SUNCOR ENERGY INC
Form 40-F
March 08, 2007

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 40-F

(Check One)

o **Registration statement pursuant to Section 12 of the Securities Exchange Act of 1934**

or

x **Annual report pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934**

For fiscal year ended	**December 31, 2006**
Commission File Number	**No. 1-12384**

SUNCOR ENERGY INC.

(Exact name of registrant as specified in its charter)

Canada	**1311,1321,2911, 4613,5171,5172**	**98-0343201**
(Province or other jurisdiction of incorporation or organization)	(Primary standard industrial classification code number, if applicable)	(I.R.S. employer identification number, if applicable)

112 - 4th Avenue S.W.

Box 38

Calgary, Alberta, Canada T2P 2V5

(403) 269-8100

(Address and telephone number of registrant s principal executive office)

CT Corporation System

111 Eighth Avenue

New York, New York, U.S.A. 10011

(212) 894-8940

(Name, address and telephone number of agent for service in the United States)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class:	Name of each exchange on which registered:
Common shares	**New York Stock Exchange**

Securities registered or to be registered pursuant to Section 12(g) of the Act:

None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:

None

For annual reports, indicate by check mark the information filed with this form:

x Annual Information Form x Annual Audited Financial Statements

Indicate the number of outstanding shares of each of the issuer s classes of capital or common stock as of the close of the period covered by the annual report:

Common Shares	**As of December 31, 2006 there were 459,943,827 Common Shares issued and outstanding**
Preferred Shares, Series A	**None**

Indicate by check mark whether the registrant by filing the information contained in this form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the Exchange Act). If Yes is marked, indicate the file number assigned to the registrant in connection with such rule.

Yes o No x

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the proceeding 12 months (or for such shorter period that the registrant was required to file such reports); and (2) has been subject to such filing requirements in the past 90 days.

Yes x No o

SUNCOR ENERGY INC. ANNUAL INFORMATION FORM

February 28, 2007

ANNUAL INFORMATION FORM

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GLOSSARY OF TERMS

In this Annual Information Form (AIF), references to we , our , us , Suncor or the company include Suncor Energy Inc., its subsidiaries, partnerships and joint venture investments unless the context otherwise requires.

Barrel of Oil Equivalent (BOE)

Suncor converts natural gas to barrels of oil equivalent (BOE) at a 6 mcf:1 bbl ratio. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6:1 is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Bitumen/Heavy Crude Oil

A naturally occurring viscous tar-like mixture, mainly containing hydrocarbons heavier than pentane, which is not recoverable at a commercial rate in its naturally occurring viscous state through a well without using enhanced recovery methods. When extracted, bitumen/heavy crude oil can be upgraded into crude oil and other petroleum products.

Capacity

Maximum output that can be achieved from a facility in ideal operating conditions in accordance with current design specifications.

Coal Bed Methane

Natural gas produced from wells drilled into a coal formation.

Conventional Crude Oil

Crude oil produced through wells by standard industry recovery methods.

Conventional Natural Gas

Natural gas produced from all geological strata, excluding coal bed methane.

Crude Oil

Unrefined liquid hydrocarbons, excluding natural gas liquids.

Developed Reserves

Developed reserves are those proved reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production.

Development Costs

Includes all costs associated with moving reserves from other classes such as proved undeveloped and probable to the proved developed class.

Downstream

These business segments manufacture, distribute and market refined products from crude oil.

Dry Hole/Well

An exploration or development well determined, on an economic basis, to be incapable of producing hydrocarbons that will be plugged, abandoned and reclaimed.

Feedstock

Purchases of components required in the production of refined product other than crude oil.

Finding Costs

Includes the cost of and investment in undeveloped land, geological and geophysical activities, exploratory drilling and direct administrative costs necessary to discover crude oil and natural gas reserves.

Gross Production/Reserves

Suncor s working interest in production/reserves, as the case may be, before deducting Crown royalties, freehold and overriding royalty interests.

Gross Wells/Land Holdings

Total number of wells or acres, as the case may be, in which Suncor has an interest.

Heavy Fuel Oil

Residue from refining of conventional crude oil that remains after lighter products such as gasoline, petrochemicals and heating oils have been extracted. This product traditionally sells at less than the cost of crude oil.

In-situ Oil

In-situ or in place refers to methods of extracting heavy crude oil from deep deposits of oil sands by drilling with minimal disturbance of the ground cover.

Lifting Costs

Includes all expenses related to the operation and maintenance of producing or producible wells and related facilities, natural gas plants and gathering systems.

MD&A

Suncor s Management s Discussion and Analysis dated February 28, 2007, accompanying its audited consolidated financial statements, notes thereto and auditor s report thereon, as at and for the three years in the period ended December 31, 2006, which is incorporated by reference herein.

Natural Gas

Hydrocarbons that at atmospheric conditions of temperature and pressure are in a gaseous state.

Natural Gas Liquids

Hydrocarbon products recovered as liquids from raw natural gas by processing through extraction plants or recovered from field separators, scrubbers or other gathering facilities. These liquids include the hydrocarbon components ethane, propane, butane and pentane, or a combination thereof.

Net Production/Reserves

Suncor s undivided percentage interest in total production or total reserves, as the case may be, after deducting Crown royalties and freehold and overriding royalty interests.

Net Wells/Land Holdings

Suncor s undivided percentage interest in the gross number of wells or gross number of acres, as the case may be, after deducting interests of third parties.

Overburden

Material overlying oil sands that must be removed before mining. Consists of muskeg, glacial deposits and sand.

Oil Sands

Oil sands are a naturally occurring mixture of water, sand, clay and bitumen, a very heavy crude oil.

Probable Reserves[1]

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely[2] that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Proved oil and gas reserves

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty[2] to be recoverable in future years from known reservoirs under assumed economic and operating conditions.

Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining

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(1) We are subject to Canadian disclosure rules in connection with the reporting of reserves. However, we have received exemptive relief from Canadian securities administrators permitting us to report our reserves in accordance with U.S. disclosure practices. Although U.S. companies do not disclose probable reserves for non-mining properties, we voluntarily disclose probable reserves for our Firebag in-situ leases as we believe this information is useful to investors. See RESERVES ESTIMATES on page 20 for a description of how our voluntary reserves disclosure differs from our U.S. required disclosure.

(2) In estimating our proved and probable reserves, our independent reserves evaluators, GLJ Petroleum Consultants Ltd. (GLJ), have targeted the following levels of certainty: at least 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves. However, as our reserves have been prepared using deterministic, rather than probabilistic methods, consistent with industry practice, GLJ s estimates do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Estimates of proved reserves do not include the following: (A) oil that may become available from known reservoirs but is classified separately as indicated additional reserves ; (B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

For a discussion of pricing assumptions see the tables under the headings REQUIRED U.S. OIL AND GAS AND MINING DISCLOSURE Proved Conventional Oil and Gas Reserves and under VOLUNTARY OIL SANDS RESERVES DISCLOSURE Oil Sands Mining and In-Situ Firebag Reserves Reconciliation .

Proved Producing Reserves

Proved producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the anticipated date of resumption of production must be known.

Reservoir

Body of porous rock containing an accumulation of water, crude oil or natural gas.

Sour Synthetic Crude Oil

Crude oil produced from oil sands that requires only partial upgrading and contains a higher sulphur content than sweet synthetic crude oil.

Sweet Synthetic Crude Oil

Crude oil produced from oil sands consisting of a blend of hydrocarbons resulting from thermal cracking and purification of bitumen.

Synthetic Crude Oil

Upgraded or partially upgraded crude oil recovered from oil sands including surface mineable oil sands leases and in-situ oil sands/heavy oil leases.

Undeveloped Oil and Natural Gas Lands

Undeveloped lands are those on which wells have not been drilled or completed to a point that would permit production of commercial quantities of crude oil and natural gas regardless of whether or not such acreage contains proved reserves.

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Upstream

These business segments include acquisition, exploration, development, production and marketing of crude oil, natural gas and natural gas liquids; and for greater clarity include the production of synthetic crude oil, bitumen and other oil products from oil sands as well as production using conventional methods.

Utilization

The average use of capacity taking into consideration planned and unplanned outages and maintenance.

