SUNCOR ENERGY INC
Form 40-F
March 05, 2010

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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

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

For fiscal year ended:	December 31, 2009
Commission File Number:	No. 1-12384

SUNCOR ENERGY INC.

(Exact name of registrant as specified in its charter)

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

ý	Annual Information Form	ý	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, 2009 there were 1,559,778,481 Common Shares issued and outstanding**
Preferred Shares, Series A	**None**

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 ý　　No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes o　　No o

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" mean Suncor Energy Inc., its subsidiaries, partnerships and joint venture investments unless the context otherwise requires. References to "legacy Suncor" and "legacy Petro-Canada" refer to the applicable entity prior to the August 1, 2009 effective date of the merger.

Barrel of oil equivalent (boe)

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

Bcf

Billions of cubic feet.

Bitumen/heavy crude oil

A naturally occurring viscous mixture, consisting mainly of pentanes and heavier hydrocarbons, 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 may be upgraded into crude oil and other petroleum products.

Bpd

Barrels per day.

Capacity

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

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 and shale gas.

Crude oil

Unrefined liquid hydrocarbons, excluding natural gas liquids.

Development costs

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

Dry hole

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

Feedstock

In the oil sands business, feedstock generally refers to raw bitumen required in the production of SCO. In the downstream business, feedstock refers to crude oil and/or other components required in the production of refined products.

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 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

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 26, 2010, accompanying its audited consolidated financial statements, notes and auditors' report, as at and for the three years in the period ended December 31, 2009.

MMbbls

Millions of barrels.

MMbtu

Millions of British Thermal Units.

MMcf

Millions of cubic feet.

Natural gas

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

Natural gas liquids (NGLs)

Those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.

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, which 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.

Reservoir

A porous and permeable subsurface rock formation that contains a separate accumulation of petroleum that is confined by impermeable rock or water barriers and is characterized by a single pressure system.

Synthetic crude oil (SCO)

A mixture of hydrocarbons derived by upgrading (thermal cracking and purification) of crude bitumen from oil sands which may contain sulphur or other non-hydrocarbon compounds and has many similarities to crude oil. SCO with lower sulphur content is referred to as "sweet"; SCO with higher sulphur content is referred to as "sour".

Utilization

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

Wells

Development or developmental well

A well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

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 or exploration 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 AIF may produce small differences from reported amounts.

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

PRESENTATION OF INFORMATION

The information contained in this AIF is dated as at December 31, 2009, unless otherwise indicated. All references in this AIF to dollar amounts are in Canadian dollars unless otherwise indicated.

FORWARD-LOOKING STATEMENTS

Certain statements contained in this AIF constitute "forward-looking statements" within the meaning of the *United States Private Securities Litigation Reform Act of 1995* and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). All forward-looking statements are based on the company's current expectations, estimates, projections, beliefs and assumptions based on information available at the time the statement was made and in light of its experience and its perception of historical trends.

Some of the forward-looking statements may be identified by words like "expects," "anticipates," "estimates," "plans," "scheduled," "intends," "may," "believes," "projects," "indicates," "could," "focus," "vision," "goal," "proposed," "target," "objective," "continue" and similar expressions. Forward-looking statements in this AIF include references to:

- business strategies and goals
- future investment decisions
- future capital, exploration and other expenditures
- future cash flows
- future resource purchases and sales (including in respect of our planned sales of certain natural gas assets)

anticipated construction and repair activities

anticipated turnarounds at upgraders, refineries and other facilities

anticipated refining margins

future oil and natural gas production levels and the sources of their growth

project development, and expansion schedules and results

future exploration activities and results, and dates by which certain areas may be developed or come on-stream

anticipated retail throughputs

anticipated pre-production and operating costs

reserves and resources estimates

future royalties and taxes payable

anticipated cost savings, and other synergies, realized from the merger with Petro-Canada

production life-of-field estimates

natural gas export capacity

future financing and capital activities

contingent liabilities

the impact and cost of compliance with existing and potential environmental regulations

future regulatory approvals

expected rates of return

In addition, all other statements that address expectations or projections about the future, including statements about our strategy for growth, commodity prices, costs, schedules, production volumes, operating and financial results and expected impact of future commitments, are forward-looking statements.

Forward-looking statements are not guarantees of future 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, many of which are beyond our control, that could influence actual results include but are not limited to: market instability affecting Suncor's ability to borrow in the debt capital markets at acceptable rates; availability of third-party bitumen; success of our hedging strategies; maintaining a desirable debt to cash flow ratio; risks associated with the integration of the business of Petro-Canada following completion of the merger; changes in the general economic, market and business conditions; fluctuations in supply and demand for our products; commodity prices, interest rates 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 and regulatory projects; the accuracy of cost estimates, some of which are provided at the conceptual or other preliminary stage of projects and prior to commencement 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; the cost of compliance with existing and future environmental laws; the accuracy of Suncor's 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; changes in refining and marketing margins; 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; 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 review of the unintended consequences of the proposed Crown royalty regime, and the Government of Canada's current review of greenhouse gas emission regulations); international political events and actions by foreign governments in jurisdictions in which we operate (including OPEC production quotas); 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 in "Risk Factors", and throughout this AIF and in our MD&A. 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 - 4 th 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, and is not incorporated into this AIF by reference.

NON-GAAP FINANCIAL MEASURES

Certain financial measures referred to in this AIF are not prescribed by Canadian generally accepted accounting principles (GAAP), namely operating earnings, cash flow from operations, return on capital employed (ROCE), and cash and total operating costs per barrel. These non-GAAP financial measures do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies. Suncor includes these non-GAAP financial measures because investors may use this information to analyze operating performance, leverage and liquidity. The additional information should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP. For more information with respect to financial measures which have not been defined by GAAP, see the "Non-GAAP Financial Measures" section of the MD&A.

ACCOUNTING MATTERS

References to our "2009 Consolidated Financial Statements" mean Suncor's audited consolidated financial statements prepared in accordance with GAAP, the notes and the auditors' report, as at and for the three years in the period ended December 31, 2009.

On August 1, 2009, Suncor completed its merger with Petro-Canada. All closing conditions were satisfied, including approvals from shareholders, the Alberta Court of Queen's Bench, and the Competition Bureau of Canada. Under the terms of the merger, Petro-Canada shareholders received 1.28 Suncor common shares for each Petro-Canada common share held. As such, the 2009 results reflect those of the post-merger Suncor from August 1, 2009 together with results of legacy Suncor only from January 1, 2009 through July 31, 2009. The comparative figures reflect solely the 2007 and 2008 results of legacy Suncor. For further information with respect to the merger transaction, please refer to note 2 of our 2009 Consolidated Financial Statements.

Certain amounts in prior years have been reclassified to enable comparison with the current year's presentation.

The Canadian Institute of Chartered Accountants Accounting Standards Board confirmed in February 2008 that Canadian publicly accountable enterprises must adopt International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board, effective January 1, 2011.

For more information with respect to the company's adoption of International Financial Reporting Standards, see the "Changes in Accounting Policies" section of our MD&A.

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, May 2002, and May 2008, we amended our articles to divide our issued and outstanding shares on a two-for-one basis.

Pursuant to an arrangement (Arrangement) which was completed effective August 1, 2009, legacy Suncor and legacy Petro-Canada amalgamated to form a single corporation continuing under the name "Suncor Energy Inc.". The Arrangement was effected pursuant to section 192 of the *Canada Business Corporations Act* through an arrangement agreement dated March 22, 2009 and accompanying plan of arrangement, as amended. Under the terms of the Arrangement, Petro-Canada shareholders received 1.28 Suncor common shares for each Petro-Canada common share held.

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

Intercorporate Relationships

Material operating subsidiaries, each of which were owned 100%, directly or indirectly, by the company as at December 31, 2009 are as follows:

Name	Jurisdiction	Purpose
Suncor Energy Oil Sands Limited Partnership	Canada	A subsidiary of Suncor Energy Inc. that holds certain oil sands assets.
Suncor Energy Products Inc.	Canada	An Ontario corporation that is wholly-owned by Suncor Energy Inc., through which some of Suncor's Canadian refining and marketing operations are conducted.
Suncor Energy Marketing Inc.	Canada	A subsidiary of Suncor Energy Products Inc., through which the products produced by our North American business are marketed. 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 business. Suncor Energy Marketing Inc. holds a 50% interest in Sun Petrochemicals Company, a petrochemical products joint venture.
Suncor Energy (U.S.A) Inc.	United States	A subsidiary of Suncor Energy Inc., through which our U.S. refining and marketing operations are conducted.
Suncor Energy Oil & Gas Partnership	Canada	A subsidiary of Suncor Energy Inc. through which certain of our upstream Canadian oil and gas operations are conducted and through which our 12% interest in the Syncrude joint venture is held.
3908968 Canada Inc.	Canada	A subsidiary of Suncor Energy Inc. that holds certain of our international interests.
Petro-Canada Cooperative Holding UA	Netherlands	A subsidiary of 3908968 Canada Inc. that holds international interests.
Petro-Canada (International) Holdings BV	Netherlands	A subsidiary of Petro-Canada Cooperative Holding UA, that holds certain of our international interests.
Petro-Canada Germany GmbH	Germany	A subsidiary of Petro-Canada (International) Holdings BV, that holds the majority of our Libya interests.
Petro-Canada Oil (North Africa) GmbH	Germany	A subsidiary of Petro-Canada Germany GmbH through which the majority of our Libya operations are conducted.
Petro-Canada U.K. Holdings Ltd.	United Kingdom (U.K.)	A subsidiary of 3908968 Canada Inc. that holds certain of our U.K. interests.
Petro-Canada U.K. Ltd.	U.K.	A subsidiary of Petro-Canada U.K. Holdings Ltd. through which certain of our operations are conducted in the U.K.

Individually, the company's remaining subsidiaries accounted for (i) less than 10% of the company's consolidated assets as at December 31, 2009, and (ii) less than 10% of the company's consolidated sales and operating revenues for the fiscal year ended December 31, 2009. In the aggregate, the remaining subsidiaries accounted for less than 20% of each of (i) and (ii) described above.

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 in Canada and internationally, and we transport and refine crude oil and market petroleum and petrochemical products primarily in Canada. 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.

Our operating business units are composed of Oil Sands, Natural Gas, East Coast Canada, International and Refining and Marketing. For financial reporting purposes, we also report financial data for activities not directly attributable to an operating business under "Corporate, Energy Trading and Eliminations". This includes third-party energy trading activities.

Suncor completed its merger with Petro-Canada on August 1, 2009, resulting in Suncor becoming Canada's largest energy company by market capitalization. After completion of the merger with Petro-Canada, Suncor's total upstream production during the final five months of 2009 averaged 635,200 barrels of oil equivalent (boe) per day.

The table below outlines the various Suncor businesses as at December 31, 2009:

Oil Sands
- Mining
- In-Situ (Firebag and MacKay River)
- Syncrude (12% Interest) mining
- Fort Hills (60% Interest) mining

Natural Gas
- Western Canada
  - *Alberta Foothills*
  - *Southeast Alberta/Southwest Saskatchewan*
  - *West Central Alberta*
  - *Northeast British Columbia (B.C.)*
- U.S. Rockies
- Northwest Territories (NWT)/Nunavut
- Alaska/Arctic Islands

East Coast Canada
- Hibernia (20% Interest)
- Terra Nova (34%[1] Interest)
- White Rose (27.5%[2] Interest)
- Hebron (22.7% Interest)
- Discovery Licences and Exploration Acreage
- Hibernia South Extension (19.5%[3] Interest)
- White Rose North Amethyst and West White Rose Extensions (26.125% Interest)

International
- North Sea
  - *Buzzard (29.9% Interest)*
  - *Triton Area*
  - *Scott/Telford Area*
  - *De Ruyter (54.07% Interest)*
  - *Hanze (45% Interest)*
  - *Other Exploration Acreage*
- Other International
  - *Libya Exploration Production Sharing Agreements (EPSAs) (50% Interest)*
  - *Syria Ebla Natural Gas Project (100% Interest)*
  - *Trinidad and Tobago North Coast Marine Area 1 (NCMA-1) (17.3% Interest)*
  - *Other Exploration Acreage*

Refining and Marketing
- Edmonton Refinery
- Montreal Refinery
- Sarnia Refinery
- Commerce City (Colorado) Refinery
- St. Clair Ethanol Plant
- Sun Petrochemicals Company (50% Interest)

Sales and Marketing
- Retail Operations
- Wholesale Operations

Corporate, Energy Trading and Eliminations
- Energy Trading activities
- Ripley Wind Farm (50% Interest)
- Chin Chute Wind Farm (33.3% Interest)
- Magrath Wind Farm (33.3% Interest)
- SunBridge Wind Farm (50% Interest)

Lubricants

Mississauga Lubricants Plant

(1) Under the Terra Nova Development and Operating Agreement, a re-determination of working interests is required following payout. The owners have been working through a process to re-determine what the future working interests will be. This process is ongoing.

(2) Suncor's working interest in the White Rose North Amethyst and West White Rose Extensions is 26.125% after the Newfoundland and Labrador Energy Corporation (NALCOR) acquired its 5% working interest effective with the signing of the final project agreements in February 2009. There is no change to the White Rose 27.5% working interest for the original field development as NALCOR is not a partner.

(3) This interest was 21.7% prior to signing the Hibernia South extension agreement with NALCOR on February 16, 2010.

Three-Year History

On August 1, 2009, Suncor Energy Inc. completed its merger with Petro-Canada. The amounts ending December 31, 2009 reflect results of the post-merger Suncor from August 1, 2009 together with results of legacy Suncor only from January 1 through July 31, 2009. Comparative figures from prior years reflect solely results of legacy Suncor. For further information with respect to the merger, please refer to note 2 to the December 31, 2009 Consolidated Financial Statements.

Oil Sands

Our Oil Sands business, located near Fort McMurray, Alberta, produces bitumen recovered from oil sands through mining and in-situ technology and upgrades it into refinery feedstock, diesel fuel and by-products. Bitumen feedstock is also occasionally supplemented by third-party suppliers. The company also has a 12% ownership interest in the Syncrude oil sands mining and upgrading joint venture, also located near Fort McMurray, Alberta.

Over the past three years we have continued to advance our multi-phased growth strategy to increase production capacity. Key milestones and significant events that have affected our Oil Sands business during this time period include the following:

Operational Issues   Oil Sands had two recent upgrader fires which negatively impacted production. In December 2009 there was a fire at our Upgrader 2 facility and in February 2010 there was a fire at our Upgrader 1 facility. Upgrader 2 was repaired and operational in early 2010, while the damage to Upgrader 1 is currently being repaired and is expected to return to production in April 2010.

Merger   On August 1, 2009, Suncor merged with Petro-Canada, resulting in the acquisition of a 12% ownership in the Syncrude joint venture (an oil sands mining operation and upgrading facility), 100% ownership of the MacKay River in-situ bitumen development (a steam-assisted gravity drainage (SAGD) operation), a 60% ownership in, and operatorship of, the proposed Fort Hills oil sands mining project, and extensive oil sands acreage considered prospective for in-situ development of bitumen resources. The merger did not result in increased Oil Sands production (excluding Syncrude) as production from MacKay River was included historically in Suncor's reported production from January 1, 2009 to July 31, 2009 as volumes processed by Suncor under a processing fee arrangement.

