SOURCES OF ATMOSPHERIC EMISSIONS IN THE ATHABASCA OIL SANDS REGION

(Report 1)

BOVAR Environmental

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Prepared for:

Suncor Inc., Oil Sands Group
and
Syncrude Canada Ltd.

Prepared by:

BOVAR Environmental

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Attention: **Don Klym, Manager** **New Mine Approvals**	Attention: **Peter Koning** **New Lease Environmental** **Coordinator**

Subject: **Air Quality Technical Report**

We are pleased to submit our final report entitled Sources of Atmospheric Emissions in the Athabasca Oil Sands Region. This report identifies sources and, based on available information, quantifies emissions from Suncor, Syncrude, other industrial sources, residential combustion and traffic activities.

If you have any comments or questions concerning this report, please contact Ann Jamieson at (403) 750-9328 or the undersigned at (403) 750-9335.

Yours sincerely,

BOVAR Environmental

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for Mervyn J.E. Davies
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This background report was prepared for Suncor Inc. Oil Sands Group and Syncrude Canada Ltd. by BOVAR Environmental. Specifically, this report was prepared for the Suncor Steepbank Mine Environmental Impact Assessment (EIA) and for the Syncrude Aurora Mine EIA. Coordinators for the Steepbank Mine EIA were Don Klym from Suncor and Hal Hamilton from Golder Associates Ltd. Coordinators for the Aurora Mine EIA were Peter Koning from Syncrude and Judy Smith from BOVAR Environmental.

The primary contact at Suncor was Mr. Gordon Kemp. At Syncrude, the primary contacts were Mr. John Ellingsen and Ms. Gail Buchanan.

Other major contacts were as follows:

- Population and housing statistics were supplied by the Fort McMurray Chamber of Commerce.
- Traffic statistics were supplied by Mr. Peter Kiburn at Alberta Transportation Utilities.
- Forest fire data were obtained from Mr. Richard Strickland of the Alberta Environmental Protection Provincial Forest Fire Centre.
- Lumber industry information was provided by Mr. Fred Power of Alberta Environmental Protection, Standards and Approvals Division.

The principal investigator for this study was Mervyn Davies, Manager of the BOVAR Environmental Air Quality Assessment Group in Calgary. Primary report preparation was completed by Ann Jamieson, with support for data analysis from Jacquie Darichuk and Peter Seville. Report typing and formatting were completed by Maureen Parsons.

1.0 INTRODUCTION

1.1 Background

Alberta produces a significant portion of Canada's energy requirements through the production of fossil fuels that include natural gas, conventional crude oil, synthetic crude oil and coal. The oil sands sector produces almost 25% of Canada's petroleum needs through the production of synthetic crude oil from bitumen. In 1994, Syncrude Canada received approval to increase crude oil production to 17.6 million m^3/a. Similarly, Suncor recently received approval for modifications to increase their bitumen throughput to 4.6 million m^3/a. Both Syncrude and Suncor have plans to develop new oil sands leases and to further increase crude oil and bitumen production.

The development of new leases (e.g. SOLV-EX) and the continuing production at the existing extraction and upgrading facilities (e.g. Suncor and Syncrude) will have effects on the environment. In recognition of these effects, Suncor has proposed modifications to reduce SO_2 emissions to the atmosphere. As part of Syncrude's approval to increase production, they are required to develop additional ambient air quality, sulphur deposition and biomonitoring programs. The objective of these programs is to ensure environmental quality is not compromised due to atmospheric emissions associated with their operations.

1.1.1 *Provincial Initiatives*

In response to the interest in atmospheric emissions in Alberta, several initiatives are underway to evaluate air quality management approaches in the province:

- The 1991 **Clean Air Strategy for Alberta** Report to the Ministers of the Environment and Energy presented a long-term framework for air quality management. This framework was developed through a multi-stakeholder consultation process. The report identified the vision and mission statements shown in Table 1.1 to provide the basis for future air quality management initiatives.

- In response to the 1991 Report, the **Clean Air Strategic Alliance (CASA)** was formed. CASA is a joint industry-government program which represents a partnership between government, industry, environmental and other key stakeholders. CASA is responsible for the strategic planning related to air quality issues in Alberta through a Comprehensive Air Quality Management System (CAQMS) for Alberta. The CAQMS allows regional stakeholders to design solutions specific to their regional air quality issues.

- In response to the CAQMS, the **West Central Regional Airshed Monitoring Committee (WCRAMC)** was established to design an environmental monitoring program for the West Central Zone of Alberta. The zone was developed in response to the zonal air quality management concept identified in the 1991 Report to the

Table 1.1 The Clean Air Strategy for Alberta vision and mission statements.

VISION STATEMENT
The air will be odourless, tasteless, look clear and have no measurable short- or long-term adverse effects on people, animals or the environment.
MISSION STATEMENT
Alberta's Clean Air Strategy is to provide guidelines for the management of emissions from human activity and encourage appropriate life-styles so as to protect human health and ecological integrity within a provincial, national and international context. *The strategy will be comprehensive but flexible and, through an ongoing consultative process, will employ a wide range of mechanisms available for implementing the strategy, including public education, market-based approaches, legislation, regulation, and research and development.*

Ministers and because of the relatively high interest of stakeholders in the area. The approach and concept for managing air quality in the West Central Zone was viewed as a prototype that could be used for other airshed zones in Alberta.

1.1.2 *Air Quality Management*

Air quality issues have been addressed in the oil sands region through a number of processes that include the following:

- **Regulatory:** Terms and conditions specified by Licences-to-Operate that were issued under the former Clean Air Act. With the introduction of the Alberta Environmental Protection and Enhancement Act (EPEA), these licences were renewed as Environmental Approvals (under EPEA).
- **EIAs:** Various impact assessments prepared for the development and expansion of existing and proposed oil sands developments have led to the collection of field data and associated air quality assessments.
- **Research:** The Alberta Oil Sands Environmental Research Program (AOSERP), a jointly funded federal and provincial program, conducted environmental and air quality research in the oil sands region from 1975 to 1981. The research program was continued by the Research Management Division of Alberta Environment from 1981 to 1986.
- **Multistakeholder:** Groups, such as the Fort McMurray Regional Air Quality Task Force (RAQTF), have been formed to address industry, government and stakeholder issues related to air emissions and their potential effects.

Multistakeholder air quality issues in the oil sands area are currently addressed by the Regional Air Quality Coordinating Committee (RAQCC) which is comprised of government, industry and committee participation. RAQCC has been responsible for establishing a number of working groups to help evaluate air quality issues in the area, develop monitoring programs and communicate with the public on these issues.

1.1.3 *Background Reports*

Given that the oil sands will continue to play a significant role in Canada's energy requirements and that air quality issues associated with oil sands mining, extraction and upgrading operations have a multistakeholder interest and furthermore, in consideration of the recent initiatives associated with addressing air quality issues in Alberta, a series of background air quality reports have been prepared for the oil sands area. The purpose of these reports is to provide air quality baseline information to mid-1995. The specific reports are as follows:

- **Report 1 Source Characterization**

  To identify and quantify anthropogenic air emissions in the Fort McMurray - Fort McKay corridor that include industrial point, fugitive, traffic and residential sources. Emissions of interest include SO_2, NO_x, CO, THC, TRS, CO_2 and particulates.

- **Report 2 Ambient Air Quality Observations**

  To summarize ambient air quality monitoring undertaken in the Fort McMurray - Fort McKay airshed. The sources include quantification data from the Suncor, Syncrude and AEP networks as well as qualitative data associated with other monitoring programs.

- **Report 3 Meteorology Observations**

  To summarize the meteorological data that can be used to describe the transport, dispersion and deposition of emissions in the area. The focus is on the meteorological data collected by Suncor from the Lower Camp and Mannix towers. A review of the terrain in the region and its effect on meteorology are provided.

- **Report 4 Air Quality Modelling**

  Concurrent source, ambient air quality and meteorological data are used to select an optimum dispersion modelling approach resulting in predictions which compare favourably with observations. The modelling complements the monitoring by providing local and regional short- and long-term air quality changes associated with the current operation in the area.

These reports serve as background reports that can be used by industry to assist with future plant applications and by other stakeholders to assist with the review of these applications. Furthermore, these reports can also be used by RAQCC in support of other regional air quality related initiatives.

1.2 Report 1 (Source Characterization)

1.2.1 *Objectives*

The operation of oil sands mining, extraction and upgrading facilities in the Athabasca oil sands region results in gaseous and particulate emissions from controlled and fugitive sources. Additional emissions can also result from other sources in the airshed that include other industrial operations, transportation and community sources. If left uncontrolled, these emissions may have deleterious effects on the environment and human health. For this reason, major emission sources are controlled and monitored by regulatory statutes and associated regulations, guidelines and industry practices.

The management of an airshed that is shared by multiple users requires an understanding of these emission sources. The objectives of Report 1 (Source Characterization) are as follows:

- Identify emission sources in the Athabasca oil sands airshed.
- Characterize the nature of these emissions with respect to spatial and temporal properties.
- Quantify the emission strengths of the identified contaminants.

The end-product of Report 1 is an emission inventory for the Athabasca oil sands airshed that can be used as a basis for subsequent air quality assessments.

1.2.2 *Approach*

In meeting these objectives, four types of sources are considered:

- **Major Industrial Emission Sources.** Emission sources associated with the two current oil sands operations are well characterized and quantified by the associated monitoring programs.
- **Fugitive and Area Emission Sources.** These sources include the volatilization of hydrocarbons from tanks and tailings ponds, which are not monitored directly but can be inferred from monitoring conducted in the area.
- **Other Industrial Emission Sources in the Area.** These sources include the AOSTRA UTF, SOLV-EX Bitumount, SOLV-EX Ruth Lake, Northland Forest Products and the Fort McMurray Hospital.
- **Highway and Residential Emission Sources.** These sources are not monitored and have to be estimated from the applications of emission factors and assumptions on intensity of use.

The focus of this report was placed on using readily available information from both of the major oil sands operations, supplemented with an emission factor approach to estimate emissions from other sources.

1.2.3 *Definition of Terms*

Given the technical nature of this report, it is useful to confirm some of the terminology used to facilitate a common understanding. Table 1.2 provides definitions of technical terms used in the report.

Table 1.2 Definition of commonly used terms.

Term	Definition
Airshed	A geographical region that shares one or more of the following: similar terrain, similar meteorology, similar sources, similar receptors. For the purposes of this report, the Athabasca oil sands region airshed was arbitrarily selected as the area located within 60 km of the Suncor and Syncrude oil sands operations. This airshed may be redefined by RAQCC.
Receptor	A biological or physical entity that is exposed to air emissions. Vegetation and humans are examples of biological receptors. Soils and water are examples of physical receptors.
Point Sources	An emission source that is described as a conventional stack, a flare stack or a process vent. Stacks and vents can range in height from a few metres to more than 100 m.
Line Sources	An emission source that can be described as single or multiple emissions that occur along a line. Dust emissions from a conveyer belt is an example of a single line source. A highway is an example of a line source that is comprised of multiple sources (i.e. vehicles).
Area Sources	An emission source that is described as occurring over a defined area. Evaporation from a pond surface is an example of a single area source. Emissions from residential heating units and vehicular traffic are examples of area sources that are comprised of multiple small emissions.
Stack Surveys	A periodic measurement taken to characterize and quantify stack emissions. Measurements for large stacks are typically taken halfway up the stack using probes. Alberta Environmental Protection and the U.S. EPA have rigourously prescribed procedures for conducting stack surveys.
CSEM	Continuous Stack Emission Monitors (CSEM) measure stack gas temperatures, exit velocities and contaminant flow rates on a continuous basis. Stack surveys are conducted to confirm satisfactory CSEM operation.

Table 1.2 Concluded.

Term	Definition
Fugitive Sources	Fugitive emissions are defined as contaminants emitted from any source except those from stacks or vents. Typical sources include gaseous leakages from valves, flanges, drains, volatilization from ponds and lagoons, and open doors and windows. Typical particulate sources include bulk storage areas, open conveyers, construction areas or plant roads.
Upset Emissions	During plant start-up, shut-down and abnormal operating conditions, gas streams can be vented directly into the atmosphere prior to usual treatment. Petrochemical (gas plants, refineries) frequently use a flare stack to dispose of gas streams under these conditions. Prudent stewardship ensures both infrequent and short duration upset emissions.
Emission Factor	In the absence of measurements, industry standard emission factors can be used to estimate emissions from a wide range of sources. An emission factor is a conversion factor and can be expressed as a contaminant release rate per amount of fuel consumed.
Emission Inventory	A database identifying, characterizing and quantifying emission sources. The database can provide spatial and temporal variation.
Stream day / Calendar day	Emissions of a pollutant are often expressed on a mass per unit time basis, for example, tonnes per day which can be abbreviated as t/d. Process engineers often distinguish between tonnes per stream day (t/sd) which is the emission rate based on the period when the facility is operating and tonnes per calendar day, which is the average over the full period (e.g., a full 365 day year). The emission rate expressed on a t/sd basis will be larger than that expressed on a t/cd basis.
Julian Day	A designation that identifies the day of the year by using a number between 1 and 365 (366 for leap years). For example, Julian day 1 = January 1, Julian day 365 = December 31.

1.2.4 *Report Organization*

Section 2 provides an overview of the source types in the Athabasca oil sands airshed. The subsequent sections describe the emission sources in more detail according to the identified contaminant:

Section	Contaminants
3	Sulphur dioxide (SO_2) emissions that result from the combustion of fuels containing sulphur compounds.
4	Oxides of nitrogen (NO_x), carbon monoxide (CO) and carbon dioxide (CO_2) emissions that result from the combustion of hydrocarbon fuels.
5	Total reduced sulphur (TRS) and total hydrocarbon (THC) compounds that originate from non-fugitive and fugitive sources.
6	Particulates that result from combustion and non-combustion sources. Particulates include total suspended particulates (TSP) with diameters less than 30 μm and particulates (PM_{10}) with diameters less than 10 μm.

Section 7 provides a summary and Section 8 identifies references. The detailed source characterization of the Suncor and Syncrude sources are presented in Appendices A and B, respectively. Appendix C identifies and characterizes other industrial emission sources in the region, while Appendix D discusses residential and traffic sources.

2.0 SOURCE IDENTIFICATION

There are two major oil sands mining, extraction and upgrading facilities operating in the Athabasca oil sands area. The Suncor Inc. Oil Sands Group facility has been in operation since 1967 and is located 35 km north of Fort McMurray. The Syncrude Canada Ltd. facility has been in operation since 1978 and is located 40 km north of Fort McMurray.

Other sources of atmospheric emissions in the region are as follows:

- Other industrial sources that include oil sands and non-oil sands related facilities.
- Transportation activities associated with highway traffic corridors.
- Residential activities that include local traffic, residential heating and other fugitive sources.
- Natural sources that include hydrocarbon emissions from vegetation ecosystems.

This section provides a brief description of each identified source and the type of emissions associated with that source.

2.1 Suncor Inc. Oil Sands Group Operation

The Suncor oil sands operation can produce and has an approved production of 79 500 bbl/cd (4.6 million m^3/a). Atmospheric emissions from this operation result from a wide range of sources and include both controlled and fugitive emissions. For the purposes of description, the Suncor facility can be divided into the following operations: mining, extraction, upgrading and utilities.

Figure 2.1 shows the overall layout of the Suncor plant site. This figure identifies the tailings pond, mining and plant areas. Figure 2.2 shows a more detailed layout of the plant area identifying the extraction, upgrading, utilities, tank farms and coke storage areas.

2.1.1 *Mining*

Pre-mining activities include: clearing of vegetation; drainage of muskeg and overburden aquifers; depressurization of the basal aquifer and muskeg; and overburden removal and storage. The mining of the oil sands is conducted by using power shovels and trucks, and the mined oil sand is carried to the extraction plant by a conveyer belt system.

Emissions associated with mining operations result from the following:

- Pre-mining slash burning. This results in products of combustion being released into the air. These emissions are similar to those which result from forest fires.

Figure 2.1 Location of area sources associated with the Suncor facility.

Figure 2.2 Suncor plant site layout.

- Products of diesel fuel combustion from mine vehicle exhausts. The primary emissions associated with these combustion products are carbon dioxide and water vapour, with smaller amounts of carbon monoxide, oxides of nitrogen, hydrocarbons and particulates.

- Mine vehicle traffic. This results in particulate emissions due to tire/road surface abrasion and entrainment of road surface dust.

- The volatilization of hydrocarbons from freshly exposed bitumen/oil sand surfaces.

- Windborne particulates from mine surfaces entrained into the air by high winds.

Particulates resulting from surface materials tend to be crustal in origin and for the most part tend to be relatively large (greater than 10 μm in diameter). In contrast, particulates resulting from combustion sources tend to be relatively small (less than 10 μm in diameter).

2.1.2 *Extraction*

The Clark hot water process separates the bitumen from the oil sands. The water and sand mixture (with residual amounts of bitumen) is disposed of in the tailings ponds which have been developed in mined pits. The bitumen/diluent mixture is then transported to upgrading or stored in the south tank farm area (9 tanks).

Emission sources associated with the extraction process are listed in Table 2.1. These sources can be classified as follows:

- Plants 3 and 4 vent gas streams composed primarily of air and steam to the atmosphere. Trace amounts of hydrocarbons are entrained into this mixture. The heaters associated with Plant 3 use steam as the heating medium, and as a consequence, no combustion products are vented.

- Tank vents release hydrocarbon vapour trapped in the head space of the tank. The emissions occur as part of the diurnal "breathing" of the tank or when it is filled.

- Hydrocarbon vapours are emitted from the surface of the tailings ponds. The largest emissions are associated with Pond 1, at the point where the tailings fluids enter the tailings pond system.

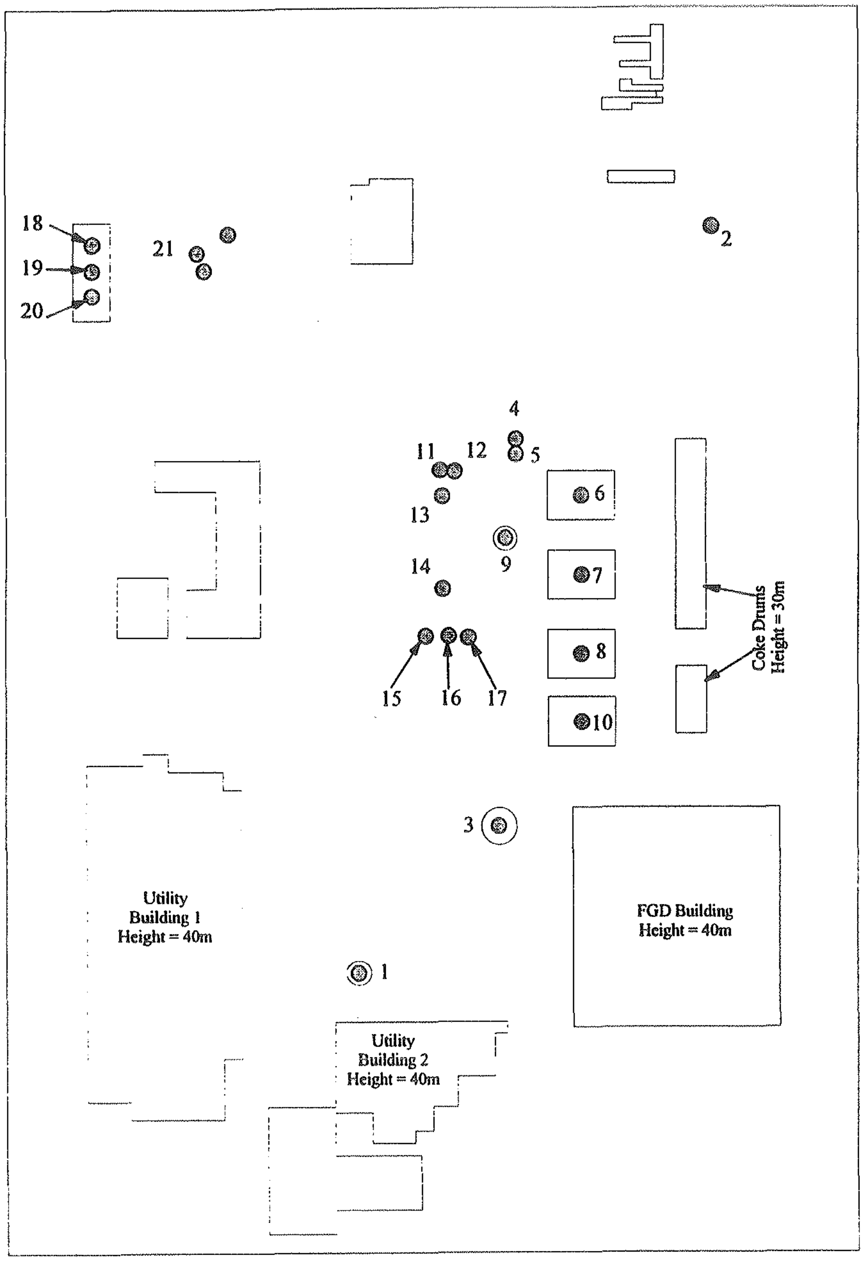
- Wind-blown dust from the sides of the tailings ponds.

The locations of these area and point sources are shown in Figures 2.2 and 2.3, respectively.

Table 2.1 Emission sources associated with Suncor extraction operations.

Plant	Source	Description
Primary Extraction Plant (Plant 3)	3D-62	Primary Froth Deaerator Vent
	3C-22A	Scavenger Froth Deaerator Vent
	3C-22B	Scavenger Froth Deaerator Vent
	3C-20	Primary Froth Heater Vent
	3C-21	Scavenger Froth Heater Vents
	3R-24	E Process Line Vent
	3R-220	A to D Conditioning Drum Vents
Froth Treatment (Plant 4)	4D-7(a)	Emergency Tailings Tank Vent
	4E-1A(a)	Vent Condenser
	4E-1B(a)	Vent Condenser
	4D-3(a)	Tank Seal Vent
	4D-4(a)	Tank Seal Vent
Naphtha Recovery Unit (Plant 16)	16C-5(a)	NRU Absorber Stack
South Tank Farm (Plant 20)	20D-1(a)	Diluted Bitumen Tank Vent
	20D-2(a)	Diluted Bitumen Tank Vent
	20D-3(a)	Diluted Bitumen Tank Vent
	20D-4(a)	Diluted Bitumen Tank Vent
	20D-5(a)	Diluted Bitumen Tank Vent
	20D-6(a)	Diluted Bitumen Tank Vent
	20D-35	Diluent Tank Vent
	20D-57	Diesel Fuel
	20D-58	Diesel Fuel
Ponds	Pond 1	Active Tailings Pond
	Pond 1A	Active Tailings Pond
	Pond 2/3	Active Tailings Pond
	Pond 4	Active Tailings Pond
	Pond 5	Tailings Pond Under Development
	-	Extraction Emergency Pond

(a) As indicated in Appendix A7.0, a Vapour Recovery Unit (VRU) was installed in 1994 to collect vapours from Plant 4, Plant 16 and the south tank farm. However, due to winter freezing problems, only vapours from Plant 4 and Plant 16 are being removed during winter. These problems are expected to be resolved in 1996.



Stack	Unit No.	Description
1		Powerhouse
2	8F-5	Incinerator
3	37F-1	FGD Stack
4	5F-1A	Diluant Heater
5	5F-1B	Diluant Heater
6	5F-2	Coker Feed Heater
7	5F-3	Coker Feed Heater
8	5F-4	Coker Feed Heater
9	5F-5	Diluant Heater
10	5F-6	Coker Feed Heater
11	7F-1	Naptha Charge Htr.
12	7F-2	Naptha Deprop Reb.
13	7F-10	Kerosene Charge Htr.
14	7F-11	Kerosene Reboiler
15	7F-20A	Gas Oil Charge Htr.
16	7F-20B	Gas Oil Charge Htr.
17	7F-20C	Gas Oil Charge Htr.
18	6F-2A	Reformer
19	6F-2B	Reformer
20	6F-2C	Reformer
21	6F-5	Preheat Furnace

Figure 2.3 Location of point sources associated with the Suncor facilities.

2.1.3 *Upgrading*

The bitumen is upgraded to produce various crude oil products. The upgrading involves the following processes:

- A diluent recovery unit (DRU) that returns diluent to the extraction plant for re-use.

- A delayed coking unit (DCU) in which the bitumen is thermally cracked into hydrocarbon vapours and solid coke (carbon) residue. Coke is used by the utilities plant and surplus coke is stockpiled between the plant area and the Athabasca River.

- The hydrocarbon vapours are separated into naphtha, kerosene and gas-oil and are hydrotreated. Gas-oil, kerosene and naphtha are stored and blended to form custom crude oils in the north tank farm area (13 tanks). A hydrogen plant is used to produce the hydrogen required for the hydrotreaters.

- Gas streams containing H_2S that are formed during the upgrading process are treated in the amine plant. The H_2S is removed and concentrated in a separate gas stream called acid gas.

- Sour water (containing H_2S) is also produced during the upgrading process. A stripper removes most of the H_2S from the sour water stream.

- A modified Claus sulphur recovery unit (SRU) recovers about 98% of the sulphur in the acid gas stream. The remaining 2% is incinerated and vented to the atmosphere. The recovered sulphur is normally transferred off-site by trucks. Sulphur that is not trucked off-site is stored in block form.

- Two hydrocarbon and one acid gas flares are used to dispose of gas process streams in emergency situations.

Emission sources associated with the upgrading processes are identified in Table 2.2. These sources can be classified as follows:

- The stack that services the sulphur recovery plant incinerator stack. The main emissions from this stack are water vapour (H_2O), carbon dioxide (CO_2) and SO_2.

- Products of combustion vented by process heaters. The main products of combustion are water (H_2O) and carbon dioxide (CO_2). Additional products include CO, NO_x and SO_2. The latter results from trace amounts of sulphur compounds contained in the fuel.

- Vents that service process drums or storage tanks result in hydrocarbon emissions.

Table 2.2 Emission sources associated with Suncor upgrading operations.

Plant	Source	Description
Delayed Coking Unit (Plant 5)	5F-1A	Diluent heater
	5F-1B	Diluent Heater
	5F-5	Diluent Heater
	5F-2	Coker Feed Heater
	5F-3	Coker Feed Heater
	5F-4	Coker Feed Heater
	5F-6	Coker Feed Heater
	5C-35	Decoke Drum Vent
Hydrogen Plant (Plant 6)	6F-3	Hydrogen Plant flare
	6C-13	CO_2 Removal Unit Vent
	6F-5	Hydrogenation Preheat Furnace
	6F-2	Reformer Furnace
Unifier Plant (Plant 7)	7F-2	Naphtha Depropanizer Boiler Heater
	7F-1	Naphtha Charge Heater
	7F-10	Kerosene Charge Heater
	7F-11	Stripper Reboiler
	7F-20A	Gas-Oil Charge Heater
	7F-20B	Gas-Oil Charge Heater
	7F-20C	Gas-Oil Charge Heater
Amine Unit Sulphur Recovery Unit (Plant 8)	8D-1	DEA Storage Tank Vent
	8D-2	Amine Sump
	-	Sulphur Pit Vent
	8F-5	Sulphur Recovery Plant Incinerator
Plant 10	10D-3	Sour Water Surge Tank Vent
	10D-4	Contaminated Seal Oil Vent
	10K-2A/C	Inert Gas Vent
Flare System (Plant 19)	19F-2	Acid Gas Flare
	19F-1	Hydrocarbon Flare
	19F-3	Hydrocarbon Flare

Table 2.2 Concluded.

Plant	Source	Description
North Tank Farm (Plant 20)	20D-34	Naphtha Tank Vent
	20D-14	Naphtha Tank Vent
	20D-15	Naphtha Tank Vent
	20D-32	Kerosene Tank Vent
	20D-12	Kerosene Tank Vent
	20D-13	Kerosene Tank Vent
	20D-30	Gas-Oil Tank Vents
	20D-10	Gas-Oil Tank Vents
	20D-31	Gas-Oil Tank Vents
	20D-11	Gas-Oil Tank Vents
	20D-36	Gas-Oil Tank Vents
	20D-55	Distillation Naphtha and/or Gas-Oil Vent
	20D-56	Distillation Naphtha and/or Gas-Oil Vent
Area Sources	-	Coke Storage Area
	-	Sulphur Block

- The flare system that is used to dispose of small amounts of waste gas stream on a continuous basis and large amounts under plant upset conditions.

- Fugitive THC emissions may also contain TRS compounds. These emissions result from leaks, drains and spills that occur in the upgrading area.

- Area sources such as the coke storage pits and the sulphur block. While the coke storage pile is normally only a source of windborne particulate emissions, any fires within the coke pile can release products of combustion to the atmosphere. Fugitive TRS emissions can result from the pouring and reclamation of the sulphur block.

The locations of these upgrading sources are shown in Figure 2.2.

2.1.4 *Utilities*

The energy needs of the mining, extraction and upgrading operations are primarily addressed by the utilities plant which produces high pressure steam using three main boilers and five back-up steam units. High pressure steam is used to drive two turbo generators which produce a maximum of 64 MW of electrical power. Alberta Power Limited can provide all additional energy needs. A water treatment plant is used to treat water which is drawn from the Athabasca River for use in the boilers.

The main emission source is the powerhouse stack which services the three large, coke-fired, utility boilers. The products of combustion include SO_2, NO_x, CO and particulates which are vented to the atmosphere. Electrostatic precipitators are used to collect flyash and to reduce the particulate emissions. The location of the powerhouse stack is shown in Figure 2.3.

2.1.5 *Source/Emission Matrix*

Table 2.3 provides a source/emission matrix for the Suncor operation. Both controlled and fugitive sources have been identified. The emissions identified in the table are quantified in subsequent sections of this report. More details for the Suncor emissions are provided in Appendix A.

Table 2.3 Suncor source/emission matrix.

	Emission							
Source	**SO_2**	**H_2S**	**TRS**	**NO_x**	**CO**	**THC**	**CO_2**	**PM[(a)]**
Mining								
Mine surfaces						✓		✓
Mine equipment								✓
Mine equipment exhausts	✓			✓	✓	✓	✓	✓
Extraction								
Extraction plant			✓			✓		
Vapour Recovery Unit						✓		
South Tank farm						✓		
Tailings pond		✓	✓			✓		
Upgrading								
Incinerator stack	✓		✓	✓	✓		✓	
Secondary combustion stacks	✓			✓	✓	✓	✓	✓
Hydrocarbon flares	✓			✓	✓	✓	✓	
Acid gas flare	✓						✓	
North Tank farm						✓		
Fugitive emissions			✓			✓		
Utilities								
Powerhouse stack	✓			✓	✓	✓	✓	✓
Coke storage	✓				✓			✓

(a) Particulate matter.

2.2 Syncrude Canada Ltd. Operations

The Syncrude oil sands operation can produce and has an approved production of 17.6 million m^3/a. Atmospheric emissions result from a wide range of controlled and fugitive emissions. The identification of emissions is divided into the following production processes: mining, extraction, upgrading and utilities.

Figure 2.4 shows the overall layout of the Syncrude plant. This figure identifies the tailings pond (Mildred Lake Settling Basin), mining, southwest sand storage and plant areas. Figure 2.5 shows a more detailed layout of the plant area identifying the individual emission sources.

2.2.1 *Mining*

Pre-mining activities include: clearing of vegetation; drainage of muskeg and overburden aquifers; depressurization of the basil aquifer and muskeg; and overburden removal and storage. The mining of the oil sands is based on the use of draglines to excavate and pile the ore parallel to the mining face. A bucketwheel reclaimer transfers the ore from the piles to the extraction plant by a conveyer belt system. This approach is supplemented with truck and shovel technology. In 1993, a hydrotransport system was added, allowing the oil sands to be mixed with hot water and to be transported from the mine area to the extraction plant via a pipeline.

Emissions associated with Syncrude's mining operations include the following:

- Pre-mining slash burning.
- Products of diesel fuel combustion from mine vehicle exhausts.
- Mine vehicle/traffic generated dust.
- Volatization of hydrocarbons from exposed oil sand surfaces.
- Windborne particulates from mine surfaces.

The emissions associated with mining operations tend to be spread over a relatively large area.

2.2.2 *Extraction*

The Clark hot water process is used to separate the bitumen from the oil sands. This process involves four steps:

- **Conditioning.** Steam and hot water are added to the oil sands to produce a slurry.