Wells

Development Well

A crude oil or natural gas well drilled in, or adjacent to, a reservoir known to be productive and expected to produce in the future.

Drilled Well

A well that has been drilled and has a defined status (e.g. gas well, shut-in well, producing oil well, producing gas well, suspended well or dry and abandoned well).

Exploratory Well

A well drilled in a territory without existing proved reserves, with the intention to discover commercial reservoirs or deposits of crude oil and/or natural gas.

CONVERSION TABLE

1 cubic metre m^3 = 6.29 barrels	1 tonne = 0.984 tons (long)
1 cubic metre m^3 (natural gas) = 35.49 cubic feet	1 tonne = 1.102 tons (short)
1 cubic metre m^3 (overburden) = 1.31 cubic yards	1 kilometre = 0.62 miles
	1 hectare = 2.5 acres

Notes:

(1) Conversion using the above factors on rounded numbers appearing in this Annual Information Form may produce small differences from reported amounts.

(2) Some information in this Annual Information Form is set forth in metric units and some in imperial units.

CURRENCY

All references in this Annual Information Form to dollar amounts are in Canadian dollars unless otherwise indicated.

FORWARD-LOOKING STATEMENTS

This Annual Information Form contains certain forward-looking statements that are based on our current expectations, estimates, projections and assumptions that we ve made in light of our experience.

All statements that address expectations or projections about the future, including statements about our strategy for growth, expected future expenditures, commodity prices, costs, schedules, production volumes, operating and financial results and expected impact of future commitments, are forward-looking statements. Some of the forward-looking statements may be identified by words like expects, anticipates, estimate , plans, believes, indicates, could, goal, t objective, will continue, schedule, foreseeable, proposed, potential, may, and similar expressions. These statements are not guarantees performance and involve a number of risks and uncertainties, some that are similar to other oil and gas companies and some that are unique to our experience. Our actual results may differ materially from those expressed or implied by our forward-looking statements and you are cautioned not to place undue reliance on them.

The risks, uncertainties and other factors that could influence actual results include but are not limited to: changes in the general economic, market and business conditions; fluctuations in supply and demand for our products; commodity prices and currency exchange rates; our ability to respond to changing markets, and to receive timely regulatory approvals; the successful and timely implementation of capital projects including growth projects (for example the continued investment in our Firebag in-situ development project) and regulatory projects (for example, the clean fuels refinery modifications projects in our downstream businesses); the accuracy of cost estimates, some of which are provided at the conceptual or other preliminary stage of projects and prior to commencement of conception of the detailed engineering needed to reduce the margin of error or level of accuracy; the integrity and reliability of our capital assets; the cumulative impact of other resource development; future environmental laws; the accuracy of our reserve, resource and future production estimates and our success at exploration and development drilling and related activities; the maintenance of satisfactory relationships with unions, employee associations and joint venture partners; competitive actions of other companies, including increased competition from other oil and gas companies and from companies that provide alternative sources of energy; labour and material shortages; and other facilities uncertainties resulting from potential delays or changes in plans with respect to projects or capital expenditures; actions by governmental authorities including the imposition of taxes or changes to fees and royalties; changes in environmental and other regulations (for example, the Government of Alberta s current review of the Crown Royalty regime, and the Government of Canada s current review of greenhouse gas emission regulations); the ability and willingness of parties with whom we have material relationships to perform their obligations to us; and the occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting us or other parties whose operations or assets directly or indirectly affect us. These important factors are not exhaustive.

Many of these risk factors and other specific risks and uncertainties are discussed in further detail throughout this Annual Information Form and in our MD&A, incorporated by reference herein. Readers are also referred to the risk factors described in other documents we file from time to time with securities regulatory authorities. Copies of these documents are available without charge from Suncor at 112 4th Avenue S.W., Calgary, Alberta, T2P 2V5, by calling 1-800-558-9071, or by email request to info@suncor.com or by referring to SEDAR at www.sedar.com or by referring to EDGAR at www.sec.gov. Information contained in or otherwise accessible through our website does not form a part of this AIF. All such references are inactive textual references only.

References herein to our 2006 Consolidated Financial Statements mean Suncor s audited consolidated financial statements prepared in accordance with Canadian generally accepted accounting principles (GAAP), notes thereto and auditor s report thereon, as at and for the three years in the period ended December 31, 2006.

NON GAAP FINANCIAL MEASURES

Certain financial measures referred to in this AIF that are not prescribed by GAAP, namely, cash flow from operations and Oil Sands cash and total operating costs per barrel, are described and reconciled in the Non GAAP Financial Measures , section of our MD&A, incorporated by reference herein.

CORPORATE STRUCTURE

Name and Incorporation

Suncor Energy Inc. (formerly Suncor Inc.) was originally formed by the amalgamation under the *Canada Business Corporations Act* on August 22, 1979, of Sun Oil Company Limited, incorporated in 1923 and Great Canadian Oil Sands Limited, incorporated in 1953. On January 1, 1989, we amalgamated with a wholly-owned subsidiary under the *Canada Business Corporations Act*. We amended our articles in 1995 to move our registered office from Toronto, Ontario, to Calgary, Alberta, and again in April 1997, to adopt our current name, Suncor Energy Inc. . In April 1997, May 2000, and May 2002, we amended our articles to divide our issued and outstanding shares on a two-for-one basis.

Our registered and principal office is located at 112 - 4th Avenue, S.W. Calgary, Alberta, T2P 2V5.

Intercorporate Relationships

We have four principal subsidiaries and partnerships.

Suncor Energy Oil Sands Limited Partnership, is an Alberta limited partnership that is indirectly wholly owned by Suncor Energy Inc. Effective February 1, 2005, Suncor Energy Inc., as general partner, and one of its wholly-owned subsidiaries, as a limited partner, formed the Suncor Energy Oil Sands Limited Partnership. At this time the partnership held certain net profits interests related to our oil sands business and natural gas business. Effective January 1, 2006, Suncor Energy Inc. contributed, subject to certain exceptions, its oil sands assets to the partnership. This internal reorganization had no effect on operations or on our consolidated net earnings.

Suncor Energy Products Inc. (formerly Sunoco Inc.) is an Ontario corporation that is wholly-owned by Suncor Energy Inc. This company refines and markets petroleum products and petrochemicals directly and indirectly through subsidiaries and joint ventures. We operate a retail business in Canada under the Sunoco brand through this subsidiary. We are unrelated to Sunoco, Inc. (formerly known as Sun Company, Inc.), headquartered in Philadelphia, Pennsylvania.

Suncor Energy Marketing Inc. (SEMI), wholly-owned by Suncor Energy Products Inc., is incorporated under the laws of Alberta. This company markets, mainly to customers in Canada and the United States, the crude oil, diesel fuel, bitumen and byproducts such as petroleum coke, sulphur and gypsum, produced by our Oil Sands business. Through this subsidiary we also administer Suncor s energy trading activities, market certain third party products, and procure crude oil feedstocks and natural gas for our downstream businesses. This subsidiary markets certain natural gas volumes produced by, and purchased from, our Natural Gas business unit. Suncor Energy Marketing Inc. also has a petrochemical marketing division that holds a 50% interest in Sun Petrochemicals Company (SPC), a petrochemical products joint venture.

Suncor Energy (U.S.A.) Inc., indirectly wholly-owned by Suncor Energy Inc., is incorporated under the laws of Delaware. Through this U.S. subsidiary, headquartered in Denver, Colorado, we refine crude oil at our refinery in Commerce City, Colorado, near Denver, into a broad range of petroleum products, and market our refined products to industrial, wholesale and commercial customers principally in Colorado and to retail customers in Colorado through Phillips 66 ® - branded sites. We also transport crude oil on our wholly or partly owned pipelines in Wyoming and Colorado.

We also have a number of other subsidiary companies. However, the total assets of such subsidiaries and partnerships combined, and their total sales and operating revenues, do not constitute more than 20 per cent of the consolidated assets, or consolidated sales and operating revenues, respectively, of Suncor.