Safe Mode   In the first quarter of 2009, Suncor placed a number of Oil Sands projects into "safe mode" as a result of economic conditions at the time. Safe mode is defined as deferring the projects and keeping the equipment and facilities in a safe manner in order to expedite remobilization. As a result of placing the company's Oil Sands projects into safe mode, pre-tax costs of $380 million were incurred in 2009.

Tailings Reduction Operations (TRO)   Suncor is seeking approval from Alberta regulators to convert from its current Consolidated Tailings (CT) tailings management process to Tailings Reduction Operations (TRO). TRO is a new "dry tailings" process in which mature fine tails (MFT) are dried, rather than mixed with sand and other materials to form CT. The processing rate for TRO is expected to be more efficient and effective than CT. If we receive timely approval to proceed, we believe that TRO will allow Suncor to meet the requirements of the new Tailings Directive issued by Alberta's Energy Resources Conservation Board (ERCB) last year. Major construction on this project is expected in mid-2010 following Board approval, assuming regulatory approvals are received.

North Steepbank Extension (NSE)   The NSE is currently under construction and is expected to begin production in 2012. The NSE was approved in early 2007 as an extension to Suncor's mining activities east of the Athabasca River. Conditions contained within the government's approval of the NSE relating to Suncor's tailings management performance are expected to be satisfied or waived if the TRO application is approved. During its peak production years, it is currently expected that the NSE will produce approximately half the total bitumen ore mined within the overall Millennium Mine/NSE mining operations.

Firebag Stage 3   in-situ oil sands expansion   This project was approximately 50% complete before being deferred due to market conditions in early 2009. The project has restarted and Suncor expects the project to begin production in the second quarter of 2011, with volumes then beginning to ramp up toward design capacity of approximately 68,000 barrels per day (bpd) of bitumen over a period of approximately 18 months.

Steepbank Extraction Plant This project was completed on schedule and on budget during the third quarter of 2009. After commissioning, the plant began operations in late September 2009 and has resulted in improved reliability and productivity within our Oil Sands business.

Firebag Sulphur Plant This project was also completed on schedule and on budget during the third quarter of 2009. The plant is currently ready to operate and is expected to support sulphur emissions reductions for existing and planned in-situ development at Firebag, including Firebag Stage 3.

Royalties In January 2008, we entered into the Suncor Royalty Amending Agreement (Amending Agreement) with the government of Alberta, which modifies the rates under the Government of Alberta's New Royalty Framework (New Royalty Framework) that applies to our in-situ operations and would otherwise apply to our base mining operations. Under the Amending Agreement, prior to January 1, 2010, we would pay a royalty in respect of our base operations at 25% of the difference between a project's annual gross revenues net of reasonable quality adjustments and related allowable transportation costs (R), less allowable costs (C) including allowable capital expenditures (the R-C Royalty). This is subject to a minimum royalty of 1% of revenues should allowable costs exceed revenues as determined using the R-C Royalty formula. Under the New Royalty Framework enacted in December 2008, royalty rates move to a sliding scale royalty of 25% 40% of R-C, subject to a minimum royalty of 1% 9%, depending on oil price. In both cases, the sliding scale royalty would move with an increase in WTI prices from Cdn$55/bbl to the maximum rate at Cdn$120/bbl. From 2010 through 2015, royalty rates on our base mining operations are those in the New Royalty Framework, with a cap of 30% of R-C and a minimum royalty of 1.0% to a cap of 1.2% of R. In 2016 and subsequent years, the royalty rates for all of our Oil Sands operations (our base mining project and our in-situ projects) will be the rates prescribed under the New Royalty Framework, unless it is amended or superseded prior to that time.

Coker Unit A $2.3 billion expansion to one of our two oil sands upgraders was completed in 2008. This new set of cokers is intended to increase our design capacity by 90,000 bpd to a total of 350,000 bpd at our Oil Sands facilities.

Voyageur South Extension of Mine In July 2007, Suncor filed a regulatory application for the Voyageur South extension of the mine. Bitumen produced at the proposed project is expected to provide additional feedstock flexibility once operational.

Operating Permit We were issued a new 10-year operating approval in connection with our Oil Sands business in August 2007.

Firebag Cogeneration A capital project expanding Firebag Stages 1 and 2 in conjunction with the addition of a cogeneration facility was completed in 2007.

Emissions In September 2007, high emissions at our Firebag in-situ operations resulted in orders being issued by both Alberta Environment and the Alberta Energy and Utilities Board that capped production. The production cap was lifted on July 22, 2008, after Suncor demonstrated the ability to meet emissions restrictions. This enforcement action was closed in March 2010. In December 2007, high emissions recorded at our base oil sands plant resulted in an order being issued by Alberta Environment. Emissions at the oil sands plant exceeded air quality standards, and accordingly, we are upgrading our emission control equipment and reducing discharges to the tailings ponds. In addition, we have introduced processing changes and are undertaking a more comprehensive monitoring program.

The following changes to our Oil Sands business have occurred, or are expected to occur, in 2010:

Approximately $950 million in growth spending will be directed toward Firebag Stages 3 and 4 in-situ oil sands expansion. Firebag Stage 3 was approximately 50 per cent complete before being deferred in early 2009 due to market conditions. Production from Firebag Stage 3 is expected to begin in the second quarter of 2011, with volumes then beginning to ramp up toward design capacity of approximately 68,000 bpd of bitumen over a period of approximately 18 months. Subject to Board approval, first bitumen for Firebag Stage 4 is targeted in the fourth quarter of 2012. Firebag Stage 4 also has a design capacity of 68,000 bpd.

Natural Gas

Our Natural Gas business, based in Calgary, Alberta, explores for, acquires, develops and produces natural gas, natural gas liquids, oil and by-products from reserves primarily in western Canada and the U.S. Rockies. This business also has established resources in Alaska, the Northwest Territories (NWT) and the Arctic Islands. The sale of natural gas production offsets natural gas purchased for internal consumption at our North American operations.

Key milestones and significant events that have affected our Natural Gas business during the past three years include the following:

Merger On August 1, 2009, Suncor merged with Petro-Canada, adding significant natural gas assets in Western Canada and the U.S. Rockies, as well as established resources in Alaska, the NWT and the Arctic Islands.

Offshore Permit In September 2008, Suncor, together with a partner, successfully bid for a large offshore parcel in the Newfoundland and Labrador Offshore Area. This land is adjacent and complementary to an existing holding in the Bjarni area and provides Suncor with a long-term option for future potential natural gas growth. In order to retain the lands, the exploration license requires Suncor to commit to exploration spending of $30 million on the lands within six years. Subsequent to the merger, these licenses are now managed by our East Coast Canada business.

Acquisition In March 2007, we acquired developed and undeveloped lands in British Columbia for approximately $160 million.

The following changes to our Natural Gas business have occurred or are expected to occur, in 2010:

Planned divestitures As part of its strategic business alignment, Suncor announced its intention to divest of a number of non-core natural gas assets. The proposed divestments identified to date include certain natural gas assets in Western Canada and the U.S. Rockies. On February 9, 2010, Suncor announced it has entered into an agreement to sell certain natural gas properties in northeastern British Columbia for proceeds of approximately $390 million. The sale is expected to close in the first quarter of 2010 and is subject customary to closing conditions and regulatory approvals. On December 31, 2009, Suncor entered into an agreement to sell substantially all of its oil and gas producing assets in the U.S. Rockies for proceeds of $517 million (US$494 million). The sale closed March 1, 2010.

East Coast Canada

Our East Coast Canada business comprises exploration and production activity offshore Newfoundland and Labrador. The company has a strong position in every major producing oil development off Canada's east coast. The company holds a 20% interest in Hibernia, a 19.5% [(1)] interest in Hibernia Southern Extension, a 27.5% interest in White Rose, a 26.125% interest in White Rose North Amethyst and West White Rose extensions, a 22.7% interest in Hebron and is the operator of Terra Nova with a 34% interest. The company also holds a number of exploration licenses and significant discovery licenses in the region.

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(1) This interest was 21.7% prior to signing the Hibernia South extension agreement with NALCOR on February 16, 2010.

Key milestones and significant events that have affected our East Coast Canada business during the past three years include the following:

- Hibernia South   Production from Hibernia South is expected later in the first quarter of 2010 with the completion of the first oil producer/water injector well pair. Final fiscal agreements were made between co-venturers and the Government of Newfoundland and Labrador in February 2010.

- Terra Nova   In 2009, Terra Nova was negatively impacted by planned and unplanned downtime for maintenance. In 2008, there were mechanical failures on the Terra Nova Floating Production, Storage and Offloading (FPSO) vessel and Terra Nova had a 16-day maintenance turnaround.

- White Rose   White Rose was negatively impacted by planned downtime for maintenance and the tie-in of the North Amethyst extension in the second half of 2009. Additionally, pack ice at the White Rose field in the second quarter of 2008 caused production deferrals and drilling delays.

- Hibernia   In 2007, Hibernia had a 30-day maintenance turnaround.

International

Our International business focuses on countries and regions where material positions of long-life assets may be built. This includes the exploration for and production of, crude oil and natural gas primarily in the U.K., The Netherlands, Norway, Trinidad and Tobago, Libya and Syria.

Key milestones and significant events that have affected our International business during the past three years include the following:

North Sea

- As part of our strategic business alignment, we plan to divest of certain non-core North Sea assets, including all assets in The Netherlands.

- Completed our first operated exploration well in January 2010 in Norway and encountered hydro-carbon; further appraisal is required to determine the potential size of this discovery. The company is committed to participating in other non-operated drilling in Norway.

- After completion of the shutdown at the Buzzard development in the third quarter of 2009, production did not return to full production capacity as quickly as planned, but this development was back operating at expected capacity by year-end.

- In 2008, there was a non-operated oil discovery, located in Block 20/1 North, called Pink. The Pink block is located in the Outer Moray Firth approximately 110 kilometres northeast of Aberdeen. Our working interest is 33%.

In the Netherlands sector of the North Sea, the company, as operator with a 50% working interest, drilled a successful exploration well in 2008, named van Ghent. The company drilled two successful exploration wells in 2007, van Nes and van Brakel, as an operator with a 50% and 60% working interest, respectively. Both van Nes and van Brakel were suspended as gas discoveries. In the third quarter of 2008, the company completed a sale and purchase agreement with Bayerngas Norge AS for the sale of all the company's interests in Denmark for net proceeds of $140 million, resulting in a $107 million ($82 million after-tax) gain on the sale of these assets.

In 2008, the company was awarded four additional production licences in the 2007 Awards in Predefined Areas round in Norway. Suncor is operator of five of the 17 licences in Norway.

In the U.K. sector of the North Sea, the Buzzard development, in which the company has a 29.9% interest, achieved first oil in January 2007.

Libya

In the five months ended December 31, 2009, Suncor's production in Libya averaged 32,600 bpd (net to Suncor). During this period, gross production from our Libya Exploration Production Sharing Agreements (EPSAs) was restricted initially to 82,000 bpd and then to 50,000 bpd from September to the end of the year. In January 2010, the Libya National Oil Company (NOC) advised the company that production from Suncor's Libya EPSAs will be limited to 70,000 bpd gross (35,000 bpd net to Suncor) due to the quota agreed to by OPEC producers.

Work on the exploration program progressed, with seven seismic surveys completed during 2009 and two seismic crews continue to acquire data in the country. At the end of 2009, the seismic program was approximately 75% complete. The company expects to begin drilling Suncor's first operated exploration well in early 2010.

In the final five months of 2009, eight development wells were completed in the producing fields in Libya, consisting of six production wells and two injection wells. A further three development wells were drilling at year end. In 2008, 12 development wells were completed in the producing fields in Libya, consisting of 11 production wells and one injection well. Additionally, one appraisal well was drilled.

In 2008, the company completed 2D and 3D seismic acquisitions.

Syria

The Ebla gas project remains on plan with first gas delivery currently expected in mid-2010. The project was 90% complete at the end of 2009. Five gas wells have been completed and are ready for production. The 3D seismic acquisition of the Cherrife field was completed at the end of the third quarter of 2009 and is currently being interpreted. The 3D seismic survey of the Ash Shaer field that was completed during the second quarter of 2009 is also now being interpreted.

In 2008, the company completed front-end engineering and design (FEED) and undertook 2D and 3D seismic operations for the Ebla gas project.

Trinidad and Tobago

As part of its strategic business alignment, Suncor announced its plans to divest a number of non-core assets, including all Trinidad and Tobago assets.

In 2008, there was maintenance at the Atlantic liquefied natural gas (LNG) plant, rebalancing of mutual aid production among producers to the Atlantic LNG plant and several brief shutdowns of the North Coast Marine Area (NCMA-1) asset to prepare for the startup of the new Poinsettia field. Development of the Poinsettia field, with a platform and pipeline tie-back to the Hibiscus platform, was carried out on schedule during 2008.

In 2008, the company completed its eight-well exploration program in Block 22 and Block 1a/1b, which yielded four material discoveries (two on Block 22 and two on Block 1a).

Other International

A 2D seismic survey was completed in Morocco in 2009 and is currently being interpreted.

In July 2008, the company converted its existing reconnaissance licence in southern Morocco to an exploration permit. The company's partners in the exploration licence include a German company called RWE AG and the Moroccan National Office of Hydrocarbons.

The following changes to our International business have occured or are expected to occur, in 2010:

On February 25, 2010, Suncor entered into an agreement to sell its assets in Trinidad and Tobago for proceeds of $396 million (US$380 million). The sale is expected to close in March 2010 and is subject to customary closing conditions, Trinidad and Tobago government approval and other regulatory approvals.

Refining and Marketing

Our Refining and Marketing business refines crude oil at Suncor's refineries in Edmonton, Alberta, Montreal, Quebec and Sarnia, Ontario in Canada, and in Commerce City, Colorado, U.S.A. into a broad range of petroleum and petrochemical products for sale to retail, commercial and industrial customers. This operating business also includes our plant in St. Clair, Ontario that produces ethanol for blending into fuels and our lubricants plant in Mississauga, Ontario that produces specialty lubricants and waxes.

In Canada, our retail businesses are managed through Petro-Canada® and Sunoco®-branded and joint venture operated retail networks. In Colorado, our retail businesses are managed through Phillips 66® and Shell® branded sites. We also transport crude oil through our wholly-owned pipelines in Eastern and Western Canada, Wyoming and Colorado. In conjunction with the merger, the Canadian Competition Bureau required Suncor to divest of 104 retail sites in Ontario and provide 1.1 billion litres of terminal and distribution capacity to an unrelated party in the Greater Toronto Area for ten years.

In 2009, our Refining and Marketing business sold approximately 345,300 bpd or 54,900 m^3 per day of refined products nationwide in Canada and in Colorado, as well as into other parts of the United States and in Europe.

Key milestones and significant events that have affected our Refining and Marketing business during the past three years include the following:

Merger On August 1, 2009, Suncor merged with Petro-Canada, resulting in the addition of two refineries, one in Edmonton, Alberta and one in Montreal, Quebec, with a total daily rated capacity of 255,000 bpd or 40,500 m^3 per day, a lubricants plant that is the largest producer of lubricant base stocks in Canada, a network of retail service stations, a national commercial road transport system and a bulk fuel sales channel.