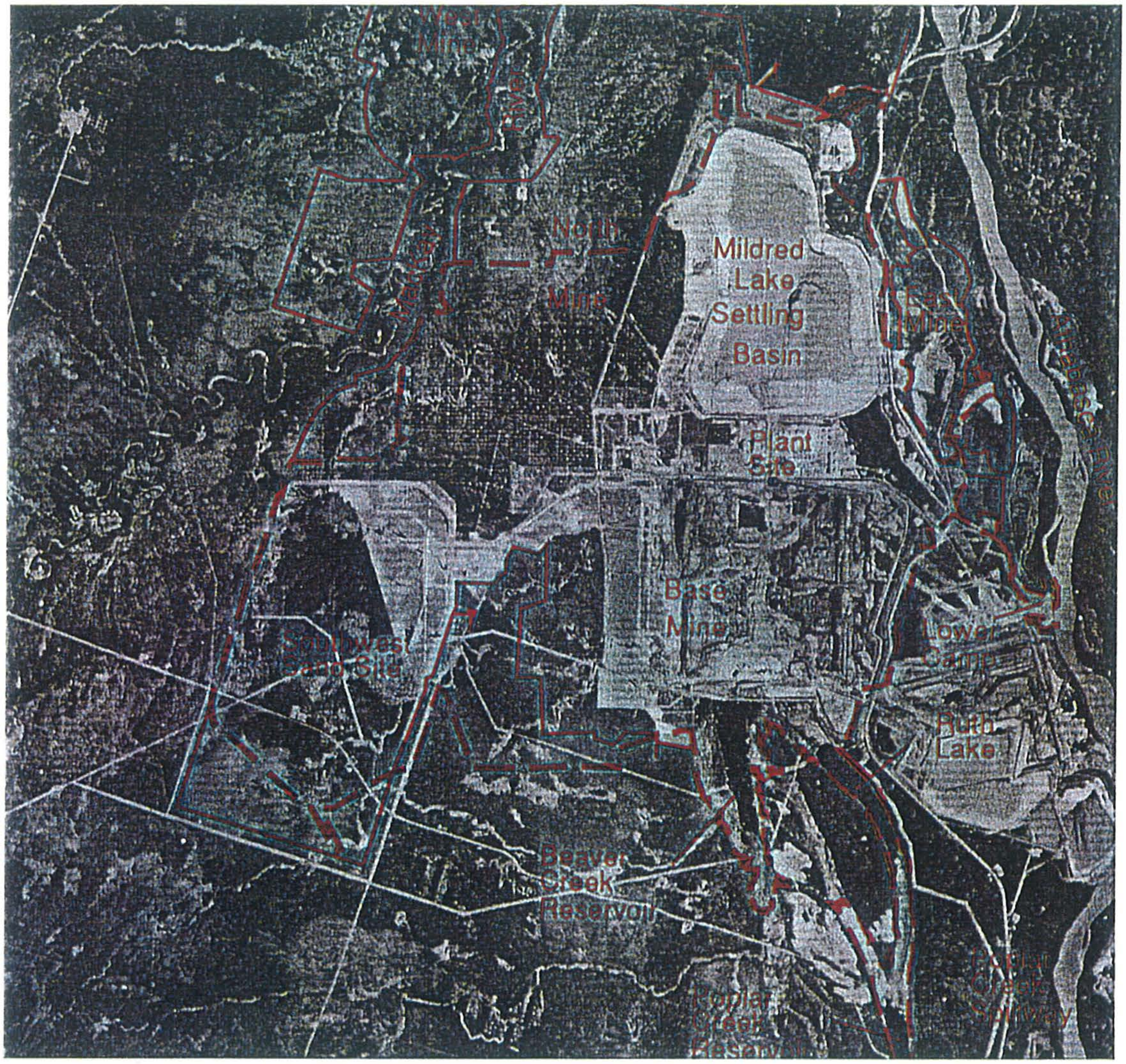
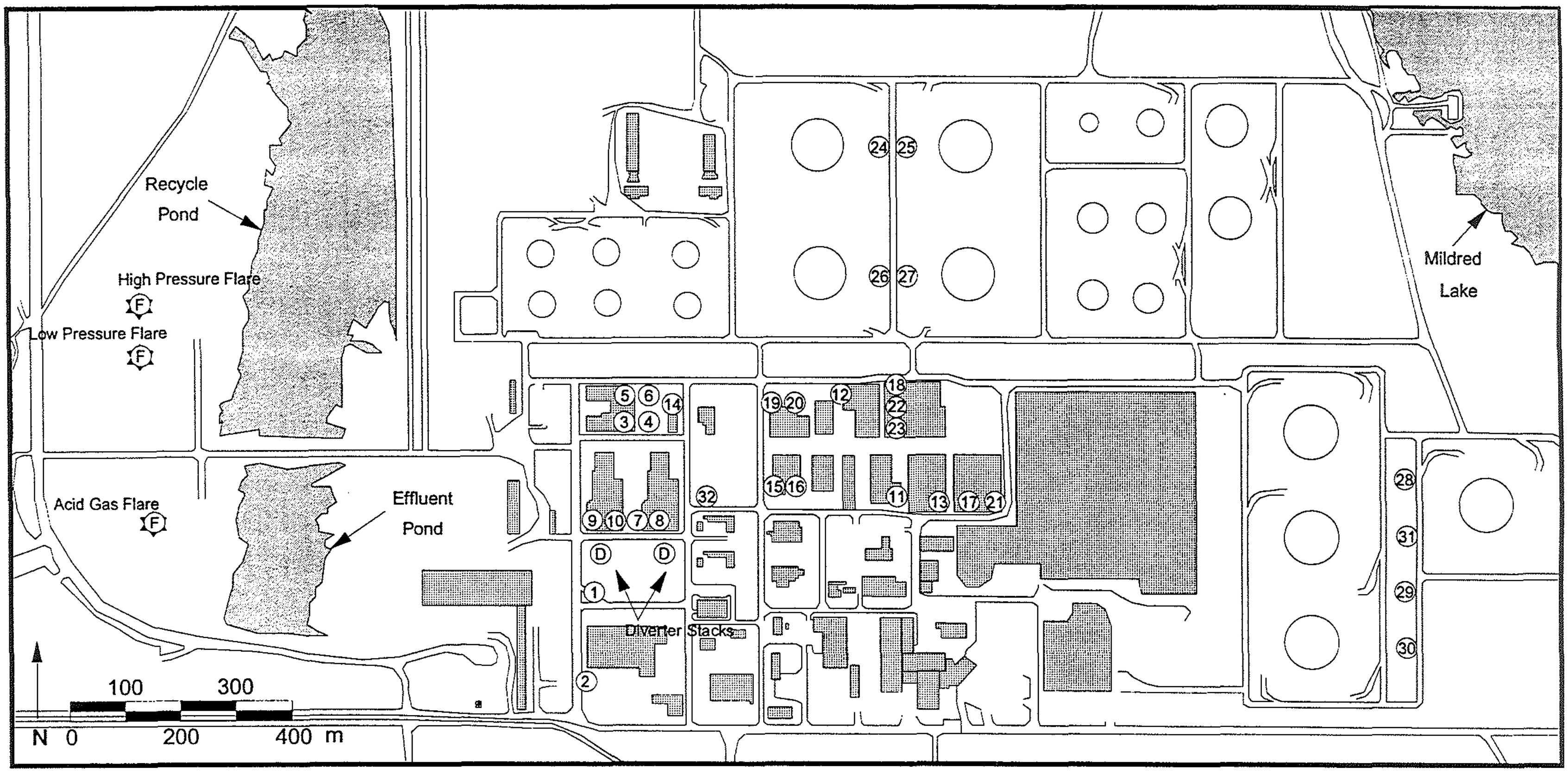


Figure 2.4 Location of area sources associated with the Syncrude facilities.

Figure 2.5 Location of point sources associated with the Syncrude facility.



Stack	Unit No.	Description
1	8F-4	Main Stack
2	31-GTC	Gas Turbine
3	7-1F-1A	Bitumen Col. Feed Heater
4	7-1F-1B	Bitumen Col. Feed Heater
5	7-2F-1A	Bitumen Col. Feed Heater
6	7-2F-1B	Bitumen Col. Feed Heater
7	8-1F-6A	Steam Superheater Stack
8	8-1F-6B	Steam Superheater Stack
9	8-2F-6A	Steam Superheater Stack
10	8-2F-6B	Steam Superheater Stack
11	9-1F-1	Reformer Furnace Stack
12	9-2F-1	Reformer Furnace Stack
13	9-3F-1	Reformer Furnace Stack
14	14F1	Diluent Reboiler
15	15-1F-1	Hydrogen Heater Stack
16	15-2F-1	Hydrogen Heater Stack
17	18F-1	Fractionator Reboiler Stack
18	22F-2	Fractionator Reboiler Stack
19	15-1F-2	Fractionator Reboiler Stack
20	15-2F-2	Fractionator Reboiler Stack
21	18F-2	Fractionator Reboiler Stack
22	22F-3	Bitumen Feed Heaters
23	22F-1	Bitumen Feed Heaters
24	21F-7	Bitumen Heater Stack (N)
25	21F-8	Bitumen Heater Stack (N)
26	21F-9	Bitumen Heater Stack (N)
27	21F-10	Bitumen Heater Stack (N)
28	21F-50	Bitumen Heater Stack (E)
29	21F-51	Bitumen Heater Stack (E)
30	21F-52	Bitumen Heater Stack (E)
31	21F-53	Bitumen Heater Stack (E)
32	12-0F-101	Sulfreen Regen Heater

- **Primary Separation.** This produces the initial separation of sand and bitumen. Sand and water are pumped to the tailings settling basin.

- **Froth Treatment.** Naphtha is added to the bitumen mixture and further separation of the bitumen, water and solids is undertaken. A naphtha recovery unit recovers naphtha from the water/solid tailings.

- **Tailings Disposal.** Tailings comprised of water, sand and small clay particles are first stored in a single tailings settling basin (Mildred Lake Settling Basin), then placed in the mine pit. The sand is disposed of in the Southwest Sand Area (SWSA).

Emission sources associated with the extraction process are listed in Table 2.4. The emission sources can be classified as the following:

- Stacks and/or vents that service the extraction plant release primarily air and steam with minor amounts of hydrocarbon mist that occur during deaerator upset conditions.

- Hydrocarbon emissions from pond surfaces.

- Wind-blown dust from the sides of the tailings pond and southwest sand storage area.

The locations of these area sources are shown in Figure 2.4.

2.2.3 *Upgrading*

The bitumen is upgraded to produce a light sweet crude oil. Upgrading involves the following:

- A diluent recovery unit which recovers the naphtha and returns it to extraction for re-use.

- An LC Finer in which a portion of the bitumen is hydrotreated to produce naphtha, light gas-oil and heavy gas-oil streams.

- Fluid cokers in which the balance of the bitumen and LC Finer pitch are thermally cracked into hydrocarbon vapours and solid coke residue.

- Additional hydrotreating of the fluid coker and LC Finer products produce synthetic crude oil products. A hydrogen plant produces the hydrogen required for the hydrotreaters and LC Finer.

- Gas streams containing H_2S are formed during the upgrading process and are treated in the amine plant. The H_2S is removed and concentrated in a separate gas stream called acid gas.

Table 2.4 Emission sources associated with Syncrude extraction operations.

Plant	Source	Description
Primary Extraction (Plant 3)	1	Extraction Unit Deaerator Stack
	2	Extraction Unit Deaerator Stack
	3	Extraction Unit Deaerator Stack
	4	Extraction Unit Deaerator Stack
	5	Extraction Unit Deaerator Stack
	6	Extraction Unit Deaerator Stack
	7	Extraction Tumbler Unit Stack
	8	Extraction Tumbler Unit Stack
	9	Extraction Tumbler Unit Stack
	10	Extraction Tumbler Unit Stack
	11	Extraction Tumbler Unit Stack
	12	Extraction Tumbler Unit Stack
	13	Extraction Tumbler Unit Stack
	15	Extraction Tumbler Unit Stack
Ponds	16	Tailings Settling Basin
	17	Recycle Pond
	18	Effluent Pond
	19	Southwest Sand Area

- A modified Claus sulphur recovery unit and sulfreen unit recover about 98.5% of the sulphur in the acid gas stream. The remaining 1.5% is sent to the CO boiler. Sulphur that is not trucked off-site is stored in block form.

- Sour water from the primary upgrading units, the cokers and the LC Finer is thermally stripped of H_2S and NH_3. The resulting stripped sour water is routed back to the cokers (as wash water) and to the Mildred Lake Settling Basin (MLSB) via the oily water sewer. Sour water from the secondary upgrading units is almost entirely (90%) returned to secondary upgrading after it passes through H_2S and NH_3 strippers. The remaining (10%) is directed to the Settling Basin.

- Hydrocarbon products are stored in the tank farm.

Emission sources associated with the upgrading process are identified in Table 2.5. These sources include the following:

- The main stack which services the CO boilers. Gas streams to the CO boilers include coker overhead gas from the fluid cokers, tail gas from the sulphur recovery unit, ammonia gas from the sour water treatment facility and effluent gas from the sulphur degassing units.

- Products of combustion vented by process heaters.

- The flare systems.

- Area sources such as the coke cells (particulate emissions) and the sulphur block (TRS emissions). However, at Syncrude, the coke cells are typically below grade and are normally kept moist or covered with a layer of water to prevent fires.

- Hydrocarbon emissions that may also contain TRS compounds. These result from tank vents and fugitive sources such as leaks, drains and spills that occur in the upgrading area.

The Syncrude facility is serviced by two vapour recovery systems that collect and recover vapour from most of the storage tanks. However, there are several tanks which are not serviced by these systems and which are vented directly to the atmosphere. These tanks are identified in Table 2.5.

2.2.4 *Utilities*

The energy needs of the mining, extraction and upgrading operations are primarily addressed by the utilities plant. Utilities operations include the utilities plant that provides the electricity, and the water plant that provides water for the entire site. In addition, the utilities operations supply

Table 2.5 Emission sources associated with Syncrude upgrading operations.

Plant	Source	Description
Hydrotreating (Plant 7)	7-1F-1A	Bitumen Column Feed Heater Stack
	7-1F-1B	Bitumen Column Feed Heater Stack
	7-2F-1A	Bitumen Column Feed Heater Stack
	7-2F-1B	Bitumen Column Feed Heater Stack
Cokers (Plant 8)	8F-4	Main Stack
	8-1F-6A	Steam Super Heater Stack
	8-1F-6B	Steam Super Heater Stack
	8-2F-6A	Steam Super Heater Stack
	8-2F-6B	Steam Super Heater Stack
		CO Boiler Diverter Stack
		CO Boiler Diverter Stack
Hydrogen Plant (Plant 9)	9-1F-1	Hydrogen Reformer Furnace Stack
	9-2F-1	Hydrogen Reformer Furnace Stack
	9-3F-1	Hydrogen Reformer Furnace Stack
	9-1	Hydrogen Vent Muffler Exhaust
	9-2	Hydrogen Vent Muffler Exhaust
	9-3	Hydrogen Vent Muffler Exhaust
Sulphur Recovery Plants (Plant 12)	12-5F-1	Sulphur Degassing Unit Incinerator
	12-0F-101	Sulphreen Regenerator Furnace
Diluent Preparation Unit (Plant 14)	14-F1	Diluent Preparation Column Reboiler Stack
Gas-Oil Hydrotreater (Plant 15)	15-1F-1	Hydrogen Heater Stack
	15-2F-1	Hydrogen Heater Stack
	15-1F-2	Fractionator Reboiler Stack
	15-2F-2	Fractionator Reboiler Stack
Light Gas-Oil Hydrotreater (Plant 18)	18F1	Hydrogen Heater Stack
	18F-2	Fractionator Reboiler Stack

Table 2.5 Concluded.

Plant	Source	Description
Tank Farm (Plant 21)	21F-7	Bitumen Heater Stack (North)
	21F-8	Bitumen Heater Stack (North)
	21F-9	Bitumen Heater Stack (North)
	21F-10	Bitumen Heater Stack (North)
	21F-50	Bitumen Heater Stack (South)
	21F-51	Bitumen Heater Stack (South)
	21F-52	Bitumen Heater Stack (South)
	21F-53	Bitumen Heater Stack (South)
LC-Finer (Plant 22)	22F-1	Bitumen Feed Heater Stack
	22F-2	Hydrogen Heater Stack
	22-1F3	Fractionator Reboiler Stack
Flare Stack (Plant 19)	19F-2	Acid Gas (H_2S Flare)
	19F-1	Smokeless Hydrocarbon
	19F-4	Unassisted Hydrocarbon
Storage Tank Vents	20-D-17	Treated heavy gas-oil
	20-D-18	Treated light gas-oil
	20-D-27	Untreated Naphtha (Floating Roof)
	20-D-28	Heavy gas-oil (Floating Roof)
	20-D-54	Sour Water (Floating Roof)
	20-D-55	Concentrated Sour Water (Floating Roof)
	20-D-57	Untreated light gas-oil (Floating Roof)
	34-D-2	Diluted Bitumen
	34-D-3	Light Slops
	41-7-D-21	Diesel Additives
	41-7-D-100	Blended Diesel
	41-7-D-102	Blended Diesel
Area Sources	-	Coke Storage Cells
	-	Sulphur Block

steam, air and nitrogen to the mining, extraction, upgrading, and administrative areas. Off-gas and fuel gas from the process are used to generate steam for the extraction process.

The following table identifies the sources associated with the utility plant:

Plant	Source	Description
Utilities (Plant 31)	8F-4	Main Stack
	31GTC201	Gas Combustion Turbine Stack
	31GTC202	Gas Combustion Turbine Stack

The emissions associated with the turbine stacks include: NO_x, CO and CO_2. Those associated with the main stack include: SO_2 and particulates, in addition to NO_x, CO and CO_2.

2.2.5 *Source/Emission Matrix*

Table 2.6 provides a source/emission matrix for the Syncrude operation. Both controlled and fugitive sources have been identified. The emissions identified in the table are quantified in subsequent sections of this report. More details for the Syncrude emissions are provided in Appendix B.

2.3 Other Industrial Sources

Other industrial sources that can result in gaseous or particulate emissions include the following:

- The AOSTRA Underground Test Facility (UTF), which is located approximately 45 km north-northwest of Fort McMurray. This facility is used for testing various in-situ bitumen recovery technologies. The vertical wells, horizontal wells and processing facilities were constructed in several phases commencing in 1984, with production and processing commencing in 1987. Currently, 10 000 m^3/month of bitumen is produced.

  Table 2.7 identifies the emission sources discussed in this report with respect to the AOSTRA UTF operation. Most of the emissions are the products of combustion associated with either heaters or vents.

- The Husky and Chevron pilot plants located in the vicinity of Fort McMurray. These plants were former test facilities for bitumen and heavy oil recovery technologies. The Husky pilot plant was shut down and decommissioned in 1991, and the Chevron plant was shut down in 1992.

Table 2.6 Syncrude source-emission matrix.

Source	Emission							
	SO_2	H_2S	TRS	NO_x	CO	THC	CO_2	PM[(a)]
Mining								
Mine surfaces						✓		✓
Mine equipment								✓
Mine equipment exhausts	✓			✓	✓	✓	✓	✓
Extraction								
Extraction plant			✓			✓		
Naphtha recovery unit						✓		
Tailings pond		✓	✓			✓		
Southwest sand storage area						✓		✓
Tank farm						✓		
Upgrading								
Main stack	✓			✓	✓	✓	✓	✓
Diverter stacks	✓	✓	✓		✓	✓	✓	✓
Hydrocarbon flares	✓	✓						
Acid gas flares	✓			✓	✓	✓		
Coke storage								✓
Sulphur block								✓
Fugitive emissions			✓			✓		
Tank farm						✓		
Secondary combustion stacks	✓			✓	✓	✓	✓	✓
Utilities								
Routed to main stack	✓			✓	✓	✓		

(a) Particulate matter.

Table 2.7 Emission sources associated with the AOSTRA UTF facility.

Source	Description
1	14.6 MW steam generator exhaust stack
2	14.6 MW stream generator exhaust stack
3	7.3 MW steam generator exhaust stack
4	7.3 MW steam generator exhaust stack
5	2.1 MW emergency steam generator exhaust stack
6	1.2 MW glycol heater exhaust stack
7	Mine air heater exhaust stack
8	Central utility flare stack

- The proposed SOLV-EX (Bitumount) oil sands co-production experimental project, which will be located on Lease 5, approximately 85 km north of Fort McMurray (20 km north of Fort McKay). This facility will be used to evaluate the feasibility of a new co-production technology for the production of pipelineable crude oil from the Athabasca oil sands and minerals from fine clay also found in the McMurray Formation. Expected production levels are as follows:

- Bitumen	2360 t/d
- Pipelineable crude oil	1674 m^3/d
- Alumina	64 000 t/y
- Potassium sulphate	12 000 t/y
- Ferrous sulphate	14 000 t/y

  The major facilities to be developed include: a surface mine; a mine waste dump area; extraction and upgrading process facilities; a dyked disposal area for the storage of dry tailings; and a utilities plant. Site preparation activities are currently underway. The mining operations and bitumen recovery processes (Phase I) are expected to commence at the end of 1996. Phase II of the project, the mineral extraction processes, is expected to start up approximately one year later.

  The sources associated with the proposed SOLV-EX operation are listed in Table 2.8. The emissions are associated with combustion sources, fines processing, and sulphur processing activities (i.e., a sulphur recovery plant and a sulphuric acid manufacturing plant).

- The proposed SOLV-EX Ruth Lake Facility which will be located approximately 45 km north of Fort McMurray, just west of the existing Suncor 2/3 Tailings Pond. This facility is proposed as an experimental project for production of metal products from mature fine tailings. The facility will incorporate sludge conditioning, mineral extraction and utilities operations, as well as off-site piping. The plant is expected to produce the following:

- Sulphuric acid	750 t/sd
- Recovered bitumen	99 t/sd
- Bitumen	206 t/sd
- Potassium sulphate	25 t/sd
- Ferrous sulphate	34 t/sd
- Silica	758 t/sd

  The preceding data are presented on a tonnes per stream day basis (i.e., tonnes per number of days the plant is operating). Start up of these operations, at one-third capacity, is scheduled to commence in the period from October 1996 to July 1997. It is expected that full design capacity will be attained by April 1998.

Table 2.8 Sources associated with the proposed SOLV-EX operations.

Plant	Source	Description
Sulphur Plant	A4[(a)]	Sulphur plant incinerator
Utilities	A12	Steam boiler/turbines
Upgrading Unit	A3	Soaker upgrader
Crystallization Plant	A6	Double salt dryer baghouse
	A7	$FeSO_4$ dryer flue gas
	A9	$FeSO_4$ dryer process exhaust
	A19	By-product sulphate dryer
Calcining and Washing Plant	A10	K_2SO_4 dryer flue gas
	A17	K_2SO_4 dryer process
	A8	Alumina dryer scrubber
Bitumen Extraction Plant	A15	Fines dryer flue gas
Leaching and Fines Storage	A5	Fines dryer venturi scrubber exhaust
Sulphuric Acid Plant	A4[(a)]	Acid plant wet scrubber exhaust

(a) A4 is the main stack. The incinerator and acid plant exhausts are proposed to share this stack.

- The Northland Forest Products Mill is located approximately 20 km north of Fort McMurray. The major emission source at the facility is the conical burner which emits particulates, sulphur oxides, carbon monoxide, non-methane organic compounds and nitrogen oxides to the atmosphere.

  The next closest mill facilities are located in Boyle (approximately 250 km south-southwest of Fort McMurray), Grande Prairie, Slave Lake and Peace River. Alberta-Pacific is responsible for forest management in a large area of the province encompassing Fort McMurray. As a result, there is a high volume of trucking associated with forest operations in the vicinity of Fort McMurray. A second forestry company, based in Boyle, is responsible for trucking spruce lumber out of the Fort McMurray area.

- The Fort McMurray Hospital, which operates a medical waste incinerator on an intermittent basis. This multi-chamber incinerator is specifically used to destroy medical "red bag" waste. Typically, medical waste incinerators emit particulate matter, carbon monoxide, hydrogen chloride, sulphur dioxide, nitrogen oxides, various metals, dioxins/furans and various VOCs.

- Currently, there are two paving companies with asphalt kilns near the community of Fort McMurray. The kilns run intermittently and produce asphalt for road paving operations. The kilns emit steam, particulate matter and VOCs, while the road paving operations generate VOC emissions. Discussions with AEP, Air Emissions Branch indicate that both paving company sources run on a seasonal basis and have had limited use over the last few years.

- Until recently, a sulphur loading facility was operational in Lynton, approximately 15 km southeast of Fort McMurray. Currently, no sulphur loading occurs at this facility.

- The nearest gas production fields and associated compressor stations are approximately 60 km southwest of Fort McMurray.

The preceding projects are either existing or currently proposed and under review by regulatory agencies (i.e. SOLV-EX). The relative locations of the existing and approved sources are shown in Figure 2.6. Table 2.9 provides a source/emission matrix for these sources.

2.4 Transportation Sources

The main north-south traffic corridor is Highway 63 which links Fort McMurray to Edmonton and to the oil sands facilities. The highway extends further north to the Peter Lougheed Bridge and Fort McKay. The majority of the traffic on the highway occurs between Fort McMurray and the oil sands facilities.

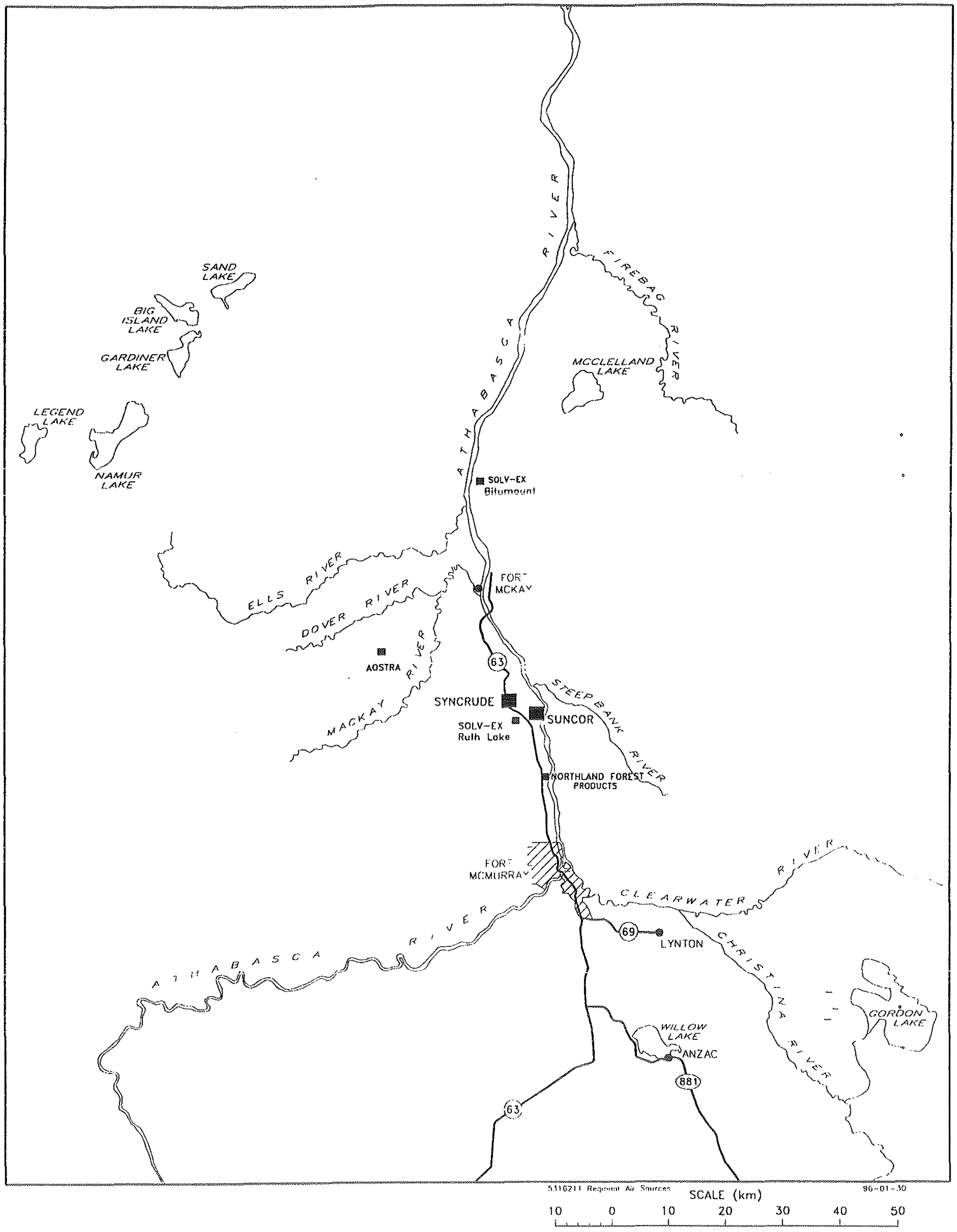


Figure 2.6 Location of regional emission sources.

Table 2.9 Source/emission matrix for other industrial sources.

Source	Emission						
	SO_2	TRS	NO_x	CO	THC	CO_2	PM[(a)]
AOSTRA UTF	✓		✓	✓	✓	✓	
SOLV-EX Bitumount	✓	✓	✓	✓	✓	✓	✓
SOLV-EX Ruth Lake	✓	✓	✓	✓	✓	✓	✓
Northland Forest Products	✓		✓	✓	✓	✓	✓
Fort McMurray Hospital Incinerator	✓		✓	✓			✓

(a) Particulate matter

Traffic is comprised of automobiles and light trucks (gasoline fueled) and of buses for transporting personnel to work (diesel fueled) as well as large trucks that provide supplies and carry products to and from the plants (diesel fueled). The traffic will result in emissions from products of fuel combustion and from the eroding and entrainment of road materials. Table 2.10 provides a summary of the types of emissions that can be expected from this highway traffic.

2.5 Residential Sources

The two primary communities in the region are Fort McMurray (population 34,706) and Fort McKay (population 322). Potential emission sources in these areas include:

- Products of combustion resulting from residential and commercial space heating, and from heating of water for domestic purposes.
- Residential combustion of wood in fireplaces and wood stoves.
- Local vehicle traffic which produces products of combustion and particulates due to tire/road interactions.
- Local light industry operations such as maintenance facilities (i.e. vehicle repairs, welding shops).
- Local bulk fuel and gasoline service stations that handle and transfer fuel.
- Products of combustion from residential use of wood for recreational or supplemental heating purposes.

The following table summarizes the types of emissions associated with these sources:

	Emission					
Source	**SO_2**	**NO_x**	**CO**	**THC**	**CO_2**	**PM_{10}[(a)]**
Vehicle traffic (community and highway)	✓	✓	✓	✓	✓	✓
Heating (natural gas)	✓	✓	✓	✓	✓	✓
Residential wood combustion	✓	✓	✓	✓	✓	✓[(b)]

(a) Particulate matter.
(a) PM_{10}.

2.6 Natural Sources

Natural sources can also result in emissions of some of the previously identified compounds. Potential sources include:

- A natural source of sulphur in the atmosphere is the biogenic production of H_2S from bacteria action in oxygen deficient atmospheres. In this process, H_2S is a by-product of the bacterial oxidation of organic matter. Typically, the process occurs in marshes and bogs. Anthropogenic sources of water effluents may enhance biogenic production of H_2S by increasing the nutrient levels and decreasing the oxygen levels in aquatic environments (Hitchcock 1994).

- Natural source emissions of carbonyl sulphide and carbon disulphide can also result from microbial processes in the soils. It is believed that a chemical reaction in the lower atmosphere of the earth transforms carbonyl sulphide and carbon disulphide into SO_2 (Khalil *et al.* 1994).

- Nitrogen oxide emissions from soil nitrification and denitrification processes have been estimated to account for the majority of all biogenic NO_x emissions. In addition, forest fires and lightning are believed to emit NO_x (Duxbury 1994).

- Vegetation is by far the largest source of biogenic VOC emissions. Other natural sources include: forest fires, soils, animals and aquatic environments. In the Fort McMurray area, the high concentration of bitumen in the soil is a significant biogenic contributor to VOC emissions in the area.

- Particulates are also generated from natural sources including: vegetation in the form of pollens and spores; forest fires; and wind-blown soil.

Forest fires, whether natural or caused by man, are also sources of combustion products (e.g., particulates, CO).

2.7 Summary

Emissions to the atmosphere result from a wide range of sources including the following:

- SO_2, NO_x, CO and CO_2 emissions result primarily from combustion processes.

- TRS and THC emissions result from the venting of hydrocarbon products and fugitive releases.

- Particulate emissions can result from combustion processes and fugitive sources.

- Natural sources can also result in emissions of the above contaminants to the atmosphere.

While the two oil sands operations are the major sources of pollutants released to the atmosphere in the region, it is important to note that other smaller sources also exist in the region. Subsequent sections of the report will quantify these emissions.

3.0 SO_2 EMISSIONS

Anthropogenic or manmade emissions of sulphur dioxide (SO_2) to the atmosphere result from the combustion of fuels which contain sulphur compounds. For the oil sands operations, the sulphur content of the processed bitumen is typically 4.5 to 5.0% by weight. The major sources of SO_2 emissions in the region result from the two existing oil sands facilities.

The continuous and intermittent SO_2 emission sources from the Suncor facilities are discussed in Appendix A and include the following:

- Powerhouse stack
- Incinerator stack
- Secondary combustion sources
- Continuous and intermittent flaring
- Mine fleet

The continuous and intermittent SO_2 emission sources from the Syncrude facilities are discussed in Appendix B and include the following:

- Main stack
- Secondary combustion sources
- Intermittent diverter stacks
- Intermittent Flaring
- Mine fleet

Other industrial sources of SO_2 emissions are discussed in Appendix C and include the following existing and proposed industrial sources:

- AOSTRA UTF flare stack and secondary combustion sources (existing)
- SOLV-EX Bitumount main stack, flare stack and process unit vents (proposed)
- SOLV-EX Ruth Lake common stack and process unit vents (proposed)
- Northland Forest Products conical burner (existing)
- Fort McMurray hospital incinerator stack (existing)

Appendix D presents estimated SO_2 emissions resulting from the following:

- Vehicular traffic
- Residential combustion sources
- Naturally occurring sources

3.1 Historical SO_2 Emissions

Table 3.1 and Figures 3.1 and 3.2 summarize the historical SO_2 emissions for the combined Suncor and Syncrude operations. The SO_2 emission information in the table and figures are expressed as "SO_2 equivalent". This is because the Syncrude diverter stack vents sulphur compounds that are primarily in the reduced form (e.g., H_2S, CS_2, COS) and not as SO_2.

The Suncor data are presented for the period 1968 to 1994, while the Syncrude data are presented for the period 1978 to 1994. From 1990 to 1994, inclusive, Suncor and Syncrude have each contributed about 50% to the combined SO_2 emissions. During this same time period, 87% of the Suncor emissions have resulted from the powerhouse stack, while 96% of the Syncrude emissions have resulted from the main stack.

3.2 Suncor SO_2 Emissions

The following table identifies the Suncor SO_2 emission sources and provides emission rates for each source or source type:

Source	SO_2 Emission Rate (t/cd)
Powerhouse	211
Incinerator	17
Secondary Combustion Sources	0.15
Intermittent Flaring	4.4
Continuous Flaring	2.3
Mine Fleet	0.3
Total	235

As indicated in the table, the total SO_2 emissions at Suncor are estimated to be approximately 235 t/cd. The powerhouse and incinerator at Suncor contribute 90 and 7% of these emissions, respectively.

Table 3.1 Summary of the average SO_2 emission rates from the existing oil sands operations. Values are in units of t/cd.

Year	Suncor				Syncrude				TOTAL
	Powerhouse	Incinerator	Flare	Subtotal	Main	Diverter	Flare	Subtotal	
1968	132	n/o(a)	n/o	132	n/o	n/o	n/o	n/o	132
1969	153	n/o	n/o	153	n/o	n/o	n/o	n/o	153
1970	193	n/o	n/o	193	n/o	n/o	n/o	n/o	193
1971	208	n/o	n/o	208	n/o	n/o	n/o	n/o	208
1972	217	52	n/a(b)	269	n/o	n/o	n/o	n/o	269
1973	222	52	n/a	274	n/o	n/o	n/o	n/o	274
1974	213	37	12	262	n/o	n/o	n/o	n/o	262
1975	213	25	12	250	n/o	n/o	n/o	n/o	250
1976	221	25	5	251	n/o	n/o	n/o	n/o	251
1977	200	21	4	225	n/o	n/o	n/o	n/o	225
1978	205	17	3	225	70	n/a	n/a	70	295
1979	207	21	3	231	19	n/a	n/a	19	250
1980	231	27	5	263	141	2	15	158	421
1981	166	19	13	198	189	5	38	232	430
1982	137	21	64	222	111	4	23	138	360
1983	139	24	35	198	157	4	28	189	387
1984	153	30	43	226	161	4	4	169	395
1985	154	28	35	217	226	1	3	230	447
1986	160	28	27	215	228	2	2	232	447
1987	159	20	13	192	227	1	11	239	431
1988	180	27	20	227	199	2	2	203	430
1989	172	33	16	221	189	2	3	194	415
1990	164	24	7	195	194	1	10	205	400
1991	175	26	6	207	203	1	8	212	419
1992	182	25	6	212	225	1	7	233	445
1993	196	24	6	226	213	2	5	220	446
1994	211	30	7	248	226	<1	3	229	477
Mean(c)	184	28	16	228	175	2	11	205	433
Years	27	23	21		17	15	15		
Total (kt)	1812	232	125	2169	1088	12	59	1159	3328
Plant (%)	83.5	10.7	5.8	100.0	93.9	1.0	5.1	100.0	
Total (%)	54.4	7.0	3.8	65.2	32.7	0.4	1.8	34.8	100.0

(a) n/o = plant was not operational
(b) n/a = no data available
(c) mean over the period when the source was operational and when data are available.

