Program

In addition to Alberta, other jurisdictions at the federal and provincial level are interested in collecting GHG emissions data. The federal government needs GHG emissions data to monitor emissions reductions from Large Final Emitters (LFE), to conduct sectoral analyses, to implement emissions trading, to create a registry to account for domestic offsets and the purchase of international permits, and to provide increased detail for Canada's Greenhouse Gas Inventory submissions to the UNFCCC. Other provinces, including Ontario and Quebec have also implemented mandatory and voluntary GHG reporting programs to assess emissions reduction progress in their respective jurisdictions. In order to better provide for the needs of varied jurisdictions while minimizing reporting burden on industry, federal, provincial/territorial and industry stakeholders have pursued the development of a national-level reporting system, which is being implemented in phases. The first two phases are: 2004-2005 (Phase I) and 2006 and beyond (Phase II).

1.3.1 Overview of Phase I

Consultations on national-level mandatory GHG reporting began in 2002 with the objective of developing common reporting requirements across jurisdictions to the maximum extent possible, to minimize duplication and to maximize consistency and comparability. Stakeholders were advised in January 2003 that mandatory national-level reporting would come into effect in 2004. In the fall of 2003, Alberta Environment, Environment Canada, Natural Resources Canada, and the Ontario Ministry of the Environment organized two national workshops with stakeholders to pursue approaches to an efficient harmonized, single-window reporting system that would satisfy the needs of national, provincial and territorial governments and the public, and minimize burdens on both Canadian industry and governments.

In March 2004, it was announced in a Canada Gazette notice that during the first phase of the domestic mandatory national reporting system, all facilities emitting 100 kilotonnes or more of CO_2 equivalent annually, would be required to report total emissions of each of six GHGs (CO_2, CH_4, N_2O, HFCs, PFCs and SF_6), reported to the United Nations Framework Convention on Climate Change (UNFCCC).[xii] Reported emissions of CO_2, CH_4 and N_2O must be further broken down by four sources, namely stationary fuel combustion, industrial process, fugitive emissions and "other." Major industrial facilities implicated in the reporting system include facilities in the power plant, steel, metal smelting and refining, petroleum refining, and chemical producing sectors. Reports on facility-level emissions will be publicly disclosed. The deadline for reporting 2004 GHG emissions is June 1, 2005.

In order to avoid duplication and to ease the reporting burden, Statistics Canada will collect the greenhouse gas emissions-related data under the authority of the Statistics Act,[xiii] the 1999 Canadian Environmental Protection Act (CEPA)[xiv] and Alberta's Climate Change Emissions Management Act.[v] Under the provisions of section 12 of the Statistics Act, Statistics Canada has entered into data sharing agreements with Environment Canada and Alberta Environment. GHG-emission-related data will be collected by Statistics Canada for statistical and research purposes and used by Environment Canada and Alberta Environment for monitoring and regulatory purposes. Alberta reporters will be required to report 2004 data only once through the single-window GHG reporting system for Environment Canada and provincial governments, but separate statements of certifications and requests for non-disclosure (if applicable) must be submitted to both the Government of Alberta and Environment Canada.

The first reporting phase has few requirements concerning GHG estimation methodologies, other than the requirement that generally accepted international practices must be followed. In subsequent reporting phases, additional reporting requirements, including the use of specified emission estimation methodologies, may be implemented following further consultations with stakeholders.

2.0 Confidentiality

2.1 Overview of Process

Pursuant to section 5(1) of the Specified Gas Reporting Regulation[iv] "A specified gas report may include a written request by the specified gas reporter that portions of the report be kept confidential, for a period of up to five years, on the basis that the information is commercial, financial, scientific or technical information that would reveal proprietary business, competitive or trade secret information about a specific facility, technology or corporate initiative." While a request is being considered, the information is kept confidential as "prescribed information". In cases where the request is well founded, the Director will order that the relevant information not be disclosed for the period prescribed by the Director. Decisions will be based on the criteria in section 5(2) including: whether disclosure would significantly harm competitive position or interfere with the negotiating position of the specified gas reporter, be expected to result in undue financial loss or gain, and whether the information contained in the report is available from other public sources. The Climate Change and Emissions Management Act[v] does not prohibit the publishing of prescribed information in summarized or statistical form in such a manner that it is not possible to relate the information to a particular facility, technology or corporate initiative (see section 17(3)).

Pursuant to section 6(2) of the Climate Change and Emissions Management Act, the Minister may disclose information reported under section 6(1) of the Act to the persons and in the form and manner provided for in the regulations. Section 7 of the Specified Gas Reporting Regulation states further that the information contained in gas reports may be published in any form and manner the Director considers appropriate. Under section 8 of the Regulation, the Director must report to the Information and Privacy Commissioner the number of requests received and number of requests approved for withholding of confidential information.

2.2 Summary of Requests Received & Outcome

Of 101 reports, 20 requested confidentiality, involving seven different companies. All 20 facilities were granted some form of data confidentiality for detailed direct emissions only, or for both detailed direct emissions and total emissions in CO_2-e. Confidentiality was granted for one or five-year periods based on the rationale provided with the request. Facilities granted confidentiality included eight gas plants, four oil sands facilities, three petroleum refining facilities, three power plants, one heavy oil plant and one lime manufacturing plant (Table 1). Some reporters requesting confidentiality were required to provide further information on their rationale for the confidentiality request.

Table 1: Number of facilities by facility type that were granted confidentiality.

Facility Type	# of Reporting Facilities	# of Facilities Granted Confidentiality for CO_2-e, CO_2, CH_4 and N_2O Emissions Data	# of Facilities Granted Confidentiality for only CO_2, CH_4 and N_2O Emissions Data
Cement/Lime	3	1	0
Chemicals	9	0	0
Coal-mining	1	0	0
Fertilizer	6	0	0
Forest Products	3	0	0
Gas Plants	34	4	4
Heavy Oil Plants	4	0	1
Landfill	1	0	0
Oil Sands	5	4	0
Petroleum Refining	4	1	2
Pipeline	12	0	0
Power Plants	19	0	3
Total Facilities	101	10	10

3.0 Statistical Review of Data

3.1 Facility Emissions

Total facility-level emissions data are provided in Table 6 of the Appendix for non-confidential data only. In the analysis that follows, care was taken to ensure that confidential data cannot be identified.

In total 101 facilities reported 2003 emissions totaling almost 104 Mt CO_2-e. The percentage composition of reported CO_2-e emissions for CO_2 (carbon dioxide), CH_4 (methane) and N_2O (nitrous oxide) is shown in Figure 1. The majority (94%) of the actual tonnes of reported emissions were CO_2. The remaining (6%) were distributed evenly between CH_4 and N_2O. Figure 1 contains total emissions from all facilities and includes confidential and non-confidential data.

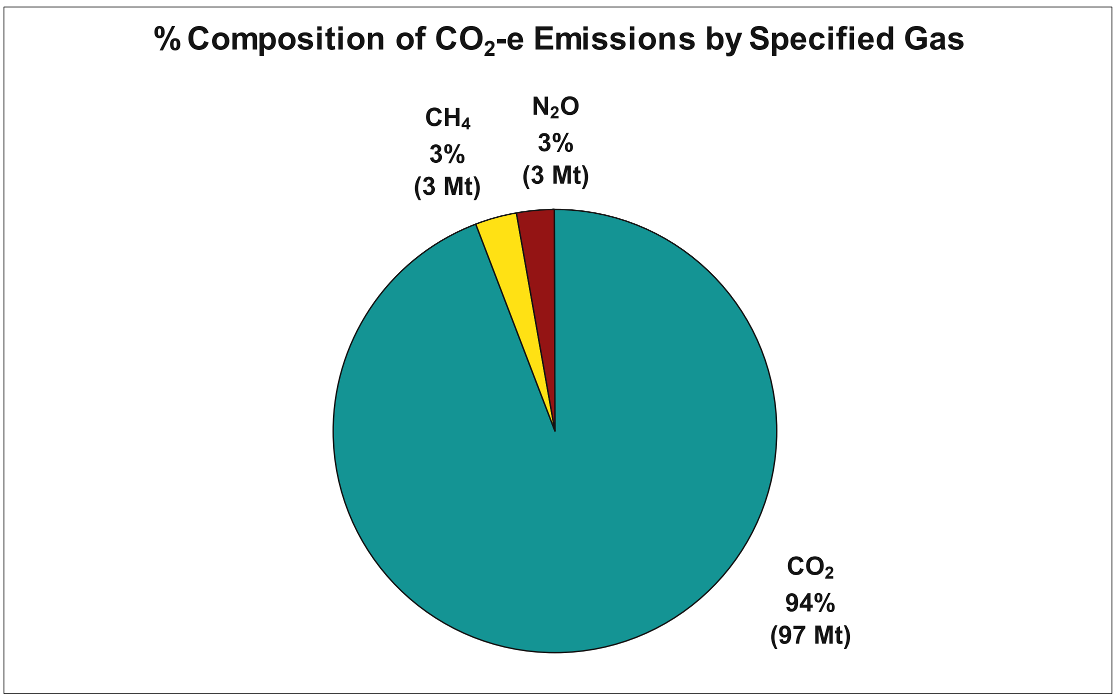

Figure 1: % composition of total reported CO_2-e emissions by specified gas for 2003.

3.2 Emissions by Facility Type

Emissions were classified according to the following facility types: gas plants, heavy oil plants, oil sands, petroleum refining/upgraders, chemicals, power plants, forest products, cement/lime, fertilizer, landfill, pipeline and coal-mining. Figure 2 shows the percentages for reported CO_2-e emissions by facility type. Total reported emissions were highest for power plants (46%), followed by oil sands facilities (17%), gas plants (9%), chemical facilities (7%) and heavy oil plants (6%). The combined total CO_2-e emissions from petroleum refining/upgrader, fertilizer, pipeline, cement/lime, forest products, coal-mining and landfill facilities was 15%, with none of these facility types contributing more than 5% to the total on an individual basis.