Terminal Storage and Distribution Capacity In conjunction with the merger, as requested by the Canadian Competition Bureau, Suncor entered into terminalling agreements with Ultramar Ltd. to provide 1.1 billion litres of terminal and distribution capacity in the Greater Toronto Area for 10 years.

Retail Site divestiture In conjunction with the merger, the Canadian Competition Bureau required Suncor to divest 104 retail sites in Ontario. On December 8, 2009, Suncor agreed to sell 98 sites with expected closing dates commencing in the first half of 2010. Agreements are also now in place to meet the full divestiture requirement and we expect to complete the divestitures in 2010.

Edmonton Refinery Conversion The Edmonton refinery completed its refinery conversion project to process oil-sands feedstock in 2008.

Sarnia and Denver Refining Capacities The observed performance of our Sarnia refinery in 2008, after completion of our diesel desulphurization and oil sands integration project in 2007, has enabled us to upwardly revise our nameplate capacity to 85,000 bpd from the previously disclosed 70,000 bpd. Starting January 1, 2009, refinery utilization was calculated using the 85,000 bpd capacity. The Commerce City, Colorado refining capacity was also increased from 90,000 bpd to 93,000 bpd effective January 1, 2009.

Diesel Desulphurization and Oil Sands Integration In November 2007, Suncor completed a multiphase three-year $950 million project at the Sarnia refinery with a 120-day shutdown to complete the tie-ins. The project increased the amount of oil sands crude oil the refinery can upgrade, improved the facility's environmental performance, and commencing in 2006, enabled the production of ultra low sulphur diesel fuel. In 2006, Suncor additionally completed diesel desulphurization and Oil Sands integration at the Commerce City refinery. This enabled the refinery to process up to 15,000 bpd of oil sands sour crude oil and increased the refinery's ability to process a broader slate of synthetic crude oil.

The following changes to our Refining and Marketing have occured or are expected to occur, in 2010:

Edmonton Refining Capacity The observed performance of our Edmonton refinery in 2009, after improvements completed in previous years, has enabled us to upwardly revise our nameplate capacity to 135,000 bpd from the previously disclosed 125,000 bpd. Starting January 1, 2010, refinery utilization will be calculated using the 135,000 bpd capacity.

Other

Renewable Energy

Suncor's renewable energy interests include four wind power plants and Canada's largest ethanol plant by production volume.

Key milestones and significant events that have affected our renewable energy interests during the past three years include the following:

Suncor re-commenced construction of $120 million St. Clair Ethanol Expansion Project in the fourth quarter of 2009, following a slow down of capital spending in the fourth quarter of 2008 and placement into safe mode in January 2009. In addition, we submitted a project application to the Alberta Utilities Commission (AUC) for the 88 megawatt (MW) Wintering Hills Wind Farm, located in Alberta.

In 2008, approval was obtained to expand our existing St. Clair Ethanol Plant, located in Ontario, from a capacity of 200 million litres to 400 million litres.

Suncor completed construction and commissioned our 76 MW Ripley Wind Farm, located in Ontario, in 2007.

Significant Acquisition in 2009

Pursuant to the Arrangement which was completed effective August 1, 2009, legacy Suncor and legacy Petro-Canada amalgamated to form a single corporation continuing under the name "Suncor Energy Inc.". The Arrangement was effected pursuant to section 192 of the *Canada Business Corporations Act* through an arrangement agreement dated March 22, 2009 and accompanying plan of arrangement, as amended. Under the terms of the Arrangement, Petro Canada shareholders received 1.28 Suncor common shares for each Petro Canada common share held. In respect of the Arrangement, we filed a Business Acquisition Report on Form 51-102F4 on October 2, 2009, which can be found under the company's SEDAR profile at www.sedar.com.

Forward-Looking Information

The preceding paragraphs describing the general development of our business contain forward looking information. The material factors used to develop target completion dates and cost estimates and expected results are: current capital spending plans, the current status of procurement, design and engineering phases of the projects, updates from third parties on delivery of services and goods associated with the project, and estimates from major project teams on completion of future phases of the project. We have assumed that commitments from third parties will be honored and that material delays and increased costs related will not be encountered. For additional information on risks, uncertainties and other factors that could cause actual results to differ, please see "Forward Looking Information" and "Major Projects" in the Risk Factors section of this AIF.

NARRATIVE DESCRIPTION OF THE BUSINESS

Oil Sands

Suncor produces a variety of refinery feedstock, diesel fuel and by-products by developing our resource leases in the Athabasca oil sands in northeastern Alberta and upgrading the bitumen extracted at our plant near Fort McMurray, Alberta. The company also has a 12% ownership interest in the Syncrude oil sands mining and upgrading joint venture, also located near Fort McMurray. Our Oil Sands operations represent a significant portion (1) of our 2009 cash flow from operations (1) (36%), net earnings (52%) and capital employed (1) excluding major projects in progress (55%).

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(1) Refer to "Non-GAAP Financial Measures" on page 5 of this AIF. Percentages have been determined excluding amounts related to Corporate, Energy Trading and Eliminations.

Operations

Our integrated oil sands business involves four operations located near Fort McMurray, Alberta.

(1) Bitumen is supplied from a combination of open pit mining operations, in-situ operations and third-party supply.

(2) Primary extraction facilities recover the bitumen from the mined oil sands ore. In in-situ operations, primary extraction occurs in the ground. All mined and some in-situ bitumen also undergo Oil Sands secondary extraction processes in preparation for upgrading.

(3) Heavy oil upgrading converts bitumen into crude oil products. Since late 2005, we have upgraded bitumen from Firebag, with only a small portion of non-upgraded production being strategically sold directly into the market. Since 2007, we have upgraded bitumen from MacKay River, originally pursuant to a processing agreement with Petro-Canada, and subsequent to the merger as proprietary bitumen. A portion of that bitumen production is also strategically sold directly into the market.

(4) Required utilities (water, steam and electricity) are generated through facilities on site, some owned and operated by Suncor and others owned and operated by third parties.

Mining/Extraction 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 either transported to fixed sizing and extraction plants or fed directly to a mobile sizing and extraction operation at the mine face. In the primary extraction process, bitumen is separated from the oil sands ore using a hot water process. After the final removal of impurities and minerals during secondary extraction, naphtha is added to dilute the bitumen to facilitate transportation to upgrading.

In-Situ Our in-situ operations (Firebag and MacKay River) use an extraction technology called Steam Assisted Gravity Drainage (SAGD) to separate 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 located above the other. Steam produced by on-site 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 back to the steam generation facilities. At our Firebag operation, naphtha is added to dilute the bitumen to facilitate transportation to upgrading. At our MacKay River operation (and in future with Firebag Stage 4), a heated pipeline is used instead of naphtha dilution for transport.

Upgrading After the diluted bitumen is transferred to the upgrading plant, the naphtha is removed and recycled to be used again as diluent. The bitumen recovered from both in-situ and mining is upgraded through a coking and distillation process. The upgraded product, referred to as sour SCO, is either sold directly to customers as sour SCO or is further upgraded into sweet SCO by removing the sulphur and nitrogen using a hydrogen treating process. Four separate streams of refined crude oil are produced: diesel, naphtha, kerosene and gas oil.

We continue to explore and develop improved and alternative technologies to facilitate increased efficiency within our operations. For example, in the past three years, we have tested new mining technology and processes for potential use in our future mine development plans.

While there is virtually no finding costs associated with oil sands resources, delineation of the resources, costs associated with production including mine development and drilling wells for SAGD operations, and costs associated with upgrading bitumen into SCO, can entail significant capital outlays. The costs associated with production at Oil Sands are largely fixed in the short term and, as a result, operating costs per unit are largely dependent on levels of production. Natural gas is used in the production of SCO, particularly in SAGD production at our Firebag and MacKay River operations, and accordingly, natural gas prices are a key variable component of SCO production costs.

In the normal course of our operations, we regularly conduct 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. In July 2007, a scheduled maintenance shutdown of Upgrader 2 occurred to facilitate the tie-in of new coker units, an important milestone in the capital expansion project to increase oil sands production capacity to 350,000 bpd in the second half of 2008. In May 2008, a planned shutdown of Upgrader 1 was undertaken to provide both preventative maintenance and capital replacement to improve operational efficiency. During September and October 2009, a planned maintenance shutdown of a vacuum unit at Upgrader 1 occurred, and was completed ahead of schedule. We have planned turnarounds scheduled for Upgrader 2 for approximately 45 days during the second quarter of 2010 and approximately 35 days during the third quarter of 2010.

Syncrude Commercial operations commenced at Syncrude in 1978. Two mines, the North mine and the Aurora mine, are currently in operation at Syncrude. Mine operations are carried out using truck, shovel and hydro-transport systems. Suncor's share of SCO production is processed primarily at our refinery in Edmonton, Alberta, with the balance periodically processed in Eastern Canada and in the United States. In the five months ended December 31, 2009, Syncrude production averaged 38,500 bpd (net to Suncor).

Principal Products

Sales of light sweet SCO and diesel represented 48% of Oil Sands consolidated operating revenues in 2009, compared to 45% in 2008. The other significant component of our revenues were light sour SCO and bitumen sales of 49% (2008 46%). Set forth below is information on daily sales volumes and the corresponding percentage of Oil Sands operating revenues by product for each of the last two years:

Product:	2009		2008	
	(thousands of barrels per day)	(% of operating revenues)	(thousands of barrels per day)	(% of operating revenues)
Light sweet crude oil/diesel	144.9	48	96.8	45
Light sour crude oil/bitumen	147.5	49	130.2	46
Total	292.4		227.0	

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 SCO from Fort McMurray, Alberta to Edmonton, Alberta. The pipeline has a capacity of approximately 110,000 bpd.

We have a transportation service agreement on the Enbridge Athabasca Pipeline for a term that commenced in 1999 and extends to 2028. Total line design capacity is 600,000 bpd and the current configuration capacity is 350,000 bpd. Under this agreement, our current pipeline commitment is 182,000 bpd for the transportation of SCO and diluted bitumen from Fort McMurray, Alberta to Hardisty, Alberta.

We are a founding member of the Waupisoo pipeline that went into service on June 1, 2008. Under this agreement, our founding member status is for a minimum term of 25 years with options to extend. Total line capacity is 350,000 bpd with potential expansion to 535,000 bpd. Under this agreement, our current pipeline commitment is 75,000 bpd for the transportation of SCO and diluted bitumen from Cheecham to Edmonton, Alberta. Following the Petro-Canada merger, we additionally assumed a short-haul commitment from Fort McMurray to Cheecham for 58,000 bpd on the Enbridge Athabasca pipeline, a lateral transportation agreement from MacKay River to the Athabasca Tank Terminal for 40,000 bpd and contracted storage facilities of 250,000 bbls for a remaining 24-year term. We also assumed contracted storage facilities at Edmonton for 500,000 bbls with a remaining nine-year term.

Suncor has entered into long-term service agreements with affiliates of TransCanada Corporation to transport crude oil on the Keystone pipeline. The agreements will provide for pipeline transportation of our crude oil from Hardisty, Alberta to both Patoka, Illinois and Cushing, Oklahoma. Linefill on the Keystone pipeline is expected to occur in early 2010, with transportation of crude oil expected to commence in the summer of 2010. Our capacity on this pipeline in 2010 will be 25,000 bpd. In 2008, Suncor contracted additional storage facilities at both Patoka and Cushing, in order to provide further flexibility for trading strategies. Both contracts are for 1.1 million barrels of storage and for fixed five-year terms. On January 1, 2009, Suncor contracted storage facilities for an additional 1.2 million barrels at Nederland, Texas, for a fixed five-year term.

In 2008, we entered into new commitments for the transportation of crude oil on the Express New pipeline (30,000 bpd starting in 2008) and the Wamsutter pipeline (10,000 bpd starting in 2009). We continue to evaluate additional pipeline agreements to support planned increases in production capacity.

Periodically, we also enter into strategic short-term cargo transport agreements to ship SCO internationally. 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 Oil Sands plant and is connected to TransCanada Pipeline's Alberta intra-provincial pipeline system. The Albersun pipeline had the capacity to move in excess of 100 mmcf/day of natural gas in both north and south directions until we closed our Atmore receipt terminal in November 2009. Following this closure, our capacity became 46 mmcf/day in the north direction only. We arrange for natural gas supply and purchase most of the natural gas on the system under delivery-based contracts.

Our Oil Sands mining facilities are readily accessible by public road. Our Firebag in-situ facilities are currently accessible by air and private road, while our MacKay River in-situ facilities are accessible by a combination of public and private roads. We anticipate termination of the Firebag current road access in 2010. An East Athabasca Highway (EAH) is under construction and is expected to be available for use in 2010. This highway is owned equally by Suncor, Husky Energy Inc. and Imperial Oil Ltd.

Competitive Conditions

For a discussion of the competitive conditions affecting our Oil Sands operations, refer to "Strategic Risks Competition" in the Risk Factors section of this AIF.

Seasonal Impacts

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

Sales of SCO and Diesel

Aside from on-site fuel use, all of our Oil Sands production is sold to, and subsequently marketed by Suncor Energy Marketing Inc. Primary markets for our crude oil products include refining operations in Alberta, Ontario, the U.S. Midwest and the U.S. Rocky Mountain region. Diesel products are sold primarily in western Canada.

In 1997, we entered into a long-term agreement with Flint Hills Resources LLC (Flint Hills) to supply Flint Hills with up to 30,000 bpd (approximately 10% of our average 2009 total production (2008 13%)) of sour crude from our Oil Sands operations. We began shipping the crude to Flint Hills at Hardisty, Alberta on January 1, 1999. The term of the initial agreement expires on June 30, 2011. A new agreement was negotiated to supply Flint Hills with 20,000 bpd beginning July 1, 2011. The initial term of that agreement extends to June 30, 2014 and will continue thereafter until termination upon a minimum of 24 months notice to either party.

Under a long-term sales agreement from August 2001 with Consumers Co-operative Refineries Limited (CCRL) we supply CCRL with 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. The initial term of both CCRL agreements is 15 years with five-year evergreen terms thereafter subject to termination by either party on 24 months notice. Neither party has provided notice of termination at this time.

A portion of our Oil Sands production is used in our refining operations. During 2009, our refineries processed the following portion of our total Oil Sands crude sales:

Refinery	2009		2008	
	(thousands of barrels per day)	(% total Oil Sands sales)[1]	(thousands of barrels per day)	(% total Oil Sands sales)
Edmonton[2]	58	25		
Sarnia	44	18	37	18
Montreal[2]				
Commerce City	9	4	9	4

(1) Calculated based on Oil Sands sales, excluding diesel and bitumen sales.

(2) Reflects operations subsequent to the Petro-Canada merger on August 1, 2009

There were no customers that represented 10% or more of our consolidated revenues in 2009 or 2008.

Environmental Compliance

For a discussion of environmental risks at our Oil Sands operations, refer to the "Legal and Regulatory Risks" in the Risk Factors section of this AIF.

Natural Gas

Our Natural Gas business explores for, develops and produces natural gas, natural gas liquids, crude oil and by-products primarily in Western Canada, supplying markets throughout North America. The sale of this production provides a natural price hedge for natural gas purchased for internal consumption at our North American operations.

