QuickLinks -- Click here to rapidly navigate through this document

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

112 - 4th Avenue S.W.
Box 38
Calgary, Alberta, Canada T2P 2V5
(403) 269-8100

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

CT Corporation System
111 Eighth Avenue
New York, New York, U.S.A. 10011
(212) 894-8940

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

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

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

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

None

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

None

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

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 DATED MARCH 5, 2010



ANNUAL INFORMATION FORM

TABLE OF CONTENTS

TABLE OF CONTENTS i
GLOSSARY OF TERMS 1
CONVERSION TABLE 3
PRESENTATION OF INFORMATION 3
FORWARD-LOOKING STATEMENTS 3
NON-GAAP FINANCIAL MEASURES 5
ACCOUNTING MATTERS 5
CORPORATE STRUCTURE 5
Name and Incorporation 5
Intercorporate Relationships 6
GENERAL DEVELOPMENT OF THE BUSINESS 7
Overview 7
Three-Year History 8
- Oil Sands 8
- Natural Gas 9
- East Coast Canada 10
- International 10
- Refining and Marketing 11
- Other 12

Significant Acquisition in 2009 12
NARRATIVE DESCRIPTION OF THE BUSINESS 13
Oil Sands 13
- Operations 13
- Principal Products 14
- Principal Markets 14
- Transportation 14
- Competitive Conditions 15
- Seasonal Impacts 15
- Sales of SCO and Diesel 15
- Environmental Compliance 15

Natural Gas 16
- Marketing, Pipeline and Other Operations 16
- Principal Products 17
- Competitive Conditions 17
- Seasonal Impacts 17
- Environmental Compliance 17

East Coast Canada 17
- Marketing, Pipeline and Other Operations 18
- Sales of Conventional Crude Oil 19
- Principal Products 19
- Competitive Conditions 19
- Seasonal Impacts 19
- Environmental Compliance 19

International 20
- Marketing, Pipeline and Other Operations 20
- Principal Products 21
- Competitive Conditions 22
- Environmental Compliance 22

Refining and Marketing 22
- Average Daily Sales of Petroleum Products 24
- Procurement of Feedstocks 25
- Transportation and Distribution 25
- Competitive Conditions 26
- Environmental Compliance 26

Corporate, Energy Trading and Eliminations 26
RESERVES ESTIMATES 27
General 27
Reserves Evaluation Process and Controls 27
Definitions and Notes to Reserves Data Tables 28
Reserves Categories (SEC definitions) 28
Discussion on Changes to Reserve Estimates 30
- Changes related to revised SEC reserves disclosure requirements 30
- Merger of Suncor and Petro-Canada 30
- Production 30
- Bitumen Reserves 30
- In-Situ 30
- Mining 30
- International 30

Required U.S. Oil and Gas Disclosure 31
Voluntary Additional Disclosure 34
Remaining Recoverable Resources 36

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Gas Reserves 37
INDUSTRY CONDITIONS 48
Pricing and Marketing – Oil and Natural Gas 48
Pipeline Capacity 48
Royalties and Incentives 48
Canada – General 48
Alberta 49
East Coast Canada 51
United States 51
Other International 51
Land Tenure 51
Environmental Regulation 52
RISK FACTORS 54
DIVIDENDS 63
DESCRIPTION OF CAPITAL STRUCTURE 63
General Description of Capital Structure 63
Constraints 63
Ratings 63
MARKET FOR OUR SECURITIES 65
Price Range and Trading Volume of Common Shares 65
Toronto Stock Exchange 65
New York Stock Exchange 65
Prior Sales 65
DIRECTORS AND EXECUTIVE OFFICERS 66
Directors 66
Corporate Officers 68
Cease Trade Orders, Bankruptcies, Penalties or Sanctions 69
Conflicts of Interest 69
SUNCOR EMPLOYEES 70
RELIANCE ON EXEMPTIVE RELIEF 70
AUDIT COMMITTEE INFORMATION 71
LEGAL PROCEEDINGS AND REGULATORY ACTIONS 73

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS 73
TRANSFER AGENT AND REGISTRAR 73
MATERIAL CONTRACTS 73
INTERESTS OF EXPERTS 74
DISCLOSURE PURSUANT TO THE REQUIREMENTS OF THE NEW YORK STOCK EXCHANGE 74
ADDITIONAL INFORMATION 74
SCHEDULE "A" – SUNCOR ENERGY INC. POLICY AND PROCEDURES FOR PRE-APPROVAL OF AUDIT AND NON-AUDIT SERVICES A-1
SCHEDULE "B" – AUDIT COMMITTEE MANDATE B-1
SCHEDULE "C" – MODIFIED FORM 51-101F3 *REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION* C-1
SCHEDULE "D" – MODIFIED FORM 51-101F2 *REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATORS* D-1
SCHEDULE "E" – REPORT OF GLJ PETROLEUM CONSULTANTS LTD. E-1
SCHEDULE "F" – REPORT OF SPROULE ASSOCIATES LTD. F-1
SCHEDULE "G" – REPORT OF RPS ENERGY PLC. G-1

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

Lubricants
- Mississauga Lubricants Plant

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)

(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.

---

(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%).

(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)

Reserve category	Reserves				Reserve category	Reserves			
	Oil & NGL	Natural Gas	SCO	Bitumen		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)
Addition of future cash flows from Oil Sands – Mining [4]	**7,302**	—	—
Balance at end of year	**16,554**	3,120	510

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

(2) Due to the SEC rule change in respect to reporting final product sold, Suncor has reserve In-situ volumes that were previously reported as Bitumen that now are to be reported as SCO. The impact of this change on the future cash flows of In-Situ has been reflected in this line item.

(3) Petro-Canada future cash flows as at August 1, 2009, including sales, production costs, development costs, asset retirement, and other expenses are reflected in "purchase and sale of reserves in place". Changes to cash flows subsequent to August 1, 2009 are presented in the respective line items. The associated tax impacts are reflected in "net change in income tax".

(4) US FASB Topic 932 disclosures for mining operations were effective December 31, 2009, therefore prior year numbers for Oil Sands mining have not been disclosed. Oil Sands mining cash flows are reflected as a cash flow addition for purposes of this table.

Capitalized Costs Relating to Oil & Gas Producing Activities [3]

Suncor's aggregate capitalized costs relating to its oil and natural gas activities are summarized in the following table.

	As at December 31,		
(millions of Canadian dollars)	2009	2008 [1][2]	2007 [1][2]
Oil and gas properties	56,079	10,171	6,971
Accumulated depreciation, depletion, and amortization, and valuation allowances	(6,234)	(1,608)	(1,306)
Net capitalized costs	49,845	8,563	5,665

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

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

(3) Includes work in progress, development assets, assets under construction which are currently not being depreciated or depleted.

Costs Incurred in Oil and Gas Property Acquisition Exploration and Development

Suncor's costs incurred on acquisition, exploration, and development, whether capitalized or expensed at the time they are incurred, are summarized in the following table.

	For the years ended December 31,		
(millions of Canadian dollars)	2009 [2]	2008 [2]	2007 [2]
Exploration			
North America Onshore	**100**	120	141
Oil Sands – Mining [1]	**2**	—	—
Oil Sands – In-Situ	**13**	13	1
East Coast Canada	**41**	—	—
North Sea	**150**	—	—
Other International	**71**	—	—
Total Exploration	**377**	133	142
Development			
North American Onshore	**239**	216	230
Oil Sands – Mining [1]	**1,561**	—	—
Oil Sands – In-Situ	**988**	2,182	1,228
East Coast Canada	**83**	—	—
North Sea	**131**	—	—
Other International	**252**	—	—
Total Development	**3,254**	2,398	1,458
Property acquisitions			
North America Onshore	**3,103**	19	172
Oil Sands – Mining [1]	**5,024**	—	—
Oil Sands – In-Situ	**1,779**	—	—
East Coast Canada	**4,701**	—	—
North Sea	**5,895**	—	—
Other International	**2,434**	—	—
Total Property Acquisitions	**22,936**	**19**	**172**
Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development	**26,567**	**2,550**	**1,772**

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

(2) The amalgamation with Petro-Canada was effective August 1, 2009. Hence comparative figures do not include the operations of Petro-Canada. Current year figures include the acquisition cost of Petro-Canada assets based on the fair values assigned on the amalgamation date and post-acquisition expenditures incurred on Petro-Canada properties.

Abandonment and Reclamation Costs

The company's upstream future asset retirement costs are estimated based on current costs and technology in accordance with existing legislation and industry practice. As of December 31, 2009, the total of these future costs was estimated to be $8.3 billion undiscounted, as disclosed in the 2009 annual MD&A, or $2.6 billion discounted at 10%. We expect to spend approximately $318 million, $254 million and $214 million in the next three years, respectively, for future asset retirement costs in our upstream operations.

Productive Wells[1][2]

Suncor's total gross and net productive wells by product are summarized in the following table.

	Crude Oil Wells		Natural Gas Wells		Total Wells	
As at December 31, 2009	Gross [3]	Net [4]	Gross [3]	Net [4]	Gross [3]	Net [4]
North America Onshore	1,446	1,253	6,239	4,206	7,685	5,459
Oil Sands – In-Situ	96	96	—	—	96	96
East Coast Canada	101	25	—	—	101	25
North Sea	80	29	29	5	109	34
Other International	146	73	11	2	157	75
Total productive wells	1,869	1,476	6,279	4,213	8,148	5,689

(1) Wells with multiple completions are counted as one well.

(2) Well data not applicable to oil sands mining operations.

(3) Gross wells include the interests of others.

(4) Net wells exclude the interests of others.

Oil and Natural Gas Rights

Suncor's oil and natural gas rights are summarized in the following table. Landholdings are subject to government regulation.

	Developed Lands [1]				Undeveloped Lands [1]				Total			
	2009		2008 [5]		2009		2008 [5]		2009		2008 [5]	
(thousands of acres)	Gross [2]	Net [3]	Gross [2]	Net [3]	Gross [2]	Net [3]	Gross [2]	Net [3]	Gross [2]	Net [3]	Gross [2]	Net [3]
North America												
Onshore [4]	**3,096**	**1,688**	700	410	**13,673**	**9,213**	1,780	880	**16,769**	**10,901**	2,480	1,290
Oil Sands – Mining	**181**	**98**	87	87	**474**	**288**	127	127	**655**	**386**	214	214
Oil Sands – In-Situ	**85**	**85**	40	40	**1,085**	**1,085**	402	402	**1,170**	**1,170**	442	442
East Coast												
Canada	**113**	**29**	—	—	**1,844**	**643**	—	—	**1,957**	**672**	—	—
North Sea	**78**	**40**	—	—	**2,211**	**788**	—	—	**2,289**	**828**	—	—
Other International	**551**	**243**	—	—	**9,718**	**5,639**	—	—	**10,269**	**5,882**	—	—
Total	**4,104**	**2,183**	827	537	**29,005**	**17,656**	2,309	1,409	**33,109**	**19,839**	3,136	1,946

(1) Developed lands are areas capable of production, while undeveloped lands are areas with rights to explore.