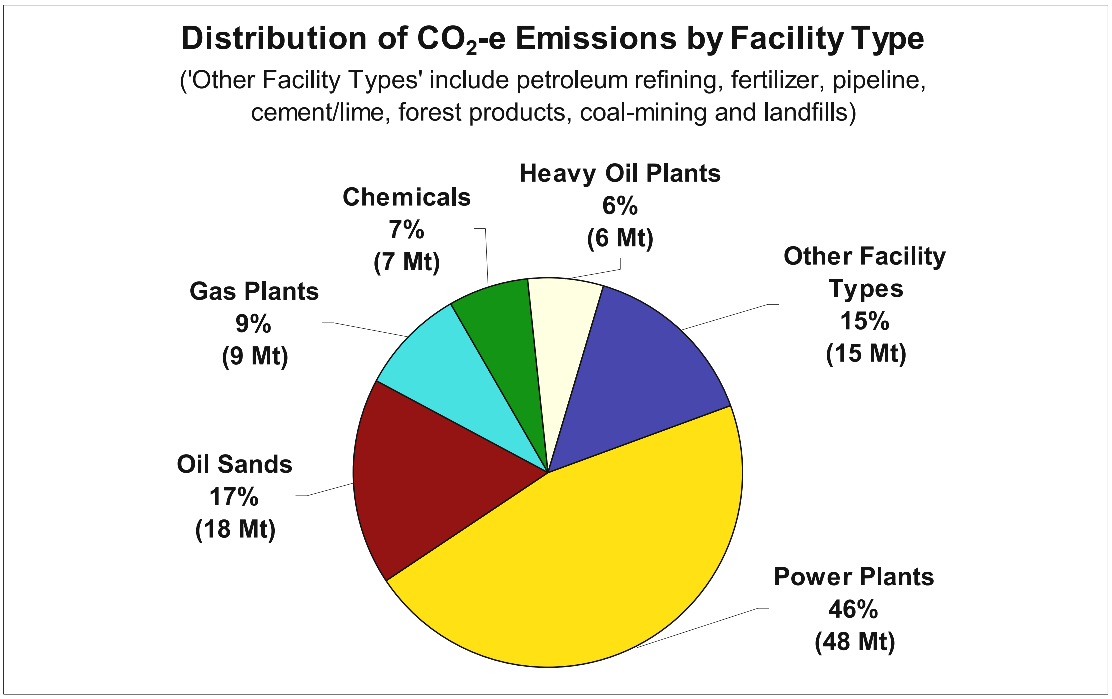

Figure 2: CO_2-e emissions by facility type for 2003.

Figure 3 shows the distribution of each reported greenhouse gas by facility type. For most facilities, CO_2 emissions constitute the majority of total CO_2-e emissions. CH_4 constitutes a significant percentage of the total CO_2-e emissions for landfill, coal-mining and pipeline facilities. N_2O constitutes a significant percentage of the total CO_2-e emissions in the fertilizer and chemical facilities.

The percentage of CO_2, CH_4 and N_2O emissions reported by facility type are shown in Figure 4, Figure 5 and Figure 6. Power plants and oil sands account for 50% and 17%, respectively of total reported CO_2 emissions. Oil sands facilities, gas plants and pipelines account for 33%, 32% and 16%, respectively, of CH_4 emissions. Fertilizer plants, chemical plants and power plants account for 47%, 25% and 14%, respectively, of N_2O emissions.

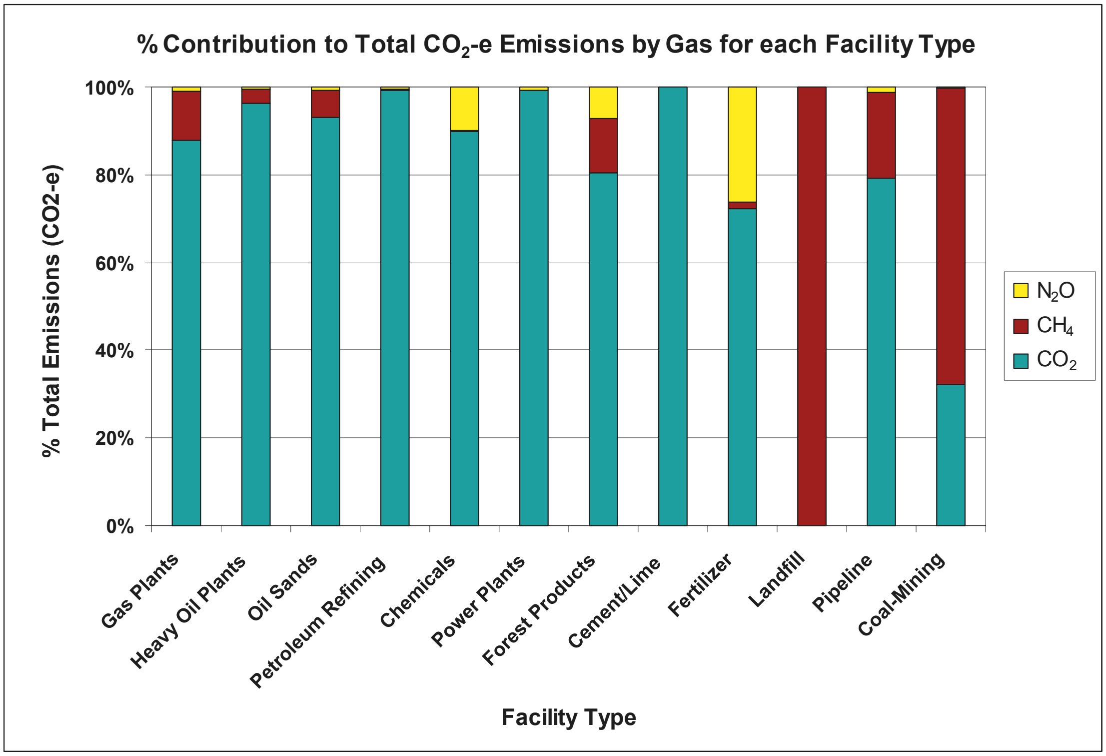

Figure 3: % contribution to CO_2-e emissions by gas for each facility type for 2003.

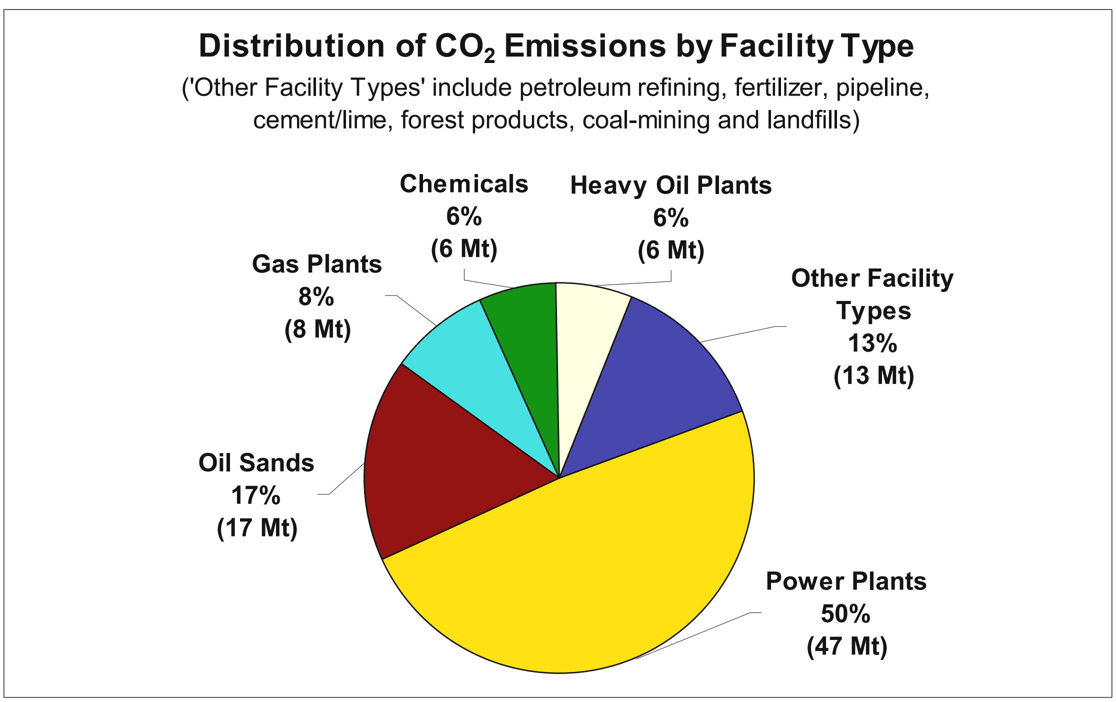

Figure 4: % CO_2 emissions by facility type for 2003.

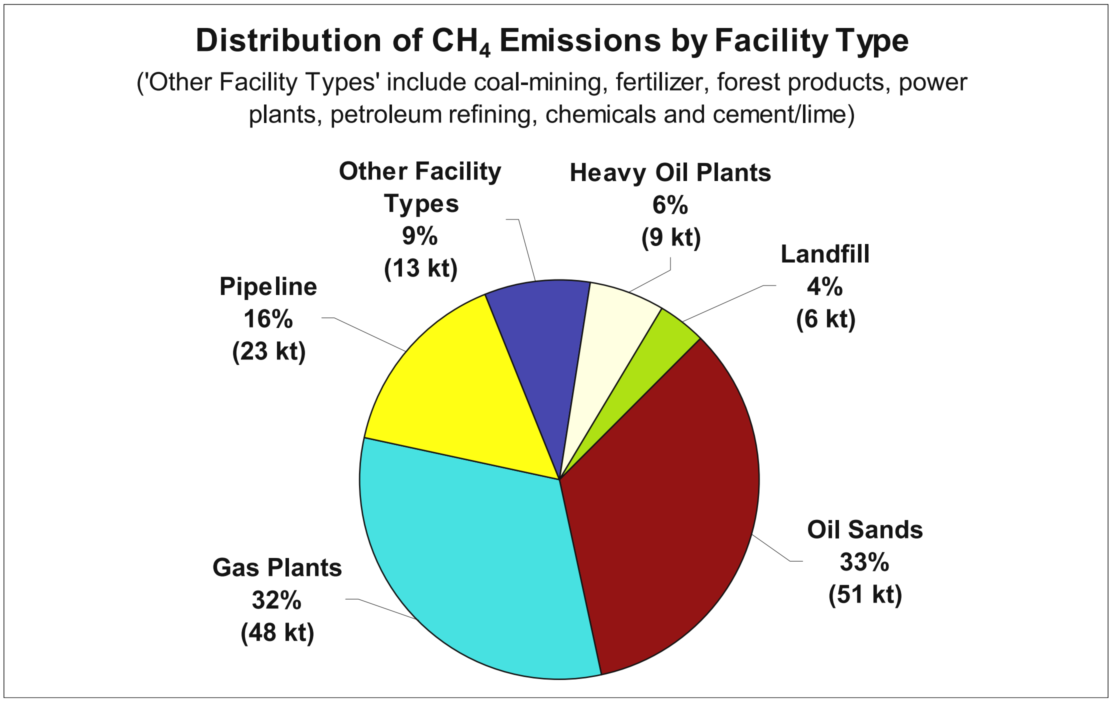

Figure 5: % CH_4 emissions by facility type for 2003.