Our exploration program is primarily focused on multiple geological zones throughout Western Canada. The business is structured with the following core asset areas: Unconventional (northeast British Columbia and southeast Alberta), Foothills (western Alberta and portions of northeast British Columbia), Conventional (Western Canada) and Alaska.

Marketing, Pipeline and Other Operations

In Western Canada, Suncor operates 15 natural gas processing plants, with total licensed capacity of approximately 1,273 million cubic feet/day (MMcf/d), of which the company's share is approximately 764 MMcf/d. The following table shows Suncor's working interest ownership and the licensed capacity of operated processing plants as at December 31, 2009.

Suncor Operated Plants	Working Interest Ownership (%)	Gross Licensed Capacity (MMcf/d)	Net Licensed Capacity (MMcf/d)
Hanlan Sweet	40.73	44.2	18.0
Hanlan Sour	46.07	382.0	176.0
Wilson Creek	52.17	34.6	18.1
Boundary Lake Sweet	100.00	20.0	20.0
Boundary Lake Sour	50.00	66.0	33.0
Parkland 1	43.98	18.1	8.0
Parkland 2	34.75	11.7	4.1
Wildcat Hills	65.78	125.0	82.2
Bearberry	100.00	94.9	94.9
Ferrier	99.37	120.0	119.2
Gilby East	100.00	52.4	52.4
South Rosevear	60.53	90.5	54.8
Pine Creek	51.46	19.5	10.0
Progress	38.46	44.0	16.9
Simonette	37.50	150.0	56.3
Total		**1 272.9**	**763.9**

Suncor also has varying working interests in other natural gas processing plants and field gathering facilities operated by other oil and natural gas companies. The company's aggregate share from such interests is 197.8 MMcf/d of licensed capacity.

Approximately 74% of our natural gas production in 2009 was sold to Suncor Energy Marketing Inc. (SEMI) and then marketed under direct sales arrangements to our customers. Approximately 25% of our natural gas production was marketed directly to customers related to legacy Petro-Canada production from August to November 2009. Starting December 2009, this production was marketed through SEMI. 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 1% of our natural gas production in 2009 was sold under existing contracts to aggregators ("system sales"). Proceeds received by producers under these system 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 Pan-Alberta Gas Ltd.

To provide exposure to the Pacific Northwest and California markets, we have a long-term gas pipeline transportation contract on the TCPL Gas Transmission Northwest Pipeline. Our contract expires in 2023 and is for 68,000 million british thermal units (MMBtu) per day.

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. We currently have no pipeline commitments related to the shipment of conventional crude oil.

As part of its strategic business alignment, Suncor announced its intention to divest of a number of non-core natural gas assets. The proposed divestments identified to date include certain natural gas assets in Western Canada and the U.S. Rockies. On December 31, 2009, Suncor entered into an agreement to sell substantially all of its oil and gas producing assets in the U.S. Rockies for proceeds of $517 million (US$494 million). The sale closed March 1, 2010. On February 9, 2010, Suncor announced it has entered into an agreement to sell certain natural gas properties in northeast British Columbia for proceeds of approximately $390 million. The sale is expected to close in the first quarter of 2010 and is subject customary to closing conditions and regulatory approvals.

Principal Products

Sales of natural gas represented 76% (2008   81%) of the Natural Gas business segment's consolidated operating revenues in 2009, with 23% (2008   11%) comprised of sales of natural gas liquids and crude oil. The remaining 1% (2008   8%) is related mainly to sales of sulphur by-product. Set forth below is information on average daily sales volumes and the corresponding percentage of Natural Gas's operating revenues by product for the last two years.

Product:	2009		2008	
	(mmcf equivalent per day)	(% of operating revenues)	(mmcf equivalent per day)	(% of operating revenues)
Natural gas	398	76	202	81
Crude oil and natural gas liquids	48	23	18	11
Total	446		220	

Product:	Five months ended December 31, 2009*	
	(mmcf equivalent per day)	(% of operating revenues)
Natural gas	677	72
Crude oil and natural gas liquids	90	28
Total	767	

* Reflects operations subsequent to the Petro-Canada merger on August 1, 2009

Competitive Conditions

For a discussion of the competitive conditions affecting the Natural Gas business, refer to "Competition" in the Risk Factors section of this AIF.

Seasonal Impacts

Risks and uncertainties associated with weather conditions and wildlife restrictions can shorten the winter drilling season and can impact the spring and summer drilling programs, potentially resulting in increased costs or reduced production.

Environmental Compliance

For a discussion of environmental risks at our Natural Gas operations, refer to the "Legal and Regulatory Risks" outlined in the Risk Factors section of this AIF.

East Coast Canada

Our East Coast Canada business explores for, develops and produces crude oil offshore Newfoundland and Labrador. Suncor has a strong position in every major producing oil development off Canada's east coast, holding a 20% interest in Hibernia, a 19.5% [(1)] interest in Hibernia Southern Extension, a 27.5% interest in White Rose, a 26.125% [(2)] interest in White Rose North Amethyst and West White Rose extensions, a 22.7% interest in Hebron and is the operator of Terra Nova with a 34% [(3)] interest. The company also holds interests in a number of exploration licenses and significant discovery licenses in the region including 47 significant discovery licenses and 7 exploration licenses offshore in Newfoundland and Labrador.

Our East Coast Canada strategy is to deliver reliable and profitable production well into the next decade, leveraging the existing infrastructure while pursuing profitable exploration and development opportunities.

(1) This interest was 21.7% prior to signing the Hibernia South extension agreement with NALCOR on February 16, 2010.

(2) Suncor's working interest in the White Rose North Amethyst and West White Rose Extensions is 26.125% after the Newfoundland and Labrador Energy Corporation (NALCOR) acquired its 5% working interest effective with the signing of the final project agreements in February 2009. There is no change to the White Rose 27.5% working interest for the original field development as NALCOR is not a partner.

(3) Under the Terra Nova Development and Operating Agreement, a re-determination of working interests is required following payout. The owners have been working through a process to re-determine what the future working interests will be. This process is ongoing.

Marketing, Pipeline and Other Operations

Hibernia

The Hibernia oilfield is approximately 315 kilometres southeast of St. John's, Newfoundland and Labrador, and was the first field to be developed in the Jeanne d'Arc Basin offshore on the Grand Banks of Newfoundland. The production system is a fixed Gravity Base Structure (GBS), which sits on the ocean floor. The GBS has a production capacity of 230,000 bpd gross and storage capacity of 1.3 million barrels (MMbbls) gross. Actual production levels are lower, however, reflecting current reservoir capability and natural decline. Hibernia commenced production in November 1997. The Hibernia oilfield, encompassing the Hibernia and Ben Nevis Avalon reservoirs, is estimated to have a remaining production life of 23 to 27 years at current rates.

In the second quarter of 2009, co-venturers in the ExxonMobil operated Hibernia South project signed a non-binding Memorandum of Understanding (MOU) with the Government of Newfoundland and Labrador establishing the key fiscal, equity and operational principles for the development of the Hibernia Southern Extension satellite (Suncor's working interest is 19.5%). Production from Hibernia South is expected later in the first quarter of 2010 with the completion of the first oil producer/water injector well pair. Final fiscal agreements were signed between co-venturers and the Government of Newfoundland and Labrador in February 2010.

At December 31, 2009, there were 33 producing oil wells, 17 water injection wells and six gas injection wells in operation. Field production is transported by shuttle tanker either from the platform to either a transshipment terminal on the Avalon Peninsula or, if tanker schedules permit, directly to market. Crude oil delivered to the transshipment facility is transferred to storage tanks and loaded onto tankers for transport to markets in Eastern Canada and the U.S. Suncor has a 14% ownership interest in the transshipment facility.

In the five months ended December 31, 2009, Hibernia production averaged 27,200 bpd (net to Suncor).

Terra Nova

The Terra Nova oilfield, which is approximately 350 kilometres southeast of St. John's, Newfoundland and Labrador, was discovered by Petro-Canada in 1984. Located about 35 kilometres southeast of Hibernia, it is the second oilfield to be developed offshore Newfoundland and Labrador. The Suncor-operated production system uses a Floating Production Storage and Offloading (FPSO) vessel, which is a ship moored on location. Terra Nova was the first harsh environment development in North America to use a FPSO vessel. It has a production capacity of 180,000 bpd gross, of which we have a 34% interest, and a storage capacity of 960,000 bbls gross; however, actual production levels reflect current reservoir capability. Production from the Terra Nova oilfield began in January 2002. The field is estimated to have a remaining production life of approximately 13 to 20 years.

Under the Terra Nova Operating Agreement, a redetermination of operating interests is required following payout. This process is ongoing.

At December 31, 2009, 15 producing oil wells, nine water injection wells and three gas injection wells were in operation. Terra Nova uses the same system of shuttle tankers and transshipment terminal that are used for Hibernia, and also transports its crude oil to markets in Eastern Canada and the U.S.

In the five months ended December 31, 2009, Terra Nova production averaged 20,800 bpd (net to Suncor) with production negatively impacted by planned and unplanned maintenance during August, September and early October.

White Rose

White Rose, the third development offshore Newfoundland and Labrador, is about 350 kilometres southeast of St. John's and approximately 50 kilometres northeast of Hibernia and Terra Nova. Operated by Husky Energy Inc., White Rose uses a FPSO vessel similar to Terra Nova, which had an initial design production capacity of 100,000 bpd gross and a storage capacity of 940,000 bbls gross. Production is offloaded to chartered tankers that go directly to markets in Eastern Canada and the U.S. Production from the White Rose oilfield began in November 2005. The field is estimated to have a remaining production life of approximately 15 to 18 years at current rates.

At December 31, 2009, eight producing oil wells and 10 water injection wells were in operation. Effective June 1, 2007, White Rose was granted regulatory approval to increase the daily oil production rate on the SeaRose FPSO to 140,000 bpd gross (38,500 bpd net) and to increase the annual oil production rate to 50 MMbbls. In the five months ended December 31, 2009, White Rose production averaged 10,000 bpd (net to Suncor) with production negatively impacted by planned downtime for maintenance and the tie-in of the North Amethyst extension during August, September and early October. Production rates have been slow to recover from these outages due to high water cuts in production wells.

In September 2007, the Government of Newfoundland and Labrador approved the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) recommendation to permit development of the South White Rose extension. Subsequently, the White Rose partners reached an agreement in principle with the province on fiscal and other terms for the White Rose extensions development, incorporating the South White Rose Extension, North Amethyst and West White Rose satellite fields. In December 2007, the partners signed a formal agreement with the Province of Newfoundland and Labrador for the development of these oilfields. Development drilling has commenced and installation of subsea infrastructure is complete for the North Amethyst portion of the White Rose extensions, with the project on schedule to deliver first oil in the second quarter of 2010. The West White Rose development will be divided into two stages. Stage 1 was approved in the second quarter of 2009, and development drilling and subsea installation of this stage will take place in 2010. Results of Stage 1, combined with ongoing evaluation, will help define the scope of Stage 2.

Other Offshore Exploration and Development

In addition to existing East Coast Canada developments, Suncor also holds interests in a number of discoveries, including a 22.7% interest in the Hebron/Ben Nevis oilfield discoveries located 340 kilometres southeast of St. John's. In 2005, Chevron Canada Resources (as operator) and the other joint venture participants signed a unitization and joint operating agreement to advance the joint evaluation of the Hebron/Ben Nevis and West Ben Nevis oilfields offshore Newfoundland and Labrador. In August 2007, the Hebron partners signed a non-binding MOU with the Government of Newfoundland and Labrador related to the fiscal and other terms for the future development of the Hebron/Ben Nevis offshore oilfield. In August 2008, the Hebron partners reached an agreement with the Government of Newfoundland and Labrador on commercial terms that will allow development activities to proceed for Hebron. The transfer of operatorship from Chevron Canada Resources to ExxonMobil Canada Properties (ExxonMobil) was effective in the fourth quarter of 2008. Pre-front-end engineering and design (pre-FEED) activities continued during the 2009 and ExxonMobil opened a Hebron project office in April 2009.

Sales of Conventional Crude Oil

We do not typically enter long-term supply arrangements for our East Coast Canada 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. We currently have no pipeline commitments related to the shipment of conventional crude oil.

Principal Products

The East Coast Canada business unit produces crude oil exclusively. Set forth below is information on daily sales volumes for 2009, subsequent to August 1, 2009, the date that the East Coast Canada assets were acquired under the merger with Petro-Canada.

Product:	Five months ended December 31, 2009*	
	(thousands of barrels per day)	(% of operating revenues)
Crude oil	58	100

* Reflects operations subsequent to the Petro-Canada merger on August 1, 2009

Competitive Conditions

For a discussion of the competitive conditions affecting the East Coast Canada business unit, refer to "Competition" in the Risk Factors section of this AIF.

Seasonal Impacts

The primary East Coast Canada seasonal impacts are caused by winter storms, pack ice, icebergs and fog. During the winter storm season (October March), we may have to reduce production rates at our offshore facilities as a result of limited storage capacity and the inability to offload to shuttle tankers due to wave height restrictions. We also experience seasonal impacts in the spring period (April June) due to pack ice and icebergs drifting in the area of our offshore facilities. We have had precautionary shut-in of FPSO production and drilling delays due to pack ice and icebergs. In late spring and early summer, fog also impacts our ability to transfer personnel to the offshore facilities by helicopter.

Environmental Compliance

For a discussion of environmental risks for our East Coast Canada operations, refer to the "Legal and Regulatory Risks" outlined in the Risk Factors section of this AIF.

International

Our International business explores for, develops and produces crude oil and natural gas in the North Sea (United Kingdom, The Netherlands and Norway), Trinidad and Tobago, Libya, and Syria. For reporting purposes, Suncor consolidates its International activities into two core areas: the North Sea (U.K., The Netherlands and Norway sectors) and Other International areas (Libya, Syria and offshore Trinidad and Tobago). As part of its strategic business alignment, Suncor plans to divest all Trinidad and Tobago assets and certain non-core North Sea assets, including all assets in The Netherlands.

Marketing, Pipeline and Other Operations

North Sea

In the North Sea, the company focuses its business around core production areas in the U.K. and the Netherlands sectors, with exploration activities extending into Norway. Total North Sea production averaged 76,500 boe per day for the final five months of 2009. As part of its strategic business alignment, Suncor plans to divest certain non-core North Sea assets, including all assets in The Netherlands.

The company's U.K. position is built around three core production hubs: Triton, Buzzard and Scott/Telford. Triton comprises the Guillemot West and Northwest fields (90% owned by Suncor), the Bittern field (4.7% owned by Suncor), the Pict field (100% owned and operated by Suncor), the Clapham field (100% owned and operated by Suncor) and the Saxon field (100% owned and operated by Suncor). All of the Triton areas are produced into the Triton FPSO. Suncor is a 33.1% owner of the Triton FPSO (operated by Hess Corporation). The crude oil gathered at Triton is shipped via tanker, while natural gas is delivered through the SEGAL system to the U.K.