(2) Gross acres include the interests of others.

(3) Net acres exclude the interests of others.

(4) Figures do not include option acreage in the Alaska Foothills.

(5) The merger with Petro-Canada was effective August 1, 2009. Hence comparative figures do not include the operations of Petro-Canada.

Land Expiries

The following table summarizes the land area by region for which Suncor's rights to explore for or develop hydrocarbons will expire in 2010.

(millions of acres)	Gross [1]	Net [2]
North America Onshore	1.2	0.8
Oil Sands – In-Situ	—	—
Oil Sands – Mining	—	—
East Coast Canada	0.3	0.2
North Sea	—	—
Other International	1.5	1.4
Total land expiries in 2010	3.0	2.4

(1) Gross acres include the interests of others.

(2) Net acres exclude the interests of others.

Work Commitments

The practice of governments requiring companies to pledge to carry out work commitments in exchange for the right to carry out exploration for and development of hydrocarbons is common, particularly in unexplored or lightly explored regions of the world. Suncor has made the following commitments in regard to the lands it holds. Work commitments as at December 31, 2009 are summarized below.

(millions of Canadian dollars)	Suncor Share of Total Work Commitments	Suncor Share of Total Work Commitments to be Incurred in 2010 [1]
North America Onshore	9	8
Oil Sands – Mining	—	—
Oil Sands – In-Situ	—	—
East Coast Canada	64	17
North Sea	199	31
Other International	428	132
Total work commitments	700	188

(1) Capital expenditure plan for 2010 includes provisions for these work commitments.

Drilling Activity

The following table shows Suncor's drilling activity during the years indicated.

Exploration and Development Wells Drilled as at December 31, [6]

	2009		2008 [7]		2007 [7]	
	Gross [1]	Net [2]	Gross [1]	Net [2]	Gross [1]	Net [2]
North America Onshore						
Exploration wells [3]						
Oil	**—**	**—**	—	—	—	—
Natural gas	**4**	**2**	7	5	10	7
Dry [4]	**8**	**6**	7	4	6	4
Subtotal	**12**	**8**	14	9	16	11
Development wells [5]						
Oil	**26**	**26**	—	—	—	—
Natural gas	**68**	**31**	25	17	29	14
Dry	**1**	**1**	7	5	2	1
Subtotal	**95**	**58**	32	22	31	15
Total North America Onshore	**107**	**66**	46	31	47	26
Total North America Onshore – In progress [8]	**32**	**32**				
Oil Sands – In-Situ						
Development wells [5]						
Bitumen	**20**	**20**	24	24	26	26
Total Oil Sands – In-Situ	**20**	**20**	24	24	26	26
Total Oil Sands – In-Situ – In progress [8]	**—**	**—**				
East Coast Canada						
Exploration wells [3]	**—**	**—**	—	—	—	—
Oil	**—**	**—**	—	—	—	—
Dry [4]	**—**	**—**	—	—	—	—
Subtotal	**—**	**—**	—	—	—	—
Development wells [5]			—	—	—	—
Oil	**6**	**2**	—	—	—	—
Dry	**—**	**—**	—	—	—	—
Subtotal	**6**	**2**	—	—	—	—
Total East Coast Canada	**6**	**2**	—	—	—	—
Total East Coast Canada – In progress [8]	**2**	**1**	—	—	—	—
International						
Exploration wells [3]						
Oil						
North Sea	**11**	**4**	—	—	—	—
Other International	**—**	**—**	—	—	—	—
Natural gas						
North Sea	**1**	**1**	—	—	—	—
Other International	**—**	**—**	—	—	—	—
Dry [4]						
North Sea	**3**	**1**	—	—	—	—
Other International	**—**	**—**	—	—	—	—
Subtotal	**15**	**6**	—	—	—	—
Development wells [5]						
Oil						
North Sea	**10**	**4**	—	—	—	—
Other International	**27**	**15**	—	—	—	—
Natural gas						
North Sea	**1**	**1**	—	—	—	—
Other International	**6**	**4**	—	—	—	—
Dry [4]						
North Sea	**4**	**2**	—	—	—	—
Other International	**1**	**1**	—	—	—	—
Subtotal	**49**	**27**	—	—	—	—

Total International	**64**	**33**	—	—	—	—
Total International – In progress [8]	**8**	**5**	—	—	—	—
Total wells drilled	**197**	**121**	70	55	73	52

(1) Gross wells (excluding all service wells) include the interests of others. This includes gross overriding royalty (GOR) wells.

(2) Net wells exclude the interests of others. Net wells exclude GOR wells.

(3) Exploration wells are wells drilled to discover crude oil or natural gas in an unproven area previously not known to contain hydrocarbons

(4) A dry hole is an exploration or development well determined to be incapable of producing either crude oil or natural gas in sufficient economic quantities to justify completion as a crude oil or natural gas well.

(5) Development wells are wells drilled in an oil or natural gas reservoir to the depth of a stratigraphic horizon previously known to be productive.

(6) Table does not include drilling activity for oil sands mining operations. For information on oil sands mining exploration and development activities, see page 8 and 9 of this AIF.

(7) The amalgamation with Petro-Canada was effective August 1, 2009. Hence comparative figures do not include the operations of Petro-Canada. Current year figures include post-acquisition drilling activity related to Petro-Canada properties.

(8) Wells in progress at December 31, 2009.

Results of Operations for Oil and Gas Producing Activities (3)

Suncor's Results of Operations for oil and gas producing activities is shown below by geographic area:

	North America Onshore			Oil Sands (1)			East Coast Canada		
(millions of Canadian dollars)	2009	2008 (2)	2007 (2)	2009	2008 (2)	2007 (2)	2009	2008 (2)	2007 (2)
Revenues									
Sales to unaffiliated customers	**527**	521	416	**3,490**	—	—	**282**	—	—
Transfers to other operations	**154**	58	9	**2,609**	713	496	**159**	—	—
	681	579	425	**6,099**	713	496	**441**	—	—
Expenses									
Purchases of crude oil and products	**—**	—	—	**325**	—	—	**33**	—	—
Operating, selling and general	**322**	160	128	**3,898**	326	280	**49**	—	—
Transportation costs	**58**	17	30	**248**	1	8	**19**	—	—
Depreciation, depletion and amortization	**448**	225	180	**922**	87	83	**184**	—	—
Exploration	**127**	73	93	**10**	17	—	**4**	—	—
Gain on disposal of assets	**(20)**	(22)	14	**70**	—	—	**—**	—	—
Other related assets	**22**	8	1	**162**	19	—	**4**	—	—
Operating profits before income taxes	**(276)**	118	(21)	**464**	263	125	**148**	—	—
Related income taxes	**77**	(29)	41	**(47)**	(70)	(40)	**(18)**	—	—
Results of operations	**(199)**	89	20	**417**	193	85	**130**	—	—

	North Sea			Other International			Total		
	2009	2008 (2)	2007 (2)	2009	2008 (2)	2007 (2)	2009	2008 (2)	2007 (2)
Revenues									
Sales to unaffiliated customers	**949**	—	—	**218**	—	—	**5,466**	521	416
Transfers to other operations	**—**	—	—	**—**	—	—	**2,922**	771	505
	949	—	—	**218**	—	—	**8,388**	1,292	921
Expenses									
Purchases of crude oil and products	**—**	—	—	**—**	—	—	**358**	—	—
Operating, selling and general	**198**	—	—	**20**	—	—	**4,487**	486	408
Transportation costs	**30**	—	—	**3**	—	—	**358**	18	38
Depreciation, depletion and amortization	**359**	—	—	**40**	—	—	**1,953**	312	263
Exploration	**59**	—	—	**36**	—	—	**236**	90	93
Gain on disposal of assets	**—**	—	—	**—**	—	—	**50**	(22)	14
Other related assets	**10**	—	—	**6**	—	—	**204**	27	1
		—	—		—	—			
Operating profits before income taxes	**293**	—	—	**113**	—	—	**742**	381	104
Related income taxes	**(136)**	—	—	**(85)**	—	—	**(210)**	(99)	1
Results of operations	**157**	—	—	**28**	—	—	**532**	282	105

(1) US FASB Topic 932 disclosures for mining operations was effective December 31, 2009. Therefore prior year numbers for mining are not disclosed.

(2) The amalgamation with Petro-Canada was effective August 1, 2009. Hence comparative figures do not include the operations of Petro-Canada. Current year figures include post-acquisition results of Petro-Canada properties.

(3) Results from operations may not agree to the operating segment results reported in the 2009 Annual Report, as the above figures have been calculated in accordance with US FASB Topic 932 requirements not Canadian Generally Accepted Accounting Principles.

Upstream Production and Prices

Average Daily Production before Royalties and Sale Prices for Crude Oil, NGL, Bitumen, Synthetic Crude Oil and Natural Gas

Production information stated before royalties does not conform to SEC standards and is supplemental general information. Refer to page 32 of this AIF for annual after royalty production as computed by third party evaluators in accordance with SEC standards. Daily production figures below are consistent with the information presented in the 2009 Annual Report and may differ in relation to the before royalty figures computed by third party evaluators reported on page 34 of this AIF.

	Twelve months ended December 31**		
	2009	2008	2007
OIL SANDS (INCLUDING IN-SITU)			
Production (1)(a)			
Total production (excluding Syncrude)	**290.6**	228.0	235.6
Firebag (h)	**49.1**	37.4	36.9
MacKay River (h)	**29.7** **	—	—
Syncrude	**38.5** **	—	—
Sales (a) (excluding Syncrude)			
Light sweet crude oil	**99.6**	77.0	101.7
Diesel	**29.1**	19.8	25.0
Light sour crude oil	**135.7**	128.7	102.3
Bitumen	**11.8**	1.5	5.7
Total sales	**276.2**	227.0	234.7
Average sales price (2)(b) (excluding Syncrude)			
Light sweet crude oil*	**67.26**	98.66	78.03
Other (diesel, light sour crude oil and bitumen) *	**64.18**	95.14	70.86
Total *	**65.29**	96.33	74.01
Total	**61.26**	95.96	74.07
Syncrude average sales price (2)(b)	**77.36**	—	—
NORTH AMERICA ONSHORE			
Gross production			
Natural gas (d)			
Western Canada	**374**	202	196
U.S. Rockies	**24**	—	—
Natural gas liquids and crude oil (a)			
Western Canada	**6.4**	3.1	3.1
U.S. Rockies	**1.7**	—	—
Total gross production (f)			
Western Canada	**412**	220	215
U.S. Rockies	**34**	—	—
Average sales price (2)			
Natural gas (g)			
Western Canada	**3.70**	8.23	6.32
U.S. Rockies	**3.93**	—	—
Natural gas (g)*			
Western Canada	**3.68**	8.25	6.27
U.S. Rockies	**3.93**	—	—
Natural gas liquids and crude oil (b)			
Western Canada	**52.97**	70.89	56.64
U.S. Rockies	**71.62**	—	—

EAST COAST CANADA			
Production [a]			
Terra Nova	**20.8**	—	—
Hibernia	**27.2**	—	—
White Rose	**10.0**	—	—
Total production	**58.0**	—	—
Average sales price [2]	**76.86**	—	—
NORTH SEA			
Production [e]			
Buzzard	**47.8**	—	—
Other U.K.	**15.5**	—	—
The Netherlands sector of the North Sea	**13.2**	—	—
Total production	**76.5**	—	—
Average sales price [2] **– crude oil and NGL**	**74.99**	—	—
Average sales price [2] **– natural gas**	**6.89**	—	—
Total average sales price [i]	**71.63**	—	—
OTHER INTERNATIONAL			
Production [e]			
Libya	**32.6**	—	—
Trinidad & Tobago	**11.7**	—	—
Total production	**44.3**	—	—
Average sales price [2] **– crude oil and NGL**	**78.05**	—	—
Average sales price [2] **– natural gas**	**2.42**	—	—
Total average sales price [i]	**61.25**	—	—

Please refer to footnotes on Page 47 of this AIF.