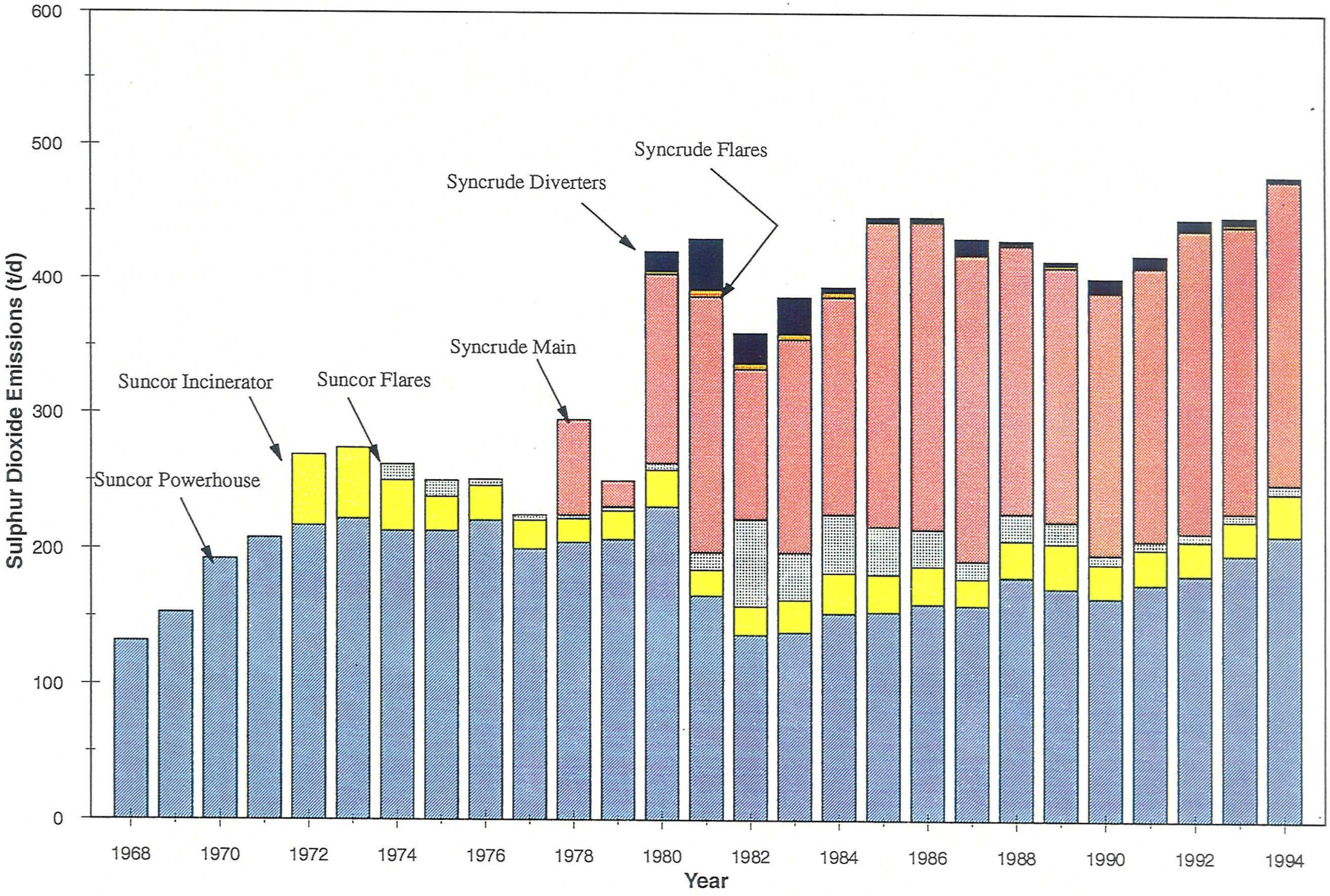
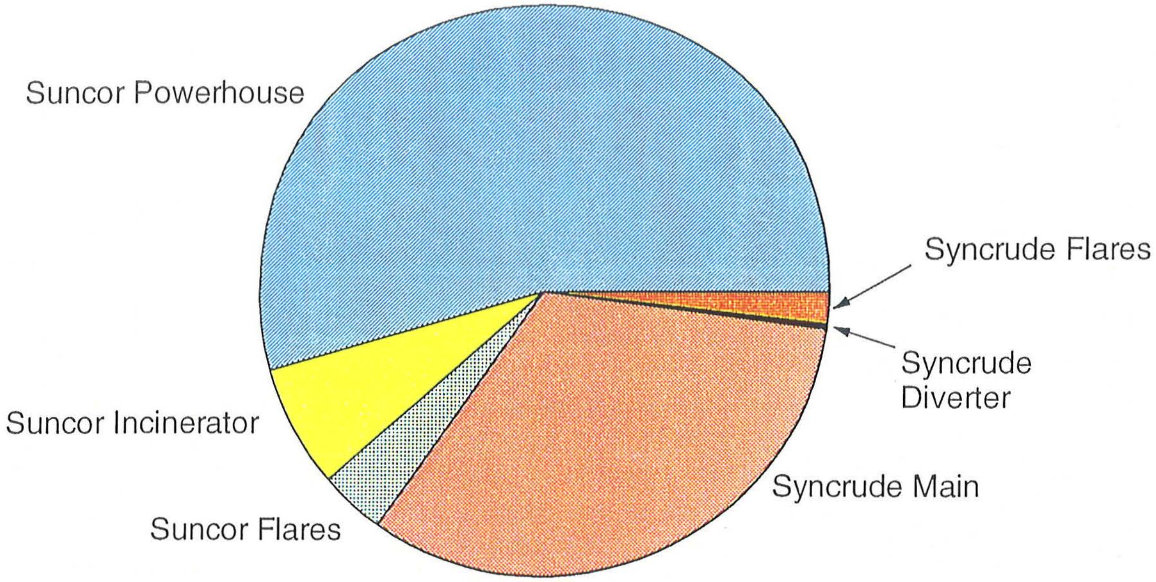
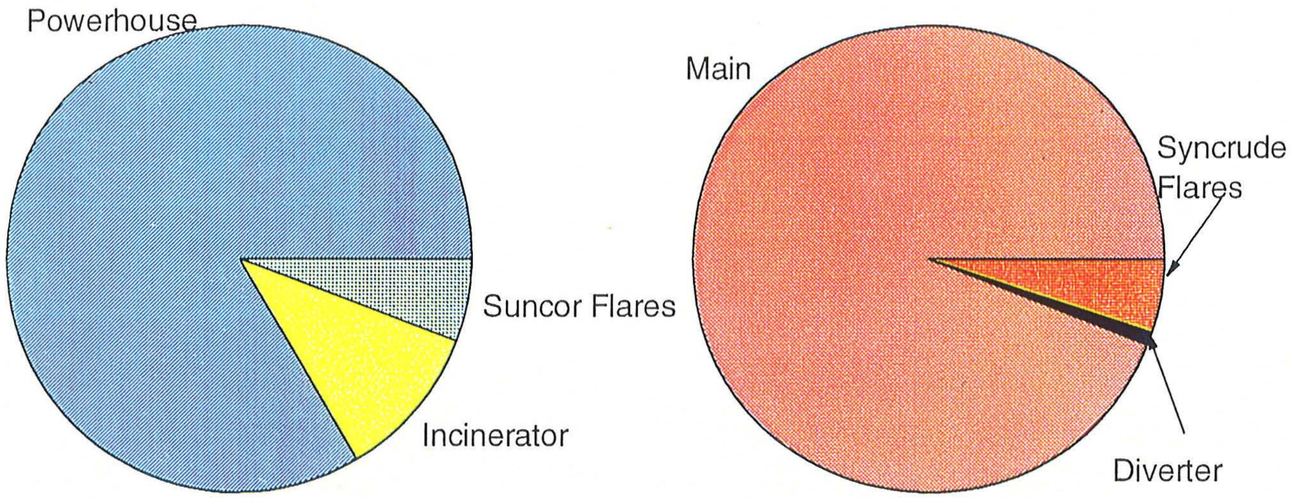


Figure 3.1 Historical SO_2 equivalent emissions from the Suncor and Syncrude oil sands operations.



Combined
(1968 to 1994)



Suncor
(1968 to 1994)

Syncrude
(1978 to 1994)

Figure 3.2 Relative contribution to total SO_2 equivalent emissions in the region over the period 1968 to 1994.

3.3 Syncrude SO_2 Emissions

The following table identifies the Syncrude SO_2 emission sources and provides emission rates for each source or source type:

Source	SO_2 Emission Rate (t/cd)
Main Stack	226
Secondary Sources	5.1
Diverter Stacks	0.28
Flare Stacks	6.6
Mine Fleet	0.76
Total	239

The preceding information is based on the 1994 CSEM data for the main stack, average operating data from 1990 to 1994 for the diverter stacks and emission factors for the secondary and mine sources. As indicated in the table, the total SO_2 emissions at Syncrude are estimated to be approximately 239 t/cd, with the main stack contributing 95% of the total SO_2 emissions. For comparison, in 1995, Syncrude estimated their total SO_2 emissions to be 207 t/cd, with the main stack contributing 99% of the total SO_2 emissions.

3.4 SO_2 Emissions from Other Industrial Sources

The following table identifies the SO_2 emission rates estimated to occur due to the operation of other industrial sources in the Athabasca Oil Sands region:

Source	SO_2 Emission Rate (t/sd)
AOSTRA	0.061
SOLV-EX Bitumount	3.57
SOLV-EX Ruth Lake	3.78
Northland Forest Products	0.03
Fort McMurray Hospital	0.0005
Total	7.4

As indicated in the table, the total estimated SO_2 emissions occurring as a result of the operation of other industrial sources in the region is 7.4 t/sd. The SOLV-EX Bitumount and Ruth Lake facilities account for 48 and 51% of the total from other industrial sources, respectively.

3.5 SO_2 Emissions from Transportation and Residential Sources

The following table identifies the SO_2 emission rates estimated to occur as a result of vehicular traffic and residential combustion in the Athabasca Oil Sands region:

Source	**SO_2 Emission Rate (t/cd)**
Highway 63	0.01
Local Traffic	
Fort McMurray	0.18
Fort McKay	0.00
Residential Heating	
Natural Gas	0.002
Wood	0.003
Total	0.2

3.6 Summary of SO_2 Emissions

The following table presents a summary of the estimated SO_2 emissions and percent contribution for sources in the Athabasca Oil Sands area:

Source	**SO_2 Emission Rate (t/cd)**	**Contribution (%)**
Suncor	235	48.8
Syncrude	239	49.6
Other Industries[a]	7.4	1.5
Transportation	0.19	0.04
Residential Combustion	0.005	0.001
Total	482	100

[a] t/sd.

As indicated in the preceding table, Suncor and Syncrude each account for approximately 49% of the total estimated SO_2 emissions in the region.

4.0 NO_x, CO AND CO_2 EMISSIONS

The primary emissions associated with combustion sources that burn fossil fuel are nitrogen (N_2), water vapour (H_2O) and carbon dioxide (CO_2). Nitrogen emission results from the inlet combustion air, whereas H_2O and CO_2 are the products of hydrocarbon oxidation. These products are accompanied by trace amounts of carbon monoxide (CO), hydrocarbon (THC) and oxides of nitrogen (NO_x). CO and THC emissions result from the less-than-perfect combustion of the hydrocarbon in the fuel. The oxides of nitrogen are comprised primarily of nitrogen oxide (NO) and nitrogen dioxide (NO_2). Emissions of nitrogen oxides result from high temperature combustion. At the combustion source, NO is formed and through subsequent reactions in the stack and the atmosphere, NO is converted to NO_2.

As indicated in Section 3.0, details for the Suncor emission sources are presented in Appendix A, while details for the Syncrude emission sources are presented in Appendix B. Other industrial sources of NO_x emissions are presented in Appendix C. Estimates of vehicular traffic and residential combustion emissions are presented in Appendix D.

4.1 Suncor NO_x, CO and CO_2 Emissions

The following table identifies the Suncor NO_x, CO and CO_2 emission sources and provides emission rates for each source or source type:

Source	Emission Rate (t/cd)		
	NO_x	CO	CO_2
Powerhouse	16.4	14.1	5665
Incinerator	0.11	5.5	92.5
Secondary Sources	4.12	0.85	3451
Intermittent Flaring	0.01	0.055	19.1
Continuous Flaring	0.01	0.038	11.6
Mine Fleet	3.06	0.89	201
Total	23.7	21.4	9440

As indicated in the table, the powerhouse is the largest emitter of NO_x, CO and CO_2 emissions at Suncor, accounting for 69, 66 and 60% of these emissions, respectively.

4.2 Syncrude NO_x, CO and CO_2 Emissions

The following table identifies the Syncrude NO_x, CO and CO_2 emission rates:

Source	Emission Rate (t/cd)		
	NO_x	CO	CO_2
Main Stack	9.6	47.2	6647
Secondary Sources	15.7	2.62	13 505[(b)]
Diverter Stacks	n/d[(a)]	6.0	-
Flare Stacks	0.04	.0.22	141
Mine Fleet	9.8	2.52	540
Total	35.1	58.6	20 833

[(a)] Not determined.

[(b)] Estimated by Syncrude and includes contribution from diverter stacks (~30t/d as estimate in Section B4.2).

As indicated by the data presented in the preceding table, the secondary sources are the main emitters of NO_x and CO_2, accounting for 45 and 65% of the Syncrude emissions, respectively. The main stack emits 80% of the CO emissions at Syncrude. In an independent assessment, Syncrude estimated the total 1995 emission rates to be 35.7, 46.2 and 23 130 t/d for NO_x, CO and CO_2, respectively (Buchanan 1996). The Syncrude CO estimate includes only the contribution from the main stack. With respect to CO_2, the Syncrude estimated 1995 emissions rates of 8117 t/d from the main stack and 963 t/d from the flare stack. More flaring occurred in 1995 than in previous years and this would account for some of the increase.

4.3 NO_x, CO and CO_2 Emissions from Other Industrial Sources

The following table identifies the NO_x, CO and CO_2 emission rates estimated to occur as a result of the operation of other industrial sources in the Athabasca Oil Sands region:

Source	Emission Rate (t/sd)		
	NO_x	CO	CO_2
AOSTRA	0.226	0.052	183.2
SOLV-EX Bitumount	0.645	0.29	1050
SOLV-EX Ruth Lake	1.71	0.34	1500
Northland Forest Products	0.27	35.1	918
Fort McMurray Hospital	0.0007	0.006	-
Total	2.8	35.8	3651

The SOLV-EX Ruth Lake facility accounts for 61% of the estimated NO_x emissions and 41% of the CO_2 emissions resulting from other industrial sources in the region. However, when compared to the total NO_x and CO_2 emissions estimated for the region (i.e., including Suncor, Syncrude, other industrial sources, vehicular traffic and residential combustion sources) the emissions from the Ruth Lake facility account for about 2.7% of the total NO_x and 4.3% of the total CO_2.

Similarly, Northland Forest Products accounts for 98% of the estimated CO resulting from other industrial sources in the region. This emission rate is about 28.9% of the total CO emissions when emissions from Suncor, Syncrude, vehicular and residential sources in the region are included.

4.4 NO_x, CO and CO_2 Emissions from Transportation and Residential Sources

The following table identifies the NO_x emission rates estimated to occur as a result of vehicular traffic and residential combustion in the Athabasca Oil Sands region:

	Emission Rate (t/cd)		
Source	**NO_x**	**CO**	**CO_2**
Highway 63	0.46	1.56	81
Local Traffic			
Fort McMurray	0.58	2.18	114
Fort McKay	0.003	0.01	0.53
Residential Heating			
Natural Gas	0.282	0.121	376.5
Wood	0.017	1.60	15.2
Total	1.3	5.5	587

Traffic emissions are proportional to traffic flow and therefore emissions are typically the highest during the morning and afternoon commuting periods. The weekend traffic flow patterns are different from those associated with the weekday. Residential heating needs are proportional to heating degree days (i.e., larger emissions are associated with colder days).

4.5 Summary of NO_x, CO and CO_2 Emissions

The following table presents a summary of the estimated NO_x, CO and CO_2 emissions and percent contribution for sources in the Athabasca Oil Sands area:

Source	Emission Rate (t/cd)			Contribution (%)		
	NO_x	CO	CO_2	NO_x	CO	CO_2
Suncor	23.7	21.4	9440	37.7	17.6	27.4
Syncrude	35.1	58.6	20 833	55.8	48.3	60.4
Other Industries[(a)]	2.8	35.8	3651	4.4	29.5	10.6
Transportation	1.0	3.8	196	1.6	3.1	0.6
Residential Combustion	0.3	1.7	392	0.5	1.4	1.1
Total	62.9	121.3	34 512	100	100	100

[(a)] t/sd.

While Suncor and Syncrude are relatively large contributors to regional NO_x, CO and CO_2 emissions, the relative contributions to these emissions from other sources are larger than those associated with SO_2.

5.0 TRS AND THC EMISSIONS

Total reduced sulphur (TRS) compounds and total hydrocarbon (THC) compounds can be a source of odours and, for the most part, they typically originate from the same type of sources. These sources include:

- Point sources are from devices that are designed to vent gaseous or particles into the atmosphere. Typical sources include building vents, tank vents or process stacks.
- Fugitive point sources are associated with emissions from a source that is not designed to vent to the atmosphere. Typical fugitive sources include leaks from valves, flanges, sampling lines, drains, seals and releases from pressure relief devices.
- Fugitive area sources are associated with evaporative emissions that result from ponds, lagoons, stockpiles and minor spills during normal operations.

TRS and HC compounds can also result from natural emission sources such as lagoons and vegetation.

Total reduced sulphur species (TRS) refer to sulphur compounds that can potentially result in odours. These include the following:

• Hydrogen sulphide	(H_2S)
• Carbonyl sulphide	(COS)
• Carbon disulphide	(CS_2)
• Methyl Mercaptan	(RSH)
• Ethyl Mercaptan	(R_2SH)
• Thiophenes	(ROS)

These products are produced during the upgrading process where sulphur compounds in the bitumen are broken down and subsequently recombine with hydrogen and hydrocarbons. Syncrude and Suncor have undertaken source surveys to identify and quantify TRS emissions from their respective facilities.

Total hydrocarbons (THC) or total organic compounds (TOC) refer to all hydrocarbon products and are usually expressed in terms of methane equivalent. Some surveys differentiate between methane (C_1) and non-methane hydrocarbons (NMHC or NMTOC) since most THC emissions are as C_1 which is much more volatile and less reactive than the other hydrocarbons. NMHC or NMTOC are often referred to as volatile organic compounds (VOC). As with TRS, Syncrude and Suncor have undertaken source surveys to identify and quantify THC and VOC emissions from their respective facilities.

5.1 Suncor Sources

As part of the Odour Abatement Program, Suncor identified the following odour causing (i.e., TRS and THC emitting) sources:

- Plant 4 tailings outfall in Pond 1.
- Plant 4 vents.
- South tank farm vents.
- Plant 3 vents.

5.1.1 *TRS Emissions*

The following table summarizes the estimated TRS emissions resulting from the various Suncor sources:

Source	TRS Emission Rate (t/cd)
Incinerator	0.6
Controlled Vents	0.021 to 0.039
Tailings Ponds	0.066
Total	0.7

As indicated in the table, 86% of the TRS emissions at Suncor are associated with the incinerator stack. This value is based on a maximum TRS concentration of 300 ppm in the incinerator stack effluent.

5.1.2 *THC Emissions*

The following table summaries the THC emission sources and estimated emission rates at Suncor:

Source	Emission Rate (t/cd)
Combustion Sources:	
Powerhouse	0.11
Incinerator	0.001
Secondary Stacks	0.04
Intermittent Flaring	0.02
Continuous Flaring	0.01
Mine Fleet	0.24
Other Sources:	
Extraction Plant 3	9.87
Extraction Plant 4	11.45 (0.11)[a]
South Tank Farm	0.26 to 6.59 (0.066)
North Tank Farm	0.004 to 0.03
Other Vents	0.39
Upgrading[b]	4.7
Tailings Ponds	1.78
Total	35.2 (17.4)[a]

[a] Values in brackets represent the successful operation of the VRU.
[b] Based on U.S. EPA (1995) emission factor for VOC.

As indicated in the table, the largest sources of THC at Suncor are associated with Extraction Plants 3 and 4, which account for a total of 60% of the THC emissions. Suncor has installed a Vapour Recovery Unit (VRU) to reduce emissions. Emissions from Extraction Plant 4 and from the south tank farm will be reduced by 99% once the VRU is fully operational.

5.2 Syncrude Sources

The Syncrude estimates of TRS and THC emissions are categorized for various areas associated with their operations.

5.2.1 *TRS Emissions*

The following table identifies the TRS emission rates estimated for Syncrude:

Source	TRS Emission Rate (t/cd)
Diverter Stacks	0.67
Area Sources	
Tailings Settling Basin	0.05
Other	0.04
Total	0.8

The preceding table indicates that the diverter stacks are the largest source of TRS emissions (primarily H_2S, COS and CS_2). The TRS emissions from the tailings ponds tend to be in the form of thiophenes.

5.2.2 *THC Emissions*

The following table provides estimates of THC emissions at Syncrude:

Source	THC Emission Rate (t/cd)
Combustion Sources:	
Main Stack	n/d(a)
Secondary Sources	0.26
Diverter Stacks	0.65
Flare Stacks	0.08
Mine Fleet	0.67
Area Sources:	
Tailings Settling Basin	2.1
Other	11.7(b)
Total	15.5

(a) Not determined.

(b) Based on 1987 data and does not account for emission reduction programs initiated since that time.

5.3 Other Industrial Sources

The following table presents a summary of the available TRS and THC emissions compiled in Appendix C for other industrial sources in the Athabasca Oil Sands region:

Source	Emission Rate (t/sd)	
	TRS	THC
AOSTRA		
Flare	n/d[(a)]	n/d
Secondary Sources	n/d	0.009[(b)]
SOLV-EX		
Bitumount	0.007	2.45
Ruth Lake	n/d	0.05
Northland Forest Products	0	2.97
Fort McMurray Hospital	n/d	0
Total	0.007	5.5

(a) Not determined.
(b) Total organic compounds.

5.4 Transportation and Residential Heating Sources

TRS was not estimated for these sources. The following table summarizes the THC emissions:

Source	THC Emission Rate (t/cd)
Highway 63	0.27
Local Traffic	
Fort McMurray	0.90
Fort McKay	0.004
Residential Combustion	
Natural Gas[(a)]	0.034
Wood[(a)]	1.12
Total	2.3

(a) Total organic compounds.

5.5 Summary of TRS and THC Emissions

The following tables summarizes the TRS and THC emissions for the Athabasca Oil Sands area:

Source	Emission Rate (t/cd)	
	TRS	THC
Suncor	0.7	35.2 (17.4)(a)(b)
Syncrude	0.8	15.5
Other Industrial Sources(c)	0.007	5.5
Transportation	n/d(d)	1.2
Residential Combustion	n/d	1.2
Total	1.5	58.6 (40.8)

(a) After Suncor VRU is in full operation.
(b) Includes combustion sources, tailings ponds, and fugitive area emissions.
(c) t/sd.
(d) Not determined.

6.0 PARTICULATES

Particulates are small solid or liquid particles in the atmosphere that come in many shapes and sizes and originate from many different sources. Particulates can be released from both natural and human caused sources. Particulates released directly into the atmosphere are called primary particulates. Physical and chemical reactions in the atmosphere can also result in the formation of particulates; these are called secondary particulates. For this assessment, primary particulate sources have been categorized into combustion and non-combustion sources.

Anthropogenic combustion sources in the region include the following:

- The Suncor powerhouse and Syncrude main stacks that burn coke. While both stacks have electrostatic precipitators (ESPs) to remove most of the particulates, a small fraction is not removed.
- Secondary stacks at these two facilities primarily burn natural gas or a plant fuel oil. Small amounts of particulates result during the combustion process.
- Motor vehicle exhausts. While particulates are primarily associated with diesel-fuelled vehicles, they can also result from gasoline fuelled vehicles.
- Conical burners that are used to dispose of forestry wood wastes and prescribed forestry burning can result in significant quantities of particulate emissions.
- Residential sources include wood burning fireplaces and wood stoves and can be a significant sources of particulates within communities.

The major natural combustion sources of particulates arise from forest fires.

Non-combustion sources of particulates can also result from both anthropogenic and natural emissions. Some of these include the following:

- Mining operations such as clearing, blasting, excavation, hauling and dumping, all result in particulate emissions from the abrasion of crustal materials.
- Highway and residential vehicle traffic result in particulate emissions from the abrasion of road material with tires and from the entrainment of surface particles in the turbulent wakes of vehicles.
- Exposed aggregate storage piles and surfaces, such as tailings pond dykes prior to reclamation, coke storage piles and areas, exposed mine surfaces and granular resource piles. The emissions related to these activities are dependent on the nature of the surfaces and wind speeds.

- Wind erosion of naturally exposed soil surfaces.
- Release of pollens and spores from vegetation.

Secondary particulate formation results from the conversion of gaseous compounds such as SO_2, NO_x and various hydrocarbons to form sulphate, nitrate and organic carbon particulate compounds. The anthropogenic sources of these emissions are primarily combustion related. Vegetation can also result in hydrocarbon emissions.

6.1 Suncor Particulate Emission Sources

The following table provides estimates of particulate emissions resulting from combustion sources at Suncor:

Source	**Particulate Emission Rate (t/cd)**
Powerhouse	6.3
Incinerator	0.003
Secondary Sources	0.27
Intermittent Flaring	0.001
Continuous Flaring	0.001
Mine Fleet	0.18
Total	6.76

The powerhouse emissions are based on measurements, while those for the other sources are based on emission factors. The powerhouse, however, appears to be the major combustion source for particulate emissions.

The emission rates of the major metals associated with particulate emissions from the powerhouse are as follows:

Element	**Emission Rate (t/cd)**
Iron	0.28
Zinc	0.16
Aluminum	0.15
Magnesium	0.12
Vanadium	0.08
Sodium	0.07
Nickel	0.02
Titanium	0.02
Boron	< 0.01

The non-metallic fraction of particulate emissions are likely to be comprised of salts, silicates, sulphates, nitrates, carbonaceous compounds, and high molecular weight hydrocarbons such as benzo-(a)-pyrene. Other particulate sources include: surface abrasion and/or wind erosion from mine vehicles; mining operations; coke stock pile operations; and handling of tailings sand.

6.2 Syncrude Particulate Emission Sources

The following table identifies the particulate emission sources and provides a summary of the estimated emissions rates for each source:

Source	**Particulate Emission Rate (t/cd)**
Main Stack	7.7
Secondary Sources	0.87
Diverter Stacks	0.5
Flare Stacks	<0.01
Mine Fleet	2.5
Total	11.6

For comparison, Syncrude estimates their 1995 particulate emission rate from the main stack to be 11.7 t/d and their total particulate emission rate to be 13.9 t/d.

Based on the 1994 emission rate indicated in the preceding table, the emission rates of the major metals associated with particulate emissions from the main stack are as follows:

Element	Emission Rate (t/cd)
Iron	0.07
Aluminum	0.02
Silicon	0.02
Calcium	0.02
Sodium	0.01
Magnesium	0.01
Titanium	0.01

The non-metallic fraction of particulate emissions are likely to be comprised of salts, silicates, sulphates, nitrates, carbonaceous compounds, and high molecular weight hydrocarbons such as benzo-(a)-pyrene.

Other particulate sources include surface abrasion and/or wind erosion from mine vehicles, mining operations, coke stock pile operations and handling of tailings sand.

6.3 Particulate Emissions from Other Industrial Sources

The following table identifies the particulate emission sources and provides a summary of the estimated emission rates for each source:

Source	Emission Rate (t/cd)
AOSTRA	n/d[a]
SOLV-EX Bitumount	1.25
SOLV-EX Ruth Lake	0.77
Northland Forest Products	0.27
Fort McMurray Hospital	0.003
Total	2.3

[a] Not determined.

These emission estimates are associated with combustion sources only.

6.4 Particulate Emissions from Transportation and Residential Sources

The following table identifies the particulate emission from combustion sources and provides a summary of the estimated emission rates for each source:

Source	Particulates Emission Rate (t/cd)
Highway Traffic	1.09
Local Traffic	
Fort McMurray	1.53
Fort McKay	0.007
Residential Combustion	
Natural Gas	0.015
Wood	0.216
Total	2.9

6.5 Summary of Particulate Emissions

The following table presents a summary of particulate emissions for combustion sources for the Athabasca Oil Sands region:

Source	Particulates Emission Rate (t/cd)
Suncor	6.8
Syncrude	11.6
Other Industrial Sources[a]	2.3
Transportation Sources	2.6
Residential Combustion	0.2
Total	23.5

[a] t/sd.

As indicated in the table, about 78% of the estimated particulate emissions result from the combined operation of the Suncor and Syncrude sources.

7.0 SUMMARY OF EMISSIONS IN THE ATHABASCA OIL SANDS REGION

The following table summarizes the emissions from Suncor, Syncrude, other industrial sources, transportation sources and residential combustion sources in the Athabasca oil sands region:

	Emission Rates (t/cd)						
	SO_2	**NO_x**	**CO**	**CO_2**	**TRS**	**THC**	**Particulates**
Suncor	235	23.7	21.4	9440	0.7	35.2 (17.4)	6.8
Syncrude	239	35.1	58.6	20 833	0.8	15.5	11.6
Other Industries[a]	7.4	2.8	35.8	3651	0.007	5.5	2.3
Transportation	0.19	1.0	3.8	196	n/d[d]	1.2	2.6
Residential Combustion	0.005	0.3	1.7	392	n/d	1.2	0.2
Total	482	62.9	121.3	34 512	1.5	58.6 (40.8)	23.5

[a] t/sd.

The THC values shown in brackets refer to the Suncor emissions after the VRU is fully operational.

While the results in the table indicate that the two oil sands operations are the major sources of emissions to the atmosphere, there are other smaller sources that can also influence air quality. This is especially true for those smaller sources which originate from the communities, particularly when evaluating effects on human health.

A considerable amount of effort is undertaken by both the two oil sands operations to document emissions for the respective operations. The development of a single database for each source is complicated by the differing evaluation approaches adopted for differing source types (i.e., CSEM, stack survey, continuous, intermittent). There also appears to be some difficulty in ensuring these emissions, plus those associated with other sources find their way into a common database.

The emission estimates for residential and traffic sources employed simplifying assumptions. While the results indicate low relative emissions, a more detailed assessment may be required to quantify these emissions during poor dispersion conditions. This would be of particular interest for the evaluation of local air quality, during winter low wind speed periods.

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APPENDIX A

Suncor Emission Sources Identification and Characterization

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A1.0 SUNCOR EMISSION SOURCES

Appendix A discusses the Suncor emission sources. For the purpose of these discussions, the emissions have been categorized as follows:

- **Powerhouse Emissions** (Section A2.0). The powerhouse stack emissions include SO_2, NO_x, CO_2 and particulates.
- **Incinerator Emissions** (Section A3.0). The incinerator emissions include SO_2, NO_x, CO and CO_2.
- **Secondary Source Emissions** (Section A4.0). Secondary source emissions include SO_2, NO_x, CO and CO_2.
- **Flaring Emissions** (Section A5.0). The flare stack emissions include SO_2, NO_x, CO and hydrocarbons.
- **Mine Fleet Emissions** (Section A6.0). The mine fleet emissions include NO_x, CO and CO_2.
- **Controlled Vents** (Section A7.0). The emissions include TRS and THC.
- **Upgrading Fugitive Point Sources** (Section A8.0). The emissions include VOC.
- **Fugitive Area Sources** (Section A9.0). The emissions include TRS and THC.
- **Fugitive Dust Sources** (Section 10.0). The emissions include SO_2, H_2S and NO_x.

For each source or source type, the emissions are discussed with respect to sulphur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO), carbon dioxide (CO_2), total hydrocarbons (THC) or volatile organic compounds (VOC) and particulates, when applicable. Section A11.0 summarizes the Suncor emissions on a contaminant basis.

A2.0 POWERHOUSE EMISSIONS

Suncor produces most of its power and steam requirements through the operation of their utilities plant. The plant is comprised of three coke-fired and three gas-fired boilers:

Boiler	Fuel	Steam Rating (lb/h)	Steam Condition (°F)	(psig)	Availability (%)
31F-01	Coke	825,000	750	790	85+
31F-01	Coke	825,000	750	790	85+
31F-03	Coke	825,000	750	790	85+
31F-08	Gas	275,000	750	790	90
35F-12	Gas	300,000	700	425	standby
35F-13	Gas	300,000	700	425	standby

The two standby units replaced four smaller units in the fall of 1995. The replacement units are more efficient than the older units and are also equipped with low-NO_x burners.

Each coke-fired boiler is serviced by an electrostatic precipitator (ESP) that is used to remove 98% of the particulates in the combustion gases prior to being directed to the powerhouse stack. The combustion gases from the gas-fired boilers are vented directly to the powerhouse stack.

A Supplemental Emission Control (SEC) system is used to reduce SO_2 emissions from the powerhouse stack when ambient SO_2 incidents are observed at any of Suncor's ambient air quality monitoring stations. When an ambient SO_2 event associated with the powerhouse stack is identified, the operator initiates a process to partially switch from using coke as a fuel to using gas-oil as a fuel. This fuel switch reduces the SO_2 emissions by about 25%. This program has been in place since the beginning of 1994 and the objective of the program is to reduce the duration of short-term ambient SO_2 fumigation events.

The operation of the powerhouse stack is regulated through Alberta Environmental Protection's (AEP) Environmental Approval. The following conditions are specified in the approval:

		Normal	Abnormal
Hourly SO_2 concentration	(ppm)	4600	4700
Daily SO_2 emission	(t/d)	259	259
Hourly SO_2 emission	(t/h)	13.8	14.2
Opacity	(%)	40	40
Particulate concentration (adjusted to 50% air)	(g/kg)	0.2	0.2

Abnormal operating conditions include plant start-up, shut-down and maintenance operations.

The powerhouse stack is equipped with a Continuous Stack Emission Monitor (CSEM) and manual stack surveys are conducted several times a year. The CSEM measures the flue gas SO_2 concentration, opacity, velocity, volumetric flow rate and temperature on a continuous basis. The manual stack surveys measure concentrations of individual flue gas components (e.g., SO_2, NO_x and particulates), volumetric flow rates and temperatures.

A2.1 SO_2 Emissions

A2.1.1 *CSEM Monitoring Results*

The following table presents the average SO_2 emissions associated with the Suncor powerhouse stack from 1990 to 1994:

		Powerhouse SO_2 Emissions	
Year	**Operating Days**	**(t/sd)**	**(t/cd)**
1990	348	172	164
1991	365	175	175
1992	366	181	181
1993	351	204	196
1994	365	211	211
Minimum	348	172	164
Mean	359	189	185
Maximum	366	211	211

The average emissions are expressed on a tonnes per stream day (t/sd) basis (i.e., tonnes per number of days when the plant was operating) and a tonnes per calendar day (t/cd) basis (i.e., tonnes per total number of days in the year). It is evident from the table that the powerhouse operates on a near-continuous basis.

Figure A.1 shows the Suncor powerhouse daily SO_2 emissions. The results indicate year-to-year and day-to-day variability. The variability is due to normal and abnormal operations. For example, the period when the powerhouse stack was not in operation during a planned plant turnaround (May 25 to June 11, 1990) [Julian Day 145 to 161] is evident by the zero SO_2 emission.

Table A.1 shows the SO_2 emissions as a function of month based on the CSEM data for the years from 1990 to 1995, inclusive. The table indicates that the SO_2 emissions tend to be lower during the summer months than during the winter months.