The second core hub in the U.K. North Sea is the Buzzard oilfield, located in the Outer Moray Firth. Buzzard achieved first oil in January 2007 and the company has a 29.9% interest in the field operated by Nexen Inc. The field ramped up to peak production in the middle of 2007. Buzzard is supported by three bridge-linked platforms supporting wellhead facilities, production facilities, living quarters and utilities. Crude oil is transported via the Forties pipeline system to shore in Scotland and natural gas is transported to the St. Fergus gas terminal in Scotland via the Frigg pipeline in the U.K. A fourth platform is being installed to remove higher than expected levels of hydrogen sulphide (H_2S) in the oil production from some segments of the field. This new platform is on budget and on schedule for start-up in late 2010 or early 2011.

The company's third core production hub, in the U.K. North Sea, Scott/Telford, is also located in the Outer Moray Firth and consists of a 20.6% interest in the Scott oilfield and production platform and a 9.4% interest in the Telford oilfield. The Telford oilfield produces through a subsea tie-back to the Scott platform. Both the Scott and Telford oilfields are operated by Nexen Inc. Crude oil from Scott and Telford is transported to shore via the Forties pipeline system. Associated natural gas is transported to the St. Fergus gas terminals via the Scottish Area Gas Evacuation pipeline system.

In The Netherlands sector of the North Sea, oil production comes from the Suncor-operated Hanze and De Ruyter platforms. The company has a 45% working interest in Hanze and a 54.07% working interest in De Ruyter. De Ruyter came on-stream in late September 2006. Oil from the Hanze and De Ruyter platforms is exported by a dedicated tanker and the cargoes are marketed on a spot basis into Northwest Europe. Natural gas production from Hanze is exported to shore via the Northern Offshore Gas Transport (NOGAT) pipeline and natural gas from De Ruyter is exported via the Noord Gas Transport (NGT) pipeline system. Production in The Netherlands sector of the North Sea was 13,200 boe per day for the final five months of 2009.

The major source of natural gas production in the Netherlands is from the L5b-L8b non-operated natural gas area, where Suncor has a working interest of approximately 30%. L5b-C, a non-operated asset in this area, achieved first natural gas in November 2006. The company has a 30% working interest in L5b-C. The produced natural gas is transported to shore by pipeline and sold to NV Nederlandse Gasunie under long-term delivery and off-take contracts. Suncor also holds a 12% interest in the onshore Bergen gas storage facility development operated by TAQA, the Abu Dhabi national energy company, and has exploration activities extending into Norway.

As noted above, Suncor plans to divest certain non-core North Sea assets including all of its assets in the Netherlands.

Other International

Crude oil production comes from interests principally in Libya, with natural gas production from assets offshore Trinidad and Tobago. A natural gas development is also underway in Syria. Total Other International production averaged 44,300 boe per day during the final five months of 2009.

Libya

The company conducts its Libyan operations pursuant to exploration and production sharing agreements (EPSAs) signed with the Libya National Oil Company (NOC). The EPSAs will run until 2033 (a five-year extension may be granted if there is commercial production for the last three years of the agreements and the extension is technically and commercially viable for

Suncor and the Libyan state) and enable the company and the NOC to jointly design and implement the redevelopment of the existing fields in the Sirte Basin. Suncor and the NOC will each pay one-half of development expenditures that are expected to total up to US$7 billion gross over the term of the licenses and to double existing production to 100,000 bpd net to Suncor. Under the agreements, the company is the exploration operator and has committed to fully fund 100% of an exploration program at an estimated cost of US$460 million over a five-year period. Suncor is also committed to EPSA signing bonus payments of approximately US$500 million payable from 2010 to 2013.

Work has now commenced on implementing the projects associated with the Libya EPSAs, with a focus on preparing the EPSA field development programs and initiating the new exploration program. Work on the exploration program is progressing, with seven seismic surveys completed during 2009 and two seismic crews continuing to acquire data in the country. At the end of 2009, the seismic program was approximately 75% complete. The company expects to begin drilling its first operated exploration well in early 2010. Suncor pays all of the exploration expenditures.

In the five months ended December 31, 2009, Suncor's production in Libya averaged 32,600 bpd (net to Suncor). During this period, gross production from our Libya EPSAs was restricted initially to 82,000 bpd and then to 50,000 bpd from September to the end of the year. In January 2010, the NOC advised the company that production from Suncor's Libya EPSAs will be limited to 70,000 bpd gross (35,000 bpd net to Suncor) due to the quota agreed to by OPEC producers.

In the final five months of 2009, eight development wells were completed in the producing fields in Libya, consisting of six production wells and two injection wells. A further three development wells were drilling at year end.

Syria

Suncor is 100% operator in a Production Sharing Contract (PSC) in the Ebla gas project. The company pays 100% of the costs which it recovers out of 40% of production. The remaining 60% of production is split between the company and the Syrian state depending on volume. Under the PSC, Suncor expects to spend approximately $1 billion to develop and produce an estimated 80 MMcf/d of natural gas from the Ash Shaer and Cherrife natural gas fields, with first gas currently expected in the second quarter of 2010. The majority of this spending ($1.1 billion) had been incurred by the end of 2009. The development includes uncapped take or pay contracts for the gas, the price of which is tied to Mediterranean heavy fuel oil prices. Overall, the Ebla gas project remains on plan and was 90% complete at the end of 2009. Five wells have been completed and are ready for production. The 3D seismic survey of the Cherrife field was completed at the end of the second quarter of 2009 and is currently being interpreted. The 3D seismic survey of Ash Shaer field that was completed in the second quarter of 2009 is also now being interpreted.

Trinidad and Tobago

On February 25, 2010, Suncor entered into an agreement to sell its assets in Trinidad and Tobago for proceeds of $396 million (US$380 million). The sale is expected to close in March 2010 and is subject to customary closing conditions, Trinidad and Tobago government approval and other regulatory approvals.

The company holds a 17.3% working interest in the NCMA-1 offshore natural gas development project operated by BG Group p.l.c. Natural gas production is delivered by pipeline to the Atlantic liquefied natural gas (LNG) facility operated by Atlantic LNG at Point Fortin for liquefaction and subsequent sale into U.S. and other international markets. Suncor has Production Sharing Contracts (PSCs) with the Trinidad and Tobago Ministry of Energy and Energy Industries for offshore exploration Blocks 1a, 1b and 22. These blocks cover a total of 4,258 square kilometres. A number of exploration wells have been drilled to date on these blocks.

In the five months ended December 31, 2009, Suncor's Trinidad and Tobago offshore gas production averaged 70.3 MMcf per day, with high demand from the Atlantic LNG terminal in the period. The company has certain minimum annual commitments to either deliver gas or reimburse the marketing company, BG Gas Marketing, a variable value as determined under the terms of the Trinidad LNG Sales Contract. Current production levels are sufficient to meet the near-term committed volumes.

Principal Products

For the five months ended December 31, 2009, sales of crude oil and natural gas liquids represented 95% of the International business unit's consolidated operating revenues, with 5% comprised of sales of natural gas. Set forth below is information on daily sales volumes and the corresponding percentage of our International business unit's operating revenues by product for the final five months of 2009.

Product:	Five months ended December 31, 2009*	
	(thousands of boe per day)	(% of operating revenues)
Crude oil and natural gas liquids	101.5	95
Natural gas	19.3	5
Total	120.8	

* Reflects operations subsequent to the Petro-Canada merger on August 1, 2009

Competitive Conditions

For a discussion of the competitive conditions affecting the International business unit, refer to "Competition" in the Risk Factors section of this AIF.

Environmental Compliance

For a discussion of environmental risks for our International operations, refer to the "Legal and Regulatory Risks" outlined in the Risk Factors section of this AIF.

Refining and Marketing

The Refining and Marketing business operates refineries in Edmonton, Alberta, Montreal, Quebec and Sarnia, Ontario in Canada and Commerce City, Colorado in the United States with a total capacity of 443,000 bpd, as well as a lubricants plant that is the largest producer of lubricant-base stocks in Canada. The Refining and Marketing business unit markets refined products to retail, commercial and industrial customers primarily in Canada and Colorado through a combination of company-owned, branded-dealer and joint venture-operated retail stations, a large Canadian national commercial road transportation network and a bulk sales channel. Assets also include the 480-kilometre Rocky Mountain pipeline system, the 140-kilometre Centennial pipeline system, thirteen major refined products terminals in Canada and two product terminals in Colorado, U.S.A. In addition, Refining and Marketing holds interests in two refined product pipelines, as well as interests in the Portland-Montreal Pipeline and a joint venture interest in one major refined products terminal.

Canada   General

Our Edmonton refinery produces light oils and currently has the potential to run entirely on oil sands-based feedstocks. The refinery primarily produces gasoline and distillates, the majority of which are distributed in Western Canada. The observed performance of our Edmonton refinery in 2009, after improvements completed in previous years, enabled us to upwardly revise our nameplate capacity to 135,000 bpd from 125,000 bpd. Starting January 1, 2010, refinery utilization will be calculated using the 135,000 bpd capacity.

Our Montreal refinery has a current crude oil capacity of 130,000 bpd. It is supplied with imported crude oil primarily through the Portland-Montreal pipeline and has a flexible configuration that allows processing of a variety of crude oils, including heavy grades, and intermediate feedstocks. The refinery produces gasoline, distillates, asphalts, heavy fuel oil, petrochemicals, solvents and feedstock for our lubricants plant. Products produced at the Montreal refinery are primarily distributed across Quebec and Ontario.

Suncor holds a 51% interest in ParaChem Chemicals L.P. (ParaChem), which owns and operates a petrochemicals plant located adjacent to the Montreal refinery. The plant primarily produces up to 350,000 metric tons/year of paraxylene, which is used to manufacture polyester textiles and plastic bottles. ParaChem also produces benzene, hydrogen and heavy aromatics.

Our refinery in Sarnia, Ontario, has a current crude oil capacity of 85,000 bpd, up from previous capacity of 70,000 bpd as a result of improvements made with the completion of our diesel desulphurization and oil sands integration project in 2007. The plant refines petroleum feedstock from oil sands and other sources into gasoline, distillates, and petrochemicals with the majority of these refined products distributed in Ontario. We also distribute product purchased from third parties.

Our ethanol plant in St. Clair, Ontario produces ethanol from corn. This ethanol is used for blending into our fuels and is also sold to third parties and has a capacity of 200 million litres per year. In 2009, Suncor announced its plans to double the capacity of its St. Clair Ethanol plant to 400 million litres per year. The construction of this expansion project is underway, and is expected to be completed by late 2010 or early 2011.

Our lubricants plant in Mississauga, Ontario produces specialty lubricants and waxes that are marketed in Canada and internationally. Suncor's lubricants plant is the largest producer of lubricant-base stocks in Canada, with annual base oil production capacity in excess of 900 million litres.

Suncor's retail service station network operates nationally under the Petro-Canada® brand and includes sites in Ontario under the Sunoco® brand and joint venture operated outlets. Suncor's owned and operated Sunoco®-branded retail and cardlock sites will be re-branded to Petro-Canada® brand starting in 2010. In addition to marketing through our proprietary retail outlets, petroleum product is marketed through independent dealers and joint venture facilities. In conjunction with the merger, the Canadian Competition Bureau required Suncor to divest 104 retail sites in Ontario. On December 8, 2009, Suncor agreed to sell 98 sites with expected closing dates commencing in the first half of 2010. Agreements are also now in place to meet the full divestiture requirement and we expect to complete the divestitures in 2010. In conjunction with the merger, as requested by the Canadian Competition Bureau, Suncor also entered into terminalling agreements with Ultramar Ltd. to provide 1.1 billion litres of terminal and distribution capacity in the Greater Toronto Area for 10 years.

As of December 31, 2009, our retail service station network consisted of 1,813 outlets across Canada which attracted a 21% share of the national retail market with annual sales of petroleum product averaging 4.1 million litres per site. Suncor also generates non-petroleum revenues from convenience stores, car washes, and automotive repair and maintenance services.

Retail Sites:	Years ended December 31, 2009	2008
Petro-Canada®-branded retail service stations	1 318	
Sunoco®-branded retail service stations	280	276
Total branded retail service stations	1 598	276
Joint venture operated retail service stations	215	211
Total retail service stations	1 813	487

Suncor also sells petroleum products into farm, home heating, paving, small industrial, commercial and truck markets. We are the leading national marketer to the commercial road transport segment in Canada through our PETRO-PASS network. We also sell large volumes of petroleum products directly to large industrial and commercial customers and independent marketers. Sun Petrochemicals Company, a joint venture between a Suncor subsidiary and a Toledo, Ohio-based refinery, also contributed to sales in this channel.

Wholesale Sites:	Years ended December 31, 2009	2008
Petro-Canada®-branded cardlock sites (PETRO-PASS)	235	
Joint venture operated bulk distribution facilities for rural and farm fuels	10	11
Sunoco®-branded Fleet Fuel Cardlock sites	49	47
	294	58

We continue to 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 leveraging our assets. We also purchase refined products in order to meet customer requirements.

Average Daily Sales of Petroleum Products in Canada

Set forth below are the daily sales volumes and corresponding percentages of Refining and Marketing's operating revenues for the last two years.

Product:	2009		2008	
	(thousands of cubic meters per day)	(% of operating revenues)	(thousands of cubic meters per day)	(% of operating revenues)
Gasoline (1)	19.0	48	7.9	55
Middle distillates (2)	12.9	31	5.2	37
Other (3)	6.4	21	2.4	8
Total	38.3		15.5	

(1) Includes motor and aviation gasoline.

(2) Includes diesel oils, heating oils and aviation jet fuels.

(3) Includes heavy fuel oil, asphalts, lubricants, liquefied petroleum gases, petrochemical feedstock and other petroleum and non-petroleum products.

Product:	Five months ended December 31, 2009*	
	(thousands of cubic meters per day)	(% of operating revenues)
Gasoline (1)	33.6	46
Middle distillates (2)	23.5	31
Other (3)	11.7	23
Total	68.8	

* Reflects operations subsequent to the Petro-Canada merger on August 1, 2009

(1) Includes motor and aviation gasoline.

(2) Includes diesel oils, heating oils and aviation jet fuels.

(3) Includes heavy fuel oil, asphalts, lubricants, liquefied petroleum gases, petrochemical feedstock and other petroleum and non-petroleum products.

United States General

Our U.S.-based Refining and Marketing business includes a refining facility, a retail network, and a pipeline transportation business primarily in Colorado and Wyoming. Our Commerce City, Colorado refining facility has a current combined crude distillation capacity of 93,000 bpd. The majority of the refined products from the Commerce City refinery are distributed to industrial, commercial, wholesale, and refining customers in Colorado. The remainder of our production was sold through a distribution network in Colorado that sells gasoline and diesel fuel to retail customers. Asphalt sales comprised the remaining refined product sales volumes for 2009. As of December 31, 2009, our retail service station network consisted of 37 Shell® and 7 Phillips 66® branded-outlets (44 in 2008) across Colorado. We additionally have supply agreements with 191 additional Phillips 66® branded retail sites (200 in 2008) throughout Colorado.

Average Daily Sales of Petroleum Products in United States

Set forth below is the daily sales volumes and corresponding percentage of refining and marketing's operating revenues for the last two years.

Product:	2009		2008	
	(thousands of cubic meters per day)	(% of operating revenues)	(thousands of cubic meters per day)	(% of operating revenues)
Gasoline [(1)]	8.5	54	8.0	49
Middle distillates [(2)]	5.3	35	5.6	42
Other [(3)]	2.7	11	2.4	9
Total	16.5		16.0	

(1) Includes motor and aviation gasoline.