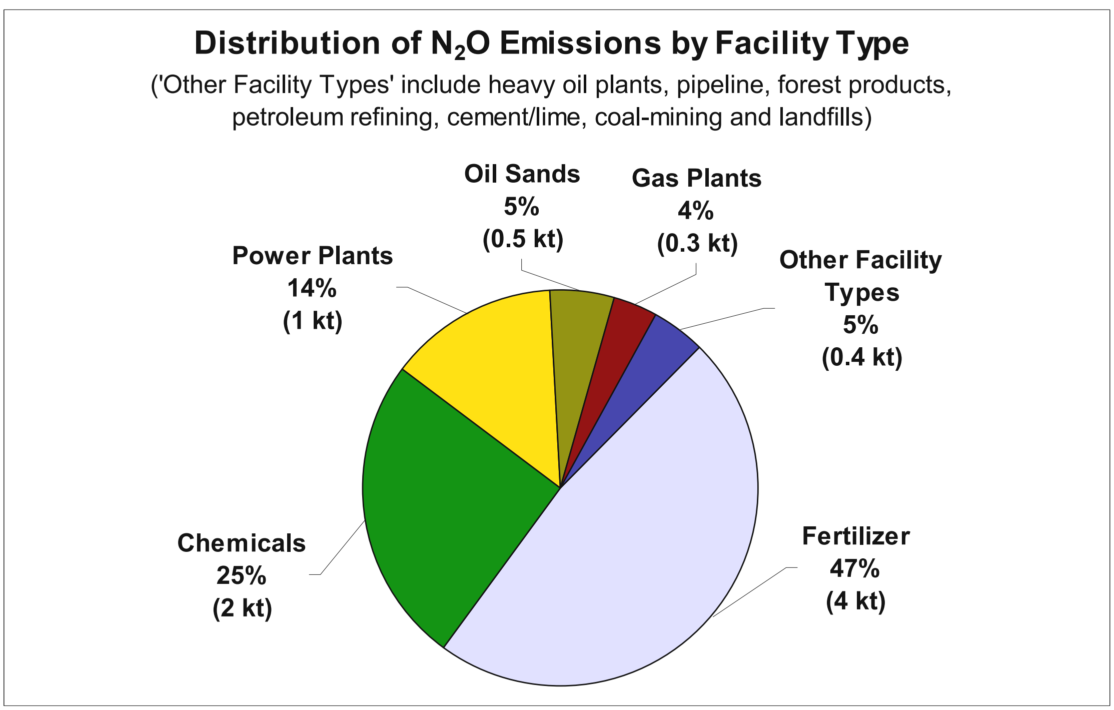

Figure 6: % N_2O emissions by facility type for 2003.

3.3 Emissions by Source Category

The Alberta reporting program[iii] requires reporting from four source categories: stationary combustion, industrial process, fugitive and other, where:

> "Stationary fuel combustion emissions" means direct emissions resulting from non-vehicular combustion of fossil or biomass fuel for the purpose of producing energy but does not include biomass combustion CO_2 emissions.
>
> "Industrial process emissions" means direct emissions from industrial processes involving a chemical reaction, where the primary purpose of the industrial process is not energy production.
>
> "Fugitive emissions" means direct emissions from the production, processing, transmission, storage, and use of fossil fuel excluding emissions from fossil fuel combustion where the energy produced is used to power an engine or other machinery or provide heat for sale or use and includes, without limitation, flaring of natural gases at oil and gas production facilities.
>
> "Other emissions" means direct emissions other than biomass combustion CO_2, fugitive, industrial process, or stationary fuel combustion emissions and includes emissions from vehicles that are integral to production processes at a facility.

An analysis of CO_2-e, CO_2, CH_4 and N_2O emissions data by source category is shown in Figures 7 through 10. Total CO_2-e and CO_2 emissions are dominated by stationary fuel combustion sources. 78% of CH_4 emissions arise from fugitive sources and 72% of N_2O emissions are from process-related sources.

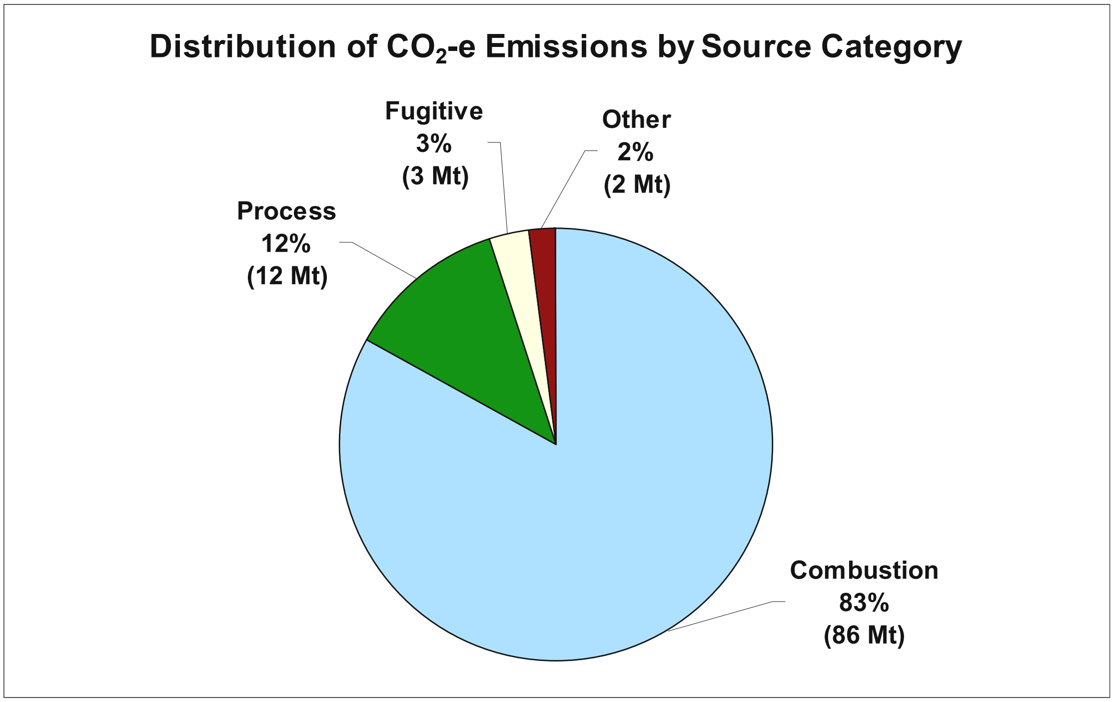

Figure 7: % composition by emission source for total CO_2-e emissions for 2003.

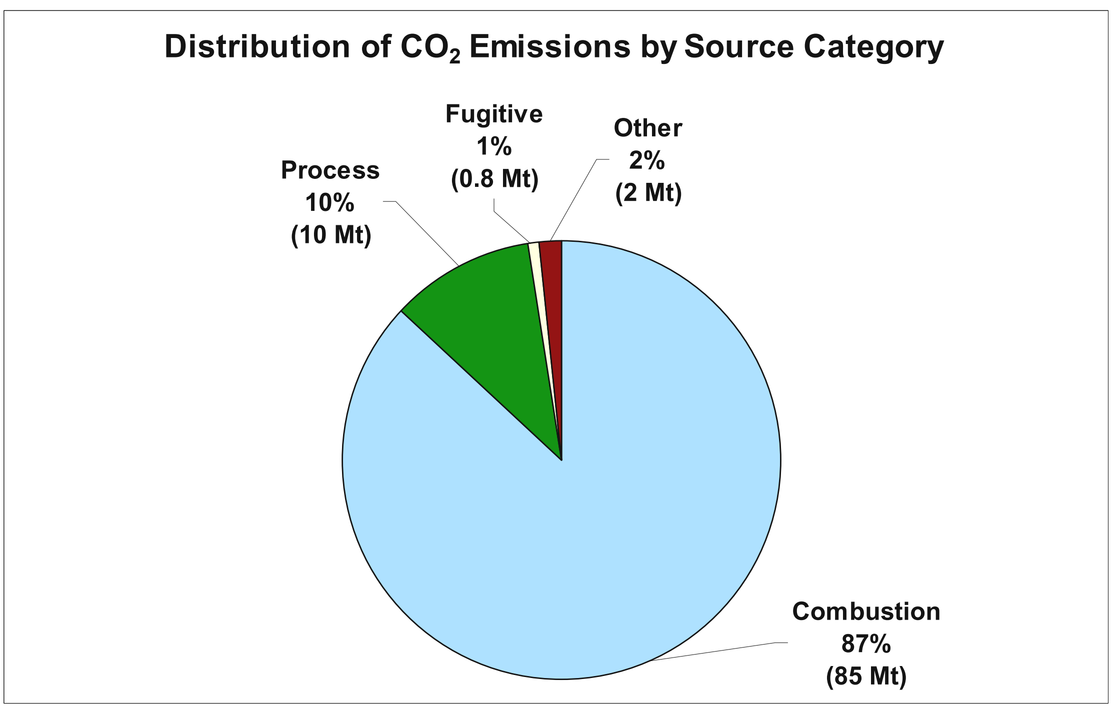

Figure 8: % composition by emission source for total CO_2 emissions for 2003.