GENERAL DEVELOPMENT OF THE BUSINESS

Overview

Suncor is an integrated energy company, with corporate headquarters in Calgary, Alberta, Canada. We are strategically focused on developing one of the world s largest petroleum resource basins Canada s Athabasca oil sands. In addition, we explore for, acquire, develop, produce and market crude oil and natural gas, transport and refine crude oil and market petroleum and petrochemical products. Periodically, we also market third party petroleum products. We also carry on energy trading activities focused principally on buying and selling futures contracts and other derivative instruments based on the commodities we produce.

We have four principal operating businesses:

Our Oil Sands business, based near Fort McMurray, Alberta, recovers bitumen, primarily through oil sands mining and in-situ development, and upgrades it into refinery feedstock, diesel fuel and by-products. Bitumen feedstock is also occasionally supplemented by third party suppliers.

Our Natural Gas business, based in Calgary, Alberta, explores for, acquires, develops and produces natural gas and natural gas liquids from reserves in Western Alberta and Northeastern British Columbia. The sale of natural gas production provides a natural price hedge for natural gas purchased for consumption at our Oil Sands facility and our refineries in Sarnia, Ontario and near Denver, Colorado. In addition, our indirectly wholly-owned U.S. subsidiary, Suncor Energy (Natural Gas) America Inc., acquires land and explores for coal bed methane in the United States.

Our third business, Energy Marketing and Refining Canada, headquartered in Toronto, Ontario, refines crude oil at Suncor s refinery in Sarnia, Ontario, into a broad range of petroleum, petrochemical and biofuel products. These products are then marketed to industrial, wholesale and commercial customers principally in Ontario and Quebec, and to retail customers in Ontario through Sunoco-branded and joint venture operated retail networks. We also engage in third party energy marketing and trading activities through this business.

Our fourth business, Refining and Marketing U.S.A., headquartered in Denver, Colorado, refines crude oil at our refinery in Commerce City, Colorado, near Denver, into a broad range of petroleum products, and markets our refined products to industrial, wholesale and commercial customers principally in Colorado and to retail customers in Colorado through Phillips 66 ® - branded sites. We also transport crude oil on our wholly or partly owned pipelines in Wyoming and Colorado.

For financial reporting purposes, we also report financial data for activities not directly attributable to an operating business under the results of Suncor s Corporate segment. This includes the activity of our self-insurance entity, as well as activities to pursue the development of low-emission and no-emission energy sources that have a reduced environmental impact outside our hydrocarbon-based businesses.

In 2006, we produced approximately 294,800 boe per day, comprised of 263,000 barrels per day (bpd) of crude oil and natural gas liquids and 191 million cubic feet per day (mmcf/d) of natural gas. In 2005, the most recent period with published results, we were the fourth largest crude oil and natural gas liquids producer in Canada (approximately 7%[3] of Canada s crude oil production in 2005) and the 18th largest natural gas producer in Canada.[4]

In 2006, our Energy Marketing and Refining business sold approximately 95,000 bpd (2005 96,000 bpd) or 15,100 m^3 per day (2005 15,200 m^3 per day) of refined products, mainly in Ontario but also in the United States and Europe. Our refined product sales in Ontario represented approximately 18% (2005

(3) CAPP Crude Oil Report Table 1 Canadian Crude Oil Production Forecast

(4) Oilweek July 2006, Top 100 Oil and Gas Producers

19%) of Ontario s total refined product sales in 2006[5]. In 2006, our Refining & Marketing business sold approximately 90,600 bpd or 14,400 m^3 of refined products in Colorado, including approximately 76,100 bpd or 12,100 m^3 per day of light oils (gasoline and distillates) (2005 86,200 bpd or 13,700 m^3 per day, including approximately 69,200 bpd or 11,000 m^3 per day of light oils).

Three-Year History

Cost estimates for major projects involve uncertainties and evolve in stages. For a discussion of this process, an update on the status of our significant capital projects in progress and an explanation of on time and on budget , see page 27 of our MD&A, incorporated by reference herein.

Oil Sands (OS)

OS growth We continue to advance our multi-phased growth strategy to increase production capacity to 500,000 to 550,000 bpd in 2010 to 2012. Key components of this strategy include the following milestones:

During the fourth quarter of 2005, we increased our production capacity to 260,000 bpd through the completion of a new vacuum unit. In addition, we also completed a debottleneck of our Steepbank mine operation.

We plan to increase production capacity to 350,000 bpd in 2008. We anticipate capital spending of approximately $2.1 billion for an additional coker unit to expand Upgrader 2. The project is currently on schedule and on budget. We currently estimate an additional $1.5 billion in costs to increase bitumen supply. (The $2.1 billion estimated cost for the coker unit has a range of uncertainty of +/- 10%. The $1.5 billion estimated cost for increased bitumen supply in connection with reaching our target of 350,000 bpd, has a range of uncertainty of +/- 10%.)

For expansion beyond 2008, toward our goal of 500,000 to 550,000 bpd in 2010 to 2012, OS filed a regulatory application in March 2005, and received regulatory approval in November 2006, to construct a third upgrader. The company expects to advance project development plans and cost estimates to a level appropriate to seek Board of Directors approval in 2007. Pending Board approval, we plan to begin construction in 2007.

In support of our plans to increase production capacity, we remain focused on increasing bitumen supply from:

i) the development of our Firebag in-situ oil sands reserves. Firebag Stage 1 began producing bitumen in 2004, and Firebag Stage 2 commenced commercial operations during the first quarter of 2006. A capital project expanding Firebag Stages 1 and 2 in conjunction with the addition of a cogeneration facility is on schedule and on budget for completion in 2007. Also planned for 2007 is the submission for approval to our Board of Directors for Firebag Stage 3;

ii) continued development of our mining leases, including our North Steepbank Mine extension, and the regulatory, consultation and engineering work supporting potential development of Lease 23; and

iii) procurement of bitumen from third parties.

Petro-Canada Agreement - Incremental bitumen to feed the expanded OS operation is also expected to be provided under a processing agreement between Suncor and Petro-Canada, expected to take effect in 2008. Under the agreement, we will process a minimum of 27,000 bpd of Petro-Canada bitumen on a fee-for-service basis. Petro-Canada will retain ownership of the bitumen and resulting sour crude oil production of about 22,000 bpd. In addition, we will sell an additional 26,000 bpd of our proprietary sour

(5) Statistics Canada Modified Monthly Report For Refined Petrochemical Production Development Sales

crude oil production to Petro-Canada. Both the processing and sales components of the agreement will be for a minimum 10-year term.

Kyoto Protocol On December 17, 2002, the Government of Canada announced its ratification of the Kyoto Protocol. On October 19, 2006, the Government of Canada announced their plan to address clean air that focuses on the regulation of indoor and outdoor air quality and greenhouse gases (GHG). The announced Clean Air Act, followed by the Notice of Intent to Regulate Criteria Air Contaminants (CACs) and GHGs has been referred to a special committee for review and revision. Consultation with key sectors is underway however, the ultimate regulatory outcome is unknown. We plan to continue to actively manage our air emissions and greenhouse gas emissions to improve performance. We also plan to advance opportunities such as carbon capture, geological sequestration and renewable and alternate forms of energy, such as wind power and biofuels.

Oil Sands Fire A fire on January 4, 2005, caused significant damage to one of our two upgraders, reducing upgraded crude oil production capacity of 225,000 bpd from base operations to about 122,000 bpd for the first nine months of 2005. Repair and maintenance work to restore the facility was completed in September 2005. Our property loss and business interruption insurance policies substantially mitigated the financial impact of the fire, and were fully settled in 2006. For additional information on our insurance policies and recoveries refer to note 10(b) to our 2006 consolidated financial statements, and page 26 of our MD&A.

Bitumen Royalty Option Agreement In September 2005, an agreement was reached with the Alberta Government on the terms and conditions of Suncor s option to transition to the generic bitumen-based royalty regime in 2009. During the fourth quarter of 2006, we elected to exercise our option to move our base operations to the bitumen-based royalty effective January 1, 2009. Under this regime we will pay a royalty based on 25% of bitumen revenues, minus allowable costs. During 2006, the government of Alberta began deliberations to establish a prescribed method of determining the fair market value of heavy oil/bitumen for the purposes of determining bitumen-based royalty. Royalty payments under this new bitumen pricing methodology may change significantly. The methodology is not likely to be finalized until 2008, and as a result, the potential future impacts are not currently known, but may be material. Any retroactive adjustment is not anticipated to be material. For additional information on our Oil Sands Crown Royalties see page 29 of our MD&A.