(2) Includes diesel oils, heating oils and aviation jet fuels.

(3) Includes heavy fuel oil, asphalts, lubricants, liquefied petroleum gases, petrochemical feedstock and other petroleum and non-petroleum products.

Procurement of Feedstocks

Canada General

Our Edmonton refinery has the ability to process SCO. The refinery has the ability to directly upgrade an Athabasca blend feed of 35,000 bpd (comprised of 25,000 bpd of bitumen and 10,000 bpd of diluent) and process 45,000 bpd of sour synthetic crude oil. The refinery can also process 55,000 bpd of sweet SCO through its synthetic train. The crude refined at the Edmonton refinery is supplied from our Oil Sands operations and third parties under month-to-month contracts.

Our Montreal refinery processes primarily foreign, conventional crude oil. The majority of the refinery's crude is procured from third parties under month-to-month contracts and delivered through the Portland-Montreal pipeline. We have not made any firm capacity commitments to the associated pipeline systems. Other feedstocks, procured under month-to-month contracts, are primarily delivered via marine movements. Crude oil is procured from the market on a spot basis or under contracts which can be terminated on short notice.

Our Sarnia refinery processes both SCO and conventional crude oil. In 2009, 56,000 bpd of the crude oil refined at the Sarnia Refinery was SCO, of which 43,700 bpd was supplied from our Oil Sands operations. The balance of the refinery's SCO, as well as its conventional and condensate feedstocks, were purchased from third parties under month-to-month contracts.

We procure conventional crude oil feedstock for our Sarnia refinery primarily from western Canada. This is supplemented periodically 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 Enbridge 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 the event of a significant disruption in the supply of SCO, the Sarnia refinery has the flexibility to substitute other sources of sweet or sour conventional crude oil.

Feedstock for our lubricants facility comes from our Montreal refinery and other purchase contracts.

United States General

Our Commerce City refining operation processes both conventional crude oil and SCO. Approximately 19% of the refinery's crude oil is purchased from Canadian sources with the remainder supplied from sources in the United States, primarily from the Rocky Mountain region.

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.

With the completion of our diesel desulphurization and oil sands integration projects, we are now capable of processing of up to 15,000 bpd of oil sands sour crude oil at our U.S. refining operation.

The below table summarizes the crude feedstock and utilizations for the refineries, for the year-ended December 31, 2009.

Refinery	Average Daily Crude Input (thousands of bpd)*					
	Average Daily Crude Input	Conventional	Synthetic	Oil Sands Synthetic	Other	(% Utilization)
Edmonton	115.6	20.4	36.8	58.4		92
Montreal	110.6	110.6				85
Sarnia	75.3	18.8	12.3	43.7	0.5	89
Commerce City	95.3	86.0		9.3		103

* Reflects August 1, 2009 to December 31, 2009 for legacy Petro-Canada assets (Edmonton and Montreal) and January 1, 2009 to December 31, 2009 for legacy Suncor assets (Sarnia and Commerce City).

Transportation and Distribution

Our Refining and Marketing business has interests in two crude oil pipelines, two refined product pipelines, the Portland-Montreal Pipeline and a joint venture interest in one major refined products terminal. Our Refining and Marketing business owns and operates thirteen major refined products terminals in Canada and two product terminals in Colorado, U.S.A.

Canada General

Our Refining and Marketing business owns and operates petroleum transportation, terminal and dock facilities across Canada.

The Edmonton refinery primarily uses the Alberta Products Pipe Line Inc., in which Suncor has a 35% ownership interest, and the Trans-Mountain Pipelines Inc. as its major modes of transporting gasoline and diesel to core markets in western Canada. In addition, the Enbridge pipeline, rail movement and trucking are used to move product in the west.

The pipelines used by the Montreal refinery for transporting its gasoline and middle distillates are the Montreal Pipeline Limited, in which Suncor has a 24% ownership interest and Trans-Northern Pipeline, in which Suncor has a 33% ownership interest.

For our Sarnia refinery, the Sun-Canadian pipeline, which is 55% owned by Suncor, serves as the major mode of transporting gasoline, diesel, jet fuel and heating fuels from this refinery to its core markets in Ontario. The pipeline operates as a private facility for its owners, serving terminal facilities in Toronto, Hamilton and London.

We also have pipeline access 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 Refining and Marketing's Sarnia and Montreal operations to move products to market or obtain feedstocks/products when market conditions are favorable in the Michigan and Ohio markets and is subject to pipeline availability constraints.

United States General

For our U.S. operations, approximately 60% of crude oil processed at our Commerce City refining operation is transported via pipeline, with the remainder supplied via truck. We own and operate the Rocky Mountain Crude pipeline system, which runs from Guernsey, Wyoming to Denver, Colorado. This is a common carrier pipeline that transports crude for the Denver refinery as well as for other shippers. We also own and operate the Centennial pipeline, which transports crude from Guernsey, Wyoming to Cheyenne, Wyoming.

The Rocky Mountain Crude system had a capacity of 38,000 bpd in 2009 for the Guernsey to Cheyenne leg of the pipeline and 73,500 bpd for the Cheyenne to Denver leg of the pipeline. In 2009, it utilized approximately 53% (2008 43%) of its capacity with average throughput of 20,000 bpd (2008 16,500 bpd) in the Guernsey to Cheyenne leg of the pipeline, and utilized approximately 87% (2008 85%) with average throughput of 64,000 bpd (2008 62,200 bpd) in the higher capacity Cheyenne to Denver leg. During the same period, the Centennial pipeline utilized approximately 57% (2008 46%) of capacity, with an average throughput of approximately 36,000 bpd (2008 29,400 bpd).

Our U.S. operations have both truck and rail loading racks at the Commerce City 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.

In both our Canadian and U.S. operations, 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 and distribution needs.

Competitive Conditions

For a discussion of the competitive conditions affecting our Refining and Marketing business, refer to "Competition" in the Risk Factors section of this AIF.

Environmental Compliance

For a discussion of environmental risks at our Refining and Marketing business operations, refer to the "Legal and Regulatory Risks" in the Risk Factors section of this AIF.

Corporate, Energy Trading and Eliminations

The Corporate, Energy Trading and Eliminations area includes third-party energy trading activity, our renewable energy business and other activities not directly attributable to an operating segment.

RESERVES ESTIMATES

General

As a Canadian issuer, Suncor is subject to the reporting requirements of the Canadian Securities Administrators (CSA), including the reporting of our reserves in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* (NI 51-101). In order to harmonize its oil and gas disclosure in both Canada and the United States, Suncor applied for, and received, an exemption from Canadian securities regulatory authorities permitting Suncor to report its reserves in accordance with the rules and regulations of the United States Securities and Exchange Commission (SEC). See "Reliance on Exemptive Relief" in this AIF. The SEC has updated its oil and gas disclosure requirements with the issuance of its final rule, Modernization of Oil and Gas Reporting, on December 31, 2008. Under the new SEC rule, disclosure of probable reserves is now permitted in addition to proved reserves. Disclosure of oil sands mining and upgrading as oil and gas activities is also permitted. Suncor's 2009 reserves disclosure includes both proved and probable reserves for all of our oil and gas operations including our oil sands areas and associated upgrading facilities.

Differences in the estimates of the reserves between U.S. disclosure requirements and NI 51-101 methodology can be material mainly due to differences in the stipulated product prices to be used for reserves evaluations. U.S. disclosure requirements mandate the use of an average of first day of the month price for the 12 months prior to the end of the reporting period, while the CSA requires a forecasted price. However this difference in pricing methodologies did not have a material impact on Suncor's 2009 reserves disclosure.

Additional differences between U.S. disclosure requirements and NI 51-101 methodology include the following:

- SEC registrants apply SEC reserves definitions and prepare their reserves estimates in accordance with SEC requirements and generally accepted industry practices in the U.S. whereas NI 51-101 requires adherence to the definitions and standards promulgated by the COGE Handbook;

- the SEC mandates disclosure of reserves by country or geographic area and sales product whereas NI 51-101 requires disclosure of more reserve categories and product types;

- the SEC prescribes certain information about proved and probable undeveloped reserves and future development costs whereas NI 51-101 requirements are different; and

- the SEC does not allow proved and probable reserves to be aggregated whereas NI 51-101 requires aggregate disclosure.

The foregoing is a general description of the principal differences only. The differences between SEC requirements and NI 51-101 may be material.

In addition to reporting our reserves in accordance with U.S. disclosure requirements, we are also providing voluntary additional disclosure (which does not conform to U.S. disclosure requirements). Our voluntary additional disclosure will differ from our required U.S. disclosure in the following ways:

- Disclosure of reserves on a gross basis (before royalty) voluntarily, as well as the required net basis (after royalty) under U.S. disclosure requirements.

- Disclosure of voluntary addition of proved and probable reserve totals on a gross basis (before royalty) together, in addition to reporting them separately as required under U.S. disclosure requirements.

- Disclosure of contingent resources and remaining recoverable resources on a gross basis (before royalty) following NI 51-101 requirements (disclosure of resources is not recognized under U.S. disclosure requirements).

The majority of Suncor's proved reserves and probable reserves are in Canada, in the Athabasca oil sands, conventional type plays in Western Canada and offshore on the east coast of Canada. Suncor also has other North American proved and probable reserves in the United States and international proved and probable reserves in the North Sea, Libya, Syria, Trinidad and Tobago.

Reserves Evaluation Process and Controls

GLJ Petroleum Consultants Ltd. (GLJ) and Sproule Associates Limited (Sproule) evaluated or reviewed all of our North American reserves and RPS Energy Plc (RPS) evaluated or reviewed all of our International reserves. All three independent petroleum consultants are industry recognized qualified reserves evaluators. For the year ended December 31, 2009, 95% of Suncor's proved and 94% of its probable reserves volumes were externally evaluated. The third party evaluations were reviewed internally by Suncor's Business Units, the Reserve Steering Committee (a management committee) and the Audit Committee of the Board of Directors prior to disclosure. Suncor's Audit Committee includes independent Board members who reviewed the qualifications and approved the appointment of the qualified independent reserve evaluators. The Audit Committee also reviewed the procedures and process for providing information to the evaluators.

Suncor's mining lease interests, Firebag in-situ lease interests, legacy Petro-Canada's Syncrude mining lease interests and nearly all of legacy Suncor's North American onshore interests have been evaluated as at December 31, 2009 by independent petroleum consultants, GLJ. Legacy Suncor North American onshore leases not evaluated by GLJ were reviewed by GLJ. In the "GLJ Summary Reserves Report" (Schedule "E") dated March 5, 2010 GLJ provides a summary of their proved and probable reserves evaluations and reviews pursuant to U.S. disclosure requirements. GLJ also evaluated the contingent resources associated with the legacy Suncor mining leases, the Firebag In-situ leases and legacy Petro-Canada's Syncrude mining lease interests.

Legacy Petro-Canada's North American onshore interests, East Coast Canada lease interests and MacKay River in-situ lease interests have been evaluated as at December 31, 2009 by independent petroleum consultants, Sproule. In the "Sproule Summary Reserves Report" (Schedule "F") dated March 5, 2010, Sproule provides a summary of their proved and probable reserves evaluations, pursuant to U.S. disclosure requirements. Sproule has also audited legacy Petro-Canada's Fort Hills contingent resources.

Approximately 45% of legacy Petro-Canada reserves related to our International operations have been evaluated as at December 31, 2009 by independent petroleum consultants, RPS. The legacy Petro-Canada international interests not evaluated by RPS were reviewed by RPS. In the "RPS Summary Reserves Report" (Schedule "G") dated March 5, 2010. RPS provides a summary of their proved and probable reserves evaluations and reviews, pursuant to U.S. disclosure requirements.

There are many uncertainties inherent in estimating quantities of oil and natural gas reserves, including many factors beyond the company's control. Estimates of economically recoverable oil and natural gas reserves are based upon a number of variables and assumptions. These include geoscientific interpretation, commodity prices, operating and capital costs and historical production from properties. These estimates have some degree of uncertainty. For these reasons, estimates of the economically recoverable oil and natural gas reserves attributed to properties and classification of reserves based on recovery risk may vary substantially. Actual production, revenues, royalties, taxes and development and operating expenditures related to reserves may vary materially from estimates.

Definitions and Notes to Reserves Data Tables

In the tables set forth below and elsewhere in this AIF the following definitions and other notes are applicable:

1. "Gross" means:
   (a) in relation to our interest in production and reserves, our interest (operating and non-operating) before deduction of royalties and without including any of our royalty interests;
   (b) in relation to wells, the total number of wells in which we have an interest; and
   (c) in relation to properties, the total area of properties in which we have an interest.
2. "Net" means:
   (a) in relation to our interest in production and reserves, our interest (operating and non-operating) after deduction of royalties obligations, plus our royalty interest in production or reserves (see royalty discussion below);
   (b) in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and
   (c) in relation to our interest in a property, the total area in which we have an interest multiplied by the working interest we own.
3. "SCO" means synthetic crude oil.
4. Columns may not add due to rounding.
5.

The oil, natural gas liquids and natural gas reserves estimates presented in the third party evaluators' reports are based on the SEC definitions and guidelines. A summary of certain of those definitions is set forth below. The SCO reserves include our Oil Sands diesel volume.

6. See "Industry Conditions Royalties and Incentives" in this AIF and the "Royalties" section of our MD&A for a discussion of the applicable royalties. These assumptions reflect market and regulatory conditions, as required, at December 31, 2009, which could differ significantly from other points in time throughout the year, or future periods. Changes in market and regulatory conditions and assumptions can materially impact the estimation of net reserves.

Reserves Categories (SEC definitions)

Reserves. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Proved oil and gas reserves. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

Probable oil and gas reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

Each of the reserves categories (proved and probable) may be divided into developed and undeveloped categories:

Developed oil and gas reserves. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Undeveloped oil and gas reserves. Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. In addition:

(i) Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

(iii) Under no circumstances are estimates for undeveloped reserves to be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology establishing reasonable certainty.

Resource Categories (NI 51-101 COGEH definitions; do not conform to U.S. disclosure requirements).

Contingent Resources. Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. There is no certainty that it will be commercially viable to produce the contingent resources.

Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage.

Contingent Resource Best Estimate is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. The best estimate of potentially recoverable volumes is prepared independent of the risks associated with achieving commercial production.

Remaining recoverable resources (unrisked). The arithmetic sum of proved and probable reserves and best estimate contingent resources. Suncor has not quantified potentially recoverable volumes from either undiscovered accumulations or its carbonate leases. The contingent resources have not been adjusted for risk based on the chance of development. It is not an estimate of volumes that may be recovered. Actual recovery may be less.

Discussion on Changes to Reserve Estimates

Changes related to revised SEC reserves disclosure requirements. With the issuance of SEC final rule, Modernization of Oil and Gas Reporting, on December 31, 2008, disclosure of oil sands mining is now considered an oil and gas activity and quantities of oil and gas that are to be upgraded and sold as SCO can now be disclosed as SCO volumes. As a result, oil sands mining reserves are now included in the reserve tables and those bitumen volumes that are to be upgraded and sold as SCO are reported as SCO volumes. To show the change of reporting bitumen only volumes to the current requirements in the SEC rule, a one line adjustment has been made to show the 2008 closing balances as if the rule took effect on December 31, 2008.