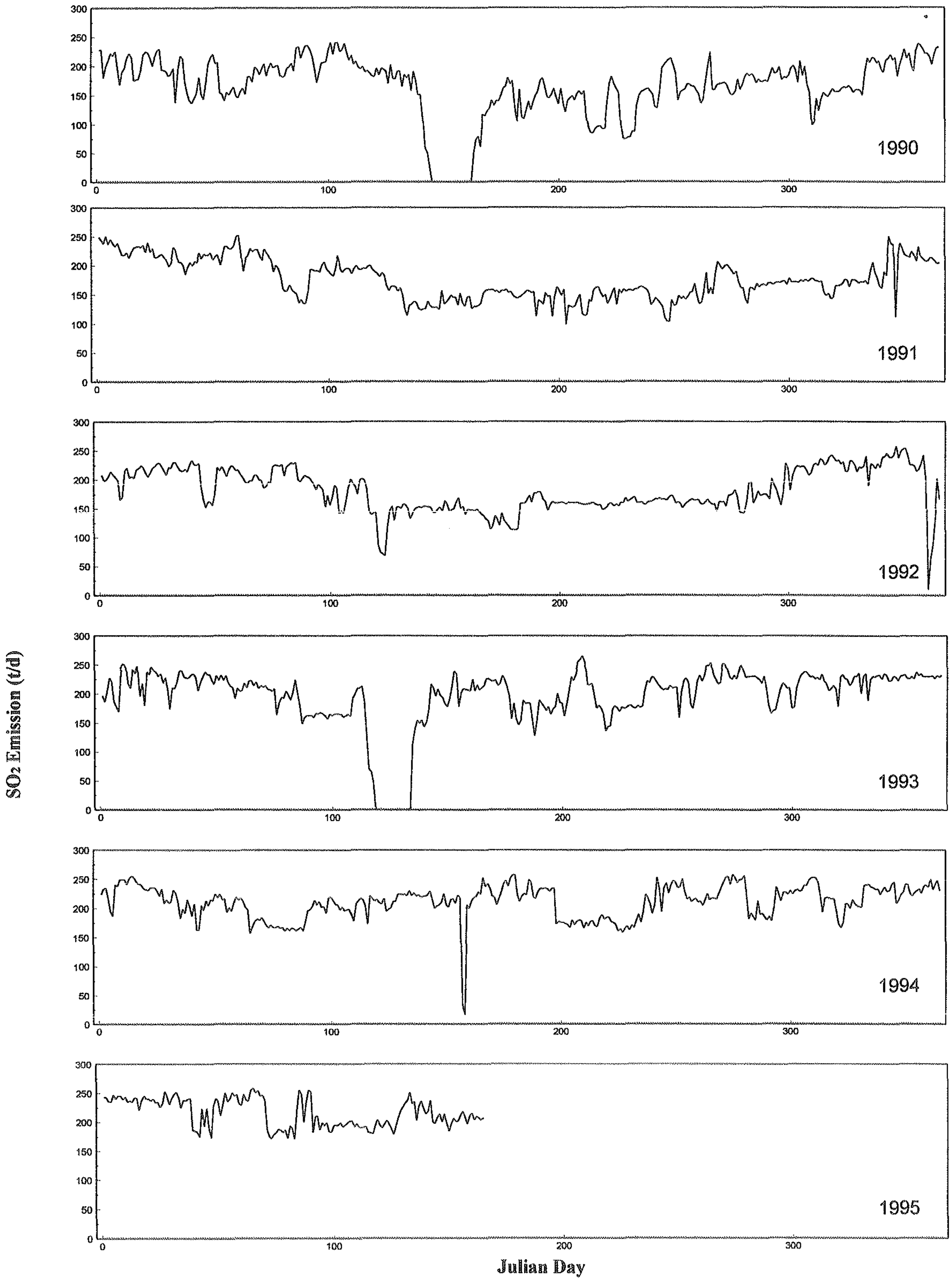

Figure A.1 Daily SO_2 emissions (t/d) from the Suncor powerhouse stack for the period January 1, 1990 to June 14, 1995.

Table A.1 Mean monthly SO_2 emissions from the Suncor powerhouse stack (t/sd).

Month	1990	1991	1992	1993	1994	1995	Average
Jan	205	228	210	218	231	239	222
Feb	172	215	208	224	205	223	208
Mar	192	193	208	199	176	217	198
Apr	210	193	172	160	205	193	189
May	161	145	141	156	215	212	173
Jun	122	146	136	208	214	207	172
Jul	144	140	162	194	203	n/a(a)	169
Aug	122	152	160	186	185	n/a	161
Sep	173	153	162	220	227	n/a	187
Oct	178	169	181	214	217	n/a	192
Nov	159	168	225	222	218	n/a	198
Dec	214	206	209	230	232	n/a	218
Annual	172	175	181	204	211	215	191(b)

(a) n/a = no data available.
(b) Annual average from 1990 to 1994 is 189 t/sd.

A2.1.2 *Stack Survey Results*

The results of the manual stack surveys conducted during the period 1990 to 1994 are presented in Table A.2. Based on the stack surveys, the mean powerhouse stack operating conditions during 1994 were as follows:

- SO_2 concentration = 2927 ppm
- SO_2 emission rate = 213 t/d
- Stack exit temperature = 256 °C
- Stack exit velocity = 22.3 m/s

The average for 1994 is presented in Table A.2 as a separate entry as it represents the most recent year of operation that does not benefit from the SO_2 reduction program (i.e., the SuperClaus process). For the purposes of comparison, the average SO_2 emissions from the CSEM for 1994 was 211 t/d. This value is similar to that measured during the stack survey. On average, sulphur dioxide emissions are about 80% of the licenced daily limit of 259 t/d.

A2.2 NO_x, CO_2, CO and THC Emissions

NO_x and CO_2 emissions are measured during the manual stack surveys performed on the powerhouse stack. The results from the 1994 and 1995 stack surveys are presented in Table A.2. The CO emission rate is based on a value measured during one stack survey in 1989. A U.S. EPA emission factor for coal combustion in a cyclone furnace and the 1995 coke consumption of 683,063 t (as provided by Suncor) were used to calculate the THC emission rate. The following table presents the mean 1994 emissions rates for NO_x and CO_2 from the stack surveys, the CO emission rate from the 1989 stack survey and the estimated THC emission rate:

Contaminant	Emission Factor (kg/t)	Emission Rate (t/d)
NO_x	-	16.4
CO_2	-	5665
CO	-	14.1
THC	0.06[a]	0.11

[a] Sum of emission factors for methane and non-methane organic compounds (Table 1.1-12, U.S. EPA 1995).

For the purpose of comparison, the NO_x emission rate is about 8% of that associated with SO_2. Similarly, the CO_2 emission rate is about 25 times of that associated with SO_2.

Table A.2 Results of Suncor Powerhouse stack emission compliance surveys (1990 to 1995).

Test	Test Date	Temp (°C)	Velocity (m/s)	SO_2			NO_x		Particulates		CO_2
				(t/h)	(t/d)	(ppm)	(ppm)	(t/d)(b)	(g/kg)(a)	(t/d)(b)	(t/d)(b)
90-1	Apr 21-22	227	20.1	8.5	205	2968	346	n/a	0.13	n/a	n/a
90-2	May 12-13	217	18.7	8.5	204	3082	286	n/a	0.01	n/a	n/a
90-3	Jul 29-30	208	21.7	4.1	99	1264	224	n/a	0.13	n/a	n/a
90-4	Aug 25-26	252	20.8	7.2	172	2507	58	n/a	0.08	n/a	n/a
90-5	Sep 15-16	227	23.5	7.7	185	2287	229	n/a	0.08	n/a	n/a
90-6	Sep 30	255	21.8	7.9	191	2685	312	n/a	0.14	n/a	n/a
91-1	Apr 27-28	234	20.2	9.0	217	3158	328	n/a	0.08	n/a	n/a
91-2	May 18-19	239	18.9	7.1	170	2668	411	n/a	0.08	n/a	n/a
91-3	Jun 1-2	239	18.3	7.4	177	2869	381	n/a	0.13	n/a	n/a
91-4	Jun 22, July 6	253	20.0	7.6	183	2798	242	n/a	0.12	n/a	n/a
91-5	Oct 19-20	216	21.5	7.4	178	2343	325	n/a	0.10	n/a	n/a
91-6	Dec 10-11	241	20.7	10.6	254	3761	558	n/a	0.14	n/a	n/a
92-1	Apr 5-6	237	18.3	7.7	186	2975	454	n/a	0.09	n/a	n/a
92-2	May 7-8	211	21.3	6.4	154	2030	166	n/a	0.09	n/a	n/a
92-3	Jun 7-8	222	19.5	6.6	159	2323	229	n/a	0.14	n/a	n/a
92-4	Aug 14-15	211	20.4	6.8	162	2235	256	n/a	0.16	n/a	n/a
92-5	Nov 17-18	243	22.3	9.2	221	2827	216	n/a	0.08	n/a	n/a
92-6	Dec 5,9,14	245	22.3	8.8	211	2880	314	n/a	0.05	n/a	n/a
93-1	Apr 3	222	20.7	7.3	174	2421	314	n/a	0.08	n/a	n/a
93-2	Apr 22	259	21.6	9.9	237	3397	303	n/a	0.13	n/a	n/a
93-3	Jun 12	246	22.2	9.1	219	2964	271	n/a	0.11	n/a	n/a
93-4	Jul 10-11	244	18.0	7.4	177	2918	306	n/a	0.12	n/a	n/a
93-5	Aug 11-12	241	18.4	7.7	184	2962	287	n/a	0.13	n/a	n/a
93-6	Sep 24	260	21.7	10.1	242	3459	287	n/a	0.12	n/a	n/a

Table A.2 Concluded.

Test	Test Date	Temp (°C)	Velocity (m/s)	SO_2			NO_x		Particulates		CO_2
				(t/h)	(t/d)	(ppm)	(ppm)	(t/d)[b]	(g/kg)[a]	(t/d)[b]	(t/d)[b]
94-1	Apr 9-10	257	22.0	9.1	218	3052	347	17.9	0.15	5.3	5709
94-2	May 1	254	23.1	9.3	223	2964	362	19.6	0.09	3.5	6158
94-3	May 28-29	257	23.4	9.4	226	2971	308	16.7	0.19	7.1	5459
94-4	Jul 16-17	265	23.2	9.8	235	3106	258	14.1	0.11	4.3	6507
94-5	Jul 15-16	244	21.0	7.1	170	2449	303	15.3	0.38	12.0	4790
94-6	Sep 17-18	257	20.8	8.5	204	3022	305	14.8	0.18	5.6	5365
Minimum	1990 to 1994	208	18.0	4.1	99	1264	58	n/a	0.01	n/a	n/a
Mean	1990 to 1994	239	20.9	8.1	194	2778	300	n/a	0.12	n/a	n/a
Maximum	1990 to 1994	265	23.5	10.6	254	3761	558	n/a	0.38	n/a	n/a
Minimum	1994	244	20.8	7.1	170	2449	258	14.1	0.09	3.5	4790
Mean	1994	256	22.3	8.9	213	2927	314	16.4	0.18	6.3	5665
Maximum	1994	265	23.4	9.8	235	3106	362	19.6	0.38	12.0	6507
95-1	Apr 22-24	261	20.6	7.1	170	2534	593	28.6	0.06	2.1	4993
95-2	Jun 17-18	231	21.5	8.4	201	2762	343	18.0	0.15	5.2	5575
95-3	Jul 22-23	252	20.1	8.0	192	2933	597	27.2	0.13	4.7	6058
95-4	Aug 12-13	249	23.7	7.7	184	2858	561	25.9	0.11	4.1	5466
95-5a	Oct 11-12	247	21.4	9.1	218	3115	468	24.7	0.35	12.3	6668
Maximum	1995	231	20.1	7.1	170	2534	343	18.0	0.06	2.1	4993
Maximum	1995	248	21.5	8.1	193	2840	512	24.9	0.16	5.7	5752
Maximum	1995	261	23.7	9.1	218	3115	597	28.6	0.35	12.3	6668

[a] Calculated at 50% excess air.

[b] Reported as kg/h in stack surveys.

A2.3 Particulate Emissions

The coke-fired boilers are serviced by an electrostatic precipitator (ESP) to remove particulate matter (ash) from flue gases generated during the combustion of coke. Suncor continuously monitors the particulate removal efficiency of the ESPs through use of an opacity meter. Increasing opacity can indicate a decrease in particulate removal efficiency and the correlation between opacity and particulate loadings allows Suncor to monitor the operation of the ESPs.

The manual stack surveys also measure the concentrations of particulates in the flue gases that are not removed by the ESP. The results of these surveys are presented in Table A.2. The concentration values shown in the table are expressed as grams of particulate per kg of air corrected to 50% excess air in the flue gas. For 1994, the average particulate emission rate was 6.3 t/d. The corresponding concentration for the period was 0.18 g/kg. The particulate emission rate is about 3% of that associated with SO_2.

In 1984, a study was conducted by The Industrial Research Institute of the University of Windsor (Gnyp *et al.* 1984) to characterize the heavy metals associated with the powerhouse particulate emissions. The test was conducted with two coke fired boilers on line with an average coke consumption of about 1850 t/d. The metals identified and emission rates are presented in Table A.3. The emission rates given in the table are based on the 1984 total particulate emission rate of 12.1 t/d and the 1994 total particulate emission rate of 6.3 t/d. The individual metal values for 1994 are based on 6.3 t/d and were calculated assuming proportionality.

A2.4 Powerhouse Stack and Emissions Summary

Table A.4 presents the stack and emission parameters for the Suncor powerhouse based on the 1994 emission rates from the CSEM and stack surveys, when applicable. The estimation of CO was based on one stack survey performed in 1989. For the estimation of other emissions not monitored at Suncor (i.e., THC), a U.S. EPA emission factor was used.

Table A.3 Metal emission rates from the Suncor powerhouse stack.

Element	Emission Rate (kg/d)	
	1984[a]	1994[b]
Total Particulate	12 084	6300
Iron (Fe)	544	283
Zinc (Zn)	302	157
Aluminum (Al)	290	151
Magnesium (Mg)	225	117
Vanadium (V)	151	79
Sodium (Na)	135	70
Nickel (Ni)	34.6	18
Titanium (Ti)	31.9	17
Boron (B)	8.2	4.3
Silver (Ag)	7.7	4.0
Manganese (Mn)	7.6	4.0
Molybdenum (Mo)	7.3	3.8
Lead (Pb)	2.7	1.4
Strontium (Sr)	1.8	0.94
Copper (Cu)	1.7	0.89
Chromium (Cr)	1.6	0.83
Lithium (Li)	0.87	0.45
Cobalt (Co)	0.77	0.40
Arsenic (As)	0.60	0.31
Cadmium (Cd)	0.16	0.08
Selenium (Se)	0.08	0.04
Mercury (Hg)	0.06	0.03

[a] Based on total particulate emission rate of 12.1 t/d (Gnyp *et al.* 1984).
[b] Based on average 1994 total particulate emission rate of 6.3 t/d (Table A.2).

Table A.4 Stack and emission parameters associated with the Suncor powerhouse stack.

		Powerhouse Stack (1994)
Base Elevation	(m)	259
Stack Height	(m)	106.7
Stack Diameter	(m)	5.79
Total Stack Flow Rate	$(m^3/s)^{(a)(b)}$	317
Exit Velocity	$(m/s)^{(b)}$	22.3
Exit Temperature	$(°C)^{(b)}$	256
Approved SO_2 Emission	(t/d)	259
Measured SO_2 Emission	$(t/d)^{(b)}$ $(t/d)^{(c)}$	213 211
NO_x Emission (as NO_2)	$(t/d)^{(b)}$	16.4
CO Emission	$(t/d)^{(d)}$	14.1
CO_2 Emission	$(t/d)^{(b)}$	5665
THC Emission	$(t/d)^{(e)}$	0.11
Particulate Emission	$(t/d)^{(b)(f)}$	6.3

(a) At a reference temperature and pressure of 21°C and 101.3 kPa, respectively.
(b) From the 1994 stack survey data.
(c) From the 1994 CSEM data.
(d) From 1989 stack survey data.
(e) Based on the emission factors for coal-fired cyclone furnaces (Table 1.1-12, U.S. EPA 1995). The 1995 coke consumption rate of 683,063 t was provided by Suncor.
(f) Based on 0.18 g/kg calculated at 50% excess air from the average of the 1994 stack tests.

A3.0 INCINERATOR EMISSIONS

The two primary sources of sour gas (i.e. gases containing H_2S) at the Suncor facility include:

- The Amine Plant which removes sour gas from refinery generated gas and sends the sour gas to the sulphur recovery plant, and
- The sour water stripper that removes H_2S from aqueous streams during upgrading and routes these gases to the sulphur recovery plant.

The sour or acid gas is directed to the sulphur plants where most of the sulphur compounds are recovered in elemental form as sulphur. The remaining sulphur compounds are incinerated to convert H_2S and other reduced sulphur species into SO_2. The sulphur SO_2 stream is then vented to the atmosphere through the 106.7 m (350 ft) high incinerator stack. Suncor must maintain a minimum incinerator stack top temperature of 400°C to ensure reduced sulphur compounds are destroyed and that adequate dispersion of SO_2 occurs. The main components emitted from the incinerator stack are SO_2 and CO_2, since very little NO_x, CO, or particulates are produced.

At the end of 1994, the Sulphur Recovery Plant was enhanced with the addition of a SuperClaus Process. Prior to the SuperClaus addition, the sulphur recovery efficiency was typically 96%. With the addition of SuperClaus, the sulphur recovery efficiency increased to 98%. This enhancement effectively reduces the SO_2 emissions from the incinerator stack by a factor of two.

The operation of the incinerator is regulated through the AEP environmental approval. The following conditions are specified in the approval and refer to the SuperClaus operation:

Incinerator Limits			
		Normal	**Abnormal**
Hourly SO_2 concentration	(ppm)	12 000	20 000
Daily SO_2 emission	(t/d)	51	51
Hourly SO_2 emission	(t/h)	1.2	3.0
15-minute temperature	(°C)	400	400

Prior to the SuperClaus operation, the maximum hourly SO_2 emission rate for normal operations was 2.6 t/h. Abnormal conditions refer to start-up, shut-down and maintenance operations.

The incinerator stack is equipped with a CSEM to measure flue gas SO_2 concentration, velocity, and temperature on a continuous basis. Four manual stack surveys are conducted each year, in accordance with the Approval, to determine flue gas SO_2 concentrations, total gas flows and temperatures.

A3.1 SO_2 Emissions

A3.1.1 *CSEM Monitoring Results*

The following table presents the average SO_2 emissions associated with the Suncor incinerator stack from 1990 to 1994:

Year	Operating Days	Incinerator SO_2 Emissions (t/sd)	Incinerator SO_2 Emissions (t/cd)
1990	318	28	24
1991	365	26	26
1992	365	25	25
1993	340	26	24
1994	364	31	30
Minimum	318	25	24
Mean	350	27	26
Maximum	365	31	30

The average emissions are expressed on a tonnes per stream day (t/sd) basis (i.e., tonnes per number of days when the incinerator was operating) and a tonnes per calendar day (t/cd) basis (i.e., tonnes per total number of days in the year). It is evident from the table that the incinerator operates on a near-continuous basis.

Figure A.2 shows the Suncor incinerator daily SO_2 emissions over the period 1990 to mid-1995. The periods when the sulphur recovery plant was down due to a plant failure or plant shutdown are evident from the figure (i.e., SO_2 emission = 0 t/d). The reduced emissions associated with the implementation of the SuperClaus process at the end of 1994 are also evident.

The monthly variance of the SO_2 emissions is shown in Table A.5. The monthly variation associated with the incinerator stack is less than that associated with the powerhouse stack. The addition of the SuperClaus at the end of 1994 resulted in reduced SO_2 emissions.

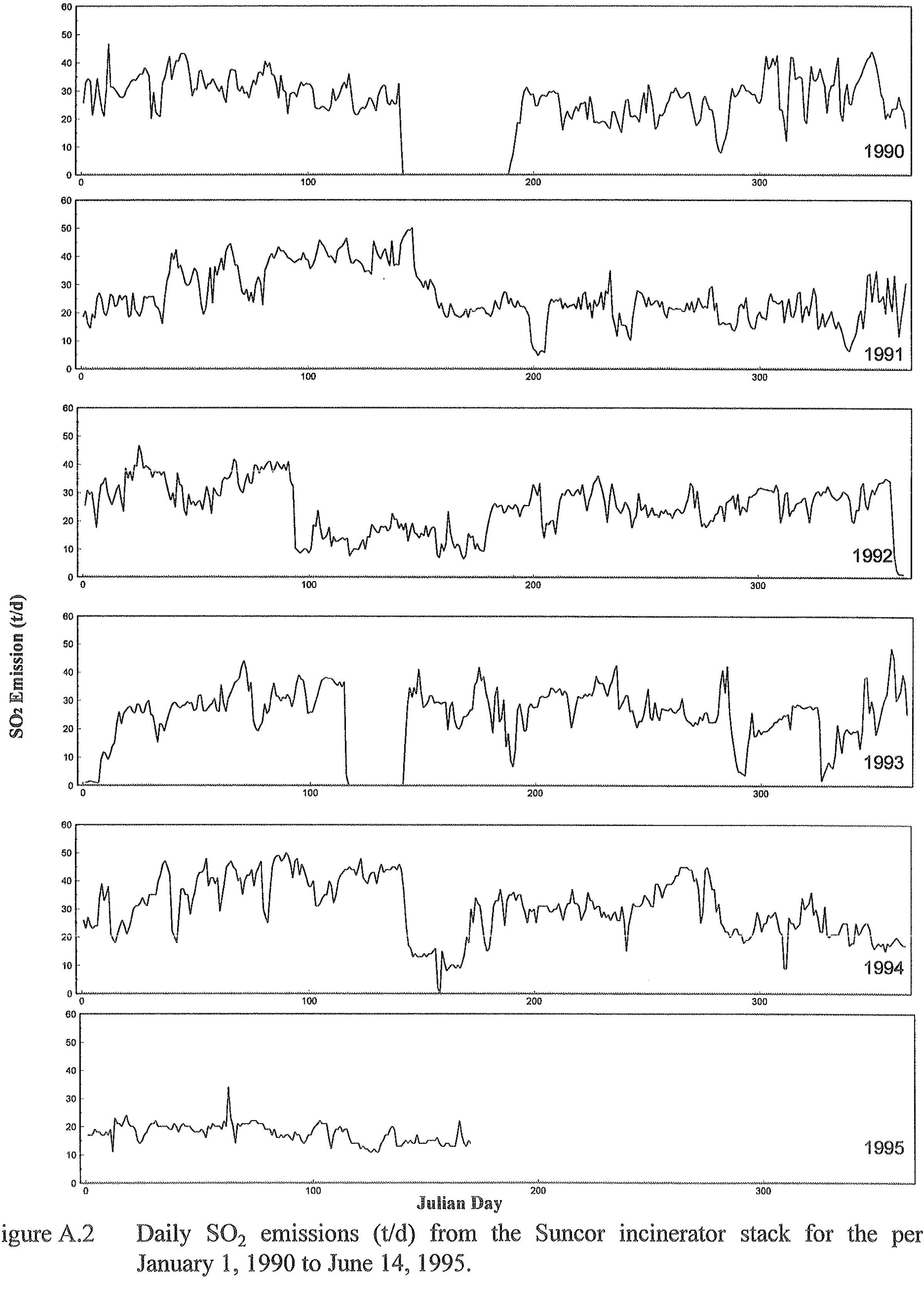

Figure A.2 Daily SO_2 emissions (t/d) from the Suncor incinerator stack for the period January 1, 1990 to June 14, 1995.

Table A.5 Mean monthly SO_2 emissions from the Suncor incinerator stack (t/sd).

Month	1990	1991	1992	1993	1994	1995	Average
Jan	31	22	33	17	28	19	25
Feb	34	30	30	26	37	19	29
Mar	33	35	37	31	41	20	33
Apr	28	40	14	33	40	17	28
May	26	39	16	31	35	14	26
Jun	0	22	13	28	16	15	19(b)
Jul	24	19	24	26	31	n/a(a)	25
Aug	21	21	28	32	29	n/a	26
Sep	24	23	24	25	38	n/a	27
Oct	25	20	26	21	26	n/a	24
Nov	32	21	28	21	25	n/a	25
Dec	30	21	25	27	20	n/a	24
Annual	28	26	25	26	31	18	26(c)

(a) n/a = data not available.
(b) Average excludes 1990 when incinerator was down.
(c) Annual average from 1990 to 1994 is 27 t/sd.

A3.1.2 *Stack Survey Results*

The results of the manual stack surveys conducted between January 1, 1990 and December 31, 1995 are presented in Table A.6. Based on the stack surveys, the mean incinerator stack operating conditions during 1994 and 1995 were as follows:

		1994	1995
SO_2 concentration	(ppm)	8568	3151
SO_2 emission	(t/d)	35	15
Stack exit temperature	(°C)	489	478
Stack exit velocity	(m/s)	18.5	20.4

On average, 1994 and 1995 SO_2 emissions were about 70% and 29% of the licenced daily value of 51 t/d, respectively. The average SO_2 emission during the 1994 stack surveys was 35 t/d, as compared to an average SO_2 emission of 31 t/d based on the CSEM. The 1995 values specifically refer to the period when the SuperClaus process was operating.

A3.2 Other Emissions

NO_x and CO emissions are not normally measured during the stack surveys. However, NO_x was measured during Stack Survey 91-4 and CO was measured during Stack Survey 89-1. These are the most recent surveys when NO_x and CO were measured. The average emission rates measured for NO_x and CO are 0.11 and 5.5 t/d, respectively.

CO_2 is also measured during the stack surveys. The 1994 and 1995 results are presented in Table A.6. The CO_2 emission rate for the 1994 surveys was 79.4 t/d. This emission rate increased to 92.5 t/d in 1995.

The incinerator will also be a source of TRS. An efficiently operated sulphur plant incinerator will ensure that the TRS concentrations in the flue gas are less than 300 ppm. For the purposes of comparison, the TRS emission rate based on this upper value corresponds to 0.60 t/d expressed as sulphur equivalent.

Table A.6 Results of Suncor incinerator stack emission compliance surveys (1990 to 1995).

Test Code	Test Date	Temp (°C)	Velocity (m/s)	SO_2			CO_2(a)
				(t/h)	(t/d)	(ppm)	(t/d)
90-1	Apr 17	559	22.8	1.5	37	7933	n/a
90-2	Sep 5	559	21.5	1.5	37	8391	n/a
90-3	Aug 16	500	17.8	1.1	25	6416	n/a
90-4	Sep 28	478	16.8	1.9	44	11 553	n/a
91-1	Aug 15	493	18.6	0.9	21	5262	n/a
91-2	Sep 23	494	19.0	0.8	18	4288	n/a
91-3	Sep 10	496	19.7	0.8	19	4337	n/a
91-4(b)	Nov 14	493	19.2	0.8	19	4407	n/a
92-1	Jun 15	508	13.8	0.4	10	3317	n/a
92-2	Jul 16	493	15.4	0.8	20	5646	n/a
92-3	Aug 7-8	498	16.1	1.2	28	7950	n/a
92-4	Sep 18	500	16.1	1.0	23	6156	n/a
93-1	Apr 24	499	16.5	1.2	29	7617	n/a
93-2	Jul 16	496	17.6	1.0	24	6225	n/a
93-3	Aug 5	487	19.7	1.1	26	5856	n/a
94-1	Mar 3	495	15.2	1.4	33	9684	69.7
94-2	May 11-12	486	19.0	1.9	45	10 652	67.1
94-3	Jul 20	488	20.0	1.4	33	7156	94.6
94-4	Aug 23	488	20.0	1.3	30	6782	86.2
Minimum	1990 to 1994	478	13.8	0.4	10	3317	n/a
Mean	1990 to 1994	500	18.1	1.2	27	6822	n/a
Maximum	1990 to 1994	559	22.8	1.9	45	11 553	n/a
Minimum	1994	486	15.2	1.3	30	6782	67.1
Mean	1994	489	18.6	1.5	35	8568	79.4
Maximum	1994	495	20.0	1.9	45	10 652	94.6
95-1	Apr 20	483	21.0	0.8	18	3805	49.2
95-2	Jul 18	474	20.2	0.5	13	2748	95.7
95-3	Aug 2	478	19.9	0.6	14	3116	119.5
95-4	Aug 17	476	20.3	0.6	14	2935	105.7
Minimum	1995	474	19.9	0.5	13	2748	49.2
Mean	1995	478	20.4	0.6	15	3151	92.4
Maximum	1995	483	21.0	0.8	18	3805	119.5

(a) CO_2 is reported as a mole % in stack surveys.

(b) NO_x was measured during Stack Survey 91-4.

U.S. EPA emission factors for natural gas combustion were used to calculate the THC and particulate emission rates. The THC emission rate for the incinerator was calculated by using the NO_x emission rate of 0.11 t/d and the ratio of the emission factors for THC and NO_x. The THC emission factor of 28 kg/10^6 m^3 is indicated in the following table. The NO_x emission factor is 86 ng/J (Table 1.3-10, U.S. EPA 1995), and the heating value for natural gas is 37 MJ/m^3. The particulate emission rate was calculated in the same manner. The estimated emission rates are indicated in the following table:

Contaminant	Emission Factor (kg/10^6 m^3)	Emission Rate (t/d)
NO_x	-	0.11
CO	-	5.5
CO_2		
1994	-	79.4
1995	-	92.5
TRS	-	0.60
THC(a)	28	0.001
Particulates(b)	80	0.003

(a) Table 1.4-3, U.S. EPA 1995.
(b) Table 1.4-1, U.S. EPA 1995.

A3.3 Incinerator Stack and Emissions Summary

Table A.7 presents the stack and emission parameters associated with the incinerator before and after the addition of the SuperClaus. As indicated in the previous sections, the CO_2 emissions increased by approximately 16%, while the SO_2 emissions decreased by approximately 50%.

Table A.7 Stack and emission parameters associated with the Suncor incinerator stack prior to and following the addition of SuperClaus.

Parameter		Prior to SuperClaus (1994)	With SuperClaus (1995)
Base Elevation	(m)	259	259
Stack Height	(m)	106.7	106.7
Stack Diameter	(m)	1.80	1.80
Total Stack Flow Rate	$(m^3/s)^{(a)}$	17.6	$17.5^{(f)}$
Exit Velocity	(m/s)	18.6	$20.4^{(f)}$
Exit Temperature	(°C)	489	$478^{(f)}$
Approved SO_2 Emissions	(t/d) (t/h)	51 2.6	51 1.2
Measured SO_2 Emissions	$(t/d)^{(b)}$ $(t/d)^{(c)}$	35 31	$14.8^{(f)}$ 17.0
NO_x Emission (as NO_2)$^{(d)}$	(t/d)	0.11	0.11
CO Emission$^{(i)}$	(t/d)	5.5	5.5
CO_2 Emission$^{(b)}$	(t/d)	$79.4^{(e)}$	$92.5^{(f)}$
TRS Emission$^{(h)}$	(t/d)	0.60	0.60
THC Emission$^{(g)}$	(t/d)	0.001	0.001
Particulate Emission$^{(g)}$	(t/d)	0.003	0.003

(a) At a reference temperature and pressure of 21°C and 101.3 kPa, respectively.
(b) From the 1994 stack survey data.
(c) From the 1994 CSEM data.
(d) Based on the November 14, 1991 stack survey.
(e) Based on 1994 data.
(f) Based on 1995 data.
(g) Based on the following U.S. EPA (1995) emission factors for natural gas combustion: 28 kg/10^6 m^3 (Table 1.4-3); 80 kg/10^6 m^3 (Table 1.4-1) for particulates; and 86 ng/J (Table 1.3-10) for NO_x. THC and particulate emissions were calculated from a ratio of the respective factor with that for NO_x, and the NO_x emission rate of 0.11 t/d.
(h) Based on maximum estimate of 300 ppm in the flue gas.
(i) Based on 1989 stack survey data.

A4.0 SECONDARY SOURCE EMISSIONS

Secondary sources are defined as all other stationary combustion sources at the Suncor plant. These sources are associated with process heaters in the upgrading area.

A4.1 SO_2 Emissions

Trace amounts of SO_2 are emitted from other Suncor sources that service the upgrader area. Although these sources are currently fueled by refinery gas (fuel gas), some may be fueled by natural gas as required. Gas compositions for both fuel types are listed in Table A 8. SO_2 emission rates were calculated based on an H_2S content in the fuel gas of 50 ppm.

Table A.9 summarizes the emission factors used to calculate the emission rates for the Suncor secondary sources. Table A.10 identifies and summarizes the emission parameters associated with these sources. The total estimated SO_2 emission rate from the Suncor secondary sources is approximately 0.15 t/d.

A4.2 Other Emissions

Emission rates for NO_x, CO, THC and particulates were estimated using the emission factors indicated in Table A.9. The CO_2 emission rate was calculated based on the heat duty of the unit and a mass and energy balance. The estimated emissions for the Suncor secondary stacks are as follows:

Contaminant	Emission Rate (t/d)
NO_x	4.12
CO	0.85
CO_2	3451
THC	0.04
Particulates	0.27

Table A.8 Average fuel gas analysis (mol%) for Suncor.

Component	**Natural Gas**(a)	**Suncor Refinery Gas**(b)
H_2S	0.000	0.005(c)
H_2	0.000	21.199
N_2	0.353	1.300
CO	0.000	1.200
CO_2	2.455	0.000
C_1	96.580	39.398
C_2	0.323	18.599
C_3	0.237	14.799
iC_4	0.029	1.650
nC_4	0.023	1.850
C_5^+	0.000	0.000
Total	100	100
Heat Content (MJ/m^3)	33.20	43.60

(a) Fort McMurray #1 Gate sample dated 95-02-01 (Navooro 1995).
(b) Doucette 1995.
(c) Based on 50 ppm (Schneider 1996).

Table A.9 Emission factors used to calculate emission rates for the Suncor secondary sources.

Compound	**U.S. EPA Table No.**	**Heat Input (mm BTU/h)**	**Emission Factor**	
			(kg/10^6 m^3)(a)	**(ng/J)(b)**
SO_2 (fuel gas)		all	-	3.04(c)
SO_2 (natural gas)	1.4-2	>100	9.6	0.23
	1.4-2	10 to 100	9.6	0.23
	1.4-2	0.3 to <10	9.6	0.23
NO_x	1.3-10	>100	-	86(d)
	1.4-2	10 to 100	2240	59
	1.4-2	0.3 to <10	1600	42
CO	1.4-2	>100	640	17
	1.4-2	10 to 100	560	15
	1.4-2	0.3 to <10	330	9
THC	1.4-3	>100	28	0.7
	1.4-3	10 to 100	92	2.4
	1.4-3	0.3 to <10	128	3.4
Particulates(e)	1.4-1	>100	200	5.3
	1.4-1	10 to 100	219	5.8
	1.4-1	0.3 to <10	192	5.1

(a) Table 1.4-2, U.S. EPA 1995.

(b) Calculated using a gross heating value for natural gas of 37.7 MJ/m^3.

(c) Based on 50 ppm H_2S in the fuel gas (Schneider 1996).

(d) Obtained directly from Table 1.3-10, U.S. EPA (1995).

(e) Sum of filterable and condensable particulate matter.

Table A.10 Emissions associated with the Suncor secondary combustion sources.

Stack Number Unit Description		1	2	3	4	5	6	7	8	9	10
		Diluent Heater		Coker Feeder			Diluent Heater	Coker Feeder	Reformer		
Unit Number		5F-1A	5F-1B	5F-2	5F-3	5F-4	5F-5	5F-6	6F-2A	6F-2B	6F-2C
Heat Duty[a]	(mm BTU/h)	98.0	98.0	152.0	152.0	152.0	96.0	155.0	155	155	155
	(MW)	28.7	28.7	44.5	44.5	44.5	28.1	45.4	454	45.4	45.4
	(GJ/h)	103.4	103.4	160.4	160.4	160.4	101.3	163.5	163.5	163.5	163.5
Fuel Type[b]		FG	FG	FG	FG	FG	FG	FG	FG	FG	FG
Fuel Consumption	(mm SCFD)	2.65	2.65	4.10	4.10	4.10	2.59	4.19	3.77	3.77	3.77
	(10^3 m^3/d)	75	75	116	116	116	73	119	107	107	107
Efficiency	(%)	77	77	77	77	77	77	77	86	86	86
Excess Air[a]	(%)	25	25	25	25	25	25	25	25	25	25
Stack Height	(m)	48.5	48.5	41.1	41.1	41.1	50.3	41.1	48.8	48.8	48.8
	(ft)	159.1	159.1	134.8	134.8	134.8	165.0	134.8	160	160	160
Stack Diameter	(m)	1.83	1.83	2.18	2.18	2.18	1.88	2.50	2.13	2.13	2.13
	(ft)	6.00	6.00	7.16	7.16	7.16	6.17	8.20	7.00	7.00	7.00
Exit Velocity	(m/s)	13.7	13.7	14.9	14.9	14.9	12.7	11.6	11.1	11.1	11.1
Exit Temperature[a]	(°C)	454	454	454	454	454	454	454	288	288	288
	(°F)	849	849	849	849	849	849	849	550	550	550
	(K)	727	727	727	727	727	727	727	561	561	561
Stack Gas Flow	(10^3 m^3/d)	1219	1219	1891	1891	1891	1194	1928	1734	1734	1734
SO_2[c]	(t/d)	0.01	0.01	0.02	0.02	0.02	0.01	0.02	0.01	0.01	0.01
NO_x[c]	(t/d)	0.27	0.27	0.42	0.42	0.42	0.27	0.43	0.39	0.39	0.39
CO[c]	(t/d)	0.05	0.05	0.08	0.08	0.08	0.05	0.09	0.08	0.08	0.08
CO_2[d]	(t/d)	219	219	339	339	339	214	346	311	311	311
THC[c]	(t/d)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Particulates[c]	(t/d)	0.02	0.02	0.03	0.03	0.03	0.02	0.03	0.02	0.02	0.02

Table A.10 Continued.