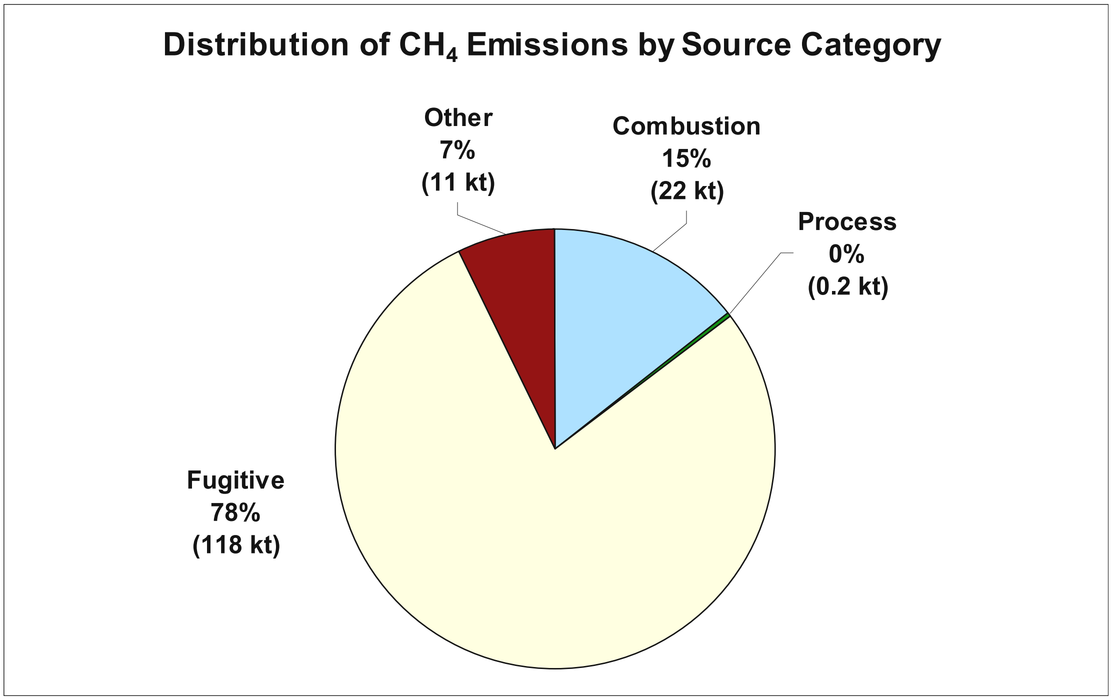

Figure 9: % composition by emission source for total CH_4 emissions for 2003.

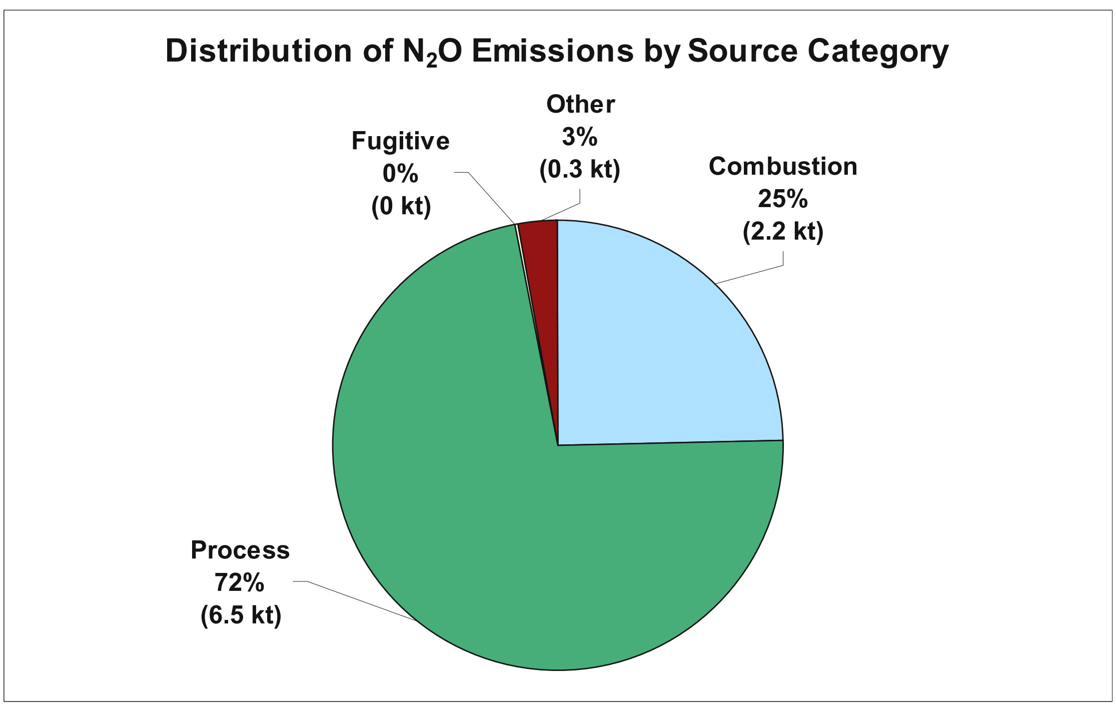

Figure 10: % composition by emission source for total N_2O emissions for 2003.

3.4 Emissions by Source Category and Facility Type

An analysis of CO_2, CH_4 and N_2O emissions data (as CO_2-e) is presented in Table 2 by source category and facility type. Stationary fuel combustion CO_2 emissions make up the largest percentage of total CO_2-e emissions for all facility types, with the exception of the cement facilities, landfills and coal-mining operations. Process-related CO_2 emissions are significant for cement/lime and fertilizer facilities. High levels of process-related CO_2 emissions for gas plants and refineries are likely due to reporting of large quantities of vented gases as process emissions, rather than fugitive emission as specified in section 2.3 of the Standard. CH_4 fugitive emissions are significant for the coal-mining facility type. The large quantity of 'other' CH_4 emissions reported for landfills is likely due to waste landfill gas. Large quantities of 'other' CH_4 emissions reported for coal-mining are likely due to erroneous reporting of large quantities of vented gases that should have been reported under fugitive emissions. N_2O process emissions are significant in the fertilizer and chemical facilities.

Table 2: Relative emissions for CO_2, CH_4 and N_2O by source category for each facility type.

Facility Type	Stationary Fuel Combustion [%]			Industrial Process [%]			Fugitive [%]			Other [%]		
	CO_2	CH_4	N_2O	CO_2	CH_4	N_2O	CO_2	CH_4	N_2O	CO_2	CH_4	N_2O
Gas Plants	54	3	1	26	0	0	1	9	0	6	0	0
Heavy Oil Plants	96	3	1	0	0	0	1	0	0	0	0	0
Oil Sands	73	0	0	12	0	0	3	6	0	5	0	0
Petroleum Refining	62	0	0	34	0	0	3	0	0	0	0	0
Chemicals	72	0	0	18	0	10	0	0	0	0	0	0
Power Plants	99	0	1	0	0	0	0	0	0	0	0	0
Forest Products	77	1	5	1	0	2	0	0	0	2	11	0
Cement/Lime	38	0	0	62	0	0	0	0	0	0	0	0
Fertilizer	43	0	0	29	0	26	0	0	0	0	1	0
Landfill	0	0	0	0	0	0	0	0	0	0	100	0
Pipeline	79	0	1	0	0	0	0	19	0	0	0	0
Coal-mining	0	0	0	0	0	0	0	68	0	32	0	0

Out of the 101 facilities, three (gas plants) reported geological injection. For two of the three gas plant facilities, the reported geologically injected CO_2 accounted for greater than 30% of total CO_2 produced from that plant.

Additionally, three oil sands and three pulp & paper and wood product facilities reported CO_2 biomass emissions. These emissions exceeded 850 kt at each of the forestry facilities. In the oil sands facility type, CO_2 biomass emissions only represented 1% of total CO_2-e emissions from both fossil fuel and biomass sources. However, in the forestry facility type, CO_2 biomass emissions represented 87% of total CO_2-e emissions from both fossil fuel and biomass sources.

3.5 Optional Emissions Data

There were 35 facilities that reported additional information. A total of 17 facilities reported intensity data, with only 9 of these facilities being outside the pipeline facility type. No facility reported the metric upon which the intensity measurement was based. One reporter mistook intensity to mean CO_2-e. Reported intensities for pipelines sometimes varied by several orders of magnitude. In the absence of reported methods, it is not possible to definitively determine whether this variation is due to calculation errors or different methods. Lack of reported intensities and associated metrics in non-pipeline facility types prevented a detailed analysis and comparison within any industry facility type.

Gas plants and pipelines were the only facility types with any significant number of reporters submitting indirect emissions. Of those facilities reporting indirect CO_2 emissions, many neglected to report CH_4 and N_2O emissions. For gas plant facilities, indirect emissions accounted for 23% of total direct and indirect emissions. For pipelines, indirect emissions accounted for approximately 10% of total direct and indirect emissions.

The lack of reporting on net specified gases made meaningful analysis difficult. Many facilities reported higher net emissions than direct emissions, suggesting that they misunderstood net emissions to be the total of direct and indirect emissions, whereas the reporting standard defines net emissions as direct emissions less emission reduction equivalences and offsets. Of those facilities reporting net emissions lower than direct emissions, net emissions were 96% lower in the fertilizer facility type and 47% lower in the gas plant facility type than respective direct emissions.

Only one facility in the oil sands facility type reported optional fluorinated gases (HFCs, PFCs, SF_6).

3.6 Emissions by Methodology

Facilities were required to report the methodology type used to estimate emissions in the stationary combustion, industrial process, fugitive, other and biomass emission source categories. The frequency of citation of the following methodology types was analyzed: monitoring/direct measurement, mass balance, emission factors and engineering estimates.