Natural Gas (NG)

South Rosevear Gas Plant In January 2006, we disposed of 15% of the total interest in the South Rosevear gas plant for proceeds of $12 million. We currently retain a 60.4% interest and continue to operate the gas plant.

Divestment of non-core properties In 2005, we disposed of non-core properties for proceeds of $21 million.

Simonette Gas Plant In December 2005, we, along with our partner, completed a plant capacity expansion and a new pipeline to connect the Simonette plant with volumes produced from the Cabin Creek and Solomon fields in the Alberta Foothills. In November 2004, Natural Gas divested 62.5% of its interest in the Simonette gas plant for proceeds of $19 million. We retain a 37.5% ownership and continue to operate the gas plant.

Land Acquisition In December 2004, we acquired assets in eastern British Columbia for $33 million. These assets consist of developed and undeveloped land.

Settlement Also in December 2004, we paid $18 million as a final arbitrated settlement relating to the termination of gas marketing contracts related to Enron Corporation s bankruptcy in December 2001.

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Energy Marketing & Refining - Canada (EM&R)

Desulphurization Projects   In 2002, the Canadian government passed legislation limiting the concentration of sulphur in diesel fuel produced or imported for use in on-road vehicles to a maximum of 15 parts per million (ppm), by June 1, 2006. The previous maximum was 500 ppm. To meet these requirements, in October 2003, we and Shell Canada Products Inc. (Shell   ) entered into a 20-year agreement under which we built hydrotreating facilities at our Sarnia refinery to process high-sulphur diesel from both Shell   s and our Sarnia refineries, to produce low sulphur diesel in compliance with the new on-road diesel limits. Under the agreement Shell pays us a processing fee. Construction of the diesel desulphurization facilities was completed in July 2006, enabling the production of ultra low sulphur diesel sufficient to meet the regulatory requirements.

Regulations reducing sulphur in off-road diesel and light fuel oil are also expected to take effect later in the decade. We believe that if the regulations are finalized as currently proposed, the new diesel desulphurization facilities for reducing sulphur in on-road diesel should also allow us to meet the requirements for reducing sulphur in off-road diesel and light fuel oil.

In combination with the diesel desulphurization project, we are in the process of modifying the refinery   s processing capacity, enabling it to process up to 40,000 bpd of Oil Sands sour crude blends. The project is expected to be completed in 2007. The original cost estimate for the combined project of $800 million has been revised upward to $960 million.

Ethanol Plant   In July 2006, we completed our ethanol facility on time and on budget, for a final cost of $112 million, and with a production capacity of 200 million litres per year. The ethanol produced is available for blending into our Sunoco-branded fuels and fuels sold through our joint venture operated networks. Natural Resources Canada contributed $22 million towards this project through their Ethanol Expansion Program.

Refining & Marketing U.S.A. (R & M)

As part of the agreement to acquire assets from ConocoPhillips Company (ConocoPhillips) in August 2003, we assumed obligations of ConocoPhillips at the refinery pursuant to a Consent Decree with the United States Environmental Protection Agency, the United States Department of Justice and the State of Colorado. These capital obligations were met during a planned maintenance shutdown in 2006. The total cost was approximately $60 million (approximately US$50 million). These expenditures reduce air emissions at our refinery, and were primarily capital in nature. There are other continuing non-capital obligations under the Consent Decree that will continue for several more years.

On May 31, 2005 we acquired a second refinery from Valero Energy Corporation (Valero) in the Denver area adjacent to our existing refinery. The 30,000 bpd Valero refinery was purchased for $37 million (US$30 million) plus working capital and associated oil and product inventory adjustments, for a total acquisition cost of $62 million (US$50 million). The refinery was acquired by purchasing all of the issued and outstanding stock of Valero s indirect wholly-owned subsidiary, Colorado Refining Company (CRC). CRC was subsequently merged into Suncor Energy (USA) Inc. effective August 1, 2005. We continue efforts to fully integrate the two operations, providing combined refining capacity of approximately 90,000 bpd in the U.S.

Along with the purchase of the Valero assets, we assumed environmental regulatory and contractual obligations of CRC at the refinery, including CRC s obligation under a Consent Decree with the United States Environmental Protection Agency, the United States Department of Justice and the State of Colorado for alleged violations of air regulations prior to our purchase, as well as a Compliance Order on Consent with the State of Colorado, relating to groundwater and soil contamination. The Consent Decree obligations are expected to require expenditures of approximately $25 million (US$20 million) through 2011.

Desulphurization Projects In July 2006, R&M completed its diesel desulphurization and oil sands integration project at a total cost of approximately $530 million (US$435 million). The completion of the project allows us to produce ultra low sulphur diesel to meet requirements for fuels desulphurization legislation, and enable the refinery to process up to 15,000 bpd of Oil Sands sour crude oil, while also increasing the refinery s ability to process a broader slate of bitumen based crude oil. The clean fuels legislation required production of lower diesel sulphur levels (15 ppm) by June 2006, and requires lower gasoline sulphur levels (30 ppm average, 80 ppm cap) by 2009.

We are currently assessing plans for additional refinery modifications in 2007 and beyond in order to have the potential to integrate additional volumes of Oil Sands crude oil.

Other

Financing Activities

Our available credit facilities at December 31, 2006 totaled approximately $2.3 billion, of which $1.8 billion was undrawn. Available credit facilities include a $2.0 billion agreement expiring in 2011, and a $300 million agreement expiring in 2008. Our current long-term debt ratings are A(low) by Dominion Bond Rating Service, A3 by Moody s Investors Service and A- by Standard & Poor s. All debt ratings have a stable outlook.

In 2004, we repurchased an undivided interest in our Oil Sands energy service assets previously held under a lease financing arrangement with a third party for $101 million.

In 1999, we completed an offering of preferred securities the proceeds of which totaled Canadian $507 million after issue. We redeemed these securities on March 15, 2004, for the original principal amount plus accrued and unpaid interest as at March 15, 2004. See Note 1(a) to our Consolidated Financial Statements, which is incorporated by reference herein.

Renewable Energy

In November 2006, we, along with our joint venture partners, Enbridge Income Fund and Acciona Wind Energy Canada Inc., officially opened a 30-megawatt wind power project near Taber, Alberta called the Chin Chute Wind Power Project. The project includes 20 wind turbines with the capacity to produce enough zero-emission electricity to offset the equivalent of approximately 102,000 tonnes of carbon dioxide per year.

In November 2005, we, along with our joint venture partner Acciona Wind Energy Canada Inc., were selected by the Ontario government to build a 76-megawatt wind power project near Ripley, Ontario. The Ripley Wind Power project is expected to include 38 wind turbines and offset approximately 66,000 tonnes of carbon dioxide annually. Commissioning is targeted for late 2007.

Other Transactions

In 2004, we repurchased approximately 2.1 million barrels of crude oil originally sold to a Variable Interest Entity (VIE) in 1999 for net consideration of $49 million. As we economically hedged the repurchase of the inventory the net consideration paid was equal to the original proceeds we received in 1999 when the inventory was sold to the VIE.

In 2004, we received $40 million for the sale of certain proprietary technology. Throughout 2005, $40 million was received for the provision of associated training services. Amounts are being recognized into income over the term of the sale agreement.

In September 2004, we, along with our joint venture partners, Enbridge Income Fund and Acciona Wind Energy Canada Inc., officially opened the 30-megawatt Magrath Wind Power Project (Magrath) in southern Alberta. Magrath s zero-emissions electricity production is expected to offset the equivalent of approximately 82,000 tonnes of carbon dioxide per year. The project has benefited from the support of the Federal Government s Wind Power Production Incentive.

For further information on developments and issues referred to above and other highlights of 2006, and a discussion of other trends known to us that could reasonably be expected to have a material effect on the company, refer to the Outlook and other sections of Suncor s MD&A, and to Risk Factors in this Annual Information Form.