Average Production Costs for Crude Oil, NGL, Bitumen, Synthetic Crude Oil and Natural Gas

	Twelve months ended December 31		
	2009	2008	2007
OIL SANDS [c]			
(Excluding Syncrude)			
Cash costs	**31.50**	31.45	24.15
Natural gas	**2.40**	5.25	3.55
Imported bitumen	**0.05**	1.80	0.10
Cash operating costs [3]	**33.95**	38.50	27.80
Project start-up costs	**0.45**	0.40	0.95
Total cash operating costs [4]	**34.40**	38.90	28.75
(Including Syncrude)			
Cash costs	**29.60**	—	—
Natural gas	**2.90**	—	—
Cash operating costs [3]	**32.50**	—	—
Project start-up costs	**—**	—	—
Total cash operating costs [4]	**32.50**	—	—
IN-SITU [c]			
Cash costs	**10.90**	13.00	10.85
Natural gas	**5.70**	12.30	9.90
Cash operating costs [5]	**16.60**	25.30	20.75
In-situ start-up costs	**1.30**	0.65	—
Total cash operating costs [6]	**17.90**	25.95	20.75
NATURAL GAS [g]			
Western Canada			
Average price realized [8]	**4.58**	9.35	6.88
Royalties	**(0.49)**	(2.17)	(1.56)
Operating costs [7]	**(1.79)**	(1.60)	(1.41)
Operating netback	**2.30**	5.58	3.91
U.S. Rockies			
Average price realized [8]	**6.35**	—	—
Royalties	**(1.01)**	—	—
Operating costs [7]	**(1.82)**	—	—
Operating netback	**3.52**	—	—
Total Natural Gas			
Average price realized [8]	**4.71**	9.35	6.88
Royalties	**(0.53)**	(2.17)	(1.56)
Operating costs [7]	**(1.79)**	(1.60)	(1.41)
Operating netback	**2.39**	5.58	3.91
EAST COAST CANADA [b]			
Average price realized [8]	**79.07**	—	—
Royalties	**(23.82)**	—	—
Operating costs [7]	**(9.76)**	—	—
Operating netback	**45.49**	—	—
NORTH SEA [b]			
Average price realized [8]	**71.63**	—	—
Operating costs [7]	**(9.78)**	—	—
Operating netback	**61.85**	—	—
OTHER INTERNATIONAL [b]			
Average price realized [8]	**61.35**	—	—
Royalties	**(30.43)**	—	—
Operating costs [7]	**(3.38)**	—	—
Operating netback	**27.54**	—	—

Definitions

(1) Total operations production	—	Total operations production includes total production from both mining and in-situ operations.
(2) Average sales price	—	This operating statistic is calculated before royalties (where applicable) and net of related transportation costs and excludes the realized impact of hedging activities unless stated.
(3) Cash operating costs	—	Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes), accretion expense, transportation costs, taxes other than income taxes and the cost of bitumen imported from third parties. Per barrel amounts are based on total production volumes. For a reconciliation of this non-GAAP financial measure for total operations (excluding Syncrude), see page 53 of our 2009 annual MD&A.
(4) Total cash operating costs	—	Include cash operating costs as defined above and cash start-up costs. Per barrel amounts are based on total production volumes.
(5) Cash operating costs – In-situ bitumen production	—	Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes), accretion expense and taxes other than income taxes. Per barrel amounts are based on in-situ production volumes only.
(6) Total cash operating costs – In-situ bitumen production	—	Include cash operating costs – In-situ bitumen production as defined above and cash start-up operating costs. Per barrel amounts are based on in-situ production volumes only.
(7) Operating costs	—	Include lifting costs and related transportation costs.
(8) Average price realized	—	This operating statistic is calculated before transportation costs and royalties and excludes the impact of hedging activities.

Explanatory Notes

* Excludes the impact of realized hedging activities.

** For the twelve months ended December 31, 2009, operating summary information reflects results of operations since the merger with Petro-Canada on August 1, 2009.

(a) thousands of barrels per day
(b) dollars per barrel
(c) dollars per barrel rounded to the nearest $0.05
(d) millions of cubic feet per day
(e) thousands of barrels of oil equivalent per day
(f) millions of cubic feet equivalent per day
(g) dollars per thousand cubic feet equivalent
(h) thousands of barrels of bitumen per day
(i) dollars per barrel of oil equivalent

Metric conversion

Crude oil, refined products, etc. 1 m^3 (cubic metre) = approx. 6.29 barrels

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, environmental, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and with respect to export and taxation of oil and natural gas by agreements among the governments of Canada and Alberta, among others, (including the governments of the United States and other foreign jurisdictions in which we operate), all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these controls or regulations will affect the company's operations in a manner materially different than they would affect other oil and gas companies of similar size. All current legislation is a matter of public record and the company is currently unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing – Oil and Natural Gas

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to the markets, the value of refined products, the supply/demand balance, and other contractual terms. In Canada, oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (NEB). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires a public hearing and the approval of the Governor in Council.

The price of natural gas is also determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires a public hearing and the approval of the Governor in Council.

The government of Alberta also regulates the volume of natural gas that may be removed from the province for consumption elsewhere based on such factors as reserve availability, transportation arrangements, and market considerations.

Internationally, prices for crude oil and natural gas fluctuate in response to changes in the supply of and demand for crude oil and natural gas, market uncertainty and a variety of other factors beyond Suncor's control. These factors include, but are not limited to, the actions of the Organization of the Petroleum Exporting Countries (OPEC), world economic conditions, government regulation, political developments, the foreign supply of oil, the price of foreign imports, the availability of alternate fuel sources and weather conditions.

Pipeline Capacity

Although pipeline expansions are ongoing, the pro-rationing of capacity on the pipeline systems can occur from time to time due to pipeline and downstream operating problems that can affect the ability to market western Canadian crude oil and natural gas.

Royalties and Incentives

Canada – General

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection, and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas liquids, sulphur, and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral freehold owner and the lessee, although production from such lands may be subject to certain provincial taxes. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery, depth of well, and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs provide for royalty rate reductions, royalty holidays and tax credits, and are generally introduced when

commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and would increase the net income and funds from operations of such producers. However, the trend in recent years has been for provincial governments to revise existing incentive programs and royalty structures, which have generally resulted in increases to the amounts of royalties ultimately payable.

The Canadian federal corporate income tax rate levied on taxable income is 19% effective January 1, 2009 for active business income including resource income. With the elimination of the corporate surtax effective January 1, 2008 and other rate reductions introduced in the October 2007 Economic Statement and subsequently enacted, the federal corporate income tax rate will decrease to 15% in five steps: 19.5% on January 1, 2008, 19% on January 1, 2009, 18% on January 1, 2010, 16.5% on January 1, 2011 and 15% on January 2012.

Alberta

In Alberta, companies are granted the right to explore, produce and develop petroleum and natural gas resources in exchange for royalties, bonus bid payments and rents. On October 25, 2007, the Alberta government released a report entitled "The New Royalty Framework" containing the government's proposals for Alberta's new royalty regime, and was followed by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*, which was given Royal Assent on December 2, 2008. The New Royalty Framework and the applicable new legislation became effective on January 1, 2009. Prior to the New Royalty Framework, the amount of conventional oil royalties that were payable was influenced by the oil production, density of the oil, and the vintage of the oil (the "Generic Regime"). Originally, the vintage classified oil was "new oil" and "old oil" depending on when the oil pools were discovered. If the pool was discovered prior to March 31, 1974 it was considered "old oil", and if it was discovered after March 31, 1974 and before September 1, 1992, it was considered "new oil". The Alberta government introduced in 1992 a Third Tier Royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 1, 1992. The new oil royalty reserved to the Crown had a base rate of 10% and a rate cap of 30%. The old oil royalty reserved to the Crown had a base rate of 10% and a rate cap of 35%. The New Royalty Framework eliminates this classification and establishes new royalty rates for conventional oil, natural gas and oil sands. As at January 1, 2009, the new royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and increases the old royalty from 30%-35% applied to the old and new tiers, to up to 50% and with rate caps once the price of conventional oil reaches Cdn$120 per barrel. The sliding rate formula includes in its calculation the price of oil and well production.

With respect to natural gas, and similar to the conventional oil framework, the royalties outlined in the New Royalty Framework are set by a single sliding rate formula ranging from 5% to 50% with a rate cap once the price of natural gas reaches Cdn$16.59/Gigajoule. The New Royalty Framework determined rate is based on well depth, production rate, gas price and gas quality. Prior to the New Royalty Framework, the royalty reserved to the Crown in respect of natural gas production, subject to various incentives, was up to 30% in the case of new natural gas (discovered after 1974), and up to 35% in the case of old natural gas (discovered prior to 1974), depending upon a prescribed or corporate average reference price. The New Royalty Framework provides some royalty relief, under the Natural Gas Deep Drilling Program, for wells drilled beyond 2,500 metres true vertical depth, based on total depth and whether the well is exploratory or developmental. In response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced on November 19, 2008, the introduction of a five year program of transitional royalty rates with the intent of promoting new drilling, which program became effective January 1, 2009. Under this new program companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 metres) will be given a one-time option, on a well by well basis, to adopt the new transitional royalty rates, which would cap the maximum royalty at 30%. However, their wells cannot also receive relief from the Natural Gas Deep Drilling Program. In order to qualify for this program wells must be drilled during the period starting on January 1, 2009 and ending in December 31, 2013. Following this period, all new wells drilled will automatically be subject to the New Royalty Framework.