Differences in the choice of methodology tended to be smaller within than between facility types. Gas plants and power plants were among the most homogenous facility types in terms of methodologies. Some facilities, such as the oil sands and fertilizer facilities used numerous types of emission methodologies, even within any given emission source category. Overall, the large variety in the use of methodologies would make comparison of emission estimates between individual facilities problematic, particularly between different facility types.

On an industry-wide basis, emission factors were the most commonly used methodology for calculation of CO_2, CH_4 and N_2O combustion, fugitive and other emissions (Figures 11 to 14). On an industry-wide basis, mass balance was the most commonly used methodology for calculating CO_2 industrial process emissions. A variety of methodologies were used to calculate CH_4 and N_2O industrial process emissions (Figure 12).

Certain facility types exhibited preferences for certain methodologies that differed from the dominant industry-wide methodologies. Most facility types used emission factors for calculating combustion emissions of CO_2, CH_4 and N_2O. However, pipelines used predominately mass balance for calculation of CO_2 combustion emissions. Considerable variation existed in the pipeline facility type for calculation of CH_4 and N_2O combustion emissions. Facilities within the oil sands and fertilizer facilities exhibited considerable variation in their approaches to calculation of CO_2, CH_4 and N_2O combustion emissions. Chemical plant facilities exhibited considerable variation for estimating N_2O emissions.

Gas plants used predominately a mass balance approach to calculating CO_2 process emissions. However, facilities outside of the gas plant facility type exhibited considerable variation in their approach to calculation of CO_2 process emissions. Fertilizer facilities exhibited considerable variation in methodology for CH_4 and N_2O process emissions. The chemical facilities exhibited considerable variation in methodology for CH_4 process emissions. Unlike gas plants, which used mostly emission factors, oil sands, chemical and pipeline facilities used a large variety of methods to determine CO_2 and CH_4 fugitives.

Unlike the power plants, which predominately used emission factors for calculating CO_2, CH_4 and N_2O “other” emissions, the gas plants used mostly mass balance for CO_2. The chemical facilities used engineering estimates for CO_2 and a variety of methods for CH_4, while the oil sands and fertilizer facilities used a wide variety of methods for CO_2, CH_4 and N_2O “other” emissions estimates.

Emission estimates from biomass were limited to the forest products and oil sands facilities. The former used predominately emission factors and the latter used both emission factors and engineering estimates.

The wide variation in the use of methodology for the "Other Emissions Source" category (Figure 14) may be due to the variable nature of this category, which would include emissions from waste (landfill, wastewater and waste incineration) and mobile transport. In the absence of more disaggregated emission sources, each individually identified with corresponding emission methodologies, it is difficult to determine whether facilities employing multiple methodologies for a given emission source (particularly in the oil sands and fertilizer facilities), are using similar methodologies for similar emission-generating activities. Large variety in the use of methodologies within any particular facility type may indicate difficulties in using a standardized methodological approach that is appropriate to facility specific conditions. However, differences might simply be a result of the methodological flexibility granted to reporters. Further information is required to ascertain the reason for these differences.

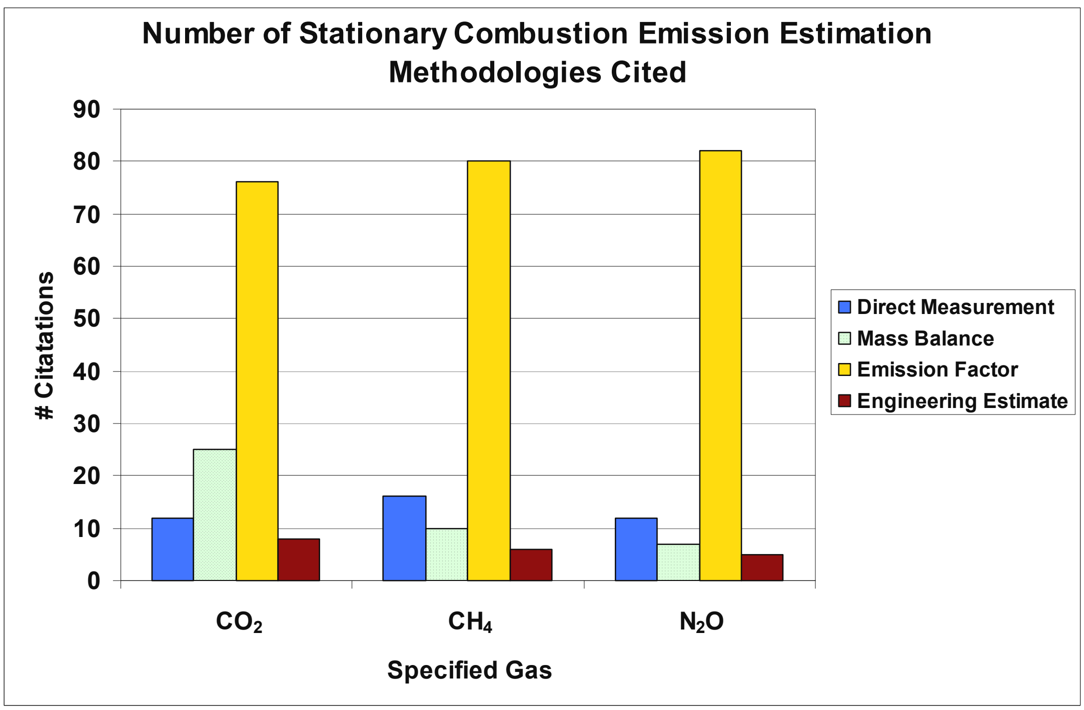

Figure 11: Number of stationary combustion emission estimation methodologies cited.

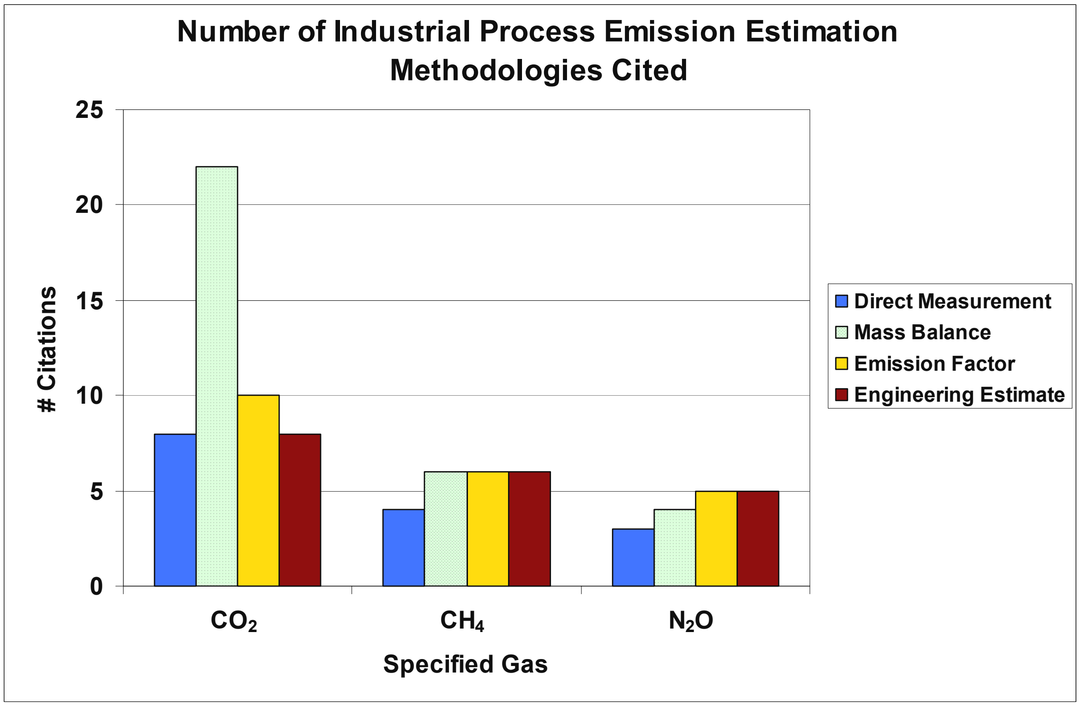

Figure 12: Number of industrial process emission estimation methodologies cited.

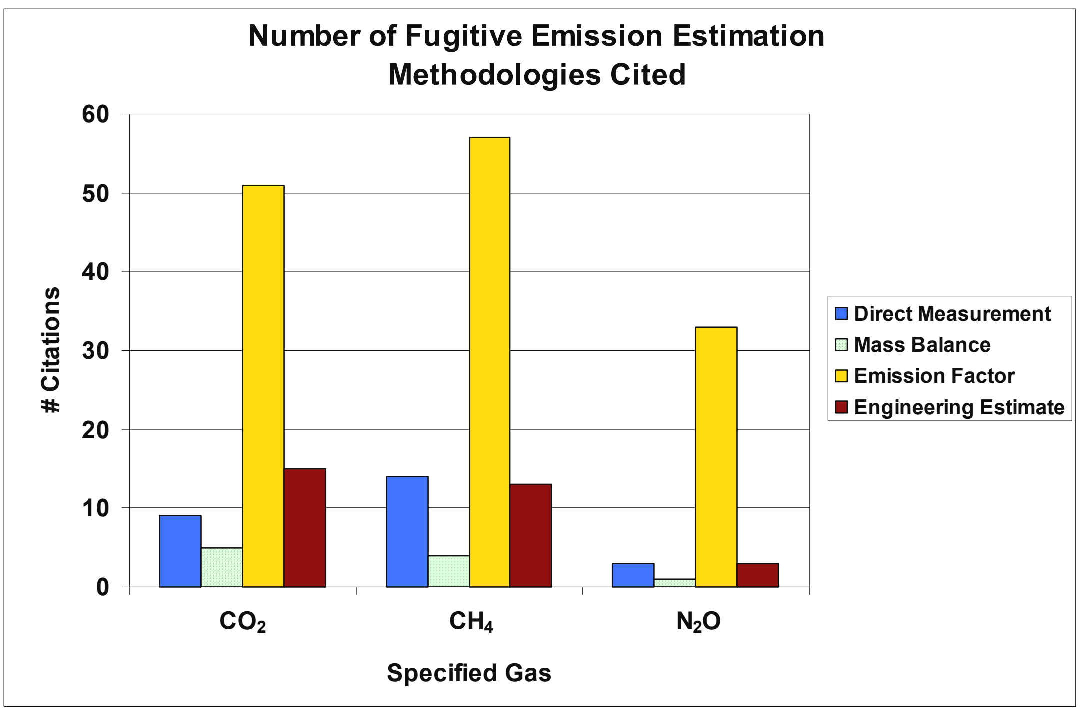

Figure 13: Number of fugitive emission estimation methodologies cited.