Stack Number Unit Description		11	12	13	14	15	16	17	18	Total
		Hydrogen	Naphtha	Deprop	Kerosene	Kerosene	Gas Oil Heater			
Unit Number		6F-5	7F-1	7F-2	7F-10	7F-11	7F-20A	7F-20B	7F-20C	
Heat Duty(a)	(mm BTU/h)	25.0	30.0	40.0	32.0	41.0	20.0	20.0	20.0	1596
	(MW)	7.3	8.8	11.7	9.4	12.0	5.9	5.9	5.5	408
	(GJ/h)	26.4	31.7	42.2	33.8	43.3	21.1	21.1	21.1	1684
Fuel Type(b)		FG	FG	FG	FG	FG	FG	FG	FG	-
Fuel Consumption	(mm SCFD)	0.66	1.07	1.43	1.15	1.43	0.72	0.72	0.72	43.6
	(10^3 m^3/d)	19	30	41	32	40	20	20	20	1234
Efficiency	(%)	79	77	77	77	79	77	77	77	-
Excess Air(a)	(%)	25	25	25	25	25	25	25	25	-
Stack Height	(m)	33.5	40.8	45.4	41.1	45.4	40.8	40.8	40.8	-
	(ft)	110.0	133.9	149.0	134.8	149.0	133.9	133.9	133.9	-
Stack Diameter	(m)	1.37	1.26	1.49	1.26	1.49	1.26	1.26	1.26	-
	(ft)	4.50	4.13	4.89	4.13	4.89	4.13	4.13	4.13	-
Exit Velocity	(m/s)	5.9	9.2	8.8	9.8	8.3	6.1	6.1	6.1	-
Exit Temperature(a)	(°C)	426	454	454	454	415	454	454	454	-
	(°F)	793	849	849	849	779	849	849	849	-
	(K)	699	727	727	727	688	727	727	727	-
Stack Gas Flow	(10^3 m^3/d)	305	388	517	413	515	258	258	258	-
SO_2(c)	(t/d)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.15
NO_x(c)	(t/d)	0.05	0.06	0.08	0.06	0.08	0.04	0.04	0.04	4.12
CO(c)	(t/d)	0.00	0.01	0.02	0.02	0.02	0.01	0.01	0.01	0.85
CO_2(d)	(t/d)	55	66	89	71	88	44	44	44	3451
THC(c)	(t/d)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04
Particulates(c)	(t/d)	0.00	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.27

Table A.10 Concluded.

(a) Duties and exit temperatures taken from Suncor 1995*a*. The duty for each of the three 6F-2 stacks is one-third of 465 MMBTU/h or 155 MMBTU/h. Excess air assumed as average for all units.

(b) FG = Plant refinery gas

(c) Based on emission factors presented in Table A.9.

(d) CO_2 emissions were based on calculated CO_2 content for given duty and excess air using a mass and energy balance for the combustion process.

A5.0 FLARING EMISSIONS

The Suncor flare stack system is comprised of two hydrocarbon flares, one acid gas flare and one hydrogen plant flare:

- The hydrocarbon flares are used to dispose of large volumes of gas streams during plant start-up, shut-down, maintenance and upset conditions. The hydrocarbon flare system is also used to dispose of smaller volumes of gas on a continuous basis. Both hydrocarbon flares stacks are 99 m in height and equipped with 1.1 m diameter smokeless flare tips. Steam is injected at the flare tip to help ensure smokeless combustion and closed circuit television provides feedback on the flare process. The base elevation of the hydrocarbon flares is 243 m ASL.

- The acid gas flare is used to dispose of sour gas from the amine or sulphur recovery plants under start-up, shut-down, maintenance and upset conditions. The acid gas flare is 99 m in height and equipped with 0.51 m diameter flare tip. Natural gas can be added to the acid gas stream to ensure adequate combustion and buoyancy. The base elevation of the acid gas flare is 243 m ASL.

- The hydrogen flare stack is used to dispose hydrogen produced by the hydrogen plant. This flare disperses of excess hydrogen produced on a continuous basis and during start-up, shut-down and maintenance operations. The base elevation of the hydrogen flare stack is about 258 m ASL.

For the purpose of presentation, the flaring operations have been defined as continuous or intermittent. The latter can be defined as either planned or unplanned. Continuous emissions result from the hydrocarbon flare operations, while intermittent emissions result from the operation of either the acid gas flare or the hydrocarbon flares.

A5.1 SO_2 Emissions

Only the Suncor hydrocarbon and acid gas flares dispose of gas streams containing sulphur products (i.e., sour gas streams). On combustion, these products are converted to SO_2. The SO_2 emissions from flaring have decreased significantly during the last five years (1990 to 1994) when compared to previous years (i.e., 1981 to 1989). These decreases result from the reduction of flaring associated with sour water acid gas (SWAG), the acid gas flare and hydrocarbon flares.

The following table presents the SO_2 emissions associated with continuous and intermittent flaring at the Suncor facility for the years 1990 to 1994:

Year	Operating Days		Flaring Emissions		
	Intermittent	**Continuous**	**Intermittent (t/sd)**	**Continuous (t/sd)**	**Total Flaring (t/cd)**
1990	56[(a)]	n/a	47[(a)]	n/a	7
1991	115	365	13	2	6
1992	124	360	10	2	6
1993	64	339	30	2	6
1994	89	365	20	2	7
Minimum	56	360	10	2	6
Mean	90	357	17	2	6
Maximum	124	365	47	2	7

(a) Includes continuous flaring for 1990.

The average emissions are expressed on a tonnes per stream day (t/sd) basis (i.e., tonnes per number of days when flaring occurred) and a tonnes per calendar day (t/cd) basis (i.e., tonnes per total number of days in the year). The number of days per year when SO_2 was vented to the atmosphere from intermittent and continuous flaring are also shown.

A5.1.1 *Intermittent Flaring*

Suncor has undertaken an analysis of current plant operations that result in the flaring of sour gas (Suncor 1995*a*). A summary of this analysis with respect to intermittent flaring is presented in Table A.11. Comments with respect to the information presented in the table are as follows:

- Individual flaring events can range from less than 1 hour to more than 5 days. The longer duration flaring events are planned.
- When flaring takes place, the SO_2 emissions can range from less than 0.1 t/event to more than 80 t/event. Again, the larger SO_2 releases are associated with the planned flaring events.
- The H_2S content of the gas streams to flare range from less than 0.1% to more than 90%. The larger 90% plus value is associated with the gas streams from sulphur recovery plant (Plant 8).

Table A.11 Summary of planned and unplanned flaring of gas streams that occur on an intermittent basis at the Suncor plant.

Plant	5	5	5	5	7	7	7	7	7	7	7	7	8	8	8	10	
Vessel	5C2	5C10	5C13/ 5C15	5C14	7C3	7C4	7C6	7C12	7C13	7C15	7C24	7C26	8C4	8C9	8C10	10C2	
Type	Unplanned	Both	Planned	Both	Unplanned	Unplanned	Unplanned	Unplanned	Unplanned	Unplanned	Unplanned	Unplanned	Both	Planned	Planned	Planned	Total
1991																	
Events	0	14	6	0	9	11	1	7	14	17	12	10	7	0	0	25	133
Total duration (h)	0	93.2	19.3	0	26.1	35.6	0.5	27.6	24.9	40.7	30.6	18.2	5.4	0	0	1413.5	1735.6
Total SO_2 (t)	0	444.3	10.1	0	1.2	18.6	<0.1	2.5	13.9	21.9	35.3	48.7	115.2	0	0	768.5	1480.2
Average duration (h/event)	0	6.7	3.2	0	2.9	3.2	0.5	3.9	1.8	2.4	2.5	1.8	0.8	0	0	56.5	13.0
SO_2/event (t/event)	0	31.9	1.7	0	0.1	1.7	<0.1	0.4	1.0	1.3	2.9	4.8	17.1	0	0	30.7	11.1
1992																	
Events	1	18	2	0	5	7	1	4	5	6	6	6	9	0	0	22	92
Total duration (h)	55.6	41.7	15.9	0	22.6	27.4	1.1	4.7	17.8	16.5	10.5	10.1	21.2	0	0	1741.1	1986.2
Total SO_2 (t)	15.3	368.6	9.6	0	0.4	35.2	0.4	1.4	6.2	19.6	6.6	11.0	102.5	0	0	623.8	1200.6
Average duration (h/event)	55.6	2.3	7.9	0	4.5	3.9	1.1	1.2	3.6	2.8	1.7	1.7	2.4	0	0	79.1	21.6
SO_2/event (t/event)	15.3	20.3	4.8	0	0.1	5.0	0.4	0.4	1.3	3.3	1.1	1.9	11.6	0	0	28.3	13.1
1993																	
Events	0	16	3	0	5	10	0	3	10	14	10	19	14	0	0	17	121
Total duration (h)	0	66.0	356.5	0	5.8	9.8	0	16.9	78.2	23.4	27.3	129.9	61.0	0	0	884.9	1659.7
Total SO_2 (t)	0	490.8	18.0	0	1.1	15.7	0	2.1	71.1	20.0	24.1	123.9	535.6	0	0	646.1	1948.5
Average duration (h/event)	0	4.1	118.0	0	1.2	1.0	0	5.6	7.8	1.7	2.7	6.8	4.4	0	0	52.1	13.8
SO_2/event (t/event)	0	30.5	6.0	0	0.2	1.6	0	0.7	7.1	1.5	2.4	6.5	38.6	0	0	38.0	16.2
1994																	
Events	0	9	5	1	5	5	0	3	6	8	7	9	9	1	0	11	79
Total duration (h)	0	79.4	683.3	0.1	8.9	5.1	0	9.7	19.0	21.7	16.2	9.5	11.9	10.2	0	582.7	1457.7
Total SO_2 (t)	0	721.0	75.0	<0.1	<0.1	3.0	0	1.0	23.0	23.0	14.0	24.0	204.0	51.0	0	677.0	1816.0
Average duration (h/event)	0	8.8	136.7	0.1	1.8	1.0	0	3.2	3.2	2.7	2.3	1.1	1.3	10.2	0	53.0	18.5
SO_2/event (t/event)	0	79.9	15.0	<0.1	<0.1	0.6	0	0.3	3.9	2.9	2.0	2.8	22.3	51.0	0	61.6	23.0
Average																	
Events (events/a)	<1	14	4	<1	6	8	<1	4	9	11	9	11	10	<1	0	19	106
Duration (h/a)	13.9	70.1	268.8	<0.1	15.8	19.5	0.4	14.7	35.0	25.6	21.2	41.9	24.9	2.6	0	1155.6	1709.8
SO_2 (t/a)	3.8	506.2	28.2	<0.1	0.7	18.1	0.1	1.8	28.6	21.1	20.0	51.9	239.3	12.8	0	678.8	1611.6
Duration (h/event)	55.6	4.9	66.9	0.1	2.6	2.4	0.8	3.5	4.0	2.3	2.4	3.8	2.6	10.2	0	61.6	16.1
SO_2 (t/event)	15.3	35.5	7.0	0.1	0.1	2.2	0.2	0.4	3.3	1.9	2.3	4.7	24.8	51.0	0	36.2	15.2
H_2S content (mole %)	23.75	9.7	n/a(a)	17.20	5.30	14.85	44.17	6.40	24.48	64.52	8.00	49.33	94.80	n/a(a)	n/a	n/a	-
Heating value (MJ/m^3)(b)	60.3	59.5	120.9	42.4	18.7	34.2	47.2	14.8	23.2	34.1	15.3	31.6	21.1	n/a	n/a	n/a	-
Molecular mass (kg/kmol)	46.43	30.74	62.13	25.25	8.83	19.69	34.09	6.76	16.08	32.02	7.29	27.00	34.19	n/a	n/a	n/a	-

(a) Data not available.

(b) Heating values for components at 15°C and 101.325 kPa (Gas Processors Suppliers Association 1980).

- Heating values of the gas streams to flare range from about 14 MJ/m^3 to more than 120 MJ/m^3. These values are in excess of the minimum 9 MJ/m^3 required to ensure a stable flame.

A5.1.2 *Continuous Flaring*

Three sour gas streams are flared on a continuous basis at Suncor. These include overheads from the vessels identified in the following table (Suncor 1995*a*):

Unit	Vessel	SO_2 Emission (t/sd)
5C-18	Oil / sour water separation	1.5
7C-28	Gas / oil uniform fractionator receiver	0.2
10C-23	Oil / water separator	0.6
Total		2.3

The gas streams from 7C-28 and 10C-23 are relatively uniform over the course of the day. The gas stream from 5C-18 peaks for about one-half hour four times per day. The peak SO_2 emissions for these half-hour periods correspond to an equivalent daily emission rate of 5.7 t/d.

A5.2 NO_x, CO, CO_2 and THC Emissions

For flare stacks, complete combustion will result in the formation of CO_2, H_2O and NO_x. Complete combustion requires sufficient combustion air and turbulent mixing of air with the gas being flared. If incomplete combustion occurs, unburned hydrocarbons, intermediate hydrocarbons, CO and carbon particulates (soot) will form. Properly operating flares have at least a 98% combustion efficiency. The following emission factors were used to estimate flare stack emissions:

Compound		Emission Factor (a)
NO_x	(ng/J)	29
CO	(ng/J)	159
THC	(ng/J)	60
Particulates (b)	(µg/L)	177

(a) Table 13.5-1, U.S. EPA 1995.
(b) Based on average smoking flares.

The CO_2 emissions were estimated by assuming essentially all (~ 98%) of the hydrocarbons flared were transformed to CO_2. Using these factors, estimated emission rates are as follows:

	Intermittent		**Continuous**	
	Gas Flow		**Gas Flow**	
	(m^3/h)	**(m^3/cd)**	**(m^3/h)**	**(m^3/d)**
	1275	5972	2822	67 724
	Emission Rate		**Emission Rate**	
	(t/h)	**(t/cd)**	**(t/h)**	**(t/cd)**
NO_x	0.036	0.010	0.003	0.007
CO	0.195	0.055	0.014	0.038
CO_2	111.7	19.1	4.36	11.6
THC	0.074	0.021	0.005	0.014
Particulates	0.008	0.001	0.016	0.001

Due to the intermittent nature of these sources, the emissions are presented on a tonnes per hour basis as well as a tonnes per calendar day basis.

A5.3 Flaring Emissions Summary

Table A.12 presents a summary of the emissions parameters for intermittent flaring at the Suncor facility. The data shown in the table are based on the 1991 to 1994 data presented in Table A.11. The following table presents a summary of the emission parameters for continuous flaring at the Suncor facility.

	SO_2 Emission Rate (t/d)	**Total Heat Release Rate (cal/s)**	**Flow Rate (m^3/h)**	**Heating Value (MJ/m^3)[(a)]**
5C18	1.5	5 456 168	2761	29.8
7C28	0.2	87 290	33.7	39.0
10C23	0.6	110 756	27.3	61.2
Total	2.3	5 654 214	-	-

(a) At 21°C and 101.3 kPa.

Table A.12 Flare stack emission parameters associated with intermittent flaring at Suncor.

	Heating Value[a] (MJ/m^3)	SO$_2$ Emission Rate		Flow Rate		Total Heat Release Rate (cal/s)[d]
		(t/h)[b]	(t/cd)	(m^3/h)[c]	(m^3/cd)	
5C2	60.3	0.3	0.01	437.0	16.6	1 749 501
5C10	59.5	7.2	1.39	28 086.0	5 392.1	110 824 846
5C13/5C15	120.9	0.1	0.08	n/a[e]	n/a	n/a
5C114	42.4	1.0	<0.01	2 192.8	n/a	6 162 657
7C3	18.7	0.1	<0.01	358.6	17.6	444 175
7C4	34.2	0.9	0.05	2 363.7	126.1	5 364 372
7C6	47.2	0.3	<0.01	266.8	0.31	835 304
7C12	14.8	0.1	<0.01	700.4	28.3	686 696
7C13	23.2	0.8	0.08	1 257.7	120.5	1 935 526
7C15	34.1	0.8	0.06	482.8	33.8	1 092 021
7C24	15.3	1.0	0.05	4 458.1	258.3	4 511 238
7C26	31.6	1.2	0.14	946.5	108.7	1 984 920
8C4	21.1	9.6	0.66	3 287.7	260.9	5 354 374
8C9	n/a	5.0	0.03	n/a	n/a	n/a
8C10	n/a	0	<0.01	n/a	n/a	n/a
10C2	n/a	0.6	1.86	n/a	n/a	n/a
Total		29	4.4		5 972	139 196 310

[a] From Table A.11.
[b] Calculated from Table A.11 using average SO$_2$ per event and duration per event.
[c] Flow rate calculated based on average SO$_2$ mass rate and H$_2$S content (Table A.11).
[d] Calculated from SO$_2$ rate in t/h and flow rate in m^3/h.
[e] Data not available

A6.0 MINE FLEET EMISSIONS

The Suncor mine fleet is primarily fueled with diesel oil. The following table presents the emission factors used to calculate the emissions rates for the mine fleet:

Compound	Emission Factor ($kg/10^3$ L)
SO_2[(a)]	3.7
NO_x[(b)]	42
CO[(a)]	12.3
CO_2[(b)]	2767
THC[(a)]	3.25
Particulate[(a)]	2.5

(a) An average of emission factors for diesel-powered shovels and trucks (Table II-7.1, U.S. EPA 1985).

(b) Sultan 1996.

The following table presents the 1995 overall fuel consumption for the mine fleet (including power shovels and trucks) and the estimated emission rates:

		Total
Fuel Consumption[(a)]	(bbl/a) (L/d)	166 671 72 599
SO_2 Emissions	(t/d)	0.27
NO_x Emissions	(t/d)	3.06
CO Emissions	(t/d)	0.89
CO_2 Emissions	(t/d)	201
THC Emissions	(t/d)	0.24
Particulates	(t/d)	0.18

(a) Sultan 1996.

A7.0 CONTROLLED VENTS

As part of the Odour Abatement Program, Suncor identified the following odour causing (i.e., TRS and THC emitting) sources:

- Plant 4 Vents.
- South Tank Farm Vents.
- Plant 3 Vents.

In response to this finding, Suncor initiated several programs over the last decade to reduce emissions from these sources. These include the installation of a Naphtha Recovery Unit (NRU) to reduce the loss of naphtha to the tailings pond. The NRU was installed in 1988 with a nominal recovery efficiency of 60%. More recently, this efficiency has increased to 70%.

In 1994, a Vapour Recovery Unit (VRU) was installed to collect vapours from the south tank farm vents, from the secondary extraction plant vents (Plant 4) and from the NRU. The VRU is comprised of a condenser to remove some of the vapour as liquids, two sulphatreat reactors to remove TRS, a refrigeration stage (-40°C) to remove additional HC vapours and an activated carbon bed to remove remaining HC vapours. Freezing problems associated with tank vents have occurred under low temperature conditions. The current status is a vapour recovery system that is removing THC and TRS vapours from Plant 4 and the NRU year-round, and from the south tank farm vents when ambient temperatures are above -15°C. The freezing problems are expected to be resolved in 1996. When fully operational, the recovery efficiency of the VRU system is expected to be 99%.

Table A.13 outlines other recent initiatives conducted by Suncor to reduce emissions of THC and TRS. As indicated in the table, Suncor has an ongoing monitoring and detection program to assist in the effort to identify and reduce fugitive emissions.

A7.1 TRS and THC Emissions

Suncor commissioned several studies to identify and quantify THC and TRS emissions from all vents and stacks, including tanks which will be controlled in the future by a vapour recovery unit. The most recent plant wide survey was conducted by BOVAR Engineered Products (1994). Based on source sampling and analysis conducted in November 1993, annual emission rates are calculated by extrapolation. Suncor also extrapolated the results to estimate annual emissions using differing assumptions.

Table A.14 summarizes the emissions from the sources based on both extrapolation approaches. The largest TRS emissions originate from the Primary Extraction Plant (Plant 3), Froth Treatment Plant (Plant 4) and the South Tank Farm (Plant 20). The sulphur pit is also a major

Table A.13 Recent initiatives by Suncor to further reduce TRS and THC emissions (Suncor 1995*b*).

Project	Status
Reroute slop oil from diluent loop.	Completed in 1991.
Replace seals in floating roof tanks.	Completed in 1992.
Upgrade naphtha recovery unit (NRU) and reroute stripped sour water through NRU.	Completed in 1993.
Install new water/oil separator for diluent.	Completed in 1993.
Install new sour water pumps.	Completed in 1993.
Diluent Improvement Project	Completed in 1993.
Extraction recovery improvement including: separation cell feed well modifications; implementation of environmental line; and conversion to hot process water to improve Westfalia centrifuge performance.	Completed in 1993 and 1994.
Increase monitoring/detection. Alarms on Distributed Control System for air monitoring station limits	On-going.
Tank and Plant 4/Plant 16 vent recovery system (VRU).	Completed in 1994.
Modifications to NRU to improve recovery rates.	Completed in 1994.
Installation of on-line GC analyzer for diluent quality and on-line H_2S analyzer for sour water stripper.	Completed in 1995.
Upgrade wastewater treatment/slop tanks.	Completed in 1995.

Table A.14 Estimated TRS and THC emissions from the Suncor controlled point sources (i.e., vents).

Plant	Source	TRS Emissions(a)		THC Emission(b)	
		(10^{-3} t/d)(c)	(10^{-3} t/d)(d)	(10^{-3} t/d)(c)	(10^{-3} t/d)(d)
Primary Extraction (Plant 3)	3D-62	2.17		32	
	3C-22A	0.02		8.0	
	3C-22B	0		8.6	
	3C-20	0		44	
	3C-21	0		0.7	
	3R-24	0		939	
	3R-220	0		5413	
	3R-232	0		3429	
Subtotal (10^{-3} t/d)		2.19	2.19	9874	9874
Froth Treatment (Plant 4)(e)	4D-7	0	0	0.06	0.05 to 0.07
	4E-1A	4.5		7378	
	4E-1B	5.0		2889	
	4D-3	0.8		175	
	4D-4	9.6		1008	
Subtotal (10^{-3} t/d)		29.8	29.8	11 450	11 450
South Tank Farm (Plant 20)(e)	20D-1	0.4 to 0.8	0.8 to 3.8	115 to 251	174 to 613
	20D-2	0.4 to 1.0	0.8 to 3.8	174 to 380	174 to 613
	20D-3	0.8 to 2.0	0.8 to 3.8	127 to 316	174 to 613
	20D-4	1.3 to 3.3	1.3 to 4.4	47 to 116	47 to 158
	20D-5	14.2 to 26.4	6.3 to 14.2	2280 to 4246	1005 to 2280
	20D-6	1.7 to 3.2	6.3 to 14.2	359 to 669	1005 to 2280
	20D-35	n/a	0.2 to 0.4	n/a	17 to 35
Subtotal (10^{-3} t/d)		18.8 to 36.6	16.4 to 44.7	3102 to 5978	259 to 6591
Delayed Coking Unit (Plant 5)	5F-1A	0		1.2	
	5F-1B	0		1.2	
	5F-5	0		5.0	
	5F-2	0		5.3	
	5F-3	0		14.1	
	5F-4	0		8.5	
	5F-6	0		5.6	
	5C-35	n/a		n/a	
Subtotal (10^{-3} t/d)		0	0	40.9	40.9

Table A.14 Continued.

Plant	Source	TRS Emissions(a)		THC Emission(b)	
		(10^{-3} t/d)(c)	(10^{-3} t/d)(d)	(10^{-3} t/d)(c)	(10^{-3} t/d)(d)
Hydrogen Plant (Plant 6)	6F-3	n/a		n/a	
	6C-13	0		n/a	
	6F-5	0		0.1	
	6F-2	0		0	
Subtotal (10^{-3} t/d)		0	0	0.1	0.1
Unifier Plant (Plant 7)	7F-2	0		7.4	
	7F-1	0		0	
	7F-10	0		1.7	
	7F-11	0		9.6	
	7F-20A	0		2.0	
	7F-20B	0		21.7	
	7F-20C	0		9.5	
Subtotal (10^{-3} t/d)		0	0	51.9	51.9
Amine Unit Sulphur Recovery Unit (Plant 8)	8D-1	0	0	0.001	0.003
	8D-2	0	0	0	0
	Sulphur pit	n/a	5.8	n/a	0.003
	8F-5	n/a	n/a	n/a	n/a
Subtotal (10^{-3} t/d)		0	5.8	0.001	0.003 to 0.006
Plant 10	10D-3	n/a	0	n/a	47.2
	10D-4	n/a	0	n/a	0
	10K-2A/C	n/a	0	n/a	n/a
Subtotal (10^{-3} t/d)		n/a	0	n/a	47.2
North Tank Farm (Plant 20)	20D-34	0	0	0.8 to 1.8	0.8 to 3.0
	20D-14	0.003 to 0.008	0.003 to 0.030	0.9 to 2.1	1.9 to 8.8
	20D-15	0	0.003 to 0.030	1.9 to 4.4	1.9 to 8.8
	20D-32	0	0	0.02	0.02 to 2.3
	20D-12	0.017	0.020 to 0.230	0.13	0.13 to 1.8
	20D-13	0	0.020 to 0.230	0.02	0.13 to 1.8
	20D-30	0	0	0.03	0.03 to 1.4
	20D-10	0.002	0.040 to 1.380	0.02	0.04 to 1.4

Table A.14 Concluded.

Plant	Source	TRS Emissions(a)		THC Emission(b)	
		(10^{-3} t/d)(c)	(10^{-3} t/d)(d)	(10^{-3} t/d)(c)	(10^{-3} t/d)(d)
North Tank Farm (Plant 20)	20D-031	0.001	0.000 to 0.003	0.02	0.02 to 0.05
(Continued)	20D-11	0.035	0.040 to 1.380	0.04	0.04 to 1.43
	20D-36	0	0	0.01	0.01 to 1.35
	20D-55	n/a	n/a	n/a	n/a
	20D-56	n/a	n/a	n/a	n/a
Subtotal (10^{-3} t/d)		0.059 to 0.063	0.110 to 3.282	3.8 to 8.6	4.9 to 32.0
Powerhouse (Plant 31)	31F-5	n/a	n/a	n/a	n/a
	31D-02A	0	0	0.01	0.02 to 0.20
	31D-02B	0	0	0.02	0.02 to 0.20
	31D-03	0	0.000 to 0.003	0.01	0.01 to 0.18
Subtotal (10^{-3} t/d)		0	0.000 to 0.003	0.04	0.05 to 0.58
Caustic Scrubber (Plant 34)	34C-2	n/a	0.003	n/a	0.47
Subtotal (10^{-3} t/d)		n/a	0.003	n/a	0.47
TOTAL (before VRU)		51 to 69	54 to 86(f)	24 524 to 27 409	24 068 to 28 089(f)
(after VRU)(g)		21 to 39	25 to 56	13 188 to 16 072	12 732 to 16 753
(after VRU)(h)		2.7 to 3.0	8 to 12	10 117 to 10 154	10 160 to 10 228

(a) TRS is expressed as S_1.

(b) THC is expressed as CH_4.

(c) BOVAR Engineered Products (1994).

(d) Kemp 1994. Subtotals and totals include BOVAR Engineered Products (1994) data when Kemp estimates were not available.

(e) As of late 1995/early 1996, Plant 4, Plant 16 and South Tank Farm vents (excluding tanks 20D-57 and 20D-58) will be serviced by the Vapour Recovery Unit (VRU) which will reduce all the corresponding emission rates.

(f) The total for TRS and THC from Kemp (1994) uses the numbers in these columns to replace those of BOVAR Engineered Products (1994). The remainder of the values are taken from BOVAR Engineered Products to complete the total.

(g) Plant 4 venting recovered by VRU at 99% efficiency.

(h) Plant 4 and South Tank Farm venting recovered by VRU at 99% efficiency.

source of TRS emissions. Plant 3, Plant 4 and the South Tank Farm vents are also major sources of THC emissions. The three totals presented in the table refer specifically to the following:

- Venting prior to installation of the VRU.
- Venting from Plant 4 recovered by the VRU at a 99% efficiency rate.
- Venting from Plant 4 and the South Tank Farm recovered by the VRU at a 99% efficiency rate.

As indicated by the table, total TRS and THC concentrations will be reduced by approximately 95% and 61%, respectively, when vapours from Plant 4 and the South Tank Farm are recovered by the VRU.

Earlier characterization studies that were carried out in 1989 (Clayton Environment Consultants 1990) provided a speciation of emissions from Plant 3 vents. These results are presented in Table A.15. The largest hydrocarbon emissions were associated with the heavier species (i.e., C_{8+}). Most of the TRS emissions were in the form of thiophenes and mercaptans.

In 1994, twelve stack surveys were conducted to characterize emissions from the Naphtha Recovery Unit (NRU). The results are summarized in the following table:

	TRS (10^{-3} t/d)	**THC (10^{-3} t/d)**
Minimum	0.07	12.4
Mean	1.94	78.2
Maximum	3.34	341.5

As indicated by the results in the preceding table, the NRU can be a source of both TRS and THC. As such, the Vapour Recovery Unit (VRU) is expected to reduce emissions from the NRU when the VRU is fully operational.

A7.2 Controlled Vents Emissions Summary

In summary, the total estimated THC and TRS emissions for controlled point sources are as follows:

	TRS (10^{-3} t/d)	**THC (10^{-3} t/d)**
Vents		
Before VRU	51 to 69	24 524 to 27 404
After VRU (Plant 4 venting recovered)	21 to 39	13 188 to 16 072
After VRU (Plant 4/South Tank Farm venting recovered)	2.7 to 3.0	10 117 to 10 154

Table A.15 Characterization of the Suncor Plant 3 vent streams (1989).

	3D-62 (kg/h)	3C-22A[(a)] (kg/h)	3C-22B (kg/h)	3C-20 (kg/h)	3C-21[(a)] (kg/h)	3R-24 (kg/h)	3R-220 (kg/h)	3R-232 (kg/h)	Total	
									kg/h	10^{-3} t/d
C_1-C_4	0.66	0.07	0.07	-	0.05	1.1	2.5	1.8	6.2	150.1
C_5	0.49	0.06	0.06	-	0.04	0.35	0.78	0.66	2.41	58.7
C_6-C_8	1.91	0.20	0.19	-	0.13	2.6	5.6	12.5	23.1	555.2
C_8^+	134.6	14.61	13.92	-	9.74	7.0	2.7	23.3	20.59	4941.0
BTEX	0.06	0.008	0.008	-	0.006	0.07	0.12	0.40	0.7	16.1
Total	137.7	14.9	14.2	7.2[(b)]	10.0	11.1	11.7	38.7	245.6[(c)]	5894[(c)]
H_2S	0.0005	-	-	-		-	-	-	0.0005	0.012
COS	-	-	-	-		-	-	-	-	-
CS_2	-	-	-	-		-	-	-	-	-
Thiophenes	0.02	0.04	0.04	0.001	0.03	0.05	0.12	0.57	0.87	20.9
Mercaptans	0.006	-	-	0.006		0.05	-	-	0.062	1.5
Total	0.026	0.04	0.04	0.007	0.03	0.10	0.12	0.57	0.93	22.4

(a) Estimated from 3C-22B data.
(b) Reported only as total hydrocarbons.
(c) Includes 3C-20.

A8.0 UPGRADING FUGITIVE POINT SOURCES

Suncor's efforts have focused on ambient air quality observations (both quantitative and qualitative) to identify sources of odours associated with their operation. The outcome of these efforts was the identification of the controlled point sources and area sources as the major sources of off-site odours. As such, no quantification of fugitive point sources associated with the upgrading has been undertaken.

A first order estimate of fugitive hydrocarbon emissions from the upgrading area can be made by extrapolating refinery emission factors to the area. The U.S. EPA estimates that a typical oil refinery with a 330 000 barrels/d (52 500 m^3/d) capacity could have fugitive VOC emissions from valves, flanges, pump seals, compressors, relief valves and drains of 19.7 t/d (without cooling towers) (Table 5.1-3, U.S. EPA 1995). Assuming a proportional extrapolation to the Suncor upgrader (79 500 barrels/d), VOC emissions could be in the order of 4.7 t/d. This extrapolated value should be used with caution since different refineries handle differing product mixes, and the U.S. values are biased to refinery in warmer climates where evaporation losses could be larger.

A9.0 FUGITIVE AREA SOURCES

A surface flux monitor can be used to determine the emission rate of a surface. The flux monitor can be deployed on liquid and solid surfaces. Flux monitoring was used to estimate emissions from the Suncor Tailings Ponds #1, #1A and 2/3 in May and August 1995. The results are summarized in Tables A.16 and A.17 for TRS and THC, respectively. The annual emission values in these tables have taken into account the variation of temperature and wind speed over the course of a year.

As shown in the tables, the TRS emissions for the largest pond (Pond #2/3) were below the detection limit of the flux monitor. The largest TRS and THC emissions were associated with Pond #1.

The following table summarizes the average 1995 TRS and THC emissions for fugitive area sources (P. Fellin 1996):

Pond	TRS (10^{-3} t/d)	THC (10^{-3} t/d)
1	65.1	1607.3
1A	1.5	45.6
2/3	0	129.4
Total	66.6	1782.2

Table A.16 Sulphur compound emissions for the Suncor Tailings Ponds (#1, #1A, and #2/3). Based on observations taken in May and August 1995[(a)].

	Emission Rate (kg/a)											
	Pond #1			Pond #1A			Pond #2/3			Total		
	May	August	Average	May	August	Average	May	August	Average	May	August	Average
Hydrogen Sulphide	0	19 200	9600	90	11	51	0	0	0	90	19 211	9651
Carbonyl Sulphide	0	0	0	0	0	0	0	0	0	0	0	0
Methyl Mercaptan	0	281	141	0	0	0	0	0	0	0	281	141
Ethyl Mercaptan	0	0	0	0	0	0	0	0	0	0	0	0
Carbon Disulphide	0	0	0	0	0	0	0	0	0	0	0	0
Thiophene	202	15 800	8001	50	28	39	0	0	0	252	15 828	8040
2-Methylthiophene	4710	1740	3225	611	0	306	0	0	0	5321	1740	3531
3-Methylthiophene	1150	0	575	167	0	84	0	0	0	1317	0	659
2-Ethylthiophene + 2,3-Dimethylthiophene	4430	0	2215	127	0	64	0	0	0	4557	0	2279
Total (kg/a)	10 472	37 021	23 757	1045	39	542	0	0	0	11 537	37 060	24 299
(10^{-3} t/d)	28.7	101.4	65.1	2.9	0.1	1.5	0	0	0	31.6	101.5	66.6

(a) Fellin 1996.