Oil sands projects are now subject to the New Royalty Framework, and regulated by, among others, the *Oil Sands Royalty Regulation, 2009* approved by the Government of Alberta on December 10, 2008. Royalties on our current Firebag and MacKay River in-situ projects were under the 1997 Generic Regime until the end of 2008, and assessed based on bitumen value. In December 2008, the Government of Alberta enacted the New Royalty Framework, which increased royalty rates from the 1997 Generic Regime to a sliding-scale royalty of 25% to 40% of R – C, subject to minimum royalty of 1% to 9% of R, depending on oil price. In both cases, a sliding-scale royalty moves with increases in WTI prices from Cdn$55/bbl to the maximum rate at a WTI price of Cdn$120/bbl. Royalty on our base Oil Sands mining and associated upgrading operations are modified by Crown agreements (including the Amending Agreement) and assessed on the R – C royalty subject to a minimum royalty as follows: (a) based on upgraded product values until December 31, 2008 with rates at 25% of R – C subject to the 1% minimum royalty of R; (b) commencing January 1, 2009, a bitumen-based royalty applies pursuant to Suncor's exercise of its option to transition to the bitumen-based Generic Regime. The royalty rates will remain at 25% of the R – C, subject to the 1% minimum royalty of R, but will apply to a revised R – C, where R will be based on bitumen value and C would exclude substantially all upgrading costs and related capital costs; (c) from January 1, 2010 through December 31, 2015, pursuant to our January 2008 royalty amending agreement with the Government of Alberta, the New Royalty Framework rates described above will apply to the bitumen royalty for current production levels, subject to a cap of 30% of R – C, and a royalty cap of

1.2% of R. In addition, the Suncor Amending Agreement provides Suncor with a level of guidance for various matters, including the bitumen valuation methodology (discussed below), allowed cost, royalty in-kind and certain taxes; and (d) in 2016 and subsequent years, the royalty rates for all of our Oil Sands operations, comprised of our base mining operations and our In-Situ projects, will be the rates prescribed under the New Royalty Framework, unless as amended or superseded prior to that time.

As part of the implementation of the New Royalty Framework, the Alberta government enacted new Bitumen Valuation Methodology (Ministerial) Regulations effective January 1, 2009. These interim regulations determine the valuation of bitumen for 2009 and 2010. The final regulations are being developed by the Crown that will establish the bitumen valuation methodology for future years. For Suncor's mining operations, the bitumen valuation methodology is based on the terms of Suncor's Amending Agreement, which we believe places certain limitations on the interim bitumen valuation methodology. For the year 2009, Suncor filed a non-compliance notice with the Crown, citing that reasonable adjustments in the determination of the Suncor bitumen value were not considered by the Crown as permitted by Suncor's Amending Agreement. Royalty payments to the Crown for our mining operations were determined in accordance with Suncor's Royalty Amending Agreement and royalty expense was recorded under the Crown's interim bitumen valuation methodology, representing a negative difference of approximately $200 million. Suncor's Royalty Amending Agreement provides for an arbitration procedure failing an agreed settlement of these issues. See also, "Risk Factors – Legal and Regulatory Risks – Risks that affect our ability to comply with regulatory and statutory requirements under applicable law – Alberta Crown Royalties" in this AIF.

In November 2008, the Alberta government and the Syncrude joint venture owners reached an agreement for the implementation of the New Royalty Framework for the Syncrude project (similar to Suncor's Amending Agreement). Under the new royalty terms, the project would continue paying the greater of 1% gross revenue, or 25% of net revenue until the end of 2015. On January 1, 2016, the royalty rates under the New Royalty Framework will apply to the Syncrude project. As part of this agreement, Syncrude exercised its option to pay royalty based on bitumen revenues rather than on SCO revenues. Due to this conversion to a bitumen-based royalty, the upgrader facility at the Syncrude project will no longer be considered as part of the oil sands project. The Syncrude owners have agreed to pay a total of $1.25 billion in royalties over the next 25 years, with interest to account for deductions of allowed costs related to the upgrader facility, which were previously received. The owners also agreed to pay an additional royalty of $975 million over a six-year period starting in 2010, contingent on achieving certain production levels. For the year 2009, Syncrude also filed a non-compliance notice with the Crown, citing that reasonable adjustments in the determination of the bitumen value were not considered by the Crown, similar to the notice filed by Suncor in respect of its Amending Agreement.

On April 10, 2008, the Government of Alberta introduced two new royalty programs to encourage the development of deep oil and gas reserves, and these are: (a) a five-year oil program for exploration wells over 2,000 metres that will provide royalty adjustments to offset higher drilling costs and provide a greater incentive for producers to continue to pursue new, deeper oil plays (these oil wells will qualify for up to $1 million or 12 months of royalty offsets, whichever comes first); and (b) a five-year natural gas deep drilling program that will replace the existing program in order to encourage continued deep gas exploration for wells deeper than 2,500 metres (the program will create a sliding scale of royalty credit according to depth, of up to $3,750 per metre).

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provided various incentives for exploring and developing oil reserves in Alberta. However, the Alberta Government announced in August of 2006 that four royalty programs were to be amended, a new program was to be introduced and the Alberta Royalty Tax Credit Program was to be eliminated, effective January 1, 2007. The programs affected by this announcement were: (i) Deep Gas Royalty Holiday; (ii) Low Productivity Well Royalty Reduction; (iii) Reactivated Well Royalty Exemption; and (iv) Horizontal Re-Entry Royalty Reduction. The program introduced was the Innovative Energy Technologies Program (IETP) which has a stated objective of promoting the producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP provides royalty reductions which are presumed to reduce financial risk. Alberta Energy decides which projects qualify and the level of support that will be provided. The deadline for the IETP's final round of applications was September 20, 2008. The successful applicants for the first two rounds have been announced, and those for the third round were announced in the first half of 2009. The technical information gathered from this program is to be made public once a two-year confidentiality period expires.

The New Royalty Framework includes a policy of "shallow rights reversion". The Government of Alberta stated that it will implement this policy in order to maximize the development of currently undeveloped resources, which is consistent with the Government of Alberta's objective of maximizing recovery of known gas resources, while increasing royalty revenues. The policy's stated objective is for the mineral rights to shallow gas geological formations that are not being developed to revert back to the government and be made available for resale, and in the event of non-productive shallow wells, to sever the rights from shallow zones and encourage increased production from up-hole zones. In December 2008, the Government of Alberta proclaimed an amendment to the *Mines and Minerals Act* (Alberta) with respect to shallow rights reversion. This amendment affects leases issued after January 1, 2009, with phased-in application for leases entered into prior to January 1, 2009.

On March 3, 2009, as result of depressed energy commodity prices and the global economic slowdown, the Government of Alberta announced a three-point incentive program to encourage additional activity in the province's conventional oil and gas sectors. The incentive program included: (i) a drilling royalty credit which offered $200 in royalty credits per meter drilled on

new conventional oil and natural gas wells; (ii) a new well incentive program which provided a maximum five-per-cent royalty rate for all new wells that begin producing conventional oil and natural gas between April 1, 2009 and March 31, 2010; and (iii) $30 million in investment by the Province of Alberta in the reclamation and abandonment of old oil and gas well sites.

East Coast Canada

The royalty regime for the Hibernia project has three tiers: gross royalty, net royalty and supplementary royalty. Gross royalty increased to 5% of gross field revenue on July 1, 2003. The gross royalty rate was at 5% until net royalty payout was reached. The gross royalty is indexed to crude oil prices under certain conditions. Upon achieving payout, including a specified return allowance, the net royalty payable becomes the greater of 30% of net revenue, or 5% of gross revenue. Suncor reached Hibernia 30% Net Royalty in 2009. After a further level of payout is reached, which includes an additional return allowance, a supplementary royalty of 12.5% of net revenue also becomes payable. In addition, Hibernia production is subject to a federal government net profits interest of up to 10% of net revenue which commenced in the first quarter of 2009. Hibernia royalty and net profits interest averaged 35% of gross revenue for the 5 month period ending December 31, 2009. An agreement has been reached with the Province of Newfoundland and Labrador on the eligibility of transportation costs for royalty deductibility.

The Terra Nova royalty regime has three tiers. The royalty consists of a sliding-scale basic royalty payable throughout the project's life, with two additional tiers of incremental net royalties, which are payable upon the achievement of specified levels of profitability. The basic royalty is payable as a percentage of gross field revenue, with an initial rate of 1%, which rises to 10% depending on cumulative production levels and the occurrence of simple payout. After tier one payout has been reached, including a specified return allowance, tier one net royalty will become the greater of the basic royalty, or 30% of net revenue. An additional tier two net royalty equal to 12.5% of net revenue will be payable once a further level of payout, including an additional return allowance, is attained. In 2008, Suncor reached Terra Nova tier two royalty payout and the royalty rate increased to 42.5% of net revenue from 30% of net revenue. Terra Nova royalty averaged 31% of gross revenue for the 5 month period ending December 31, 2009.

In July 2003, the Government of Newfoundland and Labrador published regulations for the royalty regime that will apply to the development of petroleum resources in offshore areas other than at Hibernia and Terra Nova. The generic offshore royalty regime consists of a sliding-scale basic royalty payable throughout a project's life, and a two-tier incremental net royalty payable upon the achievement of specified levels of profitability. The basic royalty is calculated as a percentage of gross field revenue, commencing at 1% and rising to 7.5%, depending on cumulative production levels and the achievement of simple payout. Upon reaching tier one payout, including a return allowance, the tier one net royalty is calculated as the greater of the basic royalty, or 20% of net revenue. An additional 10% tier two net royalty rate is payable once a higher level of return on investment is attained. In 2008, Suncor reached White Rose tier two royalty payout and the royalty rate increased to 30% of net revenue from 20% of net revenue. The total royalty payable in 2009 is expected to equate to a rate of between 20% and 25% of gross revenue, depending on crude oil prices. White Rose royalty averaged 20% of gross revenue for the 5 month period ending December 31, 2009.

See also, "Risk Factors – Legal and Regulatory Risks – Risks that affect our ability to comply with regulatory and statutory requirements under applicable law – Offshore Royalties" in this AIF.

United States

In the U.S., production is from federal, state and freehold lands. Production from federal and state lands is subject to a fixed royalty rate plus a payment to the surface landowner. Freehold royalty rates are determined by negotiations with the freehold mineral rights owner.

Other International

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.

See also, "Risk Factors – Legal and Regulatory Risks – Risks that affect our ability to comply with regulatory and statutory requirements under applicable law – International Royalties" in this AIF.

Land Tenure

In Canada, crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms from two years, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

Environmental legislation in the Province of Alberta relating to oil and gas activities has been primarily consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (EPEA), which came into force on September 1, 1993, and the *Oil and Gas Conservation Act* (Alberta) (OGCA). In 2006, the Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry.