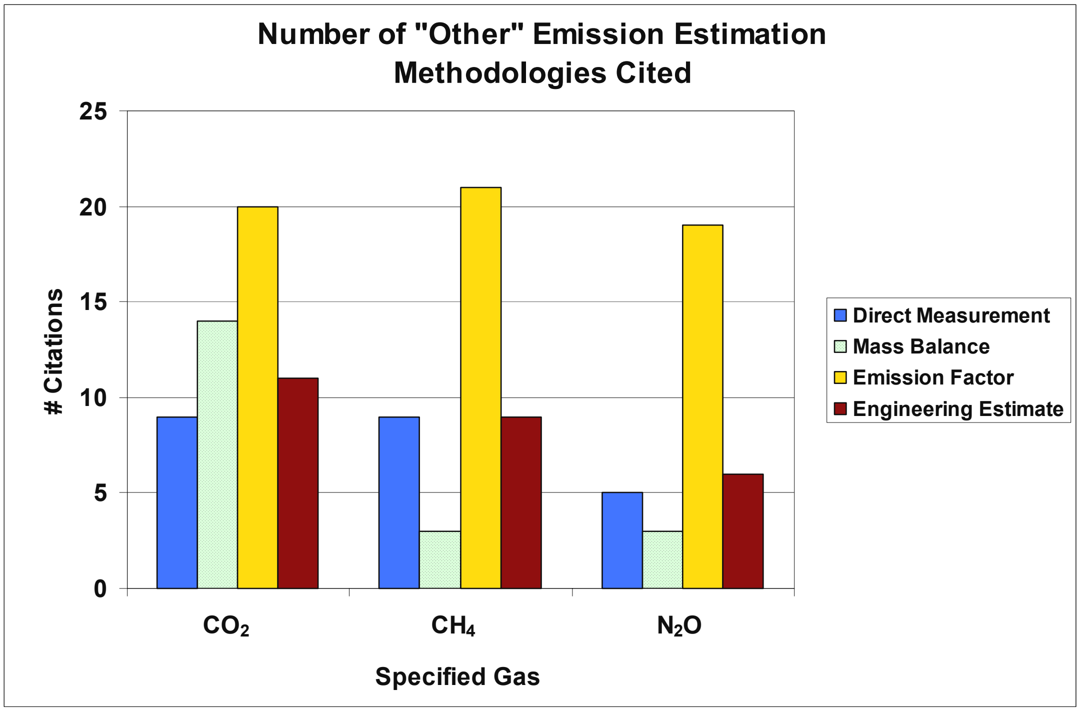

Figure 14: Number of "other" emission estimation methodologies cited.

3.7 Cited Reference Documents

The most common reference documents cited for each facility type are shown in Table 3. Multiple documents are indicated in this table where there was not one dominant reference document cited or there were several reference documents cited.

Table 3: Dominant reference documents by facility type and by source category.

Facility Type	Stationary Fuel Combustion	Industrial Process	Fugitive	Other	Biomass
Gas Plant	CAPP	CAPP	CAPP, AP-42, API	CAPP	-
Heavy Oil	CAPP, API, AP-42	-	CAPP	-	-
Oil Sands	CGGI, AP-42, CAPP, EMOH	EMOH	CAPP, EMOH, CGGI	EMOH, CGGI	CGGI
Petroleum Refining	AP-42, CGGI	AP-42, CIPEC	API, CGGI, AP-42	CGGI	-
Chemicals	CGGI, US-EPA, API, CCME	Celanese, CCME	CCME	AP-42	-
Power Plants	CGGI		CAPP	McCann	-
Forest Products	NCASI, ICFPA	NCASI, ICFPA	VCR	NCASI, ICFPA	NCASI, ICFPA
Cement	CGGI	WBCSD, Lime		WBCSD, CGGI	-
Fertilizer	AENV	AENV	AENV	AENV, CGGI	-
Landfill	-	-	-	-	-
Pipelines	AP-42, VCR	-	GRI, Tanks	VCR	-
Coal-mining	-	-	F-6	CGGI	-

AENV: Alberta Greenhouse Gas Reporting Program Guidance 1st Draft. Alberta Environment, Government of Alberta. June, 2003. http://www3.gov.ab.ca/env/air/pubs/ghg_reporting_program_guidance_draft1.pdf
API: Compendium of Greenhouse Gas Emissions Estimations Methodologies for the Oil and Gas Industry
AP-42: USEPA, Compilation Of Air Pollutant Emission Factors (AP-42 Fifth Edition), U.S. Environmental Protection Agency. http://www.epa.gov/ttn/chief/ap42/index.html
CAPP: Canadian Association of Petroleum Producers and Altus Environmental Engineering Ltd. Calculating Greenhouse Gas Emissions. [CAPP Publication #2003-0003], 60. 2003
CCME: CCME Environmental Code of Practice for the Measurement and Control of Fugitive Emissions from Equipment Leaks
CGGI: Environment Canada. Canada's Greenhouse Gas Inventory 1990-2002. Greenhouse Gas Division. 2004.
Celanese: Celanese Global EHS reporting guide
CIPEC: Task Force Guidelines for the Petroleum Sector (1995) developed by the Canadian Industry Program for Energy Conservation (CIPEC) of the Canadian Petroleum Products Institute (CPPI) & CIEE
EMOH: Greenhouse Gas Emission Estimation Methodologies for the Oil Sands / Heavy Oil Upgrader Industry
F-6: F-6 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2001
GRI: GRI-GLYCalc Glycol Dehydrator Emission Estimation Software. Gas Research Institute

ICFPA:	Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills. The International Council of Forest and Paper Associations (ICFPA)
Lime:	CO2 Emissions Calculation Protocol for the Lime Industry - Draft, National Lime Association/Canadian Lime Institute, 2003.
NCASI:	Calculation Tools for Estimating Greenhouse Gas Emissions from Wood Products Manufacturing Facilities. National Council for Air and Stream Improvement (NCASI), Inc.
McCann:	McCann, T. J. 1998 Fossil Fuel and Derivative Factors. 2000. Environment Canada.
Tanks:	USEPA, TANKS Emissions Estimation Software v4.09, U.S. Environmental Protection Agency. http://www.epa.gov/ttn/chief/software/tanks/index.html

Many reporters took advantage of a provision under section 7(8) of the Specified Gas Reporting Standard[iii] to use reference documents not listed under sections (2) to (7). Documents not found under sections (2) through (7) are listed in Table 4 according to emission source categories for which citations were made.

Table 4: Additional reference documents cited in greenhouse gas reports.

Emission Source Category	Reference Document
Stationary Fuel Combustion	Canadian GHG Challenge Registry Guide To Entity & Facility-based Reporting. Version 3.0. VCR Inc. 2004. http://www.vcr-mvr.ca/assets/pdf/Challenge_Registry_Guide_E.pdf
	Celanese Global EHS reporting guide
	WBCSD and WRI website for methane emission factor (g/GJ).
	Alberta Greenhouse Gas Reporting Program Guidance - 1st draft
Industrial Process	Task Force Guidelines for the Petroleum Sector. Canadian Industry Program for Energy Conservation (CIPEC) of the Canadian Petroleum Products Institute (CPPI) & CIEE. 1995.
	CCME Environmental Code of Practice for the Measurement and Control of Fugitive Emissions from Equipment Leaks
Fugitive	Tanks 4.09b. U.S. Environmental Protection Agency
	Lucas D. and D Littlejohn. The heavy oil storage tank (HOST) project. Ernest Orlando Lawrence Berkeley National Laboratory. 1999. http://eetd.lbl.gov/AQ/PERF/PERF_Lucas.ppt/
	Final Report on U.S. Methane Emission 1990 -2020: Inventories, Projections and Opportunities for Reductions. EPA 430-R-99-013. USEPA. 1999. Http://www.epa.gov/ghginfo/pdfs/03-natural gas.pdf
	F-6 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2001
Other	McCann, T. J. 1998 Fossil Fuel and Derivative Factors. 2000. Environment Canada.
Indirect Emissions	ARIES (Air Release Inventory and Emissions System) software. Atlus Environmental Engineering Ltd.

The considerable variation in the use of reference documents is a concern for comparability of emission estimates even between facilities using the same emission methodology type (e.g. emission factors). For example, some reference documents' emission factors are based on fuel quantity whereas others are based on heat content. While providing comparable estimates for emissions from combustion of liquid petroleum fuels, use of these different emission factors could result in significantly different emission estimates for combustion of coal and unprocessed natural gas.

4.0 Comparison with the National Inventory

Overall, the reported data accounts for approximately 47% of total Alberta emissions and 66% of Alberta industrial emissions as estimated under Canada's Greenhouse Gas Inventory for 2002[xv]. Industrial emissions from Canada's 2002 GHG inventory were calculated as the sum of stationary combustion sources (not including construction, commercial & institutional and residential), pipelines, fugitive sources and industrial processes. It is difficult to compare data in Canada's GHG Inventory to Alberta's reporting program by facility type, because the former is not adequately disaggregated. For example, chemicals, fertilizers and forest products are all aggregated in manufacturing combustion emissions. However, comparison by emission source type is possible (Table 5). The greater than 100% coverage in industrial process emissions and low percentage coverage in fugitive emissions is likely due to gas plants reporting venting emissions as process emissions rather than fugitive emissions (under Canada's Greenhouse Gas Inventory, venting emissions are classified as fugitive in accordance with Intergovernmental Panel on Climate Change (IPCC) guidelines[xvi]).

Table 5: GHG emission source-types accounted under Alberta GHG Reporting.