Table A.17 Hydrocarbon emissions for the Suncor Tailings Ponds (#1, #1A, #2/3). Based on observations taken in May and August 1995[(a)].

	Emission Rate (kg/a)											
	Pond #1			**Pond #1A**			**Pond #2/3**			**Total**		
	May	**August**	**Average**	**May**	**August**	**Average**	**May**	**August**	**Average**	**May**	**August**	**Average**
Methane	122 000	314 000	218 000	14 400	7140	10 770	4030	57 200	30 615	140 430	378 340	259 385
Ethylene	0	0	0	0	0	0	0	0	0	0	0	0
Acetylene + Ethane	364	759	562	210	0	105	0	0	0	574	759	667
Isobutane	0	0	0	0	0	0	0	0	0	0	0	0
n-Butane	287	0	144	0	0	0	0	0	0	287	0	144
Isopentane	0	0	0	0	0	0	0	0	0	0	0	0
n-Pentane	4480	557	2519	0	0	0	0	0	0	4480	557	2519
2,3-Dimethylbutane	12 400	0	6200	0	0	0	0	0	0	12 400	0	6200
Cyclopentane	0	4540	2270	0	0	0	0	1420	710	0	5960	2980
3-Methylpentane	5600	1370	3485	0	0	0	0	0	0	5600	1370	3485
1-Hexene	4940	638	2789	0	0	0	0	1710	855	4940	2348	3644
n-Hexane	36 800	8500	22 650	661	0	331	0	0	0	37 451	8500	22 981
2,4-Dimethylpentane	1680	1670	1675	0	0	0	0	0	0	1680	1670	1675
Cyclohexane	24 000	16 500	20 250	862	0	431	0	2390	1195	24 862	18 890	21 876
2,3-Dimethylpentane	12 600	0	6300	0	0	0	0	0	0	12 600	0	6300
3-Methylhexane	24 400	19 600	22 000	259	0	130	0	2970	1485	24 659	22 570	23 615
Benzene	3390	0	1695	0	0	0	0	0	0	3390	0	1695
2,2,4 Trimethylpentane	329	3480	1905	0	0	0	0	0	0	329	3480	1905
n-Heptane	71 900	37 600	54 750	1210	0	605	0	4720	2360	73 110	42 320	57 715

Table A.17 Concluded.

	Emission Rate (kg/a)											
	Pond #1			**Pond #1A**			**Pond #2/3**			**Total**		
	May	**August**	**Average**	**May**	**August**	**Average**	**May**	**August**	**Average**	**May**	**August**	**Average**
3-Methylheptane	23 400	11 600	17 500	89	0	45	0	2640	1320	23 489	14 240	18 865
2,2,5-Trimethylhexane	0	0	0	0	0	0	0	0	0	0	0	0
Toluene	21 500	12 300	16 900	1510	0	755	0	0	0	23 010	12 300	17 655
n-Octane	65 600	36 100	50 850	1620	244	932	0	5440	2720	67 220	41 784	54 502
Ethylbenzene	16 700	6730	11 715	366	0	183	0	868	434	17 066	7598	12 332
(p+m)-Xylene + Nonane	70 900	33 500	52 200	2210	195	1203	0	9450	4725	73 110	43 145	58 128
o-Xylene	37 500	5970	21 735	708	0	354	0	461	231	38 208	6431	22 320
Cumene	8520	962	4741	0	0	0	0	0	0	8520	962	4741
n-Propylbenzene	7130	2160	4645	0	705	353	0	0	0	7130	2865	4998
1,3,5-Trimethylbenzene + Decane	29 100	8480	18 790	250	0	125	217	0	109	29 567	8480	19 024
1,2,4-Trimethylbenzene	23 700	1490	12 595	328	0	164	400	569	485	24428	2059	13 244
p-Cymene	0	475	238	117	0	59	0	0	0	117	475	296
1,2,3-Trimethylbenzene	14 500	609	7555	195	0	98	0	0	0	14 695	609	7652
Total (kg/a)	643 720	529 590	586 655	24 995	8284	16 640	4647	89 838	47 243	673 362	627 712	650 537
(10^{-3} t/d)	1764	1451	1607	68	23	46	13	246	129	1845	1720	1782

(a) Fellin 1996.

A10.0 FUGITIVE DUST SOURCES

Fugitive dust sources include the following:

- Mine area shovel operations, hauling operations and dumping operations
- Plant, mine and haul roads
- Coke storage pile
- Tailings pond dykes

Methods used to reduce fugitive dust emissions include: the use of paved roadways to the plant site; the use of wetting materials on the mine and secondary plant haul roads; and the timely reclamation of tailings pond dykes.

Coke undergoes oxidation that produces heat when exposed to air. This heat can build up in the coke pile to produce spontaneous combustion. Coke pile combustion has been a periodic occurrence at Suncor. To evaluate the effects of the coke pile on air quality, a study was conducted in 1985 (Beak 1985). This study obtained ambient concentration measurements downwind of the stockpile and also estimated the emission rates.

During the study, combustion was observed at five locations on the pile. Maximum hourly average concentrations measured downwind of these combustion sources were as follows:

H_2S	45 ppb
SO_2	0.37 ppm
NO_x	0.14 ppm

Peak values were approximately twice the observed hourly average values. The downwind measurements allowed the source strengths to be estimated as follows:

Case	Type	Emission (t/d)		
		SO_2	H_2S	NO_x
1	Line (11 m long)	0.011	0.0009	0.0039
2	Area (3 m^2)	0.14	-	-
3	Line (11 m long)	0.016	0.0009	0.0078
4	Area (3 m^2)	0.019	0.0011	0.0039

It was concluded that other sources had contributed to the observations associated with Case 2 and, therefore, the emission estimates provided may be overestimated. The following table excludes the Case 2 value and is based on a combination of the other cases. Therefore, emissions can be estimated as the following:

	Emission (t/d)
SO_2	0.08
H_2S	0.005
NO_x	0.03

Four dustfall canisters were positioned around the pile for a 3 month period. Total dustfall values ranged from 28 to 258 mg/100 cm^2/30 d. Values at the two sites located between the coke pile and the river ranged from 70 to 157 mg/100 cm^2/30 d. The largest values were observed to the north of the pile. During the observation period, winds in excess of 20 km/h were most frequently associated with southerly and southeasterly winds. An analysis of the samples indicated that between 15 and 70% of the observed dustfall was from the coke pile. No estimate of dust emissions from the pile was provided in the 1985 assessment.

A11.0 SUMMARY OF SUNCOR EMISSIONS

The emissions presented in the previous sections were calculated by BOVAR from information provided by Suncor. Suncor has independently estimated emissions from their operation for the 1995 year. The BOVAR estimates were based on a combination of the 1994 and 1995 years. In some cases, the estimates by both Suncor and BOVAR are made on the basis of extrapolating results from earlier years.

The following sections present a summary on a pollutant by pollutant basis. The difference between the Suncor and BOVAR results, while not completely independent, provide an indication of the uncertainty in using differing approaches to estimate emissions.

A11.1 SO_2 Emissions

The following table identifies the SO_2 emission sources and provides an estimate of the magnitude of these emissions:

Source	SO_2 Emission Rate (t/d)	
	BOVAR (1994)	Suncor (1995)
Powerhouse	211 to 213	215
Incinerator	17[a]	19[b]
Secondary Sources	0.15	
Intermittent Flaring	4.4	
Continuous Flaring	2.3	
Mine Fleet	0.3	-
Total	236	234

[a] 1995 value.

[b] Estimated total for incinerator, secondary sources, intermittent flaring and continuous flaring.

The differences in the above table are not significant and are a result of differing approaches and different operating years.

The major sources of SO_2 emissions are the powerhouse, incinerator and flares. It should be noted that the above values are expressed on a calendar day basis and that during any given day, the actual values could be much larger. This is particularly true for the intermittent flaring when more than 50 t of SO_2 per event can occur. On average, in 1994, 1816 t of SO_2 were emitted over 1458 hours resulting in an average emission rate of 1.2 t/h which is equivalent to an emission rate of 30 t/d.

A11.2 NO_x Emissions

The following table identifies the NO_x emission sources and estimated emission rates:

Source	NO_x Emission Rate (t/d)	
	BOVAR (1994)	**Suncor (1995)**
Powerhouse	16.4	20.81
Incinerator	0.11	13.18[(a)]
Secondary Sources	4.12	
Intermittent Flaring	0.01	
Continuous Flaring	0.01	
Mine Fleet	3.06	3.09
Total	23.7	37.08

[(a)] Estimated total for incinerator, secondary sources, intermittent flaring and continuous flaring.

The Suncor estimates are 56% larger than the BOVAR estimates. The BOVAR rate of 16.4 t/d associated with the Powerhouse was based on a stack surveys, while the Suncor value of 20.59 t/d was based on emission factors for coke, natural gas and refinery gas. The main difference appears to be associated with sources in the upgrading area. The BOVAR total of 4.3 t/d is based on NO_x emission factors that range from 29 to 86 ng/J which were obtained from U.S. EPA emission factors. The Suncor emission factors for NO_x are as follows:

Fuel	Boiler	lbs/mm BTU	ng/J
Coke	1, 2 and 3	0.7	300
Natural gas	1, 2 and 3	0.7	300
Natural gas	8	0.5	215
Natural gas	1, 2 and 3	0.2	86
Natural gas	Secondary Sources	0.5	215
Refinery gas	8	0.65	280
Refinery gas	1, 2 and 3	0.26	112
Refinery gas	Secondary Sources	0.65	280

The NO_x emissions associated with the mine fleet are the same since common fuel consumption and emission factor (2.61 lb/mm BTU or 119 ng/J) were used.

A11.3 CO_2 Emissions

The following table identifies CO_2 emission sources and provides estimates of the magnitude of these emissions:

Source	**CO_2 Emission Rate (t/d)**	
	BOVAR (1994)	**Suncor (1995)**
Powerhouse	5665	6124
Incinerator	92.5[(a)]	3063
Secondary Sources	3451	
Intermittent Flaring	19.1	
Continuous Flaring	11.6	
Mine Fleet	201	208
Total	9440	9395

(a) 1995 value.

While there are variations in the distribution of the CO_2 emissions from the various sources, the total estimates agree to within less than 0.5%.

These CO_2 emissions do not include those associated with the electrical power imported by Suncor. Suncor imported about 10 MW in 1995. In Alberta, this power is generated through the combustion of coal. With an emission factor of 1016 kg/MW·h, this amount corresponds to 248 t/cd of CO_2 equivalent. Therefore, the "total" CO_2 emissions shown in the above table should be increased by 248 t/cd to account for the additional power (Sultan 1996 (personal communication)).

A11.4 CO Emissions

The following table identifies CO emission sources and provides estimates of the magnitude of the emissions:

Source	CO Emission Rate (t/d)
Powerhouse	14.1
Incinerator	5.5
Secondary Sources	0.85
Intermittent Flaring	0.055
Continuous Flaring	0.038
Mine Fleet	0.89
Total	21.4

Suncor did not calculate CO emissions. The CO emissions provided by BOVAR are based on 1989 stack surveys for the powerhouse and incinerator and on emission factors for the remainder of the sources.

A11.5 Particulate Emissions

The following table provides estimates of particulate emissions resulting from combustion sources:

Source	Particulate Emission Rate (t/d)
Powerhouse	6.3
Incinerator	0.003
Secondary Sources	0.27
Intermittent Flaring	0.001
Continuous Flaring	0.001
Mine Fleet	0.18
Total	6.76

The powerhouse emissions are based on measurements, while those for the other sources are based on emission factors. The powerhouse, however, appears to be the major combustion source for particulate emissions.

The emission rates of the major metals associated with particulate emissions from the powerhouse are as follows:

Element	**Emission Rate (t/d)**
Iron	0.28
Zinc	0.16
Aluminium	0.15
Magnesium	0.12
Vanadium	0.08
Sodium	0.07
Nickel	0.02
Titanium	0.02
Boron	< 0.01

The non-metallic fraction of particulate emissions are likely to be comprised of salts, silicates, sulphates, nitrates, carbonaceous compounds, and high molecular weight hydrocarbons such as benzo-(a)-pyrene.

Other particulate sources include surface abrasion and/or wind erosion from mine vehicles, mining operations, coke stock pile operations and handling of tailings sand.

A11.6 Total Hydrocarbon Emissions

The following table provides estimates of total hydrocarbon emissions:

Source	BOVAR (t/d)	Suncor (t/d)
Combustion Sources		
Powerhouse	0.11	0
Incinerator	0.001	0
Secondary Stacks	0.04	0
Intermittent Flaring	0.02	0
Continuous Flaring	0.01	0
Mine Fleet	0.24	0
Other Sources		
Extraction Plant 3	9.87	12.5
Extraction Plant 4	11.45 (0.11)[a]	13.07 (0.027)
South Tank Farm	0.26 to 6.59 (0.066)	6.90 (0.27)
North Tank Farm	0.004 to 0.03	0.04
Other Vents	0.39	-
Upgrading[b]	4.7	6.25
Tailings Ponds	1.78	3.50
Total	35.2 (17.4)[a]	42.3 (22.6)[a]

[a] Values in brackets represent the successful operation of the VRU.
[b] Based on U.S. EPA (1995) emission factor for VOC.

Most of the fugitive hydrocarbon emissions are estimated to result from controlled vents and/or tailings ponds, specifically Tailings Pond #1.

It should be noted that THC values includes methane (CH_4) and non-methane components. The latter is often referred to as VOC (volatile organic compounds). In the preceding table, the emission rates for the combustion sources, extraction plants, tank farms, and other vents were based on U.S. EPA emission factors for THC (i.e., methane and non-methane components). The emission rate of the upgrading facilities was based on a U.S. EPA emission factor for VOC. The emission rate for the tailings ponds was based on measurements. The methane and non-methane (VOC) components of the tailings ponds emission rate are 0.71 and 1.07 t/d, respectively.

A11.7 Total Reduced Sulphur

The following table identifies the TRS emission sources and provides an estimation of the magnitude of these emissions:

Source	TRS Emission Rate (t/d)
Incinerator	0.6
Controlled Vents[a]	0.021 to 0.039
Tailings Ponds	0.066
Total	0.7

[a] Plant 4 venting recovered by VRU at 99% efficiency.

The preceding table indicates that the incinerator is potentially the largest source of TRS emissions (primarily H_2S, COS and CS_2). The TRS emissions from controlled vents and tailings ponds tend to be in the form of thiophenes.

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APPENDIX B

Syncrude Emission Sources Identification and Characterization

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B1.0 SYNCRUDE EMISSION SOURCES

Appendix B discusses the Syncrude emission sources. For the purpose of these discussions, the emissions have been categorized as follows:

- **Main Stack Emissions** (Section B2.0). The main stack emissions include SO_2, NO_x, CO, CO_2, particulates and THC.

- **Secondary Source Emissions** (Section B3.0). Secondary source emissions include SO_2, NO_x, CO, CO_2, THC and particulates.

- **Diverter Stack Emissions** (Section B4.0). The diverter stack emissions include SO_2, CO, CO_2, H_2S, COS, CS_2, THC, NH_3 and particulates.

- **Flaring Emissions** (Section B5.0). The flare stack emissions include SO_2, NO_x, CO, CO_2, THC and particulates.

- **Mine Fleet Emissions** (Section B6.0). The mine fleet emissions include SO_2, NO_x, CO, CO_2, THC and particulates.

- **Other Sources of TRS and THC Emissions (Section 7.0)**. These sources include tanks, vents and fugitive area sources (i.e., tailings settling basin).

- **Fugitive Dust Sources** (Section B8.0). Wind-blown particulate emissions are discussed.

For each source or source type, the emissions are discussed with respect to sulphur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO), carbon dioxide (CO_2), total hydrocarbons (THC) or volatile organic compounds (VOC), total reduced sulphur (TRS) and particulates, when applicable. Section B9.0 summarizes the Syncrude emissions on a contaminant basis.

B2.0 MAIN STACK EMISSIONS

The main stack is the major source of SO_2 at Syncrude. Tail gas from the sulphur recovery plants, ammonia vapours from the sour water treatment plant and coke burner overhead gas (CBOG) from the fluid cokers are incinerated in the CO boiler and the products of combustion are vented up the main stack. Supplemental sweet fuel gas (natural gas) is added to ensure complete combustion. Fly ash and coke fines that have not been removed by the cyclone separators are entrained into the CO stream from the fluid cokers. An electrostatic precipitator (ESP) is used to remove most of the particulates that result during the combustion of these process streams. Emissions of potential concern from the main stack include SO_2, NO_x, CO, CO_2, particulates and THC.

The operation of the main stack is regulated through the AEP Environmental Approval. The following conditions are specified in the 1989 License to Operate (89-AL-174):

Hourly SO_2 emissions	(t/h)	16.4
Daily SO_2 emissions	(t/d)	292
90 Day rolling Average SO_2 emissions	(t/d)	260
NO_x emission	(t/h)	2.15
Particulates	(t/h)	0.6
Particulates (adjust 50% excess air)	(g/kg)	0.20
Opacity	(%)	40

The preceding values represent maximum limits and apply to normal, start-up and shut-down operations.

The main stack is equipped with a continuous stack emission monitor (CSEM) and manual stack surveys are conducted several times per year. The CSEM measures the following parameters on a continuous basis: flue gas SO_2 concentration, opacity, velocity, and temperature. Four manual stack surveys are conducted each year, in accordance with the Approval requirements, to determine concentrations of SO_2, H_2SO_4 (sulphuric acid as a mist), NO_x, CO, O_2, particulates, stack gas temperature and total effluent stream volume flow rate.

B2.1 SO_2 Emissions

B2.1.1 *CSEM Monitoring Results*

The following table presents the average SO_2 emissions associated with the Syncrude main stack from 1990 to 1994:

Year	Operating Days	Main Stack SO_2 Emissions (t/sd)	Main Stack SO_2 Emissions (t/cd)
1990	365	194	194
1991	365	203	203
1992	366	225	225
1993	365	213	213
1994	365	226	226
Minimum	365	194	194
Mean	365	212	212
Maximum	366	226	226

The average emissions are expressed on a tonnes per stream day (t/sd) basis (i.e., tonnes per number of days the plant was operating) and a tonnes per calendar day (t/cd) basis (i.e., tonnes per total number of days in the year). It is evident from the table that the main stack operates on a continuous basis. Emissions of SO_2 from the main stack have increased over the period from 1990 to 1994. This increase is associated with the increase in production that has occurred over the same period.

Figure B.1 shows the Syncrude main stack daily SO_2 emissions. The results indicate year-to-year and day-to-day variability. The variability is due to normal operations. For example, the figure indicates the periods associated with plant turnaround when only one of the two production trains was in operation. Turnaround generally occurs during the first quarter or during the beginning of the second quarter.

Table B.1 shows the SO_2 emissions as a function of month based on the CSEM data for the years from 1990 to 1995, inclusive. As indicated for Figure B.1, the numbers in the table also reflect the time periods associated with plant turnaround.

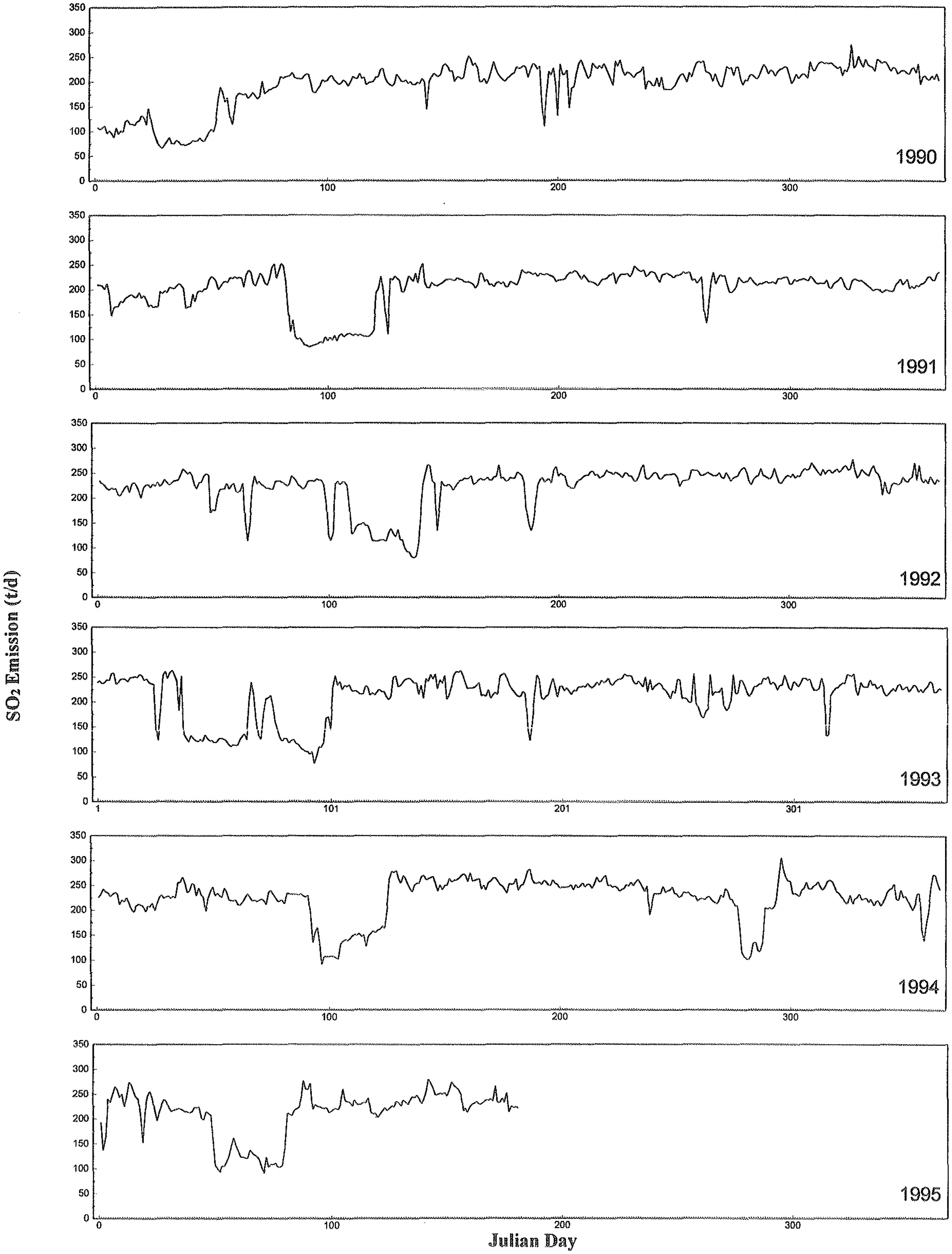

Figure B.1 Daily SO_2 emissions (t/d) from the Syncrude main stack for the period January 1, 1990 to June 30, 1995.

Table B.1 Mean monthly SO_2 emissions from the Syncrude main stack (t/sd).

Month	1990	1991	1992	1993	1994	1995	Average
Jan	105	184	222	237	219	228	199
Feb	102	204	227	149	235	179	183
Mar	188	198	219	147	225	155	189
Apr	201	103	179	186	139	227	172
May	204	210	156	234	245	240	215
Jun	217	216	237	233	258	228	232
Jul	209	229	225	217	254	n/a(a)	227
Aug	216	228	247	240	247	n/a	236
Sep	208	219	245	212	231	n/a	223
Oct	216	216	244	234	194	n/a	221
Nov	231	216	256	230	238	n/a	234
Dec	222	211	238	228	223	n/a	222
Annual	194	203	225	213	226	210	212(b)

(a) n/a = no data available.
(b) Annual average from 1990 to 1994 is also 212 t/sd.

B2.1.2 *Stack Survey Results*

The results of the manual stack surveys conducted between January 1990 and July 1995 are presented in Table B.2. Based on the stack surveys, mean operating conditions of the main stack in 1994 were as follows:

- SO_2 concentration = 1488 ppm
- SO_2 emission = 251 t/d
- Stack exit temperature = 240°C
- Stack exit velocity = 27.2 m/s

The 1994 average daily SO_2 emission rate from the CSEM was 226 t/d as compared to the average SO_2 emission rate of 251 t/cd based on the stack surveys. On average, sulphur dioxide emissions during the 1990 to 1994 stack surveys were about 80% of the licenced daily limit (292 t/d) and 59% of the licenced hourly limit (16.4 t/h).

B2.2 NO_x, CO, CO_2 and THC Emissions

NO_x, CO and CO_2 emissions are measured during the manual stack surveys performed on the main stack. The results from the stack surveys are presented in Table B.2. The THC emission rate is not determined. The following table presents the mean 1994 emission rates for NO_x, CO and CO_2 from the stack surveys:

Contaminant	Emission Rate (t/d)
NO_x	9.6
CO	47.2
CO_2	6647
THC	n/d(a)

(a)Not determined.

The NO_x emissions are about 4 to 5% of those associated with SO_2. The CO_2 emissions are more than 25 times those associated with SO_2.

Table B.2 Results of Syncrude main stack emission compliance surveys (1990 to 1995).

Test Code	Test Date	Temperature (°C)	Velocity (m/s)	SO_2			NO_x		Particulates		Sulphuric Acid Mist (g/kg)	CO_2 (t/d)	CO (t/d)
				(t/h)	(t/d)	(ppm)	(ppm)	(t/d)(a)	(g/kg)(b)	(t/d)(a)			
90-1	May 1-2	242	23.6	9.1	218	1492	128	13.6	0.130	8.6	0.003	n/a	36.0
90-2	May 15	241	24.9	8.0	192	1251	158	17.6	0.078	5.4	0.004	n/a	28.8
90-3	June 5	238	24.4	8.6	206	1387	120	12.8	0.126	8.5	0.005	n/a	20.8
90-4	July 17	228	23.2	10.9	262	1791	110	11.2	0.135	8.8	0.010	n/a	25.6
91-1	May 22	231	25.0	9.5	228	1458	82	8.8	0.240	16.8	0.017	n/a	33.6
91-2	June 5	238	24.4	9.4	225	1482	110	12.0	0.143	10.3	0.143	n/a	32.0
91-3	July 3-4	243	25.3	9.7	234	1511	89	9.6	0.133	9.3	0.045	n/a	42.4
91-4	July 23	233	24.7	9.3	223	1435	102	11.2	0.016	7.5	0.016	n/a	41.6
91-5	Oct 10-11	242	24.8	9.7	232	1527	85	8.8	0.079	5.4	0.020	n/a	9.6
92-1	June 3	236	26.1	10.0	239	1485	85	9.6	0.23	16.1	0.035	6196	72.8
92-2	July 14-15	243	25.5	10.0	237	1535	57	5.6	0.207	13.3	0.018	5587	60.8
92-3	Aug 11	240	26.3	10.4	251	1526	67	7.2	0.13	9.5	0.114	5652	225.6
92-4	Sep 9	242	26.1	9.7	221	1459	106	12.8	0.103	8.3	0.032	6653	12.8
93-1	July 13	246	26.6	9.1	218	1341	41	4.8	0.064	5.0	0.016	6818	32.8
93-2	Aug 4	253	27.1	10.3	247	1510	20	2.4	0.129	9.6	0.013	6256	32.8
93-3	Sep 13	234	25.8	9.4	226	1397	n/a(c)	n/a	0.063	4.4	0.026	6280	110.4
93-4	Sep 20	236	26.1	9.4	225	1385	n/a	n/a	0.057	4.4	0.038	7234	57.6
93-5	Sep 29-30	238	25.6	8.9	213	1376	n/a	n/a	0.106	7.8	0.043	6746	51.2
93-6	Oct 26	243	25.3	10.7	256	1633	126	14.4	0.042	3.2	0.014	7363	19.2
93-7	Nov 15	238	28.2	9.7	233	1354	135	16.8	0.049	3.6	0.080	5790	97.6

Table B.2 Concluded.

Test Code	Test Date	Temperature (°C)	Velocity (m/s)	SO_2			NO_x		Particulates		Sulphuric Acid Mist (g/kg)	CO_2 (t/d)	CO (t/d)
				(t/h)	(t/d)	(ppm)	(ppm)	(t/d)[a]	(g/kg)[b]	(t/d)[a]			
94-1	May 25-26	243	27.3	11.2	269	1611	109	12.8	0.066	4.7	0.034	7226	64.8
94-2	Aug 2-3	244	27.4	9.7	233	1380	46	4.8	0.056	4.6	0.015	6600	38.4
94-3	Sep 1	235	27.4	10.5	252	1461	109	13.6	0.055	4.7	0.009	6777	39.2
94-4	Sep 28-29	236	26.7	10.4	250	1501	67	7.2	0.053	5.1	0.037	5983	46.4
Minimum	1990 to 1994	228	23.2	8.0	192	1251	20	2.4	0.016	3.2	0.003	n/a	9.6
Mean	1990 to 1994	239	25.7	9.7	233	1470	93	10.4	0.104	7.7	0.033	n/a	51.4
Maximum	1990 to 1994	253	28.2	11.2	269	1791	158	17.6	0.240	16.8	0.143	n/a	225.6
Minimum	1994	235	26.7	9.7	233	1380	46	4.8	0.053	4.6	0.009	5983	38.4
Mean	1994	240	27.2	10.4	251	1488	83	9.6	0.058	4.8	0.024	6647	47.2
Maximum	1994	244	27.4	11.2	269	1611	109	13.6	0.066	5.1	0.037	7226	64.8
95-1	June 13	244	26.0	10.2	246	1563	87	9.6	0.138	10.4	n/a	6665	40.8
95-2	June 27	243	26.2	9.7	234	1447	76	8.9	0.322[d]	25.7[d]	n/a	6950	71.2
95-3	July 18	236	24.6	8.9	214	1397	81	9.0	0.073	5.3	n/a	6347	32.8
Minimum	1995	236	24.6	8.9	214	1397	76	8.9	0.073	5.3	n/a	6347	32.8
Mean	1995	241	25.6	9.6	231	1468	81	9.2	0.178	13.8	n/a	6654	48.3
Maximum	1995	244	26.2	10.2	246	1563	87	9.6	0.322	10.4	n/a	6665	71.2

[a] Reported as kg/h.

[b] Calculated at 50% excess air.

[c] Data not available.

[d] Particulate concentration may be high due to operational problems with CO Boiler #1 during Survey 95-2.

B2.3 Particulate Emissions

The main stack is serviced by electrostatic precipitators (ESPs) which are used to remove ash from the flue gases generated through the combustion of coke in the CO boilers. Manual stack surveys are conducted each year to measure the concentrations of particulates in the flue gases that are not removed by the ESPs. The results of these surveys were presented in Table B.2. The concentration values shown in the table are expressed as grams of particulate per kg of air corrected to 50% excess air in the flue gas.

As indicated in Table B.2, the average particulate emission rate for the period from 1990 to 1994 was 7.7 t/d, while the average emission rate for 1994 was 4.8 t/d. The particulate emission rate measured during survey 95-2 was higher than during previous surveys. This may have been due to operational problems with CO Boiler #1. Due to the uncertainty associated with the 95-2 survey and the lower than average value indicated for 1994, the average for the period from 1990 to 1994 was used for the summary tables in this report. The 1990 to 1994 particulate emission rate is about 3% of that associated with SO_2.

In 1984, a study was conducted to characterize the heavy metals associated with the main stack particulate emissions (Concord Scientific 1984). The total particulate emission rate during the tests was 3.0 t/d. This value is less than those associated with the more recent stack surveys as indicated in Table B.2. Table B.3 presents the individual metal and emission rates from the 1984 study, based on a total particulate emission rate of 3.0 t/d. For comparison, the emission rates for each metal were pro-rated, assuming a proportionality, to the 1990 to 1994 average total particulate emission rate of 7.7 t/d.

B2.4 Main Stack Emissions Summary

Table B.4 presents the stack and emission parameters for the Syncrude main stack based on the 1994 emission rates from the CSEM and stack surveys, when applicable. THC is not measured by the stack surveys and was not estimated for the purpose of this report.

Table B.3 Metal emission rates from the Syncrude main stack.

Element	Emission Rate (kg/d)	
	1984[a]	1990 to 1994[b]
Total Particulates	3024	7700
Iron (Fe)	27	68.8
Aluminum (Al)	9.8	25.0
Silicon (Si)	9.4	23.9
Calcium (Ca)	7.5	19.1
Sodium (Na)	4.2	10.7
Vanadium (V)	2.8	7.1
Magnesium (Mg)	2.6	6.6
Titanium (Ti)	2.4	6.1
Manganese (Mn)	0.90	2.3
Phosphorous (P)	0.84	2.1
Nickel (Ni)	0.80	2.0
Zinc (Zn)	0.40	1.0
Lead (Pb)	0.32	0.81
Chromium (Cr)	0.30	0.76
Copper (Cu)	0.15	0.38
Cadmium (Cd)	0.13	0.33
Barium (Ba)	0.13	0.33
Selenium (Se)	0.10	0.25
Molybdenum (Mo)	0.09	0.23
Cobalt (Co)	0.06	0.15
Zirconium (Zr)	0.05	0.13
Tin (Sn)	0.02	0.05
Arsenic (As)	0.02	0.05
Mercury (Hg)	0.004	0.010
Silver (Ag)	0.002	0.005
Beryllium (Be)	0.0005	0.001

(a) Based on total particulate emission rate of 3.0 t/d (Concord Scientific 1984).

(b) Based on 1990 to 1994 average total particulate emission rate of 7.7 t/d (Table B.2).

Table B.4 Stack and emission parameters associated with the Syncrude main stack.

		Main
Base Elevation	(m)	304
Stack Height	(m)	183
Stack Diameter	(m)	7.90
Total Stack Flow Rate	(m^3/s)(a)	738
Exit Velocity	(m/s)(b)	27.2
Exit Temperature	(°C)(b)	240
Approved SO_2 Emissions	(t/d) (t/h)	292 16.4
Measured SO_2 Emissions	(t/d)(b) (t/d)(c)	251 226
NO_x Emissions (as NO_2)	(t/d)(b)	9.6
CO Emissions	(t/d)(b)	47.2
CO_2 Emissions	(t/d)(b)	6647
Particulate Emissions	(t/d)(d)	7.7(d)
THC	(t/d)	n/d(e)

(a) At a reference temperature and pressure of 21°C and 101.3 kPa, respectively.
(b) From 1994 stack survey data.
(c) From 1994 CSEM data.
(d) Average 1990 to 1994 stack survey data.
(e) Not determined.

B3.0 SECONDARY SOURCE EMISSIONS

B3.1 SO_2 Emissions

Trace amounts of SO_2 are emitted from other combustion sources that service the upgrader area at Syncrude. These sources are fueled by refinery gas (fuel gas). Table B.5 identifies and summarizes the design parameters associated with the Syncrude secondary sources. The total estimated SO_2 emission rate from these sources is 5.1 t/d. This value was calculated based on an average 0.06 mole % H_2S in the refinery gas, a net heating value of 39.0 MJ/m^3 and an emission factor of 42 ng/J for Syncrude refinery gas (Buchanan 1996).

B3.2 Other Emissions

Emission rates for NO_x and CO_2 were calculated by Syncrude, based on an energy balance (Buchanan 1996). CO, THC and particulates were estimated using the emission factors indicated in Table B.6. Based on the individual factors, the estimated emissions from the Syncrude secondary stacks are as follows:

Contaminant	Emission Rate (t/d)
NO_x	15.74
CO	2.62
CO_2	13505(a)
THC	0.26
Particulates	0.87

(a) Includes contribution from diverting events.

While the main stack may be the largest single source of NO_x, collectively the NO_x emissions from the secondary stacks exceed those associated with the main stack.

Table B.5 Stack and emission parameters associated with the Syncrude secondary sources.