NARRATIVE DESCRIPTION OF THE BUSINESS

OIL SANDS (OS)

Suncor produces a variety of refinery feedstock, diesel fuel and by-products by developing the Athabasca oil sands in northeastern Alberta and upgrading the bitumen extracted at our plant near Fort McMurray, Alberta. Our Oil Sands operations, accounting for virtually all of our conventional and synthetic crude oil production in 2006, represent a significant portion of our 2006 capital employed (65%)[(6)], cash flow from operations (83%)[(6)] and net earnings (89%). These percentages have been determined excluding the corporate and eliminations segment information.

Operations

Our integrated Oil Sands business involves four operations located north of Fort McMurray, Alberta off Highway 63.

1) Bitumen is supplied from a combination of a mining operation using trucks and shovels, an in-situ operation and third party bitumen supply. Commencing in 2004, the Firebag in-situ operation began producing bitumen which was initially sold into the market as diluted bitumen. Since late 2005, bitumen from Firebag is being upgraded, with only a small portion of production being strategically sold directly into the market.

2) Extraction facilities recover the bitumen from the oil sands ore that is mined.

3) Heavy oil upgrading converts bitumen into crude oil products.

4) Currently, our energy service needs are primarily met through facilities operated by TransAlta that provide steam and electricity to the operations. In an effort to reduce our future external steam and electricity needs, we are constructing our own cogeneration facility to assist in meeting growth project steam and electricity needs. It is currently on schedule to be completed in 2007.

The first step of the open pit mining operation is to remove the overburden with trucks and shovels to access the oil sands - a mixture of sand, clay and bitumen. Oil sands ore is then excavated, and transported to one of five sizing plants by a fleet of trucks. The ore is dumped into sizers where it is crushed and sent to the ore preparation plants where it is mixed into a hot water slurry and pumped through hydrotransport pipelines to extraction plants on the east and west sides of the Athabasca River. The bitumen begins to separate from the sand as the slurry is pumped through the lines. Bitumen is extracted from the oil sands ore with a hot water process. After the final removal of impurities and minerals, naphtha is added to the bitumen as diluent to facilitate transportation to the upgrading plant.

We continue to explore and develop improved and alternative technologies to facilitate increased efficiency and processing within our mining operation. Based on the results of testing performed during 2006, we plan to utilize certain mobile mining and extraction equipment and processes in our future mine development plans.

Our in-situ operation uses an extraction technology called Steam Assisted Gravity Drainage (SAGD) to extract bitumen from oil sands deposits that are too deep to be mined economically. The first step of the SAGD process is to drill a pair of horizontal wells with one well located above the other. Steam produced by our steam generation facilities is injected through the top well into the oil sands. Heated bitumen and condensed steam drain into the bottom well and flow up the well to the surface. The bitumen is pumped to our oil/water separation facilities where the water is removed from the bitumen, treated, and recycled into the steam generation facilities. Naphtha is added to the bitumen to facilitate transportation and the blended bitumen is transported by pipeline to our upgrading facilities.

After the diluted bitumen is transferred to the upgrading plant, the naphtha is removed and recycled to be used again as diluent. The bitumen is upgraded through a coking and distillation process. The upgraded product, referred to as sour synthetic crude oil, is either sold directly to customers as sour synthetic crude

(6) Refer to Non GAAP Financial Measures on page ix of this AIF.

oil or is further upgraded into sweet synthetic crude oil by removing the sulphur and nitrogen using a hydrogen treating process. Three separate streams of refined crude oil are produced: naphtha, kerosene and gas oil.

While there is virtually no finding cost associated with synthetic crude oil, the delineation of the resource and development and expansion of production can entail significant capital outlays. For the same reason, the costs associated with synthetic crude oil production are largely fixed, and as a result, operating costs per unit are largely dependent on levels of production. Natural gas is used or consumed in the production of synthetic crude oil, particularly in SAGD production at our Firebag operations, and accordingly natural gas prices are a key variable component of synthetic crude oil production costs.

In the normal course of our operations we regularly complete planned maintenance shutdowns of our oil sands facilities. These shutdowns are scheduled, and provide both preventative maintenance and capital replacement which are expected to improve our operational efficiency. The next major scheduled shutdown is a planned 50 day shutdown in 2007 to enable key tie-ins for capital expansion projects expected to come online in 2008.

Principal Products

Sales of light sweet synthetic crude oil and diesel represented 58% of Oil Sands consolidated operating revenues in 2006, compared to 54% in 2005. The balance of our revenues were comprised of light sour synthetic crude oil and bitumen sales of 42% (2005 46%). Set forth below is information on daily sales volumes and the corresponding percentage of Oil Sands consolidated operating revenues by product for each of the last two years.

	2006		**2005**	
Product:	**(thousands of barrels per day)**	**(% of Oil Sands consolidated revenues)**	**(thousands of barrels per day)**	**(% of Oil Sands consolidated revenues)**
Light sweet crude oil/diesel	138.7	58	88.9	54
Light sour crude oil/bitumen	124.4	42	76.4	46
Total	263.1	100	165.3	100

In 2005, sales volumes and sales mix were adversely impacted by the fire at our Oil Sands operation that occurred January 2005. We anticipate that approximately 52% of Oil Sands sales in 2007 will be light sweet synthetic crude and diesel products.

Principal Markets

We market our crude oil product blends principally to customers in Canada and the United States, and periodically to offshore markets.

Transportation

We own and operate a pipeline that transports synthetic crude oil from Fort McMurray, Alberta to Edmonton, Alberta. The pipeline has a capacity of approximately 110,000 bpd.

Our Oil Sands business unit entered into a transportation service agreement with a subsidiary of Enbridge Inc. for a term that commenced in 1999 and extends to 2028. Under the agreement, our current pipeline capacity for the transport of synthetic crude oil and diluted bitumen from Fort McMurray, Alberta to Hardisty, Alberta is 170,000 bpd. This pipeline, together with our proprietary pipeline, is expected to meet our anticipated crude oil shipping requirements for expected future production levels until 2008.

In 2005, Suncor entered into a binding memorandum of understanding with Enbridge Pipelines (Athabasca) Inc, Petro-Canada, Total E&P Canada Limited, and ConocoPhillips Surmont Partnership for the transportation of crude oil, on a proposed new pipeline running from Cheecham, Alberta to Edmonton, Alberta. The expected in-service date of the line is targeted for July 1, 2008, with a 25 year term. Initial line capacity is expected to be 350,000 bpd with potential expansion of capacity to 600,000 bpd with the construction of additional pumping facilities. Our initial line commitment is 30,000 bpd. It is expected that the pipeline will provide an enhanced ability to access new markets on the West coast and offshore. We, along with other industry shippers, are assessing additional Athabasca-region pipeline options beyond 2008.

Periodically, we also enter into strategic short term cargo transport agreements to ship synthetic crude oil to the United States Gulf Coast. These agreements have a term of less than one year, and are specific to individual shipments.

We have a 20 year agreement with TransCanada Pipeline Ventures Limited Partnership to provide us with firm capacity on a natural gas pipeline that came into service in 1999. The natural gas pipeline ships natural gas to our Oil Sands facility.

We also transport natural gas to our Oil Sands operations on the company-owned and operated Albersun pipeline, constructed in 1968. It extends approximately 300 kilometres south of the plant and connects with TransCanada Pipeline s Alberta intra-provincial pipeline system. The Albersun pipeline has the capacity to move in excess of 100 mmcf/day of natural gas. We arrange for natural gas supply and control most of the natural gas on the system under delivery based contracts. The pipeline moves natural gas both north and south for us and other shippers.

Our Oil Sands mining facilities are readily accessible by public road. Our Firebag in-situ facilities are currently accessible by private road. We anticipate termination of such access in 2009, and are currently evaluating alternative means of access.

Competitive Conditions

Competitive conditions affecting Oil Sands are described under the heading Competition in the Risk Factors section of this Annual Information Form.

Seasonal Impacts

Severe climatic conditions at Oil Sands can cause reduced production and, in some situations, can result in higher costs.

Sales of Synthetic Crude Oil and Diesel

Aside from on site fuel use, all of Oil Sands production is sold to, and subsequently marketed by, Suncor Energy Marketing Inc.