Emission Source-Type	Emissions (kt CO2-e)		
	Alberta Emissions from Canada's GHG Inventory*	Alberta GHG Reporting	% Coverage**
Stationary Fuel Combustion*	116670	86039	74
Industrial Process	7300	12199	167
Fugitive	33000	3308	10

* Includes combustion emissions from pipeline facilities and does not include construction, commercial & institutional, and residential.

** The greater than 100% coverage in industrial process emissions and low percentage coverage in fugitive emissions is due to gas plants reporting venting emissions as process emissions rather than fugitive emissions.

5.0 Lessons Learned from First Reporting Year

5.1 Administrative Issues

Most reports were submitted using Excel templates provided by Alberta Environment, while some reports were faxed or sent in PDF files. There were some administrative problems that can be remedied if reporters exercise more vigilance. In a few cases the approval number was not given, an incorrect or range of NAICS codes was given, or no electronic copy of the Specified Gas Report was provided. In addition, one report had an incomplete address and another report was submitted in a Word document without using the template. A total of 17 statements of certification were unsigned and four reports had not been fully submitted by the reporting deadline.

To avoid withholding of valuable, but non-business sensitive data, it must be clearly specified which specific emissions data must be kept confidential.

5.2 Technical Issues

There are a number of technical issues that need to be addressed to increase the usefulness of GHG data collected under the reporting program. These are:

- The level of detail and amount of supporting data that is submitted.
- The level of aggregation or disaggregation needed to appropriately classify emissions from complex facilities.
- The use of standardized methodology within industry facility types.
- Whether biomass and geologically injected CO_2 should be included in the reporting threshold calculation.
- Expanding the number of reported gases to include PFCs, HFCs and SF_6.
- Clarification of definitions including the definition of facility.
- Whether some optional data should be made mandatory.

Accurate emissions data is the foundation of an effective reporting and management program. Under current information requirements, it is difficult to evaluate the accuracy of the emissions data reported. For example, a number of facilities reported total CO_2-e emissions that were different than calculated CO_2-e emissions from submitted CO_2, CH_4 and N_2O data. Most of these differences were minor, and could be minimized by ensuring that total emissions of each gas from all source types are calculated prior to multiplication with global warming potentials. Other discrepancies were more substantial, possibly due to inclusion of biomass emissions in totals or exclusion of certain emission sources. Additional supporting data, such as production data and fuel consumption would allow an assessment of the accuracy of the emissions data reported. In addition implementation of a data auditing system would allow for verification of the emissions data reported.

One challenge of facility level reporting is to find a facility definition that works across facility types and ensures consistency and an appropriate level of aggregation/disaggregation to allow meaningful analysis between facilities. This is particularly important for complex operations such as oil sands facilities, which may have emissions from mining operations, bitumen extraction plants, utility plants and upgrading facilities. There is significant flexibility in how emissions can be attributed at these facilities, which makes it difficult to compare intensities between oil sands facilities with similar operations. To ensure that data can be analyzed in a meaningful way the facility definition should be clarified. This will provide better guidance to reporters on the level of aggregation/disaggregation needed to appropriately classify emission sources. There also may be a need to account for electricity not consumed onsite when calculating emission intensities.

Analysis of the submitted 2003 data indicates that there was considerable variation in the methodology type and reference documents used by reporters. The use of protocols other than those listed in the Alberta's Specified Gas Reporting Standard[iii] may have been due to a lack of a suitable protocol for certain emission sources or because of company or industry specific practices. Consideration may need to be given to expanding the list of recognized methodology documents. To increase comparability and transparency, it is recommended that government and industry evaluate and agree on reporting methodologies that are specific to facility type, or, at a minimum limit each facility type to designated industry-specific protocols when reporting.

There is an inconsistency between the reporting of biomass CO_2 emissions in specified gas reports and not including biomass CO_2 emissions in determination of exceedances of the 100 kt CO_2-e reporting threshold. The high percentage of total CO_2-e emissions arising from biomass combustion in the forest facility type (biomass emissions represent 81% of total emissions) suggests that not including biomass CO_2 emissions in the calculation of exceedance of the 100-kt threshold may exclude some forest products facilities from reporting. There was also some inconsistency in the reporting of CH_4 and N_2O emissions related to biomass combustion. These emissions were reported for combustion of fossil fuels, but were not required for biomass combustion reporting. In addition, CH_4 and N_2O emissions from biomass must be included in Canada's GHG Inventory[ii] totals.

There is some ambiguity in whether CH_4 and N_2O emissions arising from biomass combustion were to be included in the determination of exceedances of the reporting threshold. Additional clarification provided in the 2005 Specified Gas Reporting Standard[iii] should resolve this issue.

There is an inconsistency between the reporting of geologically injected CO_2 in the specified gas reports, but not including geologically-injected CO_2 emissions in the determination of exceedances of the 100-kt CO_2-e reporting threshold. At those gas plants reporting geologically injected CO_2, the high percentage (exceeding 30%) of total CO_2 captured and injected at some facilities suggests that excluding geological injected

CO_2 in the calculation of exceedance of the 100-kt threshold may exclude some gas plants from reporting.

Some emission source definitions need further clarification. Results from some reports suggest that venting from gas plants, petroleum refining and coal-mining operations were included inappropriately under either process-related or ‘other’ emissions, rather than as fugitive emissions as in the Standard[iii] and Canada’s GHG Inventory[ii]. In addition, one facility reported CH_4 arising from venting during plant start-ups or upsets under industrial process rather than fugitive emissions. Also, the definition of stationary combustion emissions could be made more specific to ensure reporting of emissions for space-heating requirements. Some power plant facilities reported emissions from natural gas space heaters under “other emissions” rather than under stationary combustion emissions. Clarification also needs to be given concerning gases shipped off site.

Additional consideration needs to be given to providing more rigorous requirements on the submission of currently optional data, including intensities, and net specified gases. Net specified gases should be the sum of direct (including biomass and geological injection) and indirect emissions less emission reduction equivalences and offsets. As we move towards a harmonized national reporting system there needs to be some clarification on what are acceptable emission reduction equivalences and offsets.

There also needs to be more clarification as to how intensity is defined and measured. For example, whether intensity includes indirect emissions or offsets. Guidance also needs to be given concerning acceptable industry metrics.

In the first year of the program, reporting of fluorinated gases (HFCs, PFCs and SF_6) was optional. As we move towards a harmonized national reporting system, reporting of HFCs, PFCs and SF_6 will be made mandatory.

5.3 Summary

The following improvements should be considered as the Alberta GHG reporting program becomes harmonized with the national program:

- Implement methods for ensuring the accuracy of the data reported either through the mandatory reporting of production/fuel consumption data, or development of an auditing program.
- Evaluate the need for submission of further disaggregated data by activity for complex operations in the oil sands, refining and chemicals facility types.
- Develop standardized reporting protocols or, if required, a suite reporting protocols that are specific to facility type.
- Include geological sequestered CO_2 and biomass emissions in calculating whether facility emissions exceed the reporting threshold.
- Revise definitions of 'stationary fuel-combustion emissions', 'process-related emissions', and 'facility' to harmonize with the national system.
- Determine intensity metrics and require intensity reporting on a CO_2-e basis.
- Specify what offsets or emission reduction equivalences are applicable for calculating net specified gases.

Appendix: Additional Emissions Data

Table 6: Total 2003 facility direct CO_2, CH_4 and N_2O emissions from non-confidential reporters.

Facility Type	Facility ID	Facility	Company	Total CO_2 (kt)	Total CH_4 (kt)	Total N_2O (kt)	Total CO_2-e (kt)
Cement/Lime	165	Lafarge Canada Inc - Exshaw Plant	Lafarge Canada Inc	958.7	0	0	958.7
Cement/Lime	235	Inland Cement	Lehigh Inland Cement	640.1	0	0	640.9
Cement/Lime	435	Graymont Western Canada Inc. - Exshaw	Graymont Western Canada Inc.	confidential	confidential	confidential	confidential
Chemicals	461	Alberta Envirofuels Inc.	Alberta Envirofuels Inc.	354.8	0.1	0	358.9
Chemicals	653	Joffre LAO Plant	BP Canada Chemical Company	96.5	0	0	97.1
Chemicals	364	Cancarb	Cancarb Ltd	132	0	2.2	134.2
Chemicals	164	Edmonton Facility	Celanese Canada Inc.	620.5	0	0	621.5
Chemicals	172	Prentiss Operations	Dow Chemical Canada Inc.	348.1	0.1	0	350.7
Chemicals	244, 420	Fort Saskatchewan	Dow Chemical Canada Inc.	1454.9	0.1	0	1456.7
Chemicals	171	NOVA Chemicals Corporation (Joffre Petrochemical Plantsite)	NOVA Chemicals Corporation	2986.2	0	0	2998.7
Chemicals	170	Shell Chemicals Scotford	Shell Chemicals Canada Ltd	331.7	0	0	333.1
Coal-mining	772	Highvale Coal Mine	TransAlta Utilities Corporation	55.6	5.6	0	173.5
Fertilizer	224	Carseland Nitrogen Operations	Agrium Inc.	483.1	0	0	364.1
Fertilizer	216	Redwater Fertilizer Operations	Agrium Products Inc.	830.2	3	0.1	913.2
Fertilizer	559	Redwater Fertilizer Operations	Agrium Products Inc.	587.2	0.1	0	590.6
Fertilizer	225	Canadian Fertilizers Limited	Canadian Fertilizers Limited	1392.4	0	0	1397.4
Fertilizer	181	Orica Carseland Works	Orica Canada Inc	0	0	4.1	1285.3
Fertilizer	227	Sherritt International Corporation (Fort Saskatchewan Chemical & Metal Manufacturing Plant)	Sherritt International Corporation	318.6	0	0	319.9
Forest Products	352	Peace River Pulp Division	Daishowa-Marubeni International Ltd	70.7	0.8	0	98.3
Forest Products	255	Hinton Pulp	Weldwood of Canada	150.4	0.5	0	165.0
Forest Products	168	Grande Prairie Operations (Pulpmill/Sawmill)	Weyerhaeuser Company Limited	99.7	1.1	0	131.3
Gas Plants	702	Hamburg Gas Processing Facility	Apache Canada Ltd.	142.6	1.5	0	176.6
Gas Plants	54, 470, 572	Zama Gas Processing Complex	Apache Canada Ltd.	83	2.2	0	132.2