Stack Description		Gas Turbine	Gas Turbine	Bitumen Column Feed Heater Stacks				Stream Super Heater Stacks			
Stack Number		**31 GTG 201**	**31 GTG 202**	**7-1F-1A**	**7-1F-1B**	**7-2F-1A**	**7-2F-1B**	**8-1F-6A**	**8-1F-6B**	**8-2F-6A**	**8-2F-6B**
Heat Duty	(mm BTU/h)	109.2	109.2	246.0	246.0	246.0	246.0	62.6	19.2	62.6	19.2
	(MW)	32.0	32.0	72.1	72.1	72.1	72.1	18.3	5.6	18.4	5.6
	(GJ/h)	115.2	115.2	259.5	259.5	259.5	259.5	66.0	20.3	66.0	20.3
Fuel Type(a)		FG	FG	FG	FG	FG	FG	FG	FG	FG	FG
Fuel Consumption	(mm SCFD)	7.19	7.19	6.90	6.90	6.90	6.90	1.82	0.56	1.82	0.56
	$(10^3\ m^3/d)$	204	204	195	195	195	195	52	16	52	16
Efficiency	(%)	45(b)	45(b)	86	86	86	86	83	83	83	83
Assumed Excess Air	(%)	200	200	25	25	25	25	25	25	25	25
Stack Height	(m)	34.0	34.0	51.8	51.8	53.2	53.2	39.6	44.7	39.6	44.7
	(ft)	111.5	111.5	169.9	169.9	174.5	174.5	129.9	146.7	129.9	146.7
Stack Diameter	(m)	2.4	2.4	3.2	3.2	3.0	3.0	2.1	1.1	2.1	1.1
	(ft)	7.9	7.9	10.5	10.5	10.0	10.0	7.0	3.5	7.0	3.5
Exit Velocity	(m/s)	46.4	46.4	7.7	7.7	8.5	8.5	5.2	6.1	5.2	6.1
Exit Temperature	(°C)	490	490	283	283	283	283	343	343	343	343
	(°F)	914	914	541	541	541	541	649	649	649	649
	(K)	763	763	556	556	556	556	616	616	616	616
Stack Gas Flow	$(10^3\ m^3/d)$	6291	6291	2756	2756	2756	2756	727	223	727	223

Table B.5 Continued.

Stack Description		**Reformer Furnace Stacks**			**Hydrogen Heater Stacks**				**Fractionator Reboiler Stacks**				**Sulfreen Regeneration Furnace**
Stack Number		**9-1F-1**	**9-2F-1**	**9-3F-1**	**15-1F-1**	**15-2F-1**	**18F-1**	**22-1F-2**	**15-1F-2**	**15-2F-2**	**18F-2**	**22-1F-3**	**12-0F-101**
Heat Duty	(mm BTU/h)	630.0	630.0	820.0	81.0	81.0	61.0	60.0	50.0	50.0	61.0	20.0	21.0
	(MW)	184.6	184.6	240.3	23.7	23.7	17.9	17.6	14.7	14.7	17.9	5.9	6.2
	(GJ/h)	664.7	664.7	865.1	85.5	85.5	64.4	63.3	52.8	52.8	64.4	21.1	22.2
Fuel Type[(a)]		FG	FG	FG	FG	FG	FG	FG	FG	FG	FG	FG	FG
Fuel Consumption	(mm SCFD)	17.51	17.51	21.46	2.11	2.11	1.60	1.70	1.49	1.49	1.60	0.57	0.61
	(10^3 m^3/d)	496	496	608	60	60	45	48	42	42	45	16	17
Efficiency	(%)	87	87	93	93	93	93	86	81	81	93	85	83
Assumed Excess Air	(%)	25	25	25	25	25	25	25	25	25	25	25	25
Stack Height	(m)	23.5	23.5	22.9	41.8	41.8	42.7	45.7	45.7	45.7	42.7	45.7	15.4
	(ft)	77.0	77.0	75.1	137.0	137.0	140.0	150.0	150.0	150.0	140.0	150.0	5.0
Stack Diameter	(m)	4.1	4.1	3.7	1.7	1.7	1.8	1.7	1.9	1.9	1.8	1.1	0.5
	(ft)	13.5	13.5	12.0	5.6	5.6	6.0	5.5	6.4	6.4	6.0	3.5	1.5
Exit Velocity	(m/s)	11.6	11.6	14.3	6.3	6.3	4.3	7.2	5.3	5.3	4.3	6.1	37.2
Exit Temperature	(°C)	267	267	160	153	153	160	296	380	380	160	312	343
	(°F)	513	513	320	307	307	320	565	716	716	320	594	649
	(K)	540	540	433	426	426	433	569	653	653	433	585	616
Stack Gas Flow	(10^3 m^3/d)	6993	6992	8572	844	844	638	678	595	595	638	228	244

Table B.5 Continued.

Stack Description		Bitumen Feed Heater	Diluent Reboiler	Bitumen Heater Stacks (North)				Bitumen Heater Stacks (East)			
Stack Number		**22-1F-1**	**14F-1**	**21F-7**	**21F-8**	**21F-9**	**21F-10**	**21F-50**	**21F-51**	**21F-52**	**21F-53**
Heat Duty	(mm BTU/h)	57.0	24.0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	(MW)	16.7	7.0	n/a	na	n/a	n/a	n/a	n/a	n/a	n/a
	(GJ/h)	60.1	25.3	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Fuel Type[(a)]		FG	FG	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Fuel Consumption	(mm SCFD)	1.70	0.70	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	(10^3 m^3/d)	48	20	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Efficiency	(%)	81	83	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Assumed Excess Air	(%)	25	25	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Stack Height	(m)	45.7	30.5	6.1	6.1	6.1	6.1	7.6	7.6	7.6	7.6
	(ft)	150.0	100.0	20.0	20.0	20.0	20.0	24.9	24.9	24.9	24.9
Stack Diameter	(m)	1.7	1.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	(ft)	5.5	3.5	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Exit Velocity	(m/s)	8.2	7.8	29.0(c)	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Exit Temperature	(°C)	379	345	566(c)	566(c)	566(c)	566(c)	566(c)	566(c)	566(c)	566(c)
	(°F)	714	653	1050	1050	1050	1050	1050	1050	1050	1050
	(K)	652	618	839	839	839	839	839	839	839	839
Stack Gas Flow	(10^3 m^3/d)	678	279	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

(a) FG = Plant refinery gas

(b) Assumed efficiency. Data not available.

(c) Concord Environmental 1992a.

Table B.6 Emission factors used to calculate emission rates for the Syncrude secondary sources.

Compound	U.S. EPA Table No.	Heat Input (mm BTU/h)	Emission Factor	
			(kg/10^6 m^3)[(a)]	(ng/J)
SO_2 (refinery gas)		all		42[(b)]
CO	1.4-2 1.4-2 1.4-2	>100 10 to 100 0.3 to <10	640 560 330	17 15 9
THC	1.4-3 1.4-3 1.4-3	>100 10 to 100 0.3 to <10	28 92 128	0.7 2.4 3.4
Particulates[(c)]	1.4-1 1.4-1 1.4-1	>100 10 to 100 0.3 to <10	200 219 192	5.3 5.8 5.1

(a) Table 1.4-2, U.S. EPA 1995. Based on a gross heating value for natural gas of 37.4 MJ/m^3.

(b) Based on 0.06 mole % H_2S in refinery gas and a heating value of 39.0 MJ/m^3 for Syncrude refinery gas (Buchanan 1996).

(c) Sum of filterable and condensable particulate matter.

B4.0 DIVERTER STACK EMISSIONS

Two diverter stacks service the Syncrude plant (i.e., one diverter stack for each fluid coker). The diverter stacks are an emergency bypass venting system used to release large volumes of gas in the event of a plant failure. Each diverter stack is 73.2 m in height with a stack diameter of 3.7 m. The diverter stacks are used to vent the following gas streams:

- **Coker Burner Overhead Gas (CBOG).** This gas can be vented directly to the atmosphere through a diverter stack rather than being incinerated in the CO boiler in the event of a coker upset or a failure at, or downstream of, the CO boiler. Syncrude estimates a maximum total flow rate of 96 m^3/s (at 21°C and 101.3 kPa) for this type of diverting event. There were no CBOG diverting events in 1994. However, for comparison, the average total flow rate for 1993 was 82.2 m^3/s.
- **Combined Gas.** Tail gas from the sulphur plant and ammonia gas from the sour water plant can also be vented to the diverter stacks in addition to the coker overhead gas. Syncrude estimates a maximum total flow rate of 125 m^3/s (at 21°C and 101.3 kPa) for this type of diverting event. The average total flow rate in 1994 was 93.1 m^3/s.

Based on 1990 to 1994 data, combined gas events typically last 2.9 hours on average. In an effort to reduce the gas released during longer diverting events (i.e., when the restart of the CO boiler is not imminent), the gas streams from the sulphur plant and the sour water plant are usually directed to the remaining on-line CO boiler.

B4.1 SO_2 Emissions

Table B.7 presents a composition of the flue gas streams vented under the two diverting scenarios described in the previous section. As indicated in the table, the diverter stacks are a source of H_2S, COS, SO_2, CS_2 and other gaseous and particulate compounds..

Table B.8 presents a summary of the events when the diverter stacks were used at Syncrude between 1990 and 1994, inclusive. As indicated in the table, the diverter stacks are used infrequently (i.e., 3 to 10 times per year). The equivalent SO_2 emission rates shown in the table include all sulphur compounds (i.e., SO_2, H_2S, COS and CS_2).

Figure B.2 presents the daily equivalent SO_2 emissions (i.e., includes all sulphur compounds) from the Syncrude diverter stacks for the period January 1, 1990 to June 14, 1995. The figure clearly illustrates the infrequent use of these stacks and also shows a reduction of diverter stack usage in 1994 and the first half of 1995.

Table B.7 Properties of gas streams to diverter stacks.

Component		**Composition (mole %)**	
		CBOG[(a)]	**Combined Gas**[(b)]
Hydrogen	(H_2)	0.76	1.07
Argon	(Ar)	0.77	0.72
Oxygen	(O_2)	0	0.03
Nitrogen	(N_2)	66.20	60.66
Carbon Monoxide	(CO)	3.62	2.47
Carbon Dioxide	(CO_2)	10.84	8.40
Hydrogen Sulphide	(H_2S)	0.092	0.082
Carbonyl Sulphide	(COS)	0.066	0.073
Sulphur Dioxide	(SO_2)	0.073	0.027
Carbonyl Disulphide	(CS_2)	0.001	0.002
Methane	(C_1)	1.04	0.87
Ethane	(C_2)	0.025	0.015
Propane	(C_3)	0.016	0.003
Butane+	(C_4^+)	0.00	0.001
Water	(H_2O)	16.50	25.16
Ammonia	(NH_3)	0.012	0.41
Total		100	100

(a) Based on an average gas composition measured during stack surveys between 1987 and 1995 (Buchanan 1996).

(b) Based on stack surveys conducted at the CO boiler inlet on January 24, April 3 and August 22, 1995 (Buchanan 1996).

Table B.8 Summary of diverter stack events at Syncrude from 1990 to 1994, inclusive.

		1990	1991	1992	1993	1994
Number of Events		8	3	8	10	4
Total Number of Hours	(h)	169.4	50.2	177.0	277.2	10.0
Total Equivalent SO_2	(t)(a)	496.4	204.0	531.4	819.8	44.8
Average Duration	(h/event)	21.1	16.7	22.1	27.7	2.5
Average Equivalent SO_2	(t/event)(a)	62.0	68.0	66.4	82.0	11.2

(a) Includes all sulphur compounds in terms of equivalent SO_2 mass.

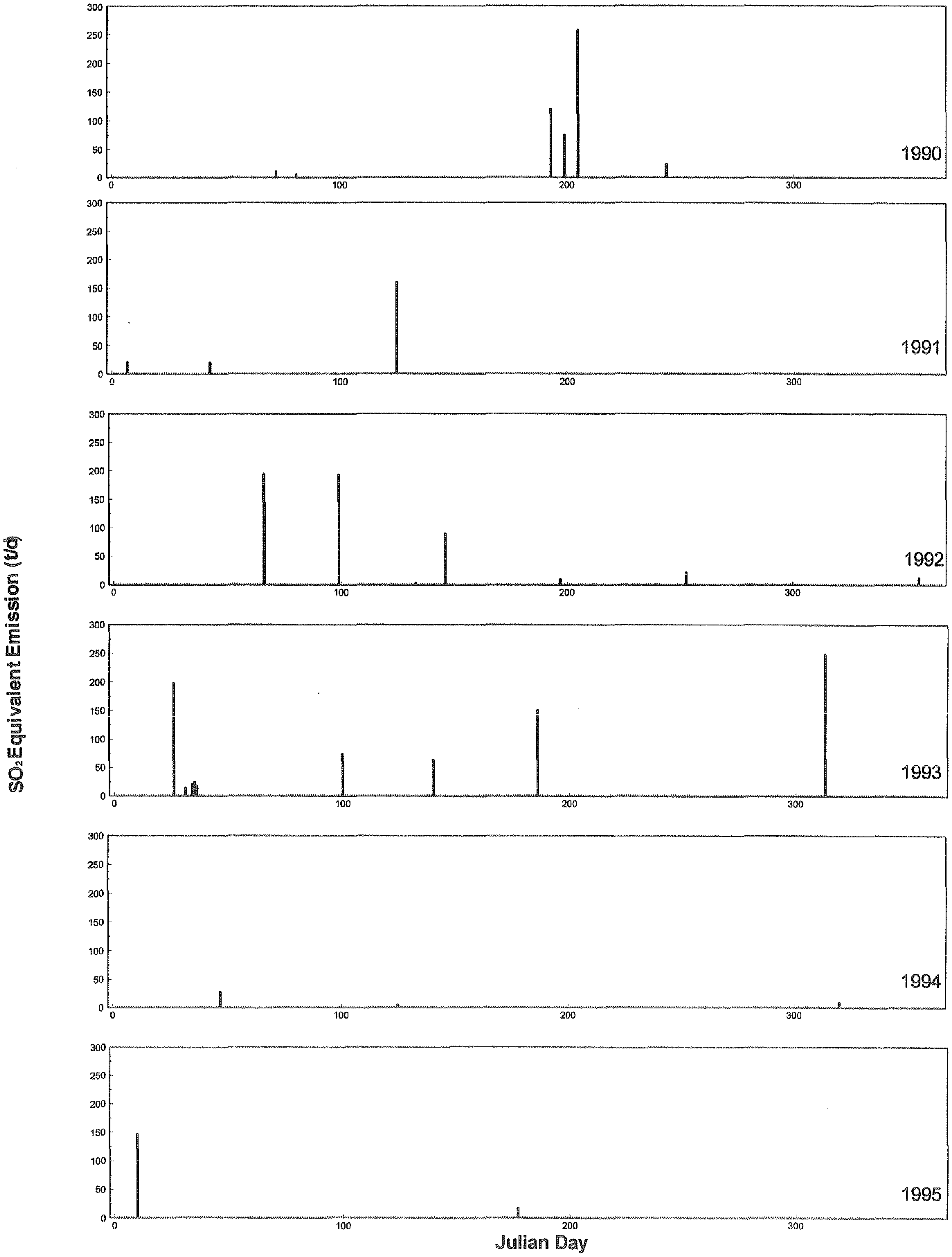

Figure B.2 Daily equivalent SO_2 emissions (t/d) from the Syncrude diverter stacks for the period January 1, 1990 to June 14, 1995.

The following table presents estimated actual SO_2 emission rates (i.e., not equivalent SO_2) for coker burner overhead and combined gas diverting events:

		CBOG	Combined Gas
SO_2	(t/sd) (t/cd)	40.4 0.27	0.48 0.006

The preceding estimates are based on the total flow rates for diverting events from 1990 to 1994, the number of days on which diverting events occurred, and the gas compositions presented in Table B.7. The emission rates are presented on a tonnes per stream day (t/sd) basis (i.e., tonnes per number of operating days per year) and on a tonnes per calendar day basis (i.e., tonnes per number of days in the year).

B4.2 NO_x, NH_3, CO and CO_2 Emissions

Since the diverter stacks do not involve a combustion process, NO_x emissions are not measured during stack surveys. Emission rates for NH_3, CO and CO_2 are presented in the following table:

	CBOG		Combined Gas	
	(t/sd)	(t/cd)	(t/sd)	(t/cd)
NO_x	n/d[a]	n/d	n/d	n/d
NH_3	1.8	0.01	1.9	0.02
CO	875.0	5.8	19.0	0.23
CO_2	4116.7	27.2	101.7	1.2

[a] Not determined.

The preceding estimates are based on the total flow rates for diverting events from 1990 to 1994, the number of days on which diverting events occurred, and the gas compositions presented in Table B.7. The emission rates are presented on a tonnes per stream day (t/sd) basis (i.e., tonnes per number of operating days per year) and on a tonnes per calendar day basis (i.e., tonnes per number of days in the year).

B4.3 Particulate Emissions

For coker burner overhead and combined gas diverter events, gas stream sample surveys completed in 1994 and 1995 indicate the following average emission rates for particulates:

	CBOG	Combined Gas
Particulates (t/sd)	40.8	21.2
(t/cd)	0.3	0.2

The preceding estimates are based on the total flow rates for diverting events from 1990 to 1994, the number of days on which diverting events occurred, and the particulate emission rates based on gas stream sample surveys completed in 1994 and 1995. The average CBOG particulate emission factor was 1960 mg/m^3. The average combined gas diverting events was 6.65 t/h. The emission rates are presented on a tonnes per stream day (t/sd) basis (i.e., tonnes per number of operating days per year) and on a tonnes per calendar day basis (i.e., tonnes per number of days in the year).

B4.4 TRS Emissions

The diverter stacks are the primary controlled release source of TRS at the Syncrude plant. As indicated in Table B.7, the diverters emit hydrogen sulphide (H_2S), carbonyl sulphide (COS), and carbon disulphide (CS_2). The estimated emission rates for the TRS compounds are presented in the following table:

	CBOG		Combined Gas	
	(t/sd)	(t/cd)	(t/sd)	(t/cd)
H_2S	27.0	0.18	0.8	0.009
COS	34.2	0.23	1.2	0.01
CS_2	0.49	0.003	0.04	0.0005
TRS(a)	87.5	0.58	2.8	0.03

(a) As SO_2 equivalents

The preceding estimates are based on the total flow rates for diverting events from 1990 to 1994, the number of days on which diverting events occurred, and the gas compositions presented in Table B.7. The emission rates are presented on a tonnes per stream day (t/sd) basis (i.e., tonnes per number of operating days per year) and on a tonnes per calendar day basis (i.e., tonnes per number of days in the year).

B4.5 THC Emissions

The diverter stacks are a source of THC emissions. As indicated in Table B.7, most of the THC emissions are associated with methane (CH_4), although there are also some non-methane or VOC emissions (i.e., C_2, C_3 and C_4^+). The following table presents the THC emissions:

	CBOG		Combined Gas	
	(t/sd)	(t/cd)	(t/sd)[(a)]	(t/cd)[(b)]
CH_4	106.7	0.6	3.8	0.05
VOC[(a)]	4.2	0.03	0.08	0.001
THC[(a)]	110.9	0.6	3.9	0.05

[(a)] As methane equivalents.

The preceding estimates are based on the total flow rates for diverting events from 1990 to 1994, the number of days on which diverting events occurred, and the gas compositions presented in Table B.7. The emission rates are presented on a tonnes per stream day (t/sd) basis (i.e., tonnes per number of operating days per year) and on a tonnes per calendar day basis (i.e., tonnes per number of days in the year).

B4.6 Diverter Stack and Emissions Summary

Table B.9 summarizes the emissions associated with the coker burner overhead and combined gas diverting events at Syncrude.

Table B.9 Syncrude diverter stack and emission parameters.

		CBOG		Combined Gas	
Base elevation	(m)	304		304	
Stack height	(m)	73.2		73.2	
Stack Diameter	(m)	3.70		3.70	
Total Stack Flow Rate	(m^3/s)$^{(a)}$	96		125	
Exit Velocity	(m/s)	26.5		30.6	
Exit Temperature	(°C)	600		500	
Composition		**(t/sd)**	**(t/cd)**	**(t/sd)**	**(t/cd)**
SO_2		40.4	0.27	0.48	0.006
NO_x		n/d$^{(b)}$	n/d	n/d	n/d
CO		875.0	5.8	19.0	0.23
CO_2		4116.7	27.2	101.7	1.2
TRS (as SO_2 equivalents)		87.5	0.58	2.8	0.03
THC (as methane equivalents)		110.9	0.6	3.9	0.05
NH_3		1.8	0.01	1.9	0.02
Particulates		40.8	0.3	21.2	0.2

(a) At 21°C and 101.325 kPa.
(b) Not determined.

B5.0 FLARING EMISSIONS

The Syncrude flaring system is comprised of the following:

- One acid gas flare stack which is 71.6 m high and has a 1.07 diameter. This flare is used when there are upsets within the amine plant, the sulphur recovery plant or the sour water plant. The heating values of these gases during upset conditions are in the 9.4 to 11.2 MJ/m^3 range.

- One hydrocarbon flare which is 7.6 m high and has a 0.76 m diameter. This flare is equipped with steam injection to ensure smokeless operation and is the primary hydrocarbon flare stack (low pressure). When this flare is used, the heating values of the gases are in the 10.8 to 39.4 MJ/m^3 range.

- A secondary hydrocarbon or high pressure flare which is 71.6 m high and has a 1.21 m diameter. This flare is used when the capacity of the primary system is exceeded.

B5.1 SO_2 Emissions

Syncrude has undertaken an analysis of current plant operations that result in the flaring of sour gas streams (Syncrude 1995*b*). The analysis is presented in Table B.10. Comments with respect to the information presented in the table are as follows:

- Individual flaring events range from 0.3 to 26.6 hours.

- When flaring takes place, the SO_2 emissions can range from less than 0.1 t/event to 59.7 t/event.

- Most of the SO_2 emitted is associated with upsets in Plant 11 (amine plants), Plant 8 (the cokers) or Plant 16 (sour water plants).

- On average, there are approximately 233 flaring events per year.

- The average amount of SO_2 emitted from flaring events is approximately 2176 t/a.

Table B.10 Summary of flaring of gas streams that occur at the Syncrude plant.[(a)]

Plant	8 Cokers	11 Amine Plants	12 Sulphur Recovery Plants	13 Naphtha Hydrotreaters	15 Gas-Oil Hydrotreaters	16 Sour Water Plants	18 Light Gas-Oil Hydrotreaters	22 LC-Finer	Total
1989									
Events	22	24	0	9	16	46	1	78	196
Total duration (h)	156.2	52.8	0	121.5	302.4	722.2	7	1224.6	2586.7
Total SO_2 (t)	258	514	0	59	26	53	<1	10	920
Average duration (h/event)	7.1	2.2	0	13.5	18.9	15.7	7	15.7	13.2
SO_2/event (t/event)	11.7	21.4	0.0	6.6	1.6	1.2	<1	0.1	4.7
1990									
Events	48	31	6	15	21	93	14	83	311
Total duration (h)	537.6	186	19.8	211.5	558.6	1404.3	238	1485.7	4641.5
Total SO_2 (t)	357	1852	<1	35	1167	161	3	20	3595
Average duration (h/event)	11.2	6	3.3	14.1	26.6	15.1	17	17.9	14.9
SO_2/event (t/event)	7.4	59.7	<0.1	2.3	55.6	1.7	0.2	0.2	11.6
1991									
Events	41	30	0	57	20	50	2	57	257
Total duration (h)	344.4	183	0	980.4	318	865	1.6	837.9	3530.3
Total SO_2 (t)	1241	1022	0	184	37	161	<1	163	2808
Average duration (h/event)	8.4	6.1	0	17.2	15.9	17.3	0.8	14.7	13.7
SO_2/event (t/event)	30.3	34.1	0.0	3.2	1.9	3.2	<1	2.9	10.9
1992									
Events	55	36	2	24	21	103	2	17	260
Duration (h/a)	665.5	378	0.6	235.2	151.2	1648	21	204	3303.5
SO_2 (t/a)	450	972	1	202	35	823	12	15	2510
Duration (h/event)	12.1	10.5	0.3	9.8	7.2	16	10.5	12	12.7
SO_2/event (t/event)	8.2	27.0	0.5	8.4	1.7	8.0	6.0	0.9	9.7

Table B.10 Concluded.

Plant	8 Cokers	11 Amine Plants	12 Sulphur Recovery Plants	13 Naphtha Hydrotreaters	15 Gas-Oil Hydrotreaters	16 Sour Water Plants	18 Light Gas-Oil Hydrotreaters	22 LC-Finer	Total
1993									
Events	39	17	2	18	35	96	10	16	233
Total duration (h)	491.4	64.6	5.6	84.6	626.5	912	94	148.8	2427.5
Total SO_2 (t)	471	556	3	127	51	772	<1	2	1982
Average duration (h/event)	12.6	3.8	2.8	4.7	17.9	9.5	9.4	9.3	10.4
SO_2/event (t/event)	12.1	32.7	1.5	7.1	1.5	8.0	<1	0.1	8.5
1994									
Events	35	28	3	5	14	51	0	4	140
Total duration (h)	374.5	128.8	3.6	103.5	151.2	326.4	0	32.4	1120.4
Total SO_2 (t)	51	734	31	31	24	369	0	<1	1240
Average duration (h/event)	10.7	4.6	1.2	20.7	10.8	6.4	0	8.1	8.0
SO_2/event (t/event)	1.5	26.2	10.3	6.2	1.7	7.2	0.0	<1	8.8
Average									
Events	40	28	2	21	21	73	5	43	233
Duration (h/a)	428.3	165.5	4.9	289.5	351.3	979.7	60.3	656.6	2935.0
SO_2 (t/a)	471	942	6	106	223	390	2	35	2176
Duration (h/event)	10.7	6.0	2.3	13.6	16.6	13.4	12.4	15.4	12.6
SO_2 (t/event)	12	34	3	5	11	5	<1	1	9.3

[a] Syncrude (1995*a*).

The following table presents the SO_2 emissions associated with flaring at the Syncrude facility for the years from 1990 to 1994:

Year	Operating Days[a]	SO_2 Emission Rate	
		(t/sd)	(t/cd)
1990	131	27.4	9.8
1991	132	21.3	7.7
1992	153	16.4	6.8
1993	125	15.8	5.4
1994	93	13.3	3.4
Minimum	93	13.3	3.4
Mean	127	18.8	6.6
Maximum	153	27.4	9.8

[a] Twenty-four hours or less of flaring.

The amount of SO_2 released under flaring events has decreased by almost a factor of three over the period 1990 to 1994.

B5.2 NO_x, CO, CO_2 and THC Emissions

For flare stacks, complete combustion will result in the formation of CO_2, H_2O and NO_x. Complete combustion requires sufficient combustion air and turbulent mixing of air with the gas being flared. If incomplete combustion occurs, unburned hydrocarbons, intermediate hydrocarbons, CO and carbon particulates (soot) will form. The following emission factors, which are specific to flaring, were used to estimate flare stack emissions:

Component		Emission Factor[a]
NO_x	(ng/J)	29
CO	(ng/J)	159
THC	(ng/J)	60
Particulates[b]	(µg/L)	177

[a] Table 13-5.1, U.S. EPA (1995).
[b] Average smoking flare.

The CO_2 emissions were calculated by Syncrude using 1990 heat loss and an assumed emission factor (Clark 1990). Using the preceding factors, the estimated emissions are as follows:

		Flaring
Gas Flow	(m^3/d)	329 000
NO_x	(t/d)	0.040
CO	(t/d)	0.219
CO_2	(t/d)	141(a)
THC	(t/d)	0.083
Particulates	(t/d)	0.0065

(a) Based on 1990 total heat loss of 974 549 x 10^6 BTU and the formation of 116.2 lbs CO_2 for every 10^6 BTU combusted (Clark 1990).

B5.3 Flaring Emissions Summary

Table B.11 presents a summary of the flare stack and emissions parameters for flaring at the Syncrude facility. Data from 1994 were not used as the base year in these calculations due to the lower than average emissions during that year. As such, the estimated emissions shown in the table are based on the 1989 to 1994 data presented in Table B.10.

Table B.11 Emission parameters associated with flaring at Syncrude.[a]

	SO_2 Emission Rate (t/h)[a]	**Total Heat Release Rate (cal/s)[b]**
Cokers (Plant 8)	1.1	32 484 564
Amine Plants (Plant 11)	5.7	19 252 833
Sulphur Recovery Plants (Plant 12)	1.3	11 289 590
Naphtha Hydrotreaters (Plant 13)	0.4	7 393 840
Gas-Oil Hydrotreaters (Plant 15)	0.7	18 282 672
Sour Water Plants (Plant 16)	0.4	3 017 063
Light Gas-Oil Hydrotreaters (Plant 18)	0.1	4 235 215
LC-Finer (Plant 22)	0.1	16 454 585

[a] Calculated from Table B.10 using average SO2 per event and average duration per event for the period from 1989 to 1994.

[b] Calculated as an average heat release rate per plant (for SO_2 flaring events) from the electronic database provided by Syncrude. The database units for heat release rates per incident were 10^6 BTU.

B6.0 MINE FLEET EMISSIONS

Small amounts of SO_2 are emitted from the combustion of diesel in mine fleet vehicles. The following table summarizes the emission factors used to calculate emission rates for the mine fleet:

Compound	Emission Factor ($kg/10^3$ L)
SO_2(a)	3.7
NO_x(b)	48
CO(a)	12.3
CO_2(c)	2640
THC(a)	3.25
Particulates(a)	2.5

(a) An average of emission factors for diesel-powered shovels and trucks (Table II-7.1, U.S. EPA 1985).

(b) Emission factor corresponds to the factors used to calculate NO_x emissions in the 1990 NO_x/CO_2 Emissions Study Report (Clark 1990).

(c) Buchanan (1996).

The following table presents the 1995 overall fuel consumption for the mine fleet (including power shovels and trucks) and the estimated emission rates:

		Total
Fuel Consumption	(m^3/a) (L/d)	74 704 204 668
SO_2 Emissions	(t/d)	0.76
NO_x Emissions	(t/d)	9.82
CO Emissions	(t/d)	2.52
CO_2 Emissions	(t/d)	540
THC Emissions	(t/d)	0.67
Particulates	(t/d)	0.51

B7.0 OTHER SOURCES OF TRS AND THC EMISSIONS

Fugitive emissions of reduced sulphur (TRS) and total hydrocarbons (THC) can originate from the process area, the mine area and the tailings settling basin at Syncrude. As summarized by the following reports, several studies have been undertaken to identify and quantify the fugitive emissions from the Syncrude facility:

- **Report 1.** The first fugitive emission study at Syncrude was conducted in 1981. This study focussed on H_2S emissions from various areas within the plant site (Concord Scientific 1981).

- **Report 2.** The second study was conducted in the fall of 1987 and investigated a variety of TRS and VOC compounds through use of flux monitoring. This second study concluded that the main tailings settling basin was the major source of fugitive emissions at Syncrude (i.e., 60 to 80% of the Syncrude total depending on the species). This finding supported the implementation of a naphtha recovery system to reduce hydrocarbon losses to the tailings settling basin (Concord Scientific 1988).

- **Report 3.** The third study was conducted in 1992 and focussed on flux monitoring of the tailing settling basin to determine the extent of improvements associated with the implementation of the naphtha recovery system (Concord Environmental 1992*b*).

- **Report 4.** The fourth study at Syncrude was conducted in 1994. The focus of this study was to obtain estimates of fugitive emissions associated with the tailings settling basin as part of Syncrude's commitment to the National Pollutant Release Inventory (NPRI) program. Passive monitoring, as opposed to flux monitoring, was used for this study (BOVAR-CONCORD Environmental 1994).

As indicated by the preceding, the Syncrude studies were conducted to estimate fugitive emissions for various areas associated with their operations, as opposed to emissions from individual sources.

Tables B.12 and B.13, respectively, compare the identified TRS and THC emissions from the water surface of the tailings settling basin during the 1987 and 1992 flux monitoring programs conducted at the Syncrude facility. Data are not shown for the 1981 study since this study focussed on H_2S and similarly, data are not shown for the 1994 study which used passive monitoring and was only concerned with selected compounds. As indicated in the tables, the total fugitive emissions from the tailings settling basin have decreased since 1987. Some compounds, such as benzene and toluene were either not found or were substantially reduced during the 1992 study as compared to the 1987 study. This reduction is due to various process changes and emission reduction programs initiated by Syncrude, such as the installation of the naphtha recovery unit.

Table B.12 Comparison of identified TRS emissions from the water surface of the tailings settling basin as observed during the 1987 and 1992 flux monitoring programs at Syncrude.

	1987 Monitoring[(a)] (kg/a)	**1992 Monitoring[(a)] (kg/a)**
Carbonyl Sulphide	300	204
Hydrogen Sulphide	7497	812
Methyl Mercaptan	1810	27
Carbon Disulphide	1402	113
Ethyl Mercaptan	886	0
Thiophene	3223	266
Isobutyle Mercaptan		100
Diethyl Sulphide		99
n-Butyl Mercaptan		0
2-Methyl Thiophene	9420	2090
3-Methyl Thiophene	1279	1038
n-Amyl Mercaptan	170	684
Diallyl Sulphide		743
2-Ethyl Thiophene	649	990
2,5-Dimethyl Thiophene	658	3010
di-n-Butyl Sulphide		8257
Total (kg/a) (t/d)	27 294 0.0748	18 433 0.0505

(a) From Table 3-13 in Concord Environmental 1992*b*.

Table B.13 Comparison of identified hydrocarbon emissions from the water surface of the tailings settling basin as observed during the 1987 and 1992 flux monitoring programs at Syncrude.

	1987 Monitoring[(a)] (kg/a)	1992 Monitoring[(a)] (kg/a)
C_1 to C_3	599 815	274 048
Isobutane	12 614	5046
n-Butane	62 441	0
Isopentane	78 840	1261
n-Pentane	150 427	1892
Cyclopentane	206 876	315
2,3-Dimethylbutane	176 602	10 722
3-Methylpentane	123 306	0
1-Hexane	905 714	0
n-Hexane	311 891	8830
2,4-Dimethylpentane	104 069	17 660
Benzene	340 589	0
Cyclohexane	429 205	32 167
2,3-Dimethylpentane		4100
3-Methylhexane	582 154	13 245
2,2,4-Trimethylpentane		29 644
n-Heptane	112 584	16 399
Toluene	514 983	27 121
3-Methylheptane	72 217	10 722
2,2,5-Trimethylhexane		31 851
n-Octane	53 296	31 221
Ethylbenzene	75 686	74 425
p-Xylene + m-Xylene	697 892	74 425
o-Xylene	269 948	23 337

Table B.13 Concluded.

		1987 Monitoring[a] (kg/a)	1992 Monitoring[a] (kg/a)
n-Nonane		3469	17 029
Cumene		4100	11 984
n-Propylbenzene		41 628	0
1,3,5-Trimethylbenzene		25 229	3469
1,2,3-TMB + n-Decane		3784	17 660
1,2,4-TMB + p-Cymene			25 229
Total: C_{1+}	(kg/a)	5 959 359	763 802
	(t/d)	16.3	2.1
C_{5+}	(kg/a)	5 107 887	473 986
	(t/d)	14.0	1.3

[a] From Table 3-12 in Concord Environmental 1992.

According to the 1987 flux monitoring study, VOC (C_5 to C_{10}) and TRS emissions for identified chemical species were as follows:

Source	VOC (t/d)	TRS (t/d)
Plant Area	9.2	-
Effluent Pond	1.5	0.01
Mine Area	0.8	0.03
Recycle Pond	0.2	0.001
Other Areas[a]	< 0.01	<0.0004
Total	11.7	0.04

(a) Includes coke storage and sulphur blocking areas.