In 2007, the Alberta government introduced the *Climate Change and Emissions Management Amendment Act* (Alberta), which places intensity (emissions per unit of production) limits on facilities emitting more than 100,000 tonnes of carbon dioxide equivalent per year. Suncor's Oil Sands business are subject to this legislation. The Act calls for intensity reductions of 12% commencing July 1, 2007.

In compliance with this new legislation, Suncor filed applications in December 2007 to establish baseline intensities for our Oil Sands facility. In March 2010, Suncor must file compliance reports that show what actions the company took during the year to demonstrate that each facility either met its intensity target for 2009 or took action to offset its emissions intensity. Compliance options available to Suncor include emission reductions, utilizing offset projects or contributing to a government climate change emission management fund at a present cost of $15/tonne.

For the compliance period of January 1 to December 31, 2009, the compliance costs to Suncor post-merger are estimated at between $3 million and $5 million. Final costs for 2009 will be determined when the company files its compliance report with the Province of Alberta in March 2010.

On April 26, 2007, the Federal Government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the Action Plan) also known as ecoACTION which includes the regulatory framework for air emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy using products.

The Government of Canada and the Province of Alberta released on January 31, 2008 the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among other things: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and (iii) targeting research to lower the cost of technology.

On March 10, 2008, the Government of Canada released "Turning the Corner – Taking Action to Fight Climate Change" (the Updated Action Plan) which provides some additional guidance with respect to the Government's plan to reduce Canada's 2006 greenhouse gas emissions levels by 20% by 2020 and by 60% to 70% by 2050.

The Updated Action Plan is primarily directed towards industrial emissions from certain specified industries including the oil sands, oil and gas and refining. The Updated Action Plan is intended to create a carbon emissions trading market, including an offset system, to provide an incentive to reduce greenhouse gas emissions and establish a market price for carbon. For the oil sands, its proposed application will be process-specific; oil sands plants built in 2012 and later, those which use heavier hydrocarbons, up-graders and in-situ production will have mandatory standards in 2018 that will be based on carbon capture and storage.

The Updated Action Plan is proposed to apply only to facilities exceeding a minimum annual emissions threshold: (i) 50,000 tonnes of CO_2 equivalent per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalent per upstream oil and gas facility; and (iii) 10,000 boe/d/company. These proposed thresholds are significantly stricter than the current Alberta regulatory threshold of 100,000 tonnes of CO_2 equivalent per year per facility.

Subsequent to the introduction of the Updated Action Plan, the Canadian federal government committed to implement a North American cap and trade system with the United States, and therefore it is currently not certain that the Updated Action Plan will be implemented as proposed or at all.

The United States federal and the Ontario provincial and Colorado state governments are also in various stages of developing greenhouse gas management legislation and regulation. At this time, no such legislation has been tabled in these jurisdictions and any potential impacts are unknown. The uncertainty and delay surrounding greenhouse gas management legislation in the U.S. has had a direct impact on Canadian greenhouse gas legislation. The Canadian government has gone on record as saying that they will delay implementing any specific greenhouse gas emissions legislation until after the U.S. implements its legislation, and that Canada is committed to having Canadian greenhouse gas legislation integrated and consistent with the U.S. legislation.

Additionally, in the United Kingdom, Phase II of the European Union Emissions Trading Scheme ('EU ETS') began in 2008 and will run until 2012. The EU ETS requires that member states set emissions limits for installations in their country covered by the

scheme and assigns such installations an emissions cap. Installations may meet their cap by reducing emissions or by buying allowances from other participants. Phase III of the EU ETS begins in 2013 and will run until 2020. The legislation has not been finalized but the emissions caps will likely be reduced under Phase III. Also, a review of regulations in the UK is currently underway which may impact the disposal of naturally occurring radioactive material (NORM). This review is currently in the consultation stages and, at this time, no such legislation has been tabled and any potential impacts are unknown.

At the end of 2009, the United Nations Climate Change Conference, commonly known as the Copenhagen Summit, was held in Copenhagen, Denmark. While an accord that endorses, among other things, the continuation of the Kyoto Protocol and the need for global emissions reductions was generally accepted by the member countries at the Copenhagen Summit, the accord is generally viewed as not being legally binding and does not contain any binding commitments for reducing carbon dioxide emissions. Canada subsequently committed to reducing its greenhouse gas emissions by 17% below 2005 levels by 2020, although it has not indicated how it will achieve gas reduction.

In addition, a number of frameworks and proposals were issued in 2009 by the various Canadian provincial regulators that oversee oil sands development. These relate to tailings management, water use and land use, to name a few. While the financial implications of such directives are not yet known, the company is committed to working with the appropriate regulatory bodies as they develop new policies and to fully complying with all existing and new regulations and directives as they apply to the company's operations.

In general, there remains uncertainty around the outcome and impacts of climate change and environmental laws and regulations (whether currently in force or proposed laws and regulations as described herein or future laws and regulations); it is not currently possible to predict either the nature of any requirements or the impact on the company and its business, financial condition, results of operations and cash flow at this time. We continue to actively work to mitigate our environmental impact, including taking action to reduce greenhouse gas emissions, investing in renewable forms of energy such as wind power and biofuels, accelerating land reclamation, installing new emission abatement equipment and pursuing other opportunities such as carbon capture and sequestration.

RISK FACTORS

As a company, we identify risks in four principal categories: 1) Operational; 2) Financial; 3) Legal and Regulatory; and 4) Strategic. These categories are defined below, and identified risks have been classified accordingly. Please note, identified risks could relate to multiple risk categories; we have classified risks based on the primary category to which they apply to Suncor.

We are continually working to mitigate the impact of potential risks to our business. This process includes an entity-wide risk review. The internal review is completed annually to help ensure that all significant risks are identified and appropriately managed.

1) Operational Risks – Risks that *directly* affect our ability to continue normal operations within our identified businesses.

Operating Hazards and Other Uncertainties. Each of our principal operating businesses, Oil Sands, Natural Gas, East Coast Canada, International and Refining and Marketing, demand significant levels of investment and therefore carry economic risks and opportunities. Generally, our operations are subject to hazards and risks such as fires, explosions, gaseous leaks, migration of harmful substances, blowouts, power outages and oil spills, any of which can cause personal injury, damage to property, information technology systems and related data and control systems, equipment and the environment, as well as interrupt operations. In addition, all of our operations are subject to all of the risks connected with transporting, processing and storing crude oil, natural gas and other related products. Risks associated with access to skilled labour to support our operations in a safe and effective manner are also discussed in "Labour and Materials Supply", below.

At Oil Sands, mining oil sands and producing bitumen through in-situ methods, extracting bitumen from the oil sands, and upgrading bitumen into SCO and other products involve particular risks and uncertainties. Oil Sands is susceptible to loss of production, slowdowns, shutdowns or restrictions on our ability to produce higher value products due to the interdependence of its component systems. Severe climatic conditions at Oil Sands can cause reduced production during the winter season and in some situations can result in higher costs. While there are virtually no finding costs associated with oil sands resources, delineation of the resources, the costs associated with production, including mine development and drilling wells for SAGD operations and the 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.

There are risks and uncertainties associated with natural gas operations, including all of the risks normally associated with drilling for natural gas wells, the operation and development of such properties, including encountering unexpected formations or pressures, premature declines of reservoirs, fires, blow-outs, equipment failures and other accidents, sour gas releases, uncontrollable flows of crude oil, natural gas or well fluids, adverse weather conditions, pollution and other environmental risks.

Our Refining and Marketing business is subject to all of the risks normally inherent in the operation of a refinery, terminals, pipelines and other distribution facilities as well as service stations, including loss of product, slowdowns due to equipment failures, unavailability of feedstock, price and quality of feedstock or other incidents.

We are also subject to operational risks such as sabotage, terrorism, trespass, related damage to remote facilities, theft and malicious software or network attacks.

Losses resulting from the occurrence of any of these risks could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Foreign Operations. The company has operations in a number of countries with different political, economic and social systems. As a result, the company's operations and related assets are subject to a number of risks, which may include, among other things, currency restrictions and exchange rate fluctuations, loss of revenue, property and equipment as a result of expropriation, nationalization, war, insurrection and geopolitical and other political risks, increases in taxes and governmental royalties, renegotiation of contracts with governmental entities and quasi-governmental agencies, changes in laws and policies governing operations of foreign-based companies, economic and legal sanctions (such as restrictions against countries that the U.S. government may deem to sponsor terrorism) and other uncertainties arising from foreign government sovereignty over the company's international operations. If a dispute arises in the company's foreign operations, the company may be subject to the exclusive jurisdiction of foreign courts or may not be able to subject foreign persons to the jurisdiction of a court in the U.S. or Canada. Additionally, as a result of activities in these areas and a continuing evolution of an international framework for corporate responsibility and accountability for international crimes, the company could also be exposed to potential claims for alleged breaches of international law.

The company has operations in Libya, which is a member of OPEC, and may operate in other OPEC-member countries in the future. Production in those countries may be constrained by OPEC quotas.

Major Projects. There are certain risks associated with the execution of our major projects. These risks include: our ability to obtain the necessary environmental and other regulatory approvals; risks relating to schedule, resources and costs, including the availability and cost of materials, equipment and qualified personnel; the impact of general economic, business and market conditions; the impact of weather conditions; our ability to finance growth if commodity prices were to decline and stay at low levels for an extended period; risks relating to restarting projects placed in "safe mode", including increased capital costs; and the effect of changing government regulation and public expectations in relation to the impact of oil sands development on the environment. The commissioning and integration of new facilities within our existing asset base could cause delays in achieving targets and objectives. Management believes the execution of major projects presents issues that require prudent risk management. There are also risks associated with project cost estimates provided by us. Some cost estimates are provided at the conceptual stage of projects and prior to commencement or completion of the final scope design and detailed engineering needed to reduce the margin of error. Accordingly, actual costs can vary from estimates and these differences can be material. Losses resulting from the occurrence of any of these risks could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Insurance. Our involvement in the exploration for and development of oil and natural gas properties may result in the company becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. Although we maintain a risk management program, which includes an insurance component, such insurance may not provide adequate coverage in all circumstances, nor are all such risks insurable. Losses beyond the scope of insurance could have a material adverse effect on our business, financial condition, results of operations and cash flow. In 1990, 2003 and 2005, we formed three self-insurance entities to provide additional business interruption coverage for potential losses. In the first quarter of 2010, these three entities were merged into one single entity.

Confidentiality. Breach of confidentiality could place us at competitive risk if confidential operational information or proprietary intellectual property was improperly disclosed.

2) Financial Risks – Risks that directly affect our business and financial condition.