Facility Type	Facility ID	Facility	Company	Total CO_2 (kt)	Total CH_4 (kt)	Total N_2O (kt)	Total CO_2-e (kt)
Gas Plants	31	Carstairs-Crossfield Gas Plant	Bonavista Petroleum Ltd.	105.2	0.1	0	106.8
Gas Plants	349	BP Canada Energy Fort Saskatchewan	BP Canada Energy Company	98.1	0	0	100.9
Gas Plants	758	Elmworth Gas Plant	Burlington Resources Canada Ltd.	120.8	0.4	0	133.0
Gas Plants	759	Karr Gas Processing Plant, Gas Gathering System and Battery	Canadian Natural Resources Limited	90.3	1	0	114.4
Gas Plants	22	West Whitecourt Plant	Central Alberta Midstream	176.2	0.2	0	183.4
Gas Plants	35	Kaybob South No. 3	Central Alberta Midstream	378.1	0.2	0	384.1
Gas Plants	39	Kaybob Amalgamated Sour Gas Plant	Central Alberta Midstream	223.2	0.4	0	235.2
Gas Plants	95	Empress	ConocoPhillips Canada	359.6	0.5	0	373.8
Gas Plants	760	Wapiti Gas Plant	Devon Canada Corporation	115.5	0.8	0	135.0
Gas Plants	7	Nevis Gas Plant	Duke Energy Field Services Canada Ltd.	129.7	0.6	0	150.1
Gas Plants	763	Calmar Gas Plant	Enbridge Midcoast Operating Corp.	3.7	0.4	0	12.0
Gas Plants	771	Caribou North Compressor Station	EnCana Corporation	94.3	1.2	0	131.4
Gas Plants	28	Quirk Creek Gas Plant	Imperial Oil Resources	123.3	0.2	0	127.8
Gas Plants	10	Bonnie Glen Gas Plant	Imperial Oil Resources Limited	301.4	1.1	0	326.4
Gas Plants	539	Cochrane Extraction Plant	Inter Pipeline Extraction Ltd.	396	0.7	0	414.3
Gas Plants	17	Rimbey Gas Plant	Keyspan Energy Canada	234.6	0.3	0	241.6
Gas Plants	38	Brazeau River Gas Plant	Keyspan Energy Canada	83.2	0.6	0	97.3
Gas Plants	40	Strachan Gas Plant	Keyspan Energy Canada	289.5	0.5	0	303.8
Gas Plants	18	Balzac Gas Processing Plant	Nexen Inc.	259.7	2.8	0	383.5
Gas Plants	26	Judy Creek Gas Conservation Plant	Pengrowth Corporation	144	0.7	0	160.5
Gas Plants	773	Judy Creek Production Complex	Pengrowth Corporation	81.1	0.5	0	96.9
Gas Plants	29	East Crossfield Gas Plant	PrimeWest Energy Inc.	184.8	0.3	0	192.6
Gas Plants	19	Burnt Timber Gas Plant	Shell Canada Limited	confidential	confidential	confidential	235.1
Gas Plants	21	Jumping Pound Gas Plant	Shell Canada Limited	confidential	confidential	confidential	322.0
Gas Plants	58	Waterton Complex	Shell Canada Limited	confidential	confidential	confidential	640.5

Facility Type	Facility ID	Facility	Company	Total CO_2 (kt)	Total CH_4 (kt)	Total N_2O (kt)	Total CO_2-e (kt)
Gas Plants	336	Caroline Complex	Shell Canada Limited	confidential	confidential	confidential	790.2
Gas Plants	53	Edson Gas Plant	Talisman Energy Inc.	208.5	0.4	0	220.4
Gas Plants	37	Wildcat Hills Gas Plant	Petro Canada	confidential	confidential	confidential	confidential
Gas Plants	130	Hanlon Robb Gas Plant	Petro Canada	confidential	confidential	confidential	confidential
Gas Plants	174	Brazeau Gas Plant	Petro Canada	confidential	confidential	confidential	confidential
Gas Plants	45	Ram River Sour Gas Processing Plant	Husky Oil Operations Ltd.	confidential	confidential	confidential	confidential
Heavy Oil	334	Wolf Lake/Primrose Thermal Operation	Canadian Natural Resources Limited	1359.1	0.3	0	1375.9
Heavy Oil	662	Foster Creek Commercial Bitumen Battery and Cogeneration Facility	EnCana Corporation	567.4	0.1	0	572.0
Heavy Oil	249	Cold Lake	Imperial Oil Resources	3992.2	7.2	0.1	4163.6
Heavy Oil	210	Peace River Complex	Shell Canada Limited	confidential	confidential	confidential	373.8
Landfill	754	East Calgary Landfill	City of Calgary	0	5.8	0	121.8
Oil Sands	259	Suncor Energy Inc. Oil Sands	Suncor Energy Inc.	7490.6	17.8	0.1	7902.3
Oil Sands	671	Muskeg River Mine	Albian Sands Energy Inc.	confidential	confidential	confidential	confidential
Oil Sands	660	MacKay River In-Situ Oil Sands Plant	Petro-Canada	confidential	confidential	confidential	confidential
Oil Sands	260	Mildred Lake Plant Site	Syncrude Canada Ltd.	confidential	confidential	confidential	confidential
Oil Sands	606	Aurora North Mine Site	Syncrude Canada Ltd.	confidential	confidential	confidential	confidential
Petroleum Refining	229	Strathcona Refinery	Imperial Oil, A Partnership of Imperial Oil Ltd and McColl-Frontenac Petroleum Inc	1395.4	0	0	1405.2
Petroleum Refining	228	Edmonton Refinery	Petro-Canada	confidential	confidential	confidential	confidential
Petroleum Refining	668, 650	Scotford Upgrader	Shell Canada Limited	confidential	confidential	confidential	1466.4
Petroleum Refining	166	Scotford Refinery	Shell Canada Products	confidential	confidential	confidential	943.2
Pipeline	755	Windfall Compressor Station	Alliance Pipeline Ltd.	242.4	0.6	0	255.9
Pipeline	756	Morinville Compressor Station	Alliance Pipeline Ltd.	117.2	0.3	0	125.3
Pipeline	757	Irma Compressor Station	Alliance Pipeline Ltd.	102.1	0.3	0	109.1

Facility Type	Facility ID	Facility	Company	Total CO_2 (kt)	Total CH_4 (kt)	Total N_2O (kt)	Total CO_2-e (kt)
Pipeline	764	MacKay River Terminal	Enbridge Pipelines (Athabasca) Inc.	0	0	0	0.0
Pipeline	765	Enbridge Pipelines (Athabasca) Inc.	Enbridge Pipelines (Athabasca) Inc.	0	0	0	0.0
Pipeline	766	Athabasca Terminal	Enbridge Pipelines (Athabasca) Inc.	0	0	0	0.0
Pipeline	767	Kirby Lake Terminal	Enbridge Pipelines (Athabasca) Inc.	0	0	0	0.0
Pipeline	762	Enbridge Pipelines Inc. - Electricity driven pumping stations	Enbridge Pipelines Inc.	0	0	0	0.0
Pipeline	768	Enbridge Pipelines Inc. - Administrative operations	Enbridge Pipelines Inc.	2.9	0	0	3.0
Pipeline	769	Edmonton Terminal	Enbridge Pipelines Inc.	0	0	0	0.0
Pipeline	770	Hardisty Terminal	Enbridge Pipelines Inc.	0	0	0	0.0
Pipeline	761	Nova Gas Transmission Ltd.	Nova Gas Transmission Ltd.	1535	22.3	0.1	2032.3
Power Plants	630	Scotford Plant	Air Liquide Canada Inc.	425.1	0	0	492.2
Power Plants	214	Battle River Generating Station	Alberta Power (2000) Ltd.	5278	0.1	0.1	5309.2
Power Plants	220	H.R. Milner Generating Station	Alberta Power (2000) Ltd.	1060.9	0	0	1067.2
Power Plants	176	Sheerness Generating Station	Alberta Power (2000) Ltd. and TransAlta Cogeneration L.P.	6594.4	0.1	0.1	6633.3
Power Plants	607	Rainbow Lake Cogeneration Power Plant	ATCO Power Canada Ltd.	confidential	confidential	confidential	270.0
Power Plants	672	Muskeg River Cogeneration Power Plant	ATCO Power Canada Ltd.	confidential	confidential	confidential	877.0
Power Plants	223	City of Medicine Hat Electric Utility - Generation	City of Medicine Hat	278.3	0.2	0	282.1
Power Plants	655	Cavalier Power Plant	EnCana Corporation	127.2	0	0	128.4
Power Plants	322	Genesee Thermal Station	EPCOR Utilities Inc.	6272.3	0.1	0.2	6328.0
Power Plants	666	Balzac Power Station	Nexen Inc.	161.9	0.1	0	165.2
Power Plants	592	Fort Saskatchewan Cogeneration Plant	TransAlta Cogeneration LP	319	0	0	320.2
Power Plants	160	Sundance Generating Station	TransAlta Utilities Corporation	15919.1	0.1	0.5	16064.0
Power Plants	175	Wabamun Generating Station	TransAlta Utilities Corporation	3274.8	0	0.1	3306.6

Facility Type	Facility ID	Facility	Company	Total CO_2 (kt)	Total CH_4 (kt)	Total N_2O (kt)	Total CO_2-e (kt)
Power Plants	215	Keephills Generating Station	TransAlta Utilities Corporation	5915.4	0	0.2	5968.5
Power Plants	654	Carseland Cogeneration Facility	TransCanada Energy Ltd.	330.5	0	0	335.3
Power Plants	667	Redwater Cogeneration Facility	TransCanada Energy Ltd.	175.3	0	0	177.9
Power Plants	694	Bear Creek Co-generation Power Plant	TransCanada Energy Ltd.	117.3	0	0	119.2

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