Merger of Suncor and Petro-Canada. Effective August 1, 2009, legacy Suncor and legacy Petro-Canada amalgamated to form a single corporation continuing under the name "Suncor Energy Inc." The addition of the Petro-Canada properties is shown as a purchase by Suncor. In determining the purchased volumes, Petro-Canada's 2008 closing reserve balances were used and adjusted for 2009 production volumes and any purchases or sales of assets prior to August 1, 2009. A total of 752 MMbbls of proved oil volumes on a net basis (after royalty) and 1179 Bcf of proved natural gas volumes on a net basis (after royalty) were added to Suncor's proved reserves base as a result of the merger.

Production

Production shown in the tables reflects full year production for the legacy Suncor properties but only represents production for the last five months of the year for the legacy Petro-Canada properties.

Bitumen Reserves

As a portion of Suncor's in-situ bitumen production will be sold directly to the market rather than being upgraded and sold as SCO, approximately one-third of our proved in-situ reserves are now shown as bitumen volumes.

In-Situ

Over 80% of our proved undeveloped reserves and over 75% of our probable undeveloped reserves are associated with our in-situ properties. These reserves are well delineated by core hole drilling, are included in our corporate business plans, and have the appropriate regulatory approvals in place. These are long life projects and new production is expected to be brought on stream throughout the majority of the project life as capacity becomes available at existing processing facilities or when new facilities are constructed. In 2009 approximately 28 MMbbls were moved from the proved undeveloped category to proved developed as a result of ongoing development work.

Mining

As a result of continued development of our North Steepbank extension, approximately 500 MMbbls of reserves were moved out of the probable undeveloped reserves category with approximately 330 MMbbls moved into proved developed reserves and the remainder moved into the probable developed reserves category.

International

A significant amount of our Other International proved and probable undeveloped gas reserves are associated with the development of the Ebla field in Syria. The majority of these reserve quantities are currently expected to be moved to the proved developed reserves category after the field commences production operations in 2010.

REQUIRED U.S. OIL AND GAS DISCLOSURE

The table below shows Suncor's 2009 year-end balances for proved and probable reserves, and was prepared in accordance with SEC standards for oil and gas activities:

Summary of Oil and Gas Reserves After Royalties (1)(2)(3)(5)

	Reserves					Reserves			
Reserve category	Oil & NGL	Natural Gas	SCO	Bitumen	Reserve category	Oil	Natural Gas	SCO	Bitumen
	(MMbbls)	(BCF)	(MMbbls)	(MMbbls)		(MMbbls)	(BCF)	(MMbbls)	(MMbbls)
PROVED					**PROBABLE**				
Developed					**Developed**				
North Sea [4]	72	29			North Sea [4]	36	23		
Other International [6][7]	38	93			Other International [6][7]	30	42		
North America Onshore	35	1229			North America Onshore	6	282		
East Coast Canada	41				East Coast Canada	39			
Oil Sands In-situ			152	22	Oil Sands In-situ			69	8
Oil Sands Mining [8]			1899		Oil Sands Mining [8]			287	
Total Developed	**186**	**1351**	**2051**	**22**	**Total Developed**	**111**	**347**	**356**	**8**
Undeveloped					**Undeveloped**				
North Sea [4]	69				North Sea [4]	36	50		
Other International [6][7]	6	294			Other International [6][7]	31	222		
North America Onshore	7	48			North America Onshore	9	211		
East Coast Canada	26				East Coast Canada	60			
Oil Sands In- situ			514	389	Oil Sands In-situ			507	1336
Oil Sands Mining [8]					Oil Sands Mining [8]			237	
Total Undeveloped	**108**	**342**	**514**	**389**	**Total Undeveloped**	**136**	**483**	**744**	**1336**
TOTAL PROVED	**294**	**1693**	**2565**	**411**	**TOTAL PROBABLE**	**247**	**830**	**1100**	**1344**

(1) Numbers in the above table are rounded to the nearest 1 MMbbls or 1 Bcf and may not add due to rounding.

(2) The reserves data are based upon evaluations by GLJ, Sproule, RPS and Suncor with an effective date of December 31, 2009 and does not account for any planned divestiture after the effective date. GLJ, Sproule, and RPS summary reserve reports are contained in Schedules "E", "F", "G" to this AIF.

(3) Proved reserves before royalties are Suncor's working interest reserves before the deduction of Crown or other royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production. Reserve quantities after royalty also reflect net overriding royalty interests paid and received.

(4) Reserves in the North Sea are subject to a conventional royalty and tax regime. No royalty is payable on reserves in the U.K. sector. Royalty is payable on onshore reserves in the Netherlands.

(5)

Proved reserves include quantities of crude oil and natural gas, which will be produced under arrangements, which involve the company or its subsidiaries in upstream risks and rewards, but which do not transfer title of the product to those companies.

(6)

In Suncor's exploration and production sharing contracts (PSCs), after royalty proved reserves have been determined using the economic interest method and includes the company's share of future production entitlement calculated using the contract's cost recovery and profit oil terms. The entitlement reserves are then adjusted to include reserves relating to income tax payable. Under this method, reported reserves will increase as oil prices decrease (and vice versa), since the bbls necessary to achieve cost recovery change with the prevailing oil prices.

(7)

All reserves reported in "Other International" (which include reserves in Libya, Syria, and Trinidad and Tobago) are calculated as per footnote 5.

(8)

Due to the SEC rule change in respect to reporting mining as an oil and gas activities, Suncor has included oil sands mining reserves which would have been previously reported under Mining Guide 7. For more information, refer to page 30.

The following tables are provided in accordance with the provisions of the Financial Accounting Standards Board's, Topic 932 Extractive Industries Oil and Gas.

Proved Developed and Undeveloped Reserves After Royalties

					Oil Activities [1][2][3][5][11][12]						
		Total By Products			International		North America				
									Oil Sands In-Situ		
	Total	Oil & NGL	SCO	Bitumen	North Sea [4] Oil & NGL	Other International [6][7] Oil & NGL	North America Onshore Oil & NGL	East Coast Canada Oil & NGL	SCO	Bitumen	Oil Sands Mining SCO [10]
	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)
Beginning of year 2007	**910**	**7**		**903**			**7**			**903**	
Revisions of previous estimates [8]	68			68						68	
Purchase of reserves in place											
Discoveries, extensions and improved recovery	99			99						99	
Production (net)	(14)	(1)		(13)			(1)			(13)	
Sale of reserves in place											
End of year 2007	**1063**	**6**		**1057**			**6**			**1057**	
Revisions of previous estimates [8]											
Purchase of reserves in place											
Discoveries, extensions and improved recovery	35			35						35	
Production net	(14)	(1)		(13)			(1)			(13)	
Sale of reserves in place											
End of year 2008	**1084**	**5**		**1079**			**5**			**1079**	
SEC rule change adjustment [9]	1218		2254	(1036)					833	(1036)	1421
Opening of year 2009	**2302**	**5**	**2254**	**43**			**5**		**833**	**43**	**1421**
Revisions of previous estimates [8]	(8)	34	(411)	369	6	4	5	19	(330)	369	(81)
Purchase of Petro-Canada reserves	752	264	488		145	36	34	49	178		310
Purchase of other reserves in place											
Discoveries, extensions and improved recovery	343	13	330		1	6	1	5			330

Production net	(118)	(21)	(96)	(1)	(11)	(2)	(3)	(5)	(15)	(1)	(81)
Sale of reserves in place	(1)	(1)						(1)			
End of year 2009	**3270**	**294**	**2565**	**411**	**141**	**44**	**42**	**67**	**666**	**411**	**1899**
Proved developed reserves											
Beginning of 2009	1565	5	1560				5		139		1421
End of 2009	**2259**	**186**	**2051**	**22**	**72**	**38**	**35**	**41**	**152**	**22**	**1899**
Proved undeveloped reserves											
Beginning of 2009	738		695	43					695	43	
End of 2009	**1011**	**108**	**514**	**389**	**69**	**6**	**7**	**26**	**514**	**389**	

(1) Numbers in the above table are rounded to the nearest 1 MMbbls or 1 Bcf and may not add due to rounding.

(2) The reserves data are based upon evaluations by GLJ, Sproule, RPS and Suncor with an effective date of December 31, 2009 and does not account for any planned divestiture after the effective date. GLJ, Sproule, and RPS summary reserve reports are contained in Schedules "E", "F", "G" to this AIF.

(3) Proved reserves before royalties are Suncor's working interest reserves before the deduction of Crown or other royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production. Reserve quantities after royalty also reflect net overriding royalty interests paid and received.

(4) Reserves in the North Sea are subject to a conventional royalty and tax regime. No royalty is payable on reserves in the U.K. sector. Royalty is payable on onshore reserves in the Netherlands.

(5) Proved reserves include quantities of crude oil and natural gas, which will be produced under arrangements, which involve the company or its subsidiaries in upstream risks and rewards, but which do not transfer title of the product to those companies.

(6) In Suncor's exploration and production sharing contracts (PSCs), after royalty proved reserves have been determined using the economic interest method and includes the company's share of future production entitlement calculated using the contract's cost recovery and profit oil terms. The entitlement reserves are then adjusted to include reserves relating to income tax payable. Under this method, reported reserves will increase as oil prices decrease (and vice versa), since the bbls necessary to achieve cost recovery change with the prevailing oil prices.

(7) All reserves reported in "Other International" (which include reserves in Libya, Syria, and Trinidad and Tobago) are calculated as per footnote 5.

(8) Revisions include changes in previous estimates, either upward or downward, resulting from new information (except an increase in acreage) normally obtained from drilling or production history or resulting from a change in economic factors.

(9) Due to the SEC rule change in respect to reporting final product sold, Suncor has in-situ reserve volumes that were previously reported as bitumen that now are to be reported as SCO. In addition, oil sands mining has also been added. This line shows the impact of that reporting change.

(10) Due to the SEC rule change in respect to reporting mining as oil and gas activities, Suncor has included a mining opening balance which would have been previously reported under Mining Guide 7. For more information, see page 30.

(11) The 2008 reserve data for legacy Suncor assets has been re-stated per SEC guidelines, this information was previously disclosed under NI 51-101.

(12) The production data in the 2009 reserve tables are estimates from the third party evaluators, and may not exactly match production shown else where in this AIF. Any variance in the production numbers is deemed not material in the disclosure of these reserves.

Proved Developed and Undeveloped Reserves After Royalties (Natural Gas)

	Natural Gas Activities (1)(2)(3)(5)(9)(10)			
		International		North America
	Total	North Sea (4) Gas	Other International (6)(7) Gas	North America Onshore Gas
	(BCF)	(BCF)	(BCF)	(BCF)
Beginning of year 2007	**426**			**426**
Revisions of previous estimates (8)	4			4
Purchase of reserves in place	19			19
Discoveries, extensions and improved recovery	33			33
Production net	(53)			(53)
Sale of reserves in place	(1)			(1)
End of year 2007	**428**			**428**
Revisions of previous estimates (8)	42			42
Purchase of reserves in place	0			
Discoveries, extensions and improved recovery	25			25
Production net	(54)			(54)
Sale of reserves in place				
End of year 2008	**441**			**441**
Revisions of previous estimates (8)	(39)	(4)	15	(50)
Purchase of Petro Canada reserves	1179	40	153	986
Purchase of other reserves in place				
Discoveries, extensions and improved recovery	248	1	229	18
Production net	(134)	(8)	(10)	(116)
Sale of reserves in place	(2)			(2)
End of year 2009	**1693**	**29**	**387**	**1277**
Proved developed reserves				
Beginning of 2009	412			412
End of 2009	**1351**	**29**	**93**	**1229**
Proved undeveloped reserves				
Beginning of 2009	28			28
End of 2009	**342**		**294**	**48**

(1) Numbers in the above table are rounded to the nearest 1 MMbbls or 1 Bcf and may not add due to rounding.

(2) The reserves data are based upon evaluations by GLJ, Sproule, RPS and Suncor with an effective date of December 31, 2009 and does not account for any planned divestiture after the effective date. GLJ, Sproule, and RPS summary reserve reports are contained in Schedules "E", "F", "G" to this AIF.

(3) Proved reserves before royalties are Suncor's working interest reserves before the deduction of Crown or other royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production. Reserve quantities after royalty also reflect net overriding royalty interests paid and received.

(4) Reserves in the North Sea are subject to a conventional royalty and tax regime. No royalty is payable on reserves in the U.K. sector. Royalty is payable on onshore reserves in the Netherlands.

(5) Proved reserves include quantities of crude oil and natural gas, which will be produced under arrangements, which involve the company or its subsidiaries in upstream risks and rewards, but which do not transfer title of the product to those companies.

(6) In Suncor's exploration and production sharing contracts (PSCs), after royalty proved reserves have been determined using the economic interest method and includes the company's share of future production entitlement calculated using the contract's cost recovery and profit oil terms. The entitlement reserves are then adjusted to include reserves relating to income tax payable. Under this method, reported reserves will increase as oil prices decrease (and vice versa), since the bbls necessary to achieve cost recovery change with the prevailing oil prices.

(7) All reserves reported in "Other International" (which include reserves in Libya, Syria, and Trinidad and Tobago) are calculated as per footnote 5.

(8) Revisions include changes in previous estimates, either upward or downward, resulting from new information (except an increase in acreage) normally obtained from drilling or production history or resulting from a change in economic factors.

(9) The 2008 reserve data for legacy Suncor assets has been re-stated per SEC guidelines, this information was previously disclosed under NI 51-101. For more information, see page 30.

(10) The production data in the 2009 reserve tables are estimates from the third party evaluators, and may not exactly match production shown else where in this AIF. Any variance in the production numbers is deemed not material in the disclosure of these reserves.

VOLUNTARY ADDITIONAL DISCLOSURE (does not conform to U.S. disclosure requirements):

Proved Reserves Before Royalties [(1)(2)(3)(5)(11)]

	Oil and Gas Activities											
	International				North America						Totals	
	North Sea [(4)]		Other International [(6)(7)]		North America Onshore		East Coast Canada	Oil Sands In-Situ		Oil Sands Mining [(9)]		
	Crude Oil & NGL	Natural Gas	Crude Oil & NGL	Natural Gas	Crude Oil & NGL	Natural Gas	Crude Oil & NGL	SCO	Bitumen	SCO	Crude Bitumen, SCO & NGL	Total Natural Gas
	(MMbbls)	(BCF)	(MMbbls)	(BCF)	(MMbbls)	(BCF)	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)	(BCF)
End of Year 2008 [(10)]					**7**	**532**		**860**	**45**	**1571**	**2483**	**532**
Revisions of previous estimates [(8)]	6	(4)	11	12	8	(67)	25	(318)	406	(23)	115	(59)
Sale of reserves in place						(2)	(1)				(1)	(2)
Purchase of reserves in place	145	40	117	155	39	1158	65	201		360	927	1353
Discoveries, extensions and improved recovery	1	1	9	351		22	8			383	401	374
Production	(11)	(8)	(5)	(11)	(4)	(146)	(8)	(16)	(1)	(88)	(133)	(165)
End of Year 2009	**141**	**29**	**132**	**507**	**50**	**1497**	**89**	**727**	**450**	**2203**	**3792**	**2033**
Proved Undeveloped Reserves **End of year 2009**	**69**		**9**	**414**	**9**	**57**	**35**	**564**	**427**		**1113**	**471**

(1) Numbers in the above table are rounded to the nearest 1 MMbbls or 1 Bcf and may not add due to rounding.