Capital Markets. The market events and conditions witnessed over the past two financial years, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility in commodity prices and increases in the rates at which we are able to borrow funds for our capital programs. While there have been recent signs which may suggest the beginning of a global economic recovery, there can be no certainty regarding the timing or extent of a potential recovery, and such continued uncertainty in the global economic situation means that the company, along with all other oil and gas entities, may continue to face restricted access to capital and increased borrowing costs. This could have an adverse effect on the company, as our ability to make future capital expenditures is dependent on, among other factors, the overall state of the capital markets and investor appetite for investments in the energy industry generally and our securities in particular.

The lending capacity of many financial institutions has diminished and risk premiums have increased. As future capital expenditures will be financed out of cash generated from operations and borrowings, our ability to do so is dependent on, among other factors, the overall state of the capital markets and investor appetite for investments in the energy industry generally and our securities in particular.

To the extent that external sources of capital become limited or unavailable or available on onerous terms, our ability to make capital investments and maintain existing properties may be impaired, and our business, financial condition, results of operations and cash flow may be materially adversely affected as a result. At December 31, 2009, we had approximately $4.2 billion of unused credit available under bank credit facilities. In addition, we have announced a planned divesture program which is expected to generate $2-4 billion in proceeds. Based on current funds available and expected cash from operations and the planned divesture program, we believe that we have sufficient funds available to fund our currently projected capital expenditures in 2010. If cash flow from operations is lower than expected or 2010 capital expenditures exceed current estimates, or if we incur major unanticipated expenses related to development or maintenance of our existing properties, we would need to undertake a serious evaluation of maintaining our capital program at planned levels and the possibility of adversely affecting our debt ratings should we seek additional capital. Choosing not to obtain the financing necessary for our capital expenditure plans may result in a delay in the planned development of production from our operations. This in turn could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Issuance of Debt. From time to time we may finance capital expenditures in whole or in part with debt, which may increase our debt levels above industry standards for oil and natural gas companies of similar size. Depending on future development plans, we may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither the company's articles nor its by-laws limit the amount of indebtedness that we may incur; however, we are subject to covenants in our existing bank facilities and seek to avoid onerous costs of debt. The level of our indebtedness from time to time, could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise and could negatively effect our debt ratings. This in turn, could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Debt Covenants. We currently have $7.5 billion in syndicated credit facilities with 19 banks expiring in 2013 and a bilateral credit facility of $61 million expiring in 2010 and approximately $13.9 billion in outstanding debt. We are required to comply with financial and operating covenants under these credit facilities and debt securities. We routinely review the covenants based on actual and forecast results and have the ability to make changes to our development plans and/or dividend policy to comply with covenants under the credit facilities. In the event that we do not comply with such covenants under the credit facilities and debt securities, our access to capital could be restricted or repayment could be required, which could have a material adverse effect on our business, financial condition, results of operations and cash flow. In addition, our inability to refinance expiring credit facilities on favorable terms, if at all or any restrictions imposed on our borrowings under these facilities due to covenant breaches or otherwise could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Hedging. The company monitors its exposure to variations in commodity prices, interest rates and foreign exchange rates. In response, the company periodically enters into physical delivery transactions for commodities at fixed or collared prices and into derivative financial instruments to reduce exposure to unfavourable movements in commodity prices, interest rates and foreign exchange rates. The terms of these contracts or instruments may limit the benefit of favourable changes in commodity prices, interest rates and currency values and may result in financial or opportunity loss due to delivery commitments, royalty rates and counterparty risks associated with the contracts.

Uncertainty of Reserve and Resource Estimates. The reserves estimates included in this AIF represent estimates only. There are numerous uncertainties inherent in estimating quantities and quality of these proved and probable reserves and resources, including many factors beyond our control.

In general, estimates of economically recoverable reserves and the future net cash flow from these assets are based upon a number of variable factors and assumptions, such as historical production from the properties, the assumed effect of regulation by governmental agencies, pricing assumptions, the timing and amount of capital expenditures, future royalties, future operating costs and yield rates for production of SCO from bitumen, all of which may vary considerably from actual results. The accuracy of any reserve and resource estimate is a matter of engineering interpretation and judgment and is a function of the quality and quantity of available data, which may have been gathered over time. In the oil sands business unit, reserve and resource estimates are based upon a geological assessment, including drilling and laboratory tests. These estimates also consider current production capacity and upgrading yields, current mine plans, operating life and regulatory constraints. The Firebag and MacKay River reserves and resource estimates are based upon a geological assessment of data gathered from evaluation drilling, the testing of core samples and seismic operations and demonstrated commercial success of the in-situ process. Our actual production, revenues, royalties, taxes and development and operating expenditures with respect to our reserves will vary from such estimates and such variances could be material. Production performance subsequent to the date of the estimate may justify revision, either upward or downward, if material. For these reasons, estimates of the economically recoverable reserves and resources attributable to any particular group of properties, and classification of such reserves and resources based on risk of recovery, prepared by different engineers or by the same engineers at different times, may vary substantially.

Actual production cash flow is derived from our oil and gas reserves and will vary from the estimates contained in the reserve evaluations, and such variations could be material. The reserve evaluations are based in part on the assumed success of activities we intend to undertake in future years. The reserves and estimated cash flow to be derived from the reserves contained in the reserve evaluations will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluations. The reserve evaluations are effective as of a specific effective date and has not been updated, and thus does not reflect changes in our reserves since that date.

Volatility of Crude Oil and Natural Gas Prices. Our future financial performance is closely linked to crude oil prices, and to a lesser extent, natural gas prices. The prices of these commodities can be influenced by global and regional supply and demand factors. Worldwide economic growth, political developments, compliance or non-compliance with quotas imposed upon members of the Organization of the Petroleum Exporting Countries and weather, among other things, can affect world oil supply and demand. Our natural gas price realizations are affected primarily by North American supply and demand and by prices of alternate sources of energy. All of these factors are beyond our control and can result in a high degree of price volatility not only in crude oil and natural gas prices, but also fluctuating price differentials between heavy and light grades of crude oil, which can impact prices for sour crude oil and bitumen. Oil and natural gas prices have fluctuated widely in recent years. Given the continued global economic uncertainty, we expect continued volatility and uncertainty in crude oil and natural gas prices and prices may remain at depressed levels in the near term and beyond. A prolonged period of low crude oil and natural gas prices could affect the value of our crude oil and gas properties and the level of spending on growth projects, and could result in curtailment of production on some properties. Accordingly, low crude oil prices in particular could have a material adverse effect on our business, financial condition, results of operations and cash flow. A key component of our business strategy is to target production of sufficient natural gas to meet or exceed internal demands for natural gas purchased for consumption in our oil sands operations, creating a natural price hedge which reduces our exposure to gas price volatility. However, there are no assurances that we will be able to continue to increase production to keep pace with growing internal natural gas demands.

We conduct an assessment of the carrying value of our assets to the extent required by Canadian generally accepted accounting principles. If crude oil and natural gas prices decline further or remain at low levels, the carrying value of our assets could be subject to downward revisions, and our earnings could be materially adversely affected.

Volatility of Downstream Margins. Our downstream business is sensitive to wholesale and retail margins for its refined products, including gasoline, diesel and asphalt. Margin volatility is influenced by, among other things, overall marketplace competitiveness, weather, the cost of crude oil (see "Volatility of Crude Oil and Natural Gas Prices" above) and fluctuations in supply and demand for refined products. We expect that margin and price volatility and overall marketplace competitiveness, including the potential for new market entrants, will continue. As a result, our operating results for our refining and marketing business unit can be expected to fluctuate and may be materially adversely affected.

Energy Trading Activities. The nature of energy trading activities creates exposure to significant financial risks. These include risks that: movements in prices or values could result in a financial loss to the company; a lack of counterparties, due to market conditions or otherwise could leave us unable to liquidate or offset a position, or unable to do so at or near the previous market price; we may not receive funds or instruments from our counterparty at the expected time; the counterparty could fail to perform an obligation owed to us; we may suffer a loss as a result of human error or deficiency in our systems or controls; or we may suffer a loss as a result of contracts being unenforceable or transactions being inadequately documented. A separate risk management function within the company develops and monitors practices and policies and provides independent verification and valuation of our trading and marketing activities. However, we may experience significant financial losses as a result of these risks, which may have a material adverse effect on our business, financial condition, results of operations and cash flow.

Exchange Rate Fluctuations. Our 2009 Consolidated Financial Statements are presented in Canadian dollars. Results of operations are affected significantly by the exchange rates between the Canadian dollar and the U.S. dollar, but are also affected by the exchange rates between the Canadian dollar, the Euro and the British pound. These exchange rates may vary substantially and may give rise to foreign currency exposure, either favourable or unfavourable, creating another element of uncertainty. To the extent such fluctuation is unfavourable, it may have a material adverse effect on our business, financial condition, results of operations and cash flow.

Dividends. Our payment of future dividends on our common shares will be dependent on, among other things, our financial condition, results of operations, cash flow, the need for funds to finance ongoing operations, debt covenants and other business considerations as the Board of Directors of the company considers relevant. There can be no assurance that we will continue to pay dividends in the future.

Interest Rate Risk. We are exposed to fluctuations in short-term Canadian interest rates as a result of the use of floating rate debt. We maintain a substantial portion of our debt capacity in revolving / floating rate bank facilities and commercial paper, with the remainder issued in fixed rate borrowings, which could increase the company's cost of capital and impact Suncor's financial performance. To manage such interest rate exposures, we occasionally enter into interest rate swap agreements and exchange contracts to either effectively fix the interest rate on floating rate debt or to float the interest rate on fixed rate debt.

Counterparties Exposure. In the normal course of business, the company enters into contractual relationships with counterparties in the energy industry and other industries, including counterparties to interest rate hedging, foreign exchange hedging and commodity derivative arrangements. If such counterparties do not fulfill their contractual obligations to the company, it may suffer losses, may have to proceed on a sole risk basis, may have to forego opportunities or may have to relinquish leases or blocks. While the company limits its exposure to any one counterparty to a level that management deems to be reasonable, losses due to counterparties failing to fulfill their contractual obligations may have material adverse effect on our business, financial condition, results of operations and cash flow.

3) Legal and Regulatory Risks – Risks that affect our ability to comply with regulatory and statutory requirements under applicable law.

Environmental Regulation and Risk. The company is subject to environmental regulation under a variety of Canadian, U.S., United Kingdom and other foreign, federal, provincial, territorial, state and municipal laws and regulations. These regulatory regimes are laws of general application that apply to us in the same manner as they apply to other international companies and enterprises in the energy industry. The regulatory regimes require us to obtain operating licenses and permits in order to operate and impose certain standards and controls on activities relating to mining, oil and gas exploration, development and production, and the refining, distribution and marketing of petroleum products and petrochemicals. Environmental assessments and regulatory approvals are generally required before initiating most new major projects or undertaking significant changes to existing operations. In addition to these specific, known requirements, we expect future changes to environmental legislation, including anticipated legislation for air pollution (Criteria Air Contaminants) and greenhouse gases that will impose further requirements on companies operating in the energy industry. See "Industry Conditions – Environmental Regulation" in this AIF.