As previously indicated, the total fugitive emissions have decreased since 1987. However, more recent studies have focussed only on the tailings settling basin, and thus, data relating to current emissions from other areas of the Syncrude facility are not available. The total estimated VOC emission rate is 10.8 t/d for the Syncrude plant area, including the effluent and recycle ponds.

For the purposes of comparison, a U.S. EPA refinery emission factor was applied to the Syncrude upgrading facilities. Specifically, the U.S. EPA estimates that a typical oil refinery with a 330 000 barrels/d (52 500 m^3/d) capacity would have fugitive VOC emissions of 20.5 t/d (including cooling towers) (Table 5.1-3, U.S. EPA 1995). Assuming a proportional extrapolation to the Syncrude upgrade (215 000 bbl/cd), VOC emissions could be in the order of 13.4 t/d. While caution should be exercised in the extrapolation of this value to Syncrude, the value compares favourably with the 1987 estimate of 10.8 t/d for VOC emissions from the plant area, effluent pond and recycle pond.

B8.0 FUGITIVE DUST SOURCES

Syncrude fugitive dust sources include the following:

- Mine area blasting, shovel operation, hauling operations and dumping operations.
- Plant and mine roads and haul roads.
- Tailings settling basin dykes.
- South West Sand Storage (SWSS) area.
- Coke storage area.

In 1986, Syncrude undertook a survey to assess the size distribution of wind-blown particulates from the dyke (Syncrude 1989). The data from this study do not quantify the emission rates of the particulates. The study states that PM_{10} comprises about 3% of the total particulates arising from the dyke and that wind conditions causing blowing sand from the dyke are expected to occur less than 20 days per year. Preliminary observations also indicated that wind-blown sand begins to leave the dyke at wind speeds around 30 to 40 km/h (8 to 11 m/s).

B9.0 SUMMARY OF SYNCRUDE EMISSIONS

The emissions presented in the previous sections were calculated by BOVAR from information provided by Syncrude or were estimated from U.S EPA emission factors. The following sections present a summary on a pollutant by pollutant basis.

B9.1 SO_2 Emissions

The following table identifies the SO_2 emission sources and provides a summary of the estimated emission rates for each source:

Source	SO_2 Emission Rate (t/cd)
Main Stack	226
Secondary Combustion Sources	5.1
Diverter Stacks	0.28
Flare Stacks	6.6
Mine Fleet	0.76
Total	239

As indicated in the table, the major source of SO_2 emissions is the main stack which accounts for about 95% of the total. It should be noted that the presented values are expressed on a calendar day basis and that during any given day, the actual values could be much larger. This is particularly true in the case of diverting or flaring incidents.

B9.2 NO_x Emissions

The following table identifies the NO_x emission sources and provides a summary of the estimated emissions rates for each source:

Source	NO_x Emission Rate (t/cd)
Main Stack	9.6
Secondary Combustion Sources	15.7
Flare Stacks	0.04
Mine Fleet	9.8
Total	35.1

B9.3 CO Emissions

The following table identifies the CO emission sources and provides a summary of the estimated emission rates for each source:

Source	CO Emission Rate (t/cd)
Main Stack	47.2
Secondary Combustion Sources	2.62
Diverter Stacks	6.03
Flare Stacks	0.22
Mine Fleet	2.52
Total	58.6

B9.4 CO_2 Emissions

The following table identifies the CO_2 emission sources and provides a summary of the estimated emissions rates for each source:

Source	CO_2 Emission Rate (t/cd)
Main Stack	6647
Secondary Combustion Sources	13505(a)
Diverter Stacks(a)	-
Flare Stacks	141
Mine Fleet	540
Total	20 833

(a) Estimate provided by Syncrude and includes contribution from diverter stacks (~30 t/cd as estimated in Section B4.2).

The preceding CO_2 emissions do not include an estimated 873 t/d of CO_2 associated with electrical power imported by Syncrude. Therefore, the "total" CO_2 emissions shown in the preceding table should be increased by 873 t/d to account for off-site power production (Syncrude 1995*a*).

B9.5 Particulate Emissions

The following table identifies the particulate emission sources and provides a summary of the estimated emissions rates for each source:

Source	Particulate Emission Rate (t/cd)
Main Stack	7.7
Secondary Combustion Sources	0.87
Diverter Stacks	0.5
Flare Stacks	0.006
Mine Fleet	2.5
Total	11.6

The emission rates of the major metals associated with particulate emissions from the main stack are as follows:

Element	Emission Rate (t/cd)
Iron	0.07
Aluminum	0.02
Silicon	0.02
Calcium	0.02
Sodium	0.01
Magnesium	0.01
Titanium	0.01

The non-metallic fraction of particulate emissions are likely to be comprised of salts, silicates, sulphates, nitrates, carbonaceous compounds, and high molecular weight hydrocarbons such as benzo-(a)-pyrene. Other particulate sources include surface abrasion and/or wind erosion from mine vehicles, mining operations, coke stock pile operations and handling of tailings sand.

B9.6 Total Hydrocarbon Emissions

The following table provides estimates of hydrocarbon emissions resulting from combustion sources:

Source	THC Emission Rate (t/cd)
Combustion Sources	
Main Stack	n/d(a)
Secondary Combustion Sources	0.26
Diverter Stacks	0.65
Flare Stacks	0.08
Mine Fleet	0.67
Area Sources	
Tailings Settling Basin	2.1(b)
Other	11.7(c)
Total	15.5

(a) Not determined.
(b) Based on 1992 data for emissions from surface water of the tailings settling basins.
(c) Based on 1987 data and does not account for emission reduction programs initiated since that time.

It should be noted that THC includes methane (CH_4) and non-methane components. The non-methane components are often referred to as VOC (volatile organic compounds). In the preceding table, the emission rates for the combustion sources were based on U.S. EPA emission factors for THC (i.e., methane and non-methane components).

B9.7 Total Reduced Sulphur Emissions

The following table identifies the TRS emission sources and provides a summary of the estimated emissions rates for each source:

Source	TRS Emission Rate (t/cd)
Diverter Stacks	0.67
Area Sources	
Tailings Settling Basin	0.05
Other	0.04
Total	0.70

The preceding table indicates that the diverter stacks are the largest source of TRS emissions (primarily H_2S, COS and CS_2). The TRS emissions from the tailings settling basin tend to be in the form of thiophenes.

B10.0 REFERENCES

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APPENDIX C

Other Industrial Emission Sources Identification and Characterization

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C1.0 OTHER INDUSTRIAL EMISSION SOURCES

Appendix C summarizes the emissions from other existing or approved industrial sources in the Athabasca Oil Sands Region. These sources include the following:

- **AOSTRA UTF.** The emission sources at the Alberta Oil Sands Technology and Research Authority (AOSTRA) Underground Test Facility (UTF) include a central utility flare stack, a glycol heater, a mine heater and five steam generators. Emissions from these sources are discussed in Section C2.0.
- **SOLV-EX Bitumount.** The emission sources at the SOLV-EX Bitumount facility include the sulphur recovery plant and tail gas incinerator, the sulphuric acid plant, and various secondary sources (i.e., heaters, boilers, dryers and turbines). These emission estimates are presented in Section C3.0.
- **SOLV-EX Ruth Lake.** The emission sources at the SOLV-EX Bitumount facility include the acid plant and various secondary sources (i.e., heaters, power boiler and dryers). These emission estimates are presented in Section C4.0).
- **Northland Forest Products. Section** C5.0 presents estimated emissions for the conical burner at the Northland Forest Products lumber mill.
- **Fort McMurray Hospital.** Section C6.0 presents estimated emissions for the hospital incinerator, which operates on an intermittent basis.

Section C7.0 summarizes and compares the emissions from these industrial sources.

C2.0 AOSTRA UTF

Emissions were estimated for the central utility flare stack at the AOSTRA UTF and for various secondary sources including the following:

- Two 14.6 MW steam generators
- Two 7.3 MW steam generators
- One 1.2 MW glycol heater
- One 1.8 MW mine heater

The mine heater was assumed to be operational for six months of the year. The existing 2.1 MW emergency steam generator at the UTF was not included in the emissions estimates, since it is used for emergencies only.

C2.1 Flare Stack Emissions

The AOSTRA flare stack is 18.3 m in height. The following table provides estimates of emissions for this source:

	Emission Rate (t/sd)
SO_2	0.06 a)
NO_x	0.014 (b)
CO	n/d (c)
CO_2	n/d (c)
THC	negligible
TRS	negligible

(a) BOVAR Environmental 1996
(b) BOVAR-CONCORD Environmental 1995.
(c) Not determined.

The design capacity of the flare is 10 000 m^3/d at 15 °C and 101.3 kPa. Analysis of the waste gas in 1995 indicated an average heating value of 22.2 MJ/m^3 (BOVAR Environmental 1996). For the purpose of estimating NO_x emissions, a U.S. EPA emission factor of 43 ng/J was used (BOVAR-CONCORD Environmental 1995).

C2.2 Secondary Source Emissions

The following table presents the source parameters associated with the secondary sources at the UTF facility (BOVAR-CONCORD Environmental 1995):

Source[(a)]	Input Capacity (MW)	Stack Height (m)	Diameter (m)	Exit Temperature (°C)	Exit Velocity (m/s)
Steam Generator	14.6	12.2	0.54	193	39.7
Steam Generator	14.6	12.0	0.91	193	14.1
Steam Generator	7.3	12.2	0.54	260	29.0
Steam Generator	7.3	12.0	0.54	260	29.0
Glycol Heater	1.2	7.3	0.31	300	15.1

(a) Data were not compiled for the mine heater.

The following table summarizes the emission factors used to estimate emission rates for the secondary sources at the UTF facility:

Source	Input Capacity (MW)	Normal Fuel Consumption (m^3/d)	Utilization	Emission Factors (kg/10^6 m^3)(a)				
				SO_2	NO_x	CO	CO_2	THC
Steam Generator	14.6	30 000	Continuous	9.6	2240	560	1.90E+06	92
Steam Generator	14.6	30 000	Continuous	9.6	2240	560	1.90E+06	92
Steam Generator	7.3	15 000	Continuous	9.6	2240	560	1.90E+06	92
Steam Generator	7.3	15 000	Continuous	9.6	2240	560	1.90E+06	92
Glycol Heater	1.2	2240	Continuous	9.6	1600	330	1.90E+06	128
Mine Heater(b)	1.8	4200	Winter	9.6	1600	330	1.90E+06	128

(a) Tables 1.4-2 and 1.4-3, U.S. EPA 1995.
(b) Assumed to operate 6 months of the year.

Using the emission factors indicated in the preceding table, the total estimated emission rates associated with the secondary sources at the AOSTRA UTF are as follows:

Contaminant	**Emission Rate (t/sd)**
SO_2	0.001
NO_x	0.212
CO	0.052
CO_2	183.2
THC	0.009
Particulates	n/d(a)

(a) Not determined.

C2.3 Summary of AOSTRA UTF Emissions

The following table presents a summary of the estimated emissions from the flare and secondary sources at AOSTRA:

Contaminant	**Emission Rate (t/sd)**
SO_2	0.061
NO_x	0.226
CO(a)	0.052
CO_2(a)	183.2
THC	0.009

(a) Not determined for flaring.

C3.0 SOLV-EX BITUMOUNT

The approved SOLV-EX Bitumount plant will be serviced by a main stack and several secondary sources which will vent gas streams to the atmosphere. The incinerator is expected to be in operation in late 1996 and the sulphuric acid plant is expected to be in operation by the end of 1997.

The main stack, which will service the sulphur recovery plant incinerator and the sulphuric acid manufacturing plant, is the largest source of SO_2 emissions. Emissions parameters associated with the main stack are presented in Table C.1. Heaters at the plant site could be additional sources of SO_2 emissions if No. 2 fuel oil is used (i.e., 0.48 t/sd SO_2 for Phase I and 1.44 t/sd SO_2 for Phase 2 (SOLV-EX 1995*b*)).

Stack parameters for the secondary combustion sources are presented in Table C.2. Although not indicated in the table, the major sources of NO_x emissions at the plant are the utilities (0.213 t/sd), the double salt dryer (0.159 t/sd), and the Bitumount upgrading soaker furnace (0.119 t/sd). These sources represent 76% of the total estimated NO_x emissions of 0.645 t/sd (SOLV-EX 1995*b*).

The major sources of particulate emissions are expected to be the double salt dryer (0.487 t/sd), the clay dryer exhaust (0.262 t/sd), utilities (0.211 t/sd) and the alumina dryer exhaust (0.187 t/sd). These three sources represent 92% of the total estimated particulate emissions of 1.25 t/sd.

C3.1 Summary of SOLV-EX Bitumount Emissions

The following table summarizes the estimated emission rates for the stationary sources at the SOLV-EX facility during normal operations:

Contaminant	**Total Stationary Sources (t/sd)**
SO_2(a)	3.57
NO_x(a)	0.645
CO	0.29
CO_2(b)	1050
THC	2.45
TRS(c)	0.007
Particulates(a)	1.25

(a) SOLV-EX Corporation 1995*b*.
(b) SOLV-EX Corporation 1995*c*.
(c) SOLV-EX Corporation 1995*f*.

Table C.1 Emission parameters associated with the proposed SOLV-EX Bitumount main stack (A4/A11).

Phase		**I**		**II**	
Year		**1996**		**1998**	
Incinerator Operation		**Yes**		**Yes**	
Sulphur Acid Plant Operation		**No**		**Yes**	
Operating Condition		**Normal**	**Abnormal**	**Normal**	**Abnormal**
Stack height	(m)	60	60	60	60
Stack diameter	(m)(a)	0.36	0.36	1.35	1.35
Exit velocity	(m/s)	18.5	52.2	18.9	38.9
Exit temperature	(°C)	538	538	250	300
SO_2 emissions					
Design	(t/sd)	0.62	1.25	2.14(c)	4.75(d)
Approved(b)	(t/sd)	0.6	1.2	2.9(c)	-
	(t/h)	0.035	0.074	0.149(c)	-

(a) Exit diameter is reduced until sulphur acid plant is in production.
(b) SOLV-EX 1995*b*.
(c) Sum of normal operating conditions for sulphuric acid plant and sulphur recovery plant.
(d) Sum of abnormal operating conditions for sulphuric acid plant and normal operating conditions for sulphuric recovery plant.

Table C.2 Identification of stack parameters associated with normal operation conditions for the approved SOLV-EX Bitumount Plant[a].

Stack	Stack Height (m)	Diameter (m)	Exit Temperature (°C)	Exit Velocity (m/s)
Utilities (A12/A14)	33	1.60	230	17.39
Bitumen upgrading soaker furnace (A3)	38	1.20	230	12.45
Clay dryer heater (A15)	53	0.90	230	14.22
Clay dryer exhaust (A5)	35	1.20	80	17.67
Ferrous sulphate dryer heater (A7)	35	0.20	230	15.58
Ferrous sulphate dryer exhaust (A9)	25	0.20	80	12.47
By-product sulphate dryer exhaust (A19)	25	0.8	100	17.25
Double salt dryer (A6)	53	1.85	200	18.02
K_2SO_4 dryer heater (A10)	33	0.20	230	14.42
K_2SO_4 dryer exhaust (A17)	33	0.20	80	11.86
Alumina dryer (A8)	33	1.0	80	16.69
Emergency flare (A13)[c]	45	0.24	1000	20.00

[a] SOLV-EX 1995*b*.

[b] Equipment identification numbers are shown in brackets.

[c] Values given are typical for emergency flaring of the sour fuel and acid gas streams.

The information in the preceding table was based on the following:

- The CO emissions were estimated from the process thermal input of 216 025 kW (SOLV-EX 1995*e*), a heating value of 9.3 x 10^6 kcal/m^3 for distillate oil (Appendix A, U.S. EPA 1985) and an emission factor of 0.6 kg/L for uncontrolled fuel oil combustion (Table 1.3-1, U.S. EPA 1995).

- The THC emissions were estimated as 0.05 t/sd resulting from the stationary combustion sources and 2.4 t/sd from fugitive sources, for a total of 2.45 t/sd (SOLV-EX 1995*f*). These emissions were estimated from the process thermal input of 216 025 kW (SOLV-EX 1995*e*), a heating value of 8270 kcal/m^3 for natural gas and a U.S. EPA emission factor of 92 kg/10^6 m^3 for natural gas combustion in small industrial boilers gas (Table 1.4-3, U.S. EPA 1995).

C4.0 SOLV-EX RUTH LAKE

The proposed SOLV-EX Ruth Lake plant will be serviced by a number of sources that vent gas streams to the atmosphere. These sources are identified in Table C.3. At full capacity, the primary emission source at the SOLV-EX Ruth Lake site will be the common stack which is expected to contribute 38% of the total estimated SO_2 emissions of 3.78 t/sd (SOLV-EX Corporation 1995*a*).

The following table summarizes the estimated emission rates for the SOLV-EX Ruth Lake facility:

Contaminant	Emission Rate (t/sd)
SO_2(a)	3.78
NO_x(a)	1.71
CO	0.34
CO_2	1500
THC	0.05
TRS	negligible
Particulates(a)	0.77

(a) SOLV-EX Corporation 1995*a*.

The preceding table is based on the following assumptions:

- The CO emissions were estimated from the process thermal input of 252 272 kW (SOLV-EX 1995*d*), a heating value of 9.3 x 10^6 kcal/m^3 for distillate oil (Appendix A, U.S. EPA 1985) and an emission factor of 0.6 kg/L for uncontrolled fuel oil combustion (Table 1.3-1, U.S. EPA 1995).

- The CO_2 emissions were estimated from the process thermal input of 252 272 kW (SOLV-EX 1995*d*), a heating value of 9.3 x 10^6 kcal/m^3 for distillate oil (Appendix A, U.S. EPA 1985). The emission factor was calculated based on a fuel carbon content of 87.3% (Table 9-10, Perry 1984), and a distillate oil density of 845 kg/m^3 (Appendix A, U.S. EPA 1985).

- The THC emissions were estimated from the process thermal input of 252 272 kW (SOLV-EX 1995*d*), a heating value of 8270 kcal/m^3 (1000 BTU/SCF) for natural gas and a U.S. EPA emission factor of 92 kg/10^6 m^3 for natural gas combustion in small industrial boilers (Table 1.4-3, U.S. EPA 1995).

Table C.3 Identification of emission sources associated with the proposed SOLV-EX Ruth Lake Plant[a].

Stack	**Stack Height (m)**	**Diameter (m)**	**Exit Temperature (°C)**	**Exit Velocity (m/s)**
Combined silica calciner and acid plant (A5/A14)[b]	60	1.5	162	16.47
$FeSO_4$ heater (A6)	35	0.2	230	16.76
K_2SO_4 heater (A9)	20	0.2	230	15.53
Utilities (A15)	35	1.75	230	20.06
Silica dryer (A3)	35	1.0	230	18.96
Double salt dryer (A11)	35	1.8	200	20.85
Hot oil dryer heater (A1)	35	0.8	230	19.98
Alumina dryer (A12)	25	0.91	80	19.96
$FeSO_4$ process dryer (A7)	35	0.15	80	21.48
K_2SO_4 process dryer (A10)	20	0.15	80	20.44
Fines process dryer (A2)	35	0.90	80	18.05
Sulphate by-product dryer (A8)	35	0.76	100	19.02

[a] SOLV-EX 1995f.

[b] Equipment identification numbers are shown in brackets.

C5.0 NORTHLAND FOREST PRODUCTS

Emissions were estimated for the Northland Forest Products lumber mill conical burner, assuming the burner operates at 75% of design capacity (75% of 90 t/h), 8 h/d, 5 days per week. The following table presents the emission factors and estimated emission rates associated with the Northland Forest Products lumber mill:

Contaminant	**Emission Factor**[a]	**Emission Rate**	
		(t/sd)	**(t/cd)**
SO_2	0.05	0.03	0.02
NO_x	0.5	0.27	0.19
CO	65	35.1	25.0
CO_2[b]	5.5	918	654
NMOC[c]	1700	2.97	2.12
Particulates	0.5	0.27	0.19

[a] Assuming satisfactory operation: 500% excess air and an exit temperature of 370°C (Table 2.7-1, U.S. EPA 1995).

[b] Assuming the emission factor for burning wood in a residential fireplace (Table 1.9-1, U.S. EPA 1995).

[c] Non-methane organic compounds.

C6.0 FORT McMURRAY HOSPITAL

The Fort McMurray Hospital produces a stream of 454 kg/d of waste which is incinerated on an intermittent basis (Powell 1987). The hospital incinerator emits approximately 0.48 kg/d (0.17 t/a) of SO_2 assuming an emission factor of 105 g SO_2/kg red bag waste (Walker *et al.* 1992). The following table summarizes the estimated emissions from the incinerator:

Contaminant	**Emission Factors (g/kg)**
SO_2 (a)	1.05
NO_x (a) (b)	1.45
CO (a)	13.3
Particulates (c)	6.67
Contaminant	**Emission Rates (10^{-3} t/sd)**
SO_2	0.48
NO_x	0.66
CO	6.04
CO_2	n/d (d)
THC	0
Particulates	3.03

(a) Walker *et al.* 1992.
(b) Emission factor for NO_x as NO.
(c) Powell 1987.
(d) Not determined.

C7.0 SUMMARY OF OTHER INDUSTRIAL SOURCE EMISSIONS

The following section summarizes the emissions on a case-by-case basis for the industrial sources discussed in the previous sections.

C7.1 SO_2 Emissions

The following table identifies the SO_2 emission sources and provides a summary of the estimated emission rates for each source:

Source	SO_2 Emission Rate (t/sd)
AOSTRA	0.061
SOLV-EX Bitumount	3.57
SOLV-EX Ruth Lake	3.78
Northland Forest Products	0.03
Fort McMurray Hospital	0.0005
Total	7.4

C7.2 NO_x Emissions

The following table identifies the NO_x emission sources and provides a summary of the estimated emission rates for each source:

Source	NO_x Emission Rate (t/sd)
AOSTRA	0.226
SOLV-EX Bitumount	0.645
SOLV-EX Ruth Lake	1.71
Northland Forest Products	0.27
Fort McMurray Hospital	0.0007
Total	2.8

C7.3 CO Emissions

The following table identifies the CO emission sources and provides a summary of the estimated emission rates for each source:

Source	CO Emission Rate (t/sd)
AOSTRA	0.052
SOLV-EX Bitumount	0.29
SOLV-EX Ruth Lake	0.34
Northland Forest Products	35.1
Fort McMurray Hospital	0.006
Total	35.8

C7.4 CO_2 Emissions

The following table identifies the CO_2 emission sources and provides a summary of the estimated emission rates for each source:

Source	CO_2 Emission Rate (t/sd)
AOSTRA	183.2
SOLV-EX Bitumount	1050
SOLV-EX Ruth Lake	1500
Northland Forest Products	918
Fort McMurray Hospital	n/d(a)
Total	3651

(a) Not determined.

C7.5 Particulate Emissions

The following table identifies the particulate emission sources and provides a summary of the estimated emission rates for each source:

Source	SO_2 Emission Rate (t/sd)
AOSTRA	n/d[a]
SOLV-EX Bitumount	1.25
SOLV-EX Ruth Lake	0.77
Northland Forest Products	0.27
Fort McMurray Hospital	0.003
Total	2.3

(a) Not determined.

C7.6 Total Hydrocarbon Emissions

The following table identifies the total hydrocarbon emission sources and provides a summary of the estimated emission rates for each source:

Source	THC Emission Rate (t/sd)
AOSTRA	0.009[a]
SOLV-EX Bitumount	2.45
SOLV-EX Ruth Lake	0.05
Northland Forest Products	2.97
Fort McMurray Hospital	0
Total	5.5

(a) Total organic compounds.

C7.7 Total Reduced Sulphur Emissions

The following table identifies the TRS emission sources and provides a summary of the estimated emission rates for each source:

Source	TRS Emission Rate (t/sd)
AOSTRA	n/d[(a)]
SOLV-EX Bitumount	0.007
SOLV-EX Ruth Lake	negligible
Northland Forest Products	0
Fort McMurray Hospital	n/d
Total	0.007

(a) Not determined.

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APPENDIX D

Transportation and Residential Emission Sources Identification and Characterization

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D1.0 TRANSPORTATION AND RESIDENTIAL EMISSION SOURCES

There are a number of non-industrial sources of NO_x, CO and CO_2 emissions in the Athabasca Oil Sands region that result from combustion sources. Appendix D identifies these transportation, residential and natural emission sources on a case-by-case basis. Specifically, these sources include the following:

- Highway 63 traffic (gasoline and diesel fuelled vehicles).
- Local community traffic (gasoline and diesel fuelled vehicles).
- Natural gas combustion for residential and commercial space heating, cooking and water heating.
- Residential wood combustion (fireplace or wood stove).
- Natural sources.

The two primary communities are Fort McMurray and Fort McKay with respective populations of 34 706 and 322. The number of occupied residences are 11 000 and 100, respectively. For the most part, natural gas is used as the primary heating source in both communities.

D2.0 HIGHWAY AND LOCAL TRAFFIC

Motor vehicle exhaust emissions can be a source of SO_2, NO_x, CO, CO_2, THC and particulate emissions. The emission rates are dependent on a wide variety of factors including the following:

- Vehicle parameters (such as fuel type and vehicle type)
- Environmental parameters (such as ambient temperature)
- Operating parameters (such as average road speed and cold start versus warm stabilized operation)

A number of simplifying assumptions were made to estimate the motor vehicle emissions from the vicinity of Fort McMurray and Fort McKay. Two major traffic conditions were considered: highway traffic flow on Highway 63, and residential traffic on local streets in Fort McMurray and Fort McKay.

The number of vehicles on Highway 63 were obtained from 1994 traffic counts as provided by Alberta Transportation and Utilities. The following assumptions were made for the communities of Fort McMurray and Fort McKay:

- There are 1.5 vehicles per household (11 004 occupied households in Fort McMurray and 102 occupied households in Fort McKay)
- Vehicles in Fort McMurray travel an average of 20 km each day
- Vehicles in Fort McKay travel an average of 10 km each day

The emission factors were obtained from the following three sources:

- The U.S. EPA (1985*b*) has compiled motor vehicle emission factors for a wide variety of vehicle, environmental and operating parameters. These emission parameters are expressed in terms of grams per vehicle mile travelled (g/mile) and are provided for carbon monoxide, oxides of nitrogen and total hydrocarbons.

  To calculate the vehicle emission estimates, the US EPA vehicle classification scheme was adopted and a breakdown of vehicle types from Concord Environmental (1991) was used. Emissions were calculated for an average annual temperature condition of 0°C.

- The U.S. EPA (1995) has compiled emission factors for stationary uncontrolled gasoline and diesel industrial engines. Emissions of SO_2 and CO_2 were calculated from these factors. The vehicle breakdown, as described above, was used to determine the percentage of gasoline engines versus diesel engines.

- In general, paved road particulate emissions result from the loose material present on the road surface. Particulate emissions were calculated using the U.S. EPA (1995) emission factors for paved roadways.

The following table summarizes the emission factors and estimated emission rates for vehicle traffic:

Emission Factors	**Highway**	**Local**	**Comment**
SO_2 (a) (g/km)	0.68	0.68	Diesel only
NO_x (b) (g/mile)	3.1	2.8	Composite gasoline & diesel
CO (b) (g/mile)	10.6	10.6	Composite gasoline & diesel
CO_2 (a) (g/km)	0.34	0.34	Gasoline
	0.38	0.38	Diesel
THC (b) (g/mile)	1.9	4.4	Composite gasoline & diesel
Particulates (c) (g/km)	4.2-6.9	4.6	A function of traffic volume
Emission Rates (t/cd)	**Highway 63**	**Fort McMurray**	**Fort McKay**
SO_2	0.01	0.18	0.00
NO_x	0.46	0.58	0.003
CO	1.56	2.18	0.01
CO_2	81	114	0.53
THC	0.27	0.90	0.004
Particulates	1.09	1.53	0.007

(a) Calculated from emission factors for highway and local traffic (Appendices J-6 and J-3, U.S. EPA 1995).

(b) Calculated from emission factors from Table 3.3-1, U.S. EPA (1995).

(c) Calculated using the equations and factors presented in Section 13.2.1 of U.S. EPA (1995).

It was assumed that traffic sources do not contribute significantly to concentrations of TRS compounds in the atmosphere.

D3.0 NATURAL GAS CONSUMPTION

About 85% of the natural gas consumed by residential/light commercial operations is for space heating purposes and the amount of fuel issued is proportional to heating degree-days. The remaining 15% is used for heating domestic water and is uniformly spread over the year. According to North Western Utilities, the City of Fort McMurray consumed 2 614 852 GJ of natural gas in 1995 and Fort McKay consumed 60 449 GJ.

The following table summarizes the emission factors and estimated emission rates associated with natural gas consumption in Fort McMurray and Fort McKay:

Contaminant	**Emission Factors ($kg/10^6\ m^3$)**
SO_2	9.6
NO_x	1500
CO	640
CO_2	2.066
THC	180
Particulates(b)	80

Emission Rates	**Fort McMurray (10^{-3} t/cd)**	**Fort McKay (10^{-3} t/cd)**	**Total (10^{-3} t/cd)**
SO_2	2	0.04	2.04
NO_x	276	6	282
CO	118	3	121
CO_2	368 000	8500	376 500
THC	33	0.76	33.76
Particulates	15	0.34	15.34
Natural Gas Use	2615 TJ/a	60 TJ/a	2685 TJ/a

(a) Table 1.4-2, U.S. EPA 1995.
(b) Table 1.4-1, U.S. EPA 1985*a*.

It was assumed that natural gas combustion sources do not contribute significantly to concentrations of TRS compounds in the atmosphere.

D4.0 RESIDENTIAL WOOD COMBUSTION

To estimate the emissions from residential wood combustion, assumptions regarding the number of residential wood burning units, frequency of use, preferred usage periods, duration of use and amount of wood consumed are required. For this assessment, residential wood combustion was not assumed to take place during the summer period (T = 20°C). However, two winter emission scenarios were assumed (i.e., T = -20°C and T = 0°C). The following table presents the assumptions used to estimate emissions from residential wood combustion:

Assumptions			
Occupied dwellings with wood combustion units (%)		50	
Number of dwellings with wood combustion units:			
Fort McMurray		5832	
Fort McKay		54	
		Winter 1	**Winter 2**
Ambient Temperature		- 20	0
Fireplace Assumptions:			
Combustion units	(%)	80	80
Utilization factor	(%)	50	20
Burning rate	(kg/h)	8	8
Burning duration	(h)	6	4
Operating days	(d/a)	20	40
Wood Stove Assumptions:			
Combustion units	(%)	20	20
Utilization factor	(%)	50	50
Burning rate	(kg/h)	4	4
Burning duration	(h)	12	6
Operating days	(d/a)	30	50

Residential wood consumption is assumed to be greater for lower temperatures. The burning duration and number of days were used to provide an estimate of annual emissions. The burning rate and duration assumptions are consistent with those presented by Concord Environmental (1991) for maximum usage (winter conditions). Furthermore, 80% of the wood combustion units were assumed to be open fireplaces and the balance being wood stoves.

The following table presents the emission factors and estimated emissions for residential wood combustion:

	Fireplace(a) (g/kg)	**Woodstove(b) (g/kg)**
Emission Factors		
SO_2	0.2	0.2
NO_x	1.3	1.4
CO	126.3	115.4
CO_2	1700	--
THC	--	24.3
VOC(c)	114.5	--
Particulates (PM_{10})	17.3	15.3

Emission Rates	**Fort McMurray (10^{-3} t/cd)**	**Fort McKay (10^{-3} t/cd)**	**Total (10^{-3} t/cd)**
Emissions			
SO_2	2.6	0.024	2.6
NO_x	17.1	0.16	17.3
CO	1580	14.7	1595
CO_2	15 088	140	15 228
THC	97	9.4	106
VOC	1016	0.90	1017
Particulates (PM_{10})	214	2.0	216

(a) Table 1.9-1, U.S. EPA (1995).
(b) Table 1.10-1, U.S. EPA (1995)
(c) Volatile Organic Compounds.

D5.0 NATURAL SOURCES

Soils and ocean contribute to atmospheric levels of SO_2. Due to the location of the Athabasca oil sands, the effect of oceans is expected to be negligible. Vegetation such as trees and bushes contain sulphur. In the event of a forest fire, sulphur may be released into the air as SO_2. The contribution of forest fires to the atmosphere levels of SO_2 in the Athabasca oil sands region has not been quantified for this study.

Natural combustion sources of NO_x, CO and CO_2 can result from forest fires. The emissions will depend on the area of the fire, the fuel consumption and the burning behaviour. Based on a fuel consumption of 100 t/ha, the following emission factors (U.S. EPA 1995) have been applied to wild fires:

Contaminant	**Emission Factors (kg/ha)**
NO_2[a]	200
CO[a]	7000
CO_2[b]	1700
THC[a] [c]	1200
Particulates[a]	850

[a] Average of emission factors presented in Table 13.1-2 (U.S. EPA 1995) for the Northern and Rocky Mountain regions.

[b] Emission factor for burning wood in residential fireplaces (Table 1.9-1, U.S. EPA 1995).

[c] Volatile organic compounds.

According to the Alberta Forest Fire Center, between 1983 and 1994 there were an average of 98 fires per year in the Waterways Forest District with an average duration of 1.7 days. Between 1983 and 1994, the average area burned was 16 ha per fire.

Based on a 16 ha wildfire lasting 1.7 days, the emissions are expected to be approximately the following:

Contaminant	**Emission Rate**	
	(t/d)[(a)]	**(t/cd)**[(b)]
NO_2	1.9	0.84
CO	66	29
CO_2	16	7.1

[(a)] Tonnes per day that a fire is burning.
[(b)] Tonnes per calendar day.

D6.0 SUMMARY OF TRANSPORTATION AND RESIDENTIAL EMISSIONS

The following section summarizes the emissions on a case-by-case basis for the transportation and residential sources discussed in the previous sections.

D6.1 SO_2 Emissions

The following table identifies the SO_2 emission sources and provides a summary of the estimated emission rates for each source:

Source	SO_2 Emission Rate (t/cd)
Highway 63	0.01
Local Traffic	
Fort McMurray	0.18
Fort McKay	0.00
Residential Heating	
Natural Gas	0.002
Wood	0.003
Total	0.2

D6.2 NO_x, CO and CO_2 Emissions

The following table identifies the NO_x, CO and CO_2 emission sources and provides a summary of the estimated emission rates for each source:

Source	Emission Rate (t/cd)		
	NO_x	CO	CO_2
Highway 63	0.46	1.56	81
Local Traffic			
Fort McMurray	0.58	2.18	114
Fort McKay	0.003	0.01	0.53
Residential Heating			
Natural Gas	0.282	0.121	376.5
Wood	0.017	1.60	15.2
Total	1.3	5.5	587

D6.3 Total Hydrocarbon Emissions

The following table identifies the total hydrocarbon emission sources and provides a summary of the estimated emission rates for each source:

Source	THC Emission Rate (t/cd)
Highway 63	0.27
Local Traffic	
Fort McMurray	0.90
Fort McKay	0.004
Residential Combustion	
Natural Gas(a)	0.015
Wood(a)	1.12
Total	2.3

(a) Total organic compounds.

D6.4 Particulate Emissions

The following table identifies the particulate emission sources and provides a summary of the estimated emission rates for each source:

Source	Particulates Emission Rate (t/cd)
Highway 63	1.09
Local Traffic	
Fort McMurray	1.53
Fort McKay	0.007
Residential Combustion	
Natural Gas	0.015
Wood	0.216
Total	2.9

D7.0 REFERENCES

Concord Environmental Corporation. 1991. An Air Quality Assessment for the Canmore/Bow Valley Corridor. Prepared for UMA Engineering Ltd. and Three Sisters Golf Resorts Inc. June 1991.

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