(2) The reserves data are based upon evaluations by GLJ, Sproule, RPS and Suncor with an effective date of December 31, 2009 and does not account for any planned divestiture after the effective date. GLJ, Sproule, and RPS summary reserve reports are contained in Schedules "E", "F", "G" to this AIF.

(3) Proved reserves before royalties are Suncor's working interest reserves before the deduction of Crown or other royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production. Reserve quantities after royalty also reflect net overriding royalty interests paid and received.

(4) Reserves in the North Sea are subject to a conventional royalty and tax regime. No royalty is payable on reserves in the U.K. sector. Royalty is payable on onshore reserves in the Netherlands.

(5) Proved reserves include quantities of crude oil and natural gas, which will be produced under arrangements, which involve the company or its subsidiaries in upstream risks and rewards, but which do not transfer title of the product to those companies.

(6) In Suncor's exploration and production sharing contracts (PSCs), after royalty proved reserves have been determined using the economic interest method and includes the company's share of future production entitlement calculated using the contract's cost recovery and profit oil terms. The entitlement reserves are then adjusted to include reserves relating to income tax payable. Under this method, reported reserves will increase as oil prices decrease (and vice versa), since the bbls necessary to achieve cost recovery change with the prevailing oil prices.

(7) All reserves reported in "Other International" (which include reserves in Libya, Syria, and Trinidad and Tobago) are calculated as per footnote 5.

(8) Revisions include changes in previous estimates, either upward or downward, resulting from new information (except an increase in acreage) normally obtained from drilling or production history or resulting from a change in economic factors.

(9) Due to the SEC rule change in respect to reporting mining as oil and gas activities, Suncor has re-stated its mining opening balance which would have been previously reported under Mining Guide 7. For more information, see page 30.

(10) The 2008 reserve data for legacy Suncor assets has been re-stated per SEC guidelines, this information was previously disclosed under NI 51-101.

(11) The production data in the 2009 reserve tables are estimates from the third party evaluators, and may not exactly match production shown else where in this AIF. Any variance in the production numbers is deemed not material in the disclosure of these reserves.

VOLUNTARY ADDITIONAL DISCLOSURE (does not conform to U.S. disclosure requirements):

Proved and Probable Reserves Before Royalties (1)(2)(3)(5)(11)

	Oil and Gas Activities											
	International				North America						Company Totals	
	North Sea (4)		Other International (6)(7)		North America Onshore		East Coast Canada	Oil Sands In-Situ		Oil Sands Mining (9)		
	Crude Oil & NGL	Natural Gas	Crude Oil & NGL	Natural Gas	Crude Oil & NGL	Natural Gas	Crude Oil & NGL	SCO	Bitumen	SCO	Crude Bitumen, SCO & NGL	Total Natural Gas
	(MMbbls)	(BCF)	(MMbbls)	(BCF)	(MMbbls)	(BCF)	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)	(BCF)
End of Year 2008 (10)					**9**	**734**		**2565**	**148**	**2316**	**5038**	**734**
Revisions of previous estimates (8)	6	(18)	6	247	15	(52)	16	(1587)	1863	(72)	247	177
Sale of reserves in place						(6)	(3)				(3)	(6)
Purchase of reserves in place	215	98	276	618	47	1498	213	437		638	1826	2214
Discoveries, extensions and improved recovery	3	29	9	352	1	52	7				20	433
Production	(11)	(8)	(5)	(11)	(4)	(146)	(8)	(16)	(1)	(88)	(133)	(165)
End of Year 2009	**213**	**101**	**286**	**1206**	**68**	**2080**	**225**	**1399**	**2010**	**2794**	**6995**	**3387**
Proved & Probable Undeveloped Reserves **End of year 2009**	**105**	**50**	**89**	**1065**	**19**	**309**	**114**	**1160**	**1977**	**264**	**3728**	**1424**

(1) Numbers in the above table are rounded to the nearest 1 MMbbls or 1 Bcf and may not add due to rounding.

(2) The reserves data are based upon evaluations by GLJ, Sproule, RPS and Suncor with an effective date of December 31, 2009 and does not account for any planned divestiture after the effective date. GLJ, Sproule, and RPS summary reserve reports are contained in Schedules "E", "F", "G" to this AIF

(3) Proved reserves before royalties are Suncor's working interest reserves before the deduction of Crown or other royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production. Reserve quantities after royalty also reflect net overriding royalty interests paid and received.

(4)

Reserves in the North Sea are subject to a conventional royalty and tax regime. No royalty is payable on reserves in the U.K. sector. Royalty is payable on onshore reserves in the Netherlands.

(5) Proved reserves include quantities of crude oil and natural gas, which will be produced under arrangements, which involve the company or its subsidiaries in upstream risks and rewards, but which do not transfer title of the product to those companies.

(6) In Suncor's production sharing contracts (PSCs), after royalty proved reserves have been determined using the economic interest method and includes the company's share of future production entitlement calculated using the contract's cost recovery and profit oil terms. The entitlement reserves are then adjusted to include reserves relating to income tax payable. Under this method, reported reserves will increase as oil prices decrease (and vice versa), since the bbls necessary to achieve cost recovery change with the prevailing oil prices.

(7) All reserves reported in "Other International" (which include reserves in Libya, Syria, and Trinidad and Tobago) are calculated as per footnote 5.

(8) Revisions include changes in previous estimates, either upward or downward, resulting from new information (except an increase in acreage) normally obtained from drilling or production history or resulting from a change in economic factors.

(9) Due to the SEC rule change in respect to reporting mining as oil and gas activities, Suncor has re-stated its mining opening balance which would have been previously reported under Mining Guide 7. For more information, see page 30.

(10) The 2008 reserve data for legacy Suncor assets has been re-stated per SEC guidelines, this information was previously disclosed under NI 51-101.

(11) The production data in the 2009 reserve tables are estimates from the third party evaluators, and may not exactly match production shown else where in this AIF. Any variance in the production numbers is deemed not material in the disclosure of these reserves.

REMAINING RECOVERABLE RESOURCES (does not conform to U.S. disclosure requirements)

In addition to Suncor's proved plus probable reserve holdings, we also have considerable contingent resources (see table below). GLJ prepared the estimates for legacy Suncor and Syncrude mining leases as well as the Firebag in-situ leases. Sproule audited the Fort Hills estimate. Estimates for the remainder of our contingent resources were prepared internally by qualified reserves evaluators.

Remaining Recoverable Resources Before Royalties:

As at December 31, 2009 (1)(6)		Conventional	Oil Sands Mining	Oil Sands In-Situ	Total
		(MMboes)	(MMboes)	(MMboes)	(MMboes)
Total Proved		751	2203	1177	4131
Total Probable		606	591	2232	3429
Total Proved Plus Probable Reserves		1357	2794	3409	7560
Contingent Resources (2)(5)(6)	Best Estimate (3)	2935	6080	10881	19896
Remaining Recoverable Resources (unrisked) (4)		4292	8874	14290	27456

(1) Numbers in the above table are rounded to the nearest 1 million boe. MMboe means millions of barrels of oil equivalent and is comprised of all liquids: 1 mmbbl = 1 mmboe and natural gas: 6 Bcf = 1 MMboe.

(2) Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. There is no certainty that it will be commercially viable to produce the contingent resources.

(3) Best Estimate is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. The best estimate of potentially recoverable volumes is generally prepared independent of the risks associated with achieving commercial production.

(4) Remaining recoverable resources (unrisked) are the arithmetic sum of proved and probable reserves and best estimate contingent resources. Suncor has not quantified potentially recoverable volumes from either undiscovered accumulations or its carbonate leases. The contingent resources have not been adjusted for risk based on the chance of development. It is not an estimate of volumes that may be recovered. Actual recovery may be less.

(5) Our contingent resources are composed primarily of resources from: (i) (in-situ) Firebag, Lewis, Meadow and Chard; (ii) (mining) Voyager South, Audette (North Leases), Fort Hills and Syncrude; and (iii) (conventional) Arctic Islands and MacKenzie corridor, Libya, Hebron/BenNevis, Labrador, White Rose, Hibernia, Terra Nova, Trinidad and Tobago and the North Sea.

(6) All mining and in-situ contingent resources are stated in SCO.

Remaining recoverable resources were 27,456 millions of barrels of oil equivalent at December 31, 2009. The increase in 2009 was primarily due to the merger with Petro-Canada.

Approximately 85% of our contingent resources are associated with our long term mining and in-situ growth projects. The remaining contingent resources are associated with our frontier North America and International assets. Contingent resources may require additional delineation drilling, future corporate approval to proceed with development, additional regulatory approvals and other commercial factors to be put in place.

Remaining recoverable resources are the best estimate of Suncor's total resource assets, which form the basis of our long term business plans and production growth. Management believes that this metric is also useful in comparing Suncor's resource base to that of our competitors. Readers are cautioned that the manner in which remaining recoverable resources are calculated may differ across companies and for that reason, direct comparisons may not be possible in some instances.

Estimates of contingent resources have not been adjusted for risk based on the chance of development. Such estimates are not estimates of volumes that may be recovered and actual recovery is likely to be less and may be substantially less or zero. There is no certainty as to the timing of such development.

There is no certainty that all or any portion of the contingent resource will be commercially viable to produce any portion of the resources. For movement of resources to reserves categories, all projects must have an economic depletion plan and may require, among other things: (i) additional delineation drilling and/or new technology for unrisked contingent resources; (ii) regulatory approvals; and (iii) company approvals to proceed with development.

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Gas Reserves

The following disclosures on Standardized Measure of discounted cash flows and changes therein relating to proved oil and natural gas reserves are presented in accordance with the U.S. FASB Topic 932, *Disclosures About Oil and Gas Producing Activities*. The future cash flows are calculated by applying a 12-month average price for the year, or prices provided by contractual arrangements, net of royalties, to year-end quantities of proved crude oil, natural gas liquids, and natural gas reserves. Future production, development and asset retirement costs are based on year-end costs and estimated future income taxes are based on legislated future income tax rates. The resulting future net cash flows are discounted at 10% per annum. The calculation does not represent a fair market value of the company's crude oil, natural gas liquids and natural gas reserves or of the future net cash flows. No consideration is given to the value of exploration properties or probable reserves. The following benchmark commodity prices and exchange rates were used as at December 31, 2009 in deriving the Standardized Measure:

		2009 12 month average	2008 Year-end
Dated Brent	USD/BBL	60.67	36.55
WTI @ Cushing	USD/BBL	61.04	44.60
Edmonton Light (Par) @ Edmonton	CAD/BBL	63.55	52.96
Condensate @ Edmonton	CAD/BBL	66.66	59.70
Syncrude/OSA @ Edmonton	CAD/BBL	69.36	59.52
WCS FOB @ Hardisty	CAD/BBL	56.60	43.53
Henry Hub Gas Price	USD/MMBTU	3.82	5.62
CIG US Rockies Gas Price	USD/MMBTU	3.30	4.61
AECO-C Canadian Gas Price	CAD/GJ	3.81	6.04
Propane @ Edmonton	CAD/BBL	36.45	37.36
Butane @ Edmonton	CAD/BBL	44.27	23.05
Canadian Dollar to US Dollar	CAD/USD	1.15	1.22
Canadian Dollar to Euro	CAD/EURO	1.52	N/A
Canadian Dollar to British Pound	CAD/GBP	1.79	N/A

Present Value of Estimated Future Net Cash Flows
(millions of Canadian dollars)

	North America Onshore			Oil Sands Mining (1)			Oil Sands In-Situ		
	2009	2008 (2)	2007 (2)	2009	2008 (2)	2007 (2)	2009	2008 (2)	2007 (2)
Future cash flows	**7,452**	3,186	3,341	**121,231**			**59,853**	35,486	27,886
Future production costs	**(3,400)**	(1,119)	(827)	**(61,740)**			**(33,947)**	(17,749)	(15,136)
Future development costs	**(451)**	(182)	(202)	**(31,567)**			**(12,634)**	(8,084)	(7,800)
Asset retirement and other	**(1,773)**	(465)	(528)	**(3,265)**			**(373)**	(238)	(214)
Future income taxes	**(77)**	(199)	(268)	**(6,205)**			**(1,922)**	(1,053)	(1,935)
Future net cash flows	**1,751**	1,221	1,516	**18,454**			**10,977**	8,362	2,801
10% annual discount for estimated timing of cash flows	**(248)**	(474)	(601)	**(11,152)**			**(7,541)**	(5,989)	(3,206)
Discounted future net cash flows	**1,503**	747	915	**7,302**			**3,436**	2,373	(405)

	East Coast Canada			North Sea			Other International		
	2009	2008 (2)	2007 (2)	2009	2008 (2)	2007 (2)	2009	2008 (2)	2007 (2)
Future cash flows	**4,711**			**9,778**			**5,610**		
Future production costs	**(1,863)**			**(3,096)**			**(1,191)**		
Future development costs	**(678)**			**(470)**			**(411)**		
Asset retirement and other	**(213)**			**(696)**			**(463)**		
Future income taxes	**(343)**			**(2,958)**			**(1,461)**		
Future net cash flows	**1,614**			**2,558**			**2,084**		
10% annual discount for estimated timing of cash flows	**(374)**			**(682)**			**(887)**		
Discounted future net cash flows	**1,240**			**1,876**			**1,197**		

	Total		
	2009	2008 (2)	2007 (2)
Future cash flows	**208,635**	38,672	31,227
Future production costs	**(105,237)**	(18,868)	(15,963)
Future development costs	**(46,211)**	(8,266)	(8,002)
Asset retirement and other	**(6,783)**	(703)	(742)
Future income taxes	**(12,966)**	(1,252)	(2,203)
Future net cash flows	**37,438**	9,583	4,317
10% annual discount for estimated timing of cash flows	**(20,884)**	(6,463)	(3,807)

Discounted future net cash flows	**16,554**	3,120	510

(1) US FASB Topic 932 disclosures for mining operations were effective December 31, 2009, therefore prior year comparative numbers for Oil Sands mining have not been disclosed.

(2) The amalgamation with Petro-Canada was effective August 1, 2009, hence comparative figures do not include the operations of Petro-Canada.

Summary of Changes in Present Value of Estimated Future Cash Flows
(millions of Canadian dollars)

	2009	2008 [1]	2007 [1]
Balance at beginning of year	**3,120**	510	3,369
Changes result from:			
Sales and transfers of oil and gas produced, net of production costs	**(2,263)**	(677)	(483)
Net changes in prices, production costs and royalties [2]	**442**	1,560	(3,226)
Extensions, discoveries, additions and improved recoveries	**1,470**	248	72
Changes in estimated future development costs	**(2,837)**	(2,494)	(2,151)
Development costs incurred during the year	**1,675**	2,389	1,459
Revisions of previous quantity estimates	**1,679**	293	(4)
Accretion of discount	**342**	93	472
Purchase and sale of reserves in place [3]	**9,371**		35
Net change in income tax [3]	**(3,600)**	130	934
Changes in timing and other	**(147)**	1,068	33
Net change	**6,132**	2,610	(2,859)