Some of the issues that are or may in future be subject to environmental regulation include:

- the possible cumulative regional impacts of oil sands development;
- the manufacture, import, storage, treatment and disposal of hazardous or industrial waste and substances;
- the need to reduce or stabilize various emissions to air;
- withdrawals, use of, and discharges to, water;
- issues relating to land reclamation, restoration and wildlife habitat protection;
- reformulated gasoline to support lower vehicle emissions; and
- U.S. implementation of regulation or policy to limit its purchases of oil to oil produced from conventional sources, or U.S. state or federal calculation and regulation of fuel lifecycle carbon content.

Changes in environmental regulation could have a material adverse effect on us from the standpoint of product demand, product reformulation and quality, methods of production, distribution costs and financial results. For example, requirements for cleaner-burning fuels could cause additional costs to be incurred, which may or may not be recoverable in the marketplace. The complexity and breadth of these issues make it extremely difficult to predict their future impact on us. Management anticipates capital expenditures and operating expenses could increase in the future as a result of the implementation of new and increasingly stringent environmental regulations. Compliance with environmental regulation can require significant expenditures and failure to comply with environmental regulation may result in the imposition of fines and penalties, liability for clean up costs and damages and the loss of important licenses and permits, which may in turn, have a material adverse effect on our business, financial condition, results of operations and cash flow.

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so called "greenhouse gases". Our exploration and production facilities and other operations and activities emit greenhouse gases and may require us to comply with the new regulatory framework announced as part of the Updated Action Plan which is intended to force large industries to reduce emissions of greenhouse gases, in addition to the Federal Government's proposed *Clean Air Act* (Alberta) of 2006 and Action Plan and Alberta's recently enacted *Climate Change and Emissions Management Act* and *Specified Gas Emitters Regulation*. However, subsequent to the introduction of the Updated Action Plan, the Canadian federal government committed to implement a North American cap and trade system with the United States. More recently, the Canadian federal government has committed to aligning its greenhouse gas legislation with U.S. legislation and therefore it is currently not certain that Updated Action Plan will be implemented as proposed or at all. See "Industry Conditions – Environmental Regulation" in this AIF. Although it is too early to predict the exact costs of compliance, it is likely that compliance costs will increase. The direct or indirect costs of these regulations may have a material adverse effect on our business, financial condition, results of operations and cash flow.

A new reclamation liability management program is under review by the Province of Alberta. The new program would involve increased reporting of progressive reclamation, an asset/liability based risk assessment and consideration of reserve life. Partial security could be required if reclamation targets are not met and full security may eventually be required. On October 15, 2009, Suncor applied to the Energy Resources Conservation Board (ERCB) and Alberta Environment (AENV) for permission to amend its existing and/or approved operations east of the Athabasca River to move from the currently adopted tailings management system, being the use of a consolidated tailings (CT) process to consolidate mature fine tailings (MFT), to Suncor's new Tailings Reduction Operations (TRO) strategy, based on MFT drying. This application is currently pending ERCB and AENV approval.

In addition, over the past few years legislation has been passed in Canada and the United States to reduce allowable levels of sulphur in transportation fuels. For a discussion of projects completed at our refining and marketing operations, see the information under Refining and Marketing in the "Three-Year History" section of this AIF. Projects to retrofit existing facilities to comply with these standards are subject to all risks inherent in large capital projects, and to the additional risk that failure to meet legislated deadlines could have a material impact on the company's ability to market its products, or subject the company to fines and penalties potentially having a material adverse effect on our business, financial condition, results of operations and cash flow.

Our Refining and Marketing business' U.S. operations are subject to Consent Decrees with the United States Environmental Protection Agency, the United States Department of Justice and the State of Colorado. The company is subject to the risk that failure to meet remaining obligations or the deadlines under these Consent Decrees could have a material impact on our ability to market our products, potentially having a material adverse effect on our business, financial condition, results of operations and cash flow.

In addition, our business could be materially adversely affected by the potential for lawsuits against greenhouse gas emitters, based on links drawn between greenhouse gas emissions and climate change. The company is also subject to the environmental laws in the international jurisdictions in which it operates and the costs of compliance with these laws and any changes to such laws could also materially adversely affect the company's results from operations. See "Industry Conditions – Environmental Regulation" in this AIF.

Governmental Regulation. The company and the oil and gas industry generally, operates under federal, provincial, state and municipal legislation in numerous countries. This industry is also subject to regulation and intervention by governments in such matters as land tenure, royalties, taxes (including income taxes), government fees, production rates, environmental protection controls, the reduction of greenhouse gas and other emissions, the export of crude oil, natural gas and other products, the awarding or acquisition of exploration and production, oil sands or other interests, the imposition of specific drilling obligations, control over the development and abandonment of fields and mine sites (including restrictions on production) and possibly expropriation or cancellation of contract rights. Before proceeding with most major projects, including significant changes to existing operations, we must obtain regulatory approvals. The regulatory approval process can involve stakeholder consultation, environmental impact assessments and public hearings, among other things. In addition, regulatory approvals may be subject to conditions including security deposit obligations and other commitments. Failure to obtain regulatory approvals, or failure to obtain them on a timely basis on satisfactory terms, could result in delays, abandonment or restructuring of projects and increased costs, all of which could have a material adverse effect on our business, financial condition, results of operations and cash flow. Such regulations may be changed from time to time in response to numerous factors, including economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the crude oil and natural gas industry could reduce demand for crude oil and natural gas, increase our costs and have a material adverse effect on our business, financial condition, results of operations and cash flow.

U.S. Policies. The U.S. government has passed legislation that may be interpreted as limiting the purchase of oil and related refined products by governmental agencies to oil and related refined products produced from conventional sources, rather than oil from the oil sands. Although we continue to focus on mitigating our business impact to air, water and land, current and future U.S. environmental laws, regulations and policies may impact or limit our current business plans and/or reduce demand for our products. As a result, our business, financial condition, results of operations and cash flow could be adversely affected.

Land Claims. First Nations peoples have claimed aboriginal title and rights to portions of western Canada. In addition, First Nations peoples have filed claims against industry participants relating in part to land claims, which may affect our business. However, at the present time, we are unable to assess the effect, if any, that these land claims may have on our business.

Alberta Crown Royalties. The following risk factors could cause royalty expenses to differ materially from current estimates and impact the royalties payable to the Crown:

- The Alberta government enacted new Bitumen Valuation Methodology (Ministerial) Regulations as part of the implementation of the New Royalty Framework effective January 1, 2009. These interim regulations determine the valuation of bitumen for 2009 and 2010. The final regulations are being developed by the Crown that will establish the bitumen valuation methodology for future years. For Suncor's mining operations, the bitumen valuation methodology is based on the terms of Suncor's Amending Agreement, which we believe places certain limitations on the interim bitumen valuation methodology as recently enacted. For the year 2009, Suncor filed a non-compliance notice with the Crown, citing that reasonable adjustments in the determination of the Suncor bitumen value were not considered by the Crown as permitted by Suncor's Amending Agreement. A similar non-compliance notice has been filed by Syncrude in respect of the determination of the bitumen value under its agreements with the Crown. The final determination of these matters may have a material impact on future royalties payable to the Crown;

- The government enacted the new Oil Sands Allowed Costs (Ministerial) Regulations as part of the implementation of the New Royalty Framework effective January 1, 2009. Further clarification of some Allowed Cost business rules is still expected. The terms of Suncor's Royalty Amending Agreement, and the similar agreement entered into by Syncrude, determine the royalty obligation through 2015 for the mining operations. However, potential changes and the interpretation of the Allowed Cost regulations could, over time, have a significant impact on the amount of royalties payable; and

- Changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs for each oil sands project; changes to the New Royalty Framework by the Government of Alberta; changes in other legislation; and the occurrence of unexpected events.

See "Industry Conditions – Royalties and Incentives" in this AIF.

East Coast Canada Royalties. The government of Newfoundland and Labrador and Suncor are in discussions to resolve several outstanding issues that impact current and prior years. Settlement of these issues could impact royalty payments to the Crown. In addition, changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs for each project; changes resulting from regulatory audits of prior year filings; further changes to applicable royalty regimes by the government of Newfoundland and Labrador; changes in other legislation and the occurrence of unexpected events could impact royalty payments to the Crown.

See "Industry Conditions – Royalties and Incentives" in this AIF.

International Royalties. Changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs; changes resulting from regulatory audits of prior year filings; further changes to applicable royalty regimes by governments or other applicable regulatory bodies; changes in other legislation and the occurrence of unexpected

events all have the potential to have an impact on royalties payable in respect of our international operations. See "Industry Conditions – Royalties and Incentives" in this AIF.

Control Environment. Based on their evaluation as of December 31, 2009, our chief executive officer and chief financial officer concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the United States *Securities Exchange Act of 1934* (the Exchange Act)) are effective to ensure that information required to be disclosed by us in reports that we file or submit to Canadian and U.S. securities authorities is recorded, processed, summarized and reported within the time periods specified in Canadian and U.S. securities laws. In addition, as of December 31, 2009, there were no changes in our internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) – 15d-15(f)) that occurred during the year ended December 31, 2009 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. We will continue to periodically evaluate our disclosure controls and procedures and internal control over financial reporting and will make any modifications from time-to-time as deemed necessary.

Management continues to integrate Petro-Canada's historical internal control over financial reporting with Suncor's internal control over financial reporting. This integration will lead to changes in these controls in future fiscal periods but management does not yet know whether these changes will materially affect the company's internal control over financial reporting. Management expects this integration process to be completed during 2010.

Based on their inherent limitations, disclosure control and procedures and internal controls over financial reporting may not prevent or detect misstatements and even those controls determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

4) Strategic Risks – Risks that affect our ability to meet long-term goals and planning initiatives.

Dependence on Oil Sands Business. Our significant capital commitment to further our growth projects and sustain operations at our Oil Sands business may require us to forego investment opportunities in other segments of our operations. The completion of future projects to increase production at Oil Sands business will further increase our dependence on the Oil Sands business. For example, in 2009, the Oil Sands business accounted for approximately 67% of our upstream production (2008 – 86%), 52% of our net earnings (2008 – 95%) and 36% of our cash flow from operations (2008 – 86%). Refer to "Non-GAAP Financial Measures" on page 5 of the AIF. These percentages have been determined excluding the Corporate, Energy Trading and Eliminations information and include twelve months of Suncor-legacy operations and five months of Petro-Canada-legacy operations.