In 1997, we entered into a long-term agreement with Koch Industries Inc. (Koch) to supply Koch with up to 30,000 bpd (approximately 11% of our average 2006 total production (2005 18%)) of sour crude from the Oil Sands operation. We began shipping the crude to Koch at Hardisty, Alberta (from which Koch ships the product to its refinery in Minnesota) under this long-term agreement effective January 1, 1999. The initial term of the agreement extends to January 1, 2009, with month to month evergreen terms thereafter, subject to termination on twenty-four months notice by either party. Neither party has provided notice of termination at this time.

Under a long term sales agreement with Consumers Co-operative Refineries Limited (CCRL) we supply 20,000 bpd of sour crude oil production. In 2005, we signed another contract with CCRL for an additional 12,000 bpd of sour crude oil. Prices for sour crude oil under both of these agreements are set at agreed differentials to market benchmarks. Both CCRL agreements extend through to 2011, with renewal options that could extend out to 2018 and beyond.

In 2001, we announced an agreement with Petro-Canada to supply up to 30,000 bpd of diluent to dilute bitumen produced by Petro-Canada. Deliveries under the contract are expected to end when the bitumen processing and sour crude oil supply agreement with Petro-Canada, described below, takes effect in 2008. Under the agreement, we will process a minimum of 27,000 bpd of Petro-Canada bitumen on a fee for service basis. Petro-Canada will retain ownership to the bitumen and resulting sour crude oil production of about 22,000 bpd. In addition, we will sell an additional 26,000 bpd of our proprietary sour crude oil production to Petro-Canada. Both the processing and sales components of the agreement will be for a minimum 10-year term.

There were no customers that represented 10% or more of our consolidated revenues in 2006, 2005, or 2004.

A portion of our Oil Sands production is used in connection with our Sarnia and Commerce city refining operations. During 2006, the Sarnia refinery processed approximately 8% (2005 - 4%) of Oil Sands crude oil production and the Commerce City refinery processed approximately 3% (2005 3%) of Oil Sands crude oil production.

Environmental Compliance

For a discussion of environmental risks at our Oil Sands operations, refer to the Legal and Regulatory Risks outlined in the Risk Factors section of this Annual Information Form, as well as the Asset Retirement Obligations section under Critical Accounting Estimates in the Suncor Overview and Strategic Priorities section of our MD&A.

NATURAL GAS (NG)

Our Natural Gas business, based in Calgary, Alberta, explores for, develops and produces conventional natural gas and natural gas liquids in western Canada, supplying it to markets throughout North America. The sale of NG s production provides a natural price hedge for natural gas purchased for consumption at our Oil Sands facility and our refineries in Sarnia, Ontario and near Denver, Colorado.

In addition, our U.S. subsidiary, Suncor Energy (Natural Gas) America Inc., continues to acquire land and explore for coal bed methane in the United States.

In 2006, natural gas and natural gas liquids accounted for approximately 97% of the NG business unit s production (2005 98%).

NG s exploration program is focused on multiple geological zones in three core asset areas: Northern (northeast British Columbia and northwest Alberta), Foothills (western Alberta and portions of northeast British Columbia) and Central Alberta. We drill primarily medium to high-risk wells focusing on prospects that are in proximity to existing infrastructure. Production in 2006 was below expectations due to shut-in production as a result of pipeline and processing facility constraints, as well as delayed production.

Marketing, Pipeline and Other Operations

We operate natural gas processing plants at South Rosevear, Pine Creek, Boundary Lake South, Progress and Simonette with a total design capacity of approximately 315 mmcf/d. Our capacity interest in these gas processing plants is approximately 135 mmcf/d. We also have varying undivided percentage interests in natural gas processing plants operated by other companies and processing agreements in facilities where we do not hold an ownership interest.

Approximately 83% of our natural gas production is sold to SEMI and then marketed under direct sales arrangements to customers in Alberta, British Columbia, Eastern Canada, and the United States. Contracts for these direct sales arrangements are of varied terms, with a majority having terms of one year or less, and incorporate pricing which is either fixed over the term of the contract or determined on a monthly basis in relation to a specified market reference price. Under these contracts, we are responsible

for transportation arrangements to the point of sale.

Approximately 17% of our natural gas production is sold under existing contracts to aggregators (system sales). Proceeds received by producers under these sales arrangements are determined on a netback basis, whereby each producer receives revenue equal to its proportionate share of sales less regulated transportation charges and a marketing fee. Most of our system sales volumes are contracted to Cargill Gas Marketing Ltd. (formerly TransCanada Gas Services) and Pan-Alberta Gas. These companies resell this natural gas primarily to eastern Canadian and Midwest and Eastern United States markets.

To provide exposure to the Pacific North West and California markets, we have a long-term gas pipeline transportation contract on the National Energy Group Transmission Pipeline (formerly Pacific Gas Transmission).

We do not typically enter long-term supply arrangements for our conventional crude oil production. Instead, our conventional crude oil production is generally sold under spot contracts or under contracts that can be terminated on relatively short notice. Our conventional crude oil production is shipped on pipelines operated by independent pipeline companies. The NG business currently has no pipeline commitments related to the shipment of crude oil.

Principal Products

Sales of natural gas represented 90% (2005 91%) of NG s consolidated operating revenues in 2006, with the remaining 10% (2005 9%) comprised of sales of natural gas liquids and crude oil. Set forth below is information on daily sales volumes and the corresponding percentage of Natural Gas consolidated operating revenues by product for the last two years.

	2006		2005	
Product:	**(thousands of barrels of oil equivalent per day)**	**(% of NG consolidated revenues)**	**(thousands of barrels of oil equivalent per day)**	**(% of NG consolidated revenues)**
Natural gas	31.8	90	31.6	91
Natural gas liquids	2.3	7	2.4	7
Crude oil	0.7	3	0.8	2
Total	34.8	100	34.8	100

Competitive Conditions

Competitive conditions affecting NG are described under Competition in the Risk Factors section of this Annual Information Form.

Seasonal Impacts

Risk and uncertainties associated with weather conditions can shorten the winter drilling season and impact the spring and summer drilling programs, with increased costs or reduced production.

Environmental Compliance

For a discussion of environmental risks at our NG operations, refer to the Legal and Regulatory Risks outlined in the Risk Factors section of this Annual Information Form, as well as the Asset Retirement Obligations section under Critical Accounting Estimates in the Suncor Overview and Strategic Priorities section of our MD&A.

ENERGY MARKETING & REFINING CANADA (EM&R)

Our EM&R business unit operates a refining and marketing business in Central Canada, and an energy marketing and trading business. Our refinery in Sarnia, Ontario, refines petroleum feedstock from Oil Sands and other sources into gasoline, distillates, biofuels and petrochemicals with the majority of these refined products being distributed in Ontario. Our ethanol facility in St. Clair, Ontario, produces ethanol from corn, which is used for blending into our fuels and sold to third parties. For information about EM&R s energy marketing and trading business, refer to Energy Marketing and Refining Canada (EM&R) under the Three-Year Highlights , Energy Marketing & Trading heading.

As a marketing channel for our refined products, EM&R s Ontario retail network generated approximately 58% of EM&R s total 2006 sales volume of 95,000 bpd. The retail networks are comprised of Sunoco-branded retail service stations, Sunoco-branded Fleet Fuel Cardlock sites, and two 50% retail joint venture(7) businesses that operate Pioneer-branded retail service stations, UPI-branded retail service stations and UPI bulk distribution facilities for rural and farm fuels. Approximately 36% of EM&R s refined product sales in 2006 were wholesale and industrial sales. Sun Petrochemicals Company (SPC), a 50% joint venture between a Suncor subsidiary and a Toledo, Ohio-based refinery, generated the remaining 6% of sales.

Procurement of Feedstocks

The Sarnia refinery uses both synthetic and conventional crude oil. In 2006, the Sarnia refinery procured approximately 55% (2005 16%) of its synthetic crude oil feedstock from our Oil Sands production. In 2006, 60% (2005 62%) of the crude oil refined at the Sarnia Refinery was synthetic crude oil. The balance of the refinery s synthetic crude oil, as well as its conventional and condensate feedstocks were purchased from others under month to month contracts. In the event of a significant disruption in the supply of synthetic crude oil, the refinery has the flexibility to substitute other sources of sweet or sour conventional crude oil.

We procure conventional crude oil feedstock for our Sarnia refinery primarily from western Canada, supplemented from time to time with crude oil from the United States and other countries. Foreign crude oil is delivered to Sarnia via pipeline from the United States Gulf Coast or via the Interprovincial Pipeline from Montreal. We have not made any firm capacity commitments on these pipeline systems. Crude oil is procured from the market on a spot basis or under contracts which can be terminated on short notice.

In 1998, EM&R signed a 10-year feedstock agreement with a Sarnia-based petrochemical refinery, Nova Chemicals (Canada) Ltd. Under this buy/sell agreement, we obtain feedstock that is more suitable for production of transportation fuels in exchange for feedstock more suitable for petrochemical cracking. We also enter into reciprocal buy/sell or exchange arrangements with other refining companies from time to time as a means of minimizing transportation costs, balancing product availability and enhancing refinery utilization. We also purchase refined products in order to meet customer requirements.

In July 2006, with the completion of our ethanol facility we produce ethanol for use in our blended gasoline products, and for sales to third parties.

Refining Operations

The Sarnia refinery produces transportation fuels (gasoline, diesel, propane and jet fuel), heating fuels, liquefied petroleum gases, residual fuel oil, asphalt feedstock, benzene, toluene, mixed xylenes and orthoxylene, as well as the petrochemicals A-100 and A-150 that are used in the manufacture of paint and chemicals.

The refinery has the capacity to refine 70,000 bpd of crude oil. Upgrading units include a 23,300 bpd hydrocracker, and a 5,400 bpd alkylation unit. The petrochemical facilities have a capacity of 13,100 bpd,

(7) Pioneer Group Inc. is an independent company with which Suncor has a 50% joint venture partnership. UPI Inc. is a 50% joint venture company Suncor has with GROWMARK Inc., a Midwest U.S. retail farm supply and grain marketing cooperative.

the aromatic solvents unit has a capacity of approximately 1,000 bpd, and our gasoline desulphurization unit has a capacity to process 10,250 bpd. The distillate hydrotreater that became operational in July 2006 has a processing capacity of 43,600 bpd

The refinery has a cracking capacity of 40,200 bpd from a Houdry catalytic cracker (catcracker) and a hydrocracker. Approximately 40% of the cracking capacity is attributable to the catcracker, which uses older cracking technology. In 2004, a sustainability study to assess the catcracker concluded that, with planned improvements and upgrades, it can continue to be operated economically and safely for up to 10 years. A range of replacement options for the catcracker was identified during a review in 2005. Continued analysis of these and other options will occur through 2007, as we work to identify the preferred option for the catcracker.

Overall, crude utilization averaged 78% for the year, compared to 95% in 2005. The following chart sets out daily crude input, average refinery utilization rates, and cracking capacity utilization of the Sarnia Refinery over the last two years. The comparatively low utilization rates in 2006 were a result of a major maintenance shutdown during 2006.

Sarnia Refinery Capacity	2006	2005
Average daily crude input (barrels per day)	57,400	66,700
Average crude utilization rate (%)(1)	78	95
Average cracking capacity utilization (%)(2)	82	95

Notes:

(1) Based on crude unit capacity and input to crude units.

(2) Based on cracking capacity and input to the hydrocracker and catcracker.

The refinery s external steam and electricity needs are currently being met by supply from the Sarnia Regional Co-generation Project.

In the normal course of our operations we regularly complete planned maintenance shutdowns of our EM&R refinery facilities. These shutdowns are scheduled, and provide both preventative maintenance and capital replacement which is expected to improve our operational efficiency. During 2006, a significant maintenance shutdown was successfully completed.

Principal Products

Sales of gasoline and other transportation fuels represented 58% of EM&R s consolidated operating revenues in 2006, compared to 68% in 2005. Set forth below is information on daily sales volumes and percentage of EM&R s consolidated operating revenues contributed by product group for the last two years.

Product:	2006 (thousands of cubic meters per day)	(% of EM&R s consolidated revenues)	2005 (thousands of cubic meters per day)	(% of EM&R s consolidated revenues)
Transportation Fuels				
Gasoline				
Retail	4.6	24	4.5	27
Joint Ventures	3.0	10	2.8	15
Other	0.9	9	1.1	7
Jet Fuel	0.7	2	0.9	4
Diesel	3.3	13	3.3	15
Sub-total Transportation Fuels	12.5	58	12.6	68
Petrochemicals	0.9	5	0.7	4
Heating Fuels	0.5	2	0.4	3
Heavy Fuel Oils	0.8	1	1.0	2
Other	0.6	2	0.5	2
Total Refined Products	15.3	68	15.2	79
Other Non-Refined Products(1)		3		3
Energy Marketing & Trading		29		18
Total %		100		100

Note:

(1) Includes ancillary revenues

Principal Markets

Approximately 58% (2005 57%) of EM&R s total sales volumes are marketed through retail networks, including the Sunoco-branded retail network, joint venture operated retail stations and cardlock operations. In 2006, this network was comprised of:

272 (2005 275) Sunoco-branded retail service stations

151 (2005 149) Pioneer-operated retail service stations

53 (2005 50) UPI-operated retail service stations and a network of 14 bulk distribution facilities for rural and farm fuels

36 (2005 28) Sunoco branded Fleet Fuel Cardlock sites

UPI Inc. is a joint venture company owned 50% by each of EM&R and GROWMARK Inc., a U.S. Midwest agricultural supply and grain marketing cooperative. Pioneer is a 50% joint venture partnership between EM&R and The Pioneer Group Inc.

Refined petroleum products (excluding petrochemicals) are marketed under several brands, including the Company s Canadian Sunoco trademark. EM&R s other principal trademarks include our Ultra 94 , our premium high octane gasoline, and our Gold Diesel premium low sulphur diesel product.

Approximately 36% (2005 39%) of EM&R s total sales volumes are sold to industrial, commercial, wholesale and refining customers, primarily in Ontario. EM&R also supplies industrial and commercial customers in Quebec through long-term arrangements with other regional refiners.

EM&R markets toluene, mixed xylenes, orthoxylene and other petrochemicals, primarily in Canada and the U.S., through Sun Petrochemicals Company (SPC). EM&R has a 50% interest in SPC, a petrochemical marketing joint venture that markets products from our Sarnia, Ontario refinery and from a Toledo, Ohio, refinery owned by the joint venture partner. SPC markets petrochemicals used to manufacture plastics, rubber, synthetic fibres, industrial solvents and agricultural products, and as gasoline octane enhancers. All benzene production is sold directly to other petrochemical manufacturers in Sarnia, Ontario.

EM&R s share of total refined product sales in its primary market of Ontario was approximately 18% in 2006 (2005 19%). Transportation fuels accounted for 82% of EM&R s total sales volumes in 2006 (2005 82%); and petrochemicals accounted for 6% (2005 4%). The remaining volumes included other refined products such as heating fuels, heavy oils and liquefied petroleum gases, and were sold to industrial users and resellers.

EM&R supplies refined petroleum products to the Pioneer and UPI joint ventures. We have a separate supply agreement with each of UPI and Pioneer. These supply agreements are evergreen, subject to termination only in accordance with the terms of the various agreements between the parties.

Transportation and Distribution

EM&R uses a variety of transportation modes to deliver products to market, including pipeline, water, rail and road. EM&R owns and operates petroleum transportation, terminal and dock facilities, including storage facilities and bulk distribution plants in Ontario. The major mode of transporting gasoline, diesel, jet fuel and heating fuels from the Sarnia refinery to core markets in Ontario is the Sun-Canadian Pipe Line, which is 55% owned by us and 45% owned by another refiner. The pipeline operates as a private facility for its owners, serving terminal facilities in Toronto, Hamilton and London, with a capacity of 130,800 bpd (20,800 cubic metres). EM&R utilized 50% of this capacity in 2006 (2005 54%). Total utilization of the pipeline was 77% in 2006 (2005 - 84%).

EM&R also has pipeline access, subject to availability, to petroleum markets in the Great Lakes region of the United States by way of a pipeline system in Sarnia operated by a U.S. based refiner. This link to the U.S. allows EM&R to move products to market or obtain feedstocks/products when market conditions are favourable in the Michigan and Ohio markets.

We believe our own storage facilities, and those under long-term contractual arrangements with other parties, are sufficient to meet our current and foreseeable storage needs.

Competitive Conditions

Competitive conditions affecting our EM&R business are described under Competition in the Risk Factors section of this Annual Information Form.

Environmental Compliance

For a discussion of environmental risks at our EM&R operations, refer to the Legal and Regulatory Risks outlined in the Risk Factors section of this Annual Information Form, as well as the Asset Retirement Obligations section under Critical Accounting Estimates in the Suncor Overview and Strategic Priorities section of our MD&A.

REFINING & MARKETING U.S.A. (R & M)

Our R&M business unit operates a refining and marketing, and pipeline transportation business primarily in Colorado and Wyoming. The Denver area refining facility, located in Commerce City, Colorado, has a combined crude distillation capacity of 90,000 bpd. The majority of the refined products from the Denver refinery are distributed in Colorado.

Approximately 18% of R&M s petroleum products sales in 2006 (2005 18%) were sold through a distribution network in Colorado that sells gasoline and diesel fuel to retail customers. In 2006, approximately 74% (2005 70%) of R&M s petroleum product sales volumes were to industrial, commercial, wholesale and refining customers in Colorado, representing primarily jet fuels, diesel and gasoline. Asphalt sales comprised the remaining 8% of R&M s refined product sales volumes for 2006 (2005 12%).

Procurement of Feedstocks

The Denver refining operation uses both conventional and synthetic crude oil. Approximately one-quarter of the refinery s crude oil is purchased from Canadian sources, with the remainder supplied from sources in the United States, primarily in the Rocky Mountain region. With the completion of our diesel desulphurization and oil sands integration project in July 2006, the refinery facility commenced processing up to 15,000 bpd of Oil Sands sour crude oil.

The refinery s crude oil purchase contracts have terms ranging from month-to-month to multi-year. In the event of a significant disruption in the supply of crude oil, the refinery has the flexibility to substitute other sources of sweet or sour crude oil on a spot purchase basis.

Refining Operations

Upgrading units at the refining operation include two fluidized catalytic crackers with a 29,500 bpd combined capacity, a 19,000 bpd distillate hydrotreater and a 26,000 bpd gas oil hydrotreater. The refined gasoline products from the Denver refinery supply R&M s marketing operations in Colorado. Refining sales in 2006 averaged approximately 90,600 bpd (14,400 m^3 per day) compared to 86,200 bpd (13,700 m^3) in 2005.

The Denver area refining operation is a high conversion operation that produces a full range of products, including gasoline, jet fuels, diesel and asphalt. The refinery s upgrading units enable it to process a crude slate containing approximately one-third heavy, high sulphur crude. Overall, crude utilization averaged 92% in 2006 (2005 98%). The following chart sets out daily crude input, average refinery utilization rates and cracking capacity utilization for 2006 and 2005.

Denver Refining Capacity	**2006**	**2005**
Average daily crude input (barrels per day)(1)	82,600	76,300
Average crude utilization rate (%)(2)	92	98
Average fluidized catalytic cracker capacity utilization rate (%)(3)	76	89

Notes:

(1) 30,000 bpd Valero refinery capacity acquired May 31, 2005.

(2) Based on crude unit capacity and input to crude units.

(3) Based on cracking capacity and input to other units or sales made to customers.

In the normal course of our operations we regularly complete planned maintenance shutdowns of our R&M refinery facilities. These shutdowns are scheduled, and provide both preventative maintenance and capital replacement which is expected to improve our operational efficiency. During 2006, a significant maintenance and capital tie-in shutdown was successfully completed.

Principal Products

Sales of gasoline and other transportation fuels represented 93% of R&M s consolidated operating revenues in 2006 (2005 90%). Set forth below is information on daily sales volumes and percentage of R&M s consolidated operating revenues contributed by product group for 2006 and 2005.

	2006		2005	
Product:	**(Thousands of cubic meters per day)**	**(% of R&M s consolidated revenues)**	**(Thousands of cubic meters per day)**	**(% of R&M s consolidated revenues)**
Transportation Fuels				
Gasoline				
Retail	0.7	11	0.7	11
Other	6.8	48	6.2	46
Jet Fuel	1.0	7	0.8	6
Diesel	3.6	27	3.3	27
Total Transportation Fuels	12.1	93	11.0	90
Asphalt	1.2	4	1.6	4
Other	1.1	2	1.1	4
Total Refined Product Sales	14.4	99	13.7	98
Other Non-Refined Product(1)		1		2
		100		100

Note:

(1) Ancillary revenues include non-fuel retail sales.

Principal Markets

Approximately 18% of R&M s total sales volumes are marketed through Phillips 66 ® - branded retail outlets. This network is comprised of:

43 owned Phillips 66 ® - branded retail sites, which account for approximately 5% of R&M s sales volumes; and

Supply agreements with 167 Phillips 66 ® branded marketer outlets throughout the state of Colorado, which account for approximately 13% of R&M s sales volumes. These agreements are typically for three year terms with provision for automatic three year renewal periods on an evergreen basis.

We have an exclusive license from ConocoPhillips to use the Phillips 66 ® and related trademarks and brand names in Colorado until December 31, 2012.

The Denver refining operation also supplies all of its asphalt production to SemMaterials, L.P. Asphalt sales made up about 8% of R&M s total 2006 sales volumes (2005 12%).

Approximately 74% of R&M s total sales volumes are sold to industrial, commercial, wholesale, and refining customers, primarily in Colorado, of which approximately 13% was sold under a long-term supply agreement with ConocoPhillips (expiring in 2013) and 24% under a supply agreement with Valero (expiring in 2008).

R&M estimates its sales of total light fuels refined product in 2006 represented a market share, in its primary market of Colorado, of approximately 40% (2005 35%). Within this market, R&M s Phillips 66 ® - branded sites represent a 15% market share (2005 18%).

Transportation and Distribution

Approximately three-quarters of crude oil processed at the Denver refining operation is transported via pipeline, with the remainder supplied via truck. R&M owns and operates the Rocky Mountain Crude system which runs from Guernsey, Wyoming to Denver, Colorado. This pipeline is a common carrier pipeline that transports crude for the Denver refinery as well as for other shippers. We also operate a joint venture crude pipeline, the Centennial pipeline, from Guernsey, Wyoming to Cheyenne, Wyoming. We own approximately 65% of the Centennial pipeline. The other 35% is owned by another area refiner. The Rocky Mountain crude system had a capacity of 38,000 bpd in 2006 for the Guernsey to Cheyenne leg of the pipeline and 73,500 bpd for the Cheyenne to Denver leg of the pipeline. In 2006, the Rocky Mountain Crude system utilized approximately 81% (2005 115%) of its capacity with average throughput of 28,200 bpd (2005 35,400 bpd) in the Guernsey to Cheyenne leg of the pipeline, and 62,400 bpd (2005 - 70,150 bpd) in the higher capacity Cheyenne to Denver leg. During the same period, the Centennial pipeline utilized approximately 85% (2005 102%) of capacity, with an average throughput of approximately 54,400 bpd (2005 62,500 bpd).

R&M has both truck and rail loading racks at the Denver area refining facility with product loading capacity in excess of 30,000 bpd, a one mile long 7,000 bpd jet fuel pipeline that connects to a common carrier pipeline system for deliveries to the Denver International Airport, and a four mile long 14,000 bpd diesel pipeline that delivers diesel product directly to the Union Pacific railroad yard in Denver, Colorado.

We believe our own storage facilities, and those under long-term contractual arrangements with other parties, are sufficient to meet our current and foreseeable storage needs.

Competitive Conditions

Competitive conditions affecting our R&M business are described under the heading Competition in the Risk Factors section of this Annual Information Form.

Environmental Compliance

Due to increasingly stringent regulations regarding water discharges, we need to improve water treatment capability at our Denver refining operation which will require additional water treating equipment for the discharge of process waste water. It is estimated that this will cost approximately $19 to $23 million (US$16 to $20 million) and be completed in the 2007 to 2010 timeframe.

For a discussion of environmental risks at our R&M operations, refer to the Legal and Regulatory Risks outlined in the Risk Factors section of this Annual Information Form, as well as the Asset Retirement Obligations section under Critical Accounting Estimates in the Suncor Overview and Strategic Priorities section of our MD&A.