Reclamation. There are risks associated with our ability to complete reclamation work, specifically reclaiming tailings ponds which contain water, clay and residual bitumen produced through the extraction process. To reclaim tailings ponds, we are using a process referred to as consolidated tailings (CT) technology. At this time, no ponds have been fully reclaimed using this technology. The success of the CT technology and time to reclaim the tailings ponds could increase or decrease the current asset retirement cost estimates. We continue to monitor and assess other possible technologies and/or modifications to the consolidated tailings process now being used. Regulatory approval of our North Steepbank extension of mine is subject to certain conditions related to the performance of CT technology. Our failure to adequately implement our reclamation plans could have a material adverse effect on our business, financial condition, results of operations and cash flow.

In February 2009, the Energy Resources Conservation Board (ERCB) released a directive, Tailings Performance Criteria and Requirements for Oil Sands Mining Schemes. The directive establishes performance criteria for CT operations, a requirement for specific approval and monitoring of CT ponds, a requirement for reporting tailings plans, and changes to the ERCB annual mine plan requirements and approval process to regulate tailings operations. We are currently assessing the impact of the directive.

On October 15, 2009, the company applied to the ERCB and Alberta Environment (AENV) for permission to amend its existing and/or approved operations east of the Athabasca River to move from the currently approved tailings management system, being the use of CT technology to consolidate mature fine tailings (MFT), to the company's new planned Tailings Reduction Operations (TRO) strategy, based on MFT drying. This application is currently pending ERCB and AENV approval.

Integration Risk. The company completed the merger with Petro-Canada in order to strengthen its position in the oil and natural gas industry and to create the opportunity to realize certain benefits, including cost savings and other operational synergies. Achieving the benefits of the merger depends in part on the ability of Suncor to effectively capitalize on its scale, scope and leadership position in the oil sands industry, to realize the anticipated capital and operating synergies, to profitably sequence the growth prospects of its asset base, to execute planned divestments and to maximize the potential of its improved growth opportunities and capital funding opportunities as a result of combining the businesses and operations of Suncor and Petro-Canada. A variety of factors, including those risk factors set forth in this AIF, may adversely affect the ability to achieve the anticipated benefits of the merger.

The ability to realize the benefits of the merger will also depend in part on successfully consolidating functions and integrating operations, procedures and personnel in a timely and efficient manner, as well as on Suncor's ability to realize the anticipated

growth opportunities and synergies from integrating Suncor's and Petro-Canada's businesses. This integration is ongoing and requires the dedication of substantial management effort, time and resources which may divert management's focus and resources from other strategic opportunities, and from operational matters during this process. The integration process may result in the loss of key employees and the disruption of ongoing business, customer and employee relationships that may adversely affect the ability of Suncor to achieve the anticipated benefits of the merger.

Interdependence of Oil Sands Systems. Our Oil Sands business is susceptible to loss of production due to the interdependence of its component systems. Through growth projects, we expect to further mitigate adverse impacts of interdependent systems and to reduce the production and cash flow impacts of complete plant-wide shutdowns. For example, we added a second upgrader, which provides us with the flexibility to conduct periodic plant maintenance on one operation while continuing production and cash flow generation from the other. Our inability to sufficiently manage these risks could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Need to Replace Conventional Reserves. Future conventional oil and natural gas reserves and production from our East Coast, International and Natural Gas business unit are highly dependent on our successful discovery or acquisition of additional reserves and exploitation of our current reserve base. Without conventional oil and natural gas reserve additions through exploration and development or acquisitions, our conventional oil and natural gas reserves and production will decline over time as reserves are depleted. Decline rates will vary with the nature of the reservoir, life-cycle of the well and other factors. Therefore, historical decline rates are not necessarily indicative of future performance. Exploring for, developing and acquiring reserves is highly capital intensive. To the extent cash flow from operations [(1)] is unable to generate sufficient capital and external sources of capital become limited or unavailable, our ability to make the necessary capital investments to maintain and expand our conventional oil and natural gas reserves could be impaired. In addition, the long-term performance of the conventional oil and natural gas business is dependent on our ability to consistently and competitively find and develop low-cost, high-quality reserves that can be economically brought on stream. There can be no assurance that we will be able to find and develop or acquire additional reserves to replace production at acceptable costs.

Competition. The petroleum industry is highly competitive globally in all aspects, including the exploration for, and the development of, new sources of supply, the acquisition of crude oil and natural gas interests and the refining, distribution and marketing of petroleum products and chemicals. We compete in virtually every aspect of our business with other energy companies. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers. We believe the primary competition for our crude oil production are major international oil and natural gas producers.

A number of other companies have entered or have indicated their intention to enter the oil sands business and begin producing bitumen and SCO or expand their existing operations. While this activity has declined with the corresponding decline in economic conditions, it is expected to resume once there is more market certainty. It is difficult to assess the number, level of production and ultimate timing of all potential new projects or when existing production levels may increase. The Canadian Association of Petroleum Producers estimates that Canada's production of bitumen and upgraded SCO could increase from approximately 1.2 million bpd in 2007 to approximately 3 million bpd by 2020 [(2)]. Increasing industry consolidation, a global focus on oil sands and additional competitors with financial capacity has, over the past number of years: (a) materially increased the supply of bitumen and SCO and other competing crude oil products in the marketplace; (b) exponentially increased land values and availability of new leases; and (c) placed stress on the availability and cost of all resources required to build and run new and existing oil sands operations. If we are unable to transport our produced crude oil products, production levels may be adversely affected.

---

(1) Refer to "Non GAAP Financial Measures" on page 5 of this AIF.

(2) Canadian Association of Petroleum Producers' Canadian Crude Oil Forecast and Market Outlook, 5 June 2009.

Historically, the industry-wide oversupply of refined petroleum products and the overabundance of retail outlets have kept downward pressure on downstream refining and retail margins. Management expects that fluctuations in demand for refined products, margin volatility and overall marketplace competitiveness will continue. In addition, to the extent that our downstream business unit participates in new product markets, it could be exposed to margin risk and volatility from either cost and/or selling price fluctuations.

Labour and Materials Supply. The successful operation of the company's business and ability to expand its operations will depend upon the availability of, and competition for, skilled labour and materials supply. The demand for skilled labour ability is and the supply remains limited, even in uncertain economic conditions, and there is a risk that we may have difficulty sourcing the required labour for current and future operations. As well, materials may be in short supply due to smaller labour forces in many manufacturing operations. Our ability to operate safely and effectively and complete all our projects on time and on budget has the potential to be significantly impacted by these risks. Risks associated with completion of significant capital projects are discussed in "Major Projects" above.

Constraints. Pipeline capacity constraints combined with plant capacity constraints could negatively impact our ability to produce at capacity levels in our crude oil and natural gas business. See "Industry Conditions – Pipeline Capacity".

Technology Risk. There are risks associated with growth and other capital projects that rely largely or partly on new technologies and the incorporation of such technologies into new or existing operations, particularly as the results of the technology in real-world applications may differ from test environments. The success of projects incorporating new technologies, such as in-situ technology, cannot be assured.

In-Situ Recovery. Current steam-assisted gravity drainage (SAGD) technologies for in-situ recovery of heavy oil and bitumen are energy intensive, requiring significant consumption of natural gas and other fuels in the production of steam which is used in the recovery process. The amount of steam required in the production process can also vary and impact costs. The performance of the reservoir can also impact the timing and levels of production using this technology. While SAGD technology is now being used by several producers, commercial application of this technology is still in the early stages relative to other methods of production and accordingly, in the absence of an extended operating history, there can be no assurances with respect to the sustainability of SAGD operations.

Reliance on Key Personnel. Our success depends in a large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse effect on the company. The contributions of the existing management team to the immediate and near-term operations of the company are likely to continue to be of central importance for the foreseeable future. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that we will be able to continue to attract and retain all personnel necessary for the development and operation of our business.

Labour Relations. Hourly employees at our Oil Sands facility near Fort McMurray, Alberta, our London, Ontario terminal operation, our Sarnia, Ontario refinery, our Commerce City, Colorado refinery, our Montreal refinery, our Terra Nova FPSO, certain of our lubricants operations, certain of our terminalling operations and at Sun-Canadian Pipeline Company Limited are represented by labour unions or employee associations. Approximately 87% of our unionized employees are members of the Communications Energy and Paperworkers Union (CEP). Three-year collective bargaining agreements with most CEP locals will expire in 2010. Negotiations are ongoing. Any work interruptions involving our employees, and/or contract trades utilized in our projects or operations, could have a material adverse effect on our business, financial condition, results of operations and cash flow. See "Suncor Employees" in this AIF.

DIVIDENDS

Our Board of Directors has established a policy of paying dividends on a quarterly basis. We review our policy from time to time in light of our financial position, financing requirements for growth, cash flow and other factors which our Board of Directors considers relevant. Our Board of Directors approved an increase in the quarterly dividend to $0.10 per share* from $0.05 per share* in the third quarter of 2009 and an increase in the quarterly dividend to $0.05 per share* from $0.04 per share* in the second quarter of 2007.

The following table sets forth the per share* amount of dividends we paid to shareholders during the last three years.

	Year Ended December 31,		
	2009	2008	2007
Common shares			
Cash dividends**	$0.30	$0.20	$0.19
Dividends paid in common shares	—	—	—

* Per share amounts have been adjusted to reflect a two-for-one share split in May 2008.

** Petro-Canada declared dividends in an aggregate amount of $0.40 per share for the first two quarters of 2009, which amount is not included in the above table.

DESCRIPTION OF CAPITAL STRUCTURE

General Description of Capital Structure

The company's authorized share capital is comprised of an unlimited number of common shares, an unlimited number of preferred shares issuable in series designated as senior preferred shares and an unlimited number of preferred shares issuable in series designated as junior preferred shares. As at December 31, 2009, there were 1,559,778,481 common shares issued and outstanding. To the knowledge of the Board of Directors and executive officers of Suncor, no person beneficially owns or exercises control or direction over securities carrying 10% or more of the voting rights attached to any class of voting securities of the company. The holders of common shares are entitled to attend all meetings of shareholders and vote at any such meeting on the basis of one vote for each common share held. As no senior preferred shares or junior preferred shares are issued and outstanding, common shareholders are entitled to receive any dividend declared by the Board of Directors on the common shares and to participate in a distribution of the company's assets among its shareholders for the purpose of winding up its affairs. The holders of the common shares shall be entitled to share equally, share for share, in all distributions of such assets.

Constraints

The *Petro-Canada Public Participation Act* requires that the Articles of Suncor include certain restrictions on the ownership and voting of voting shares of the company. The common shares of Suncor are voting shares.

No person, together with associates of that person, may subscribe for, have transferred to that person, hold, beneficially own or control otherwise than by way of security only, or vote in the aggregate, voting shares of Suncor to which are attached more than 20% of the votes attached to all outstanding voting shares of Suncor. Additional restrictions include provisions for suspension of voting rights, forfeiture of dividends, prohibitions against share transfer, compulsory sale of shares, and redemption and suspension of other shareholder rights. The Board of Directors may at any time require holders of, or subscribers for, voting shares, and certain other persons, to furnish statutory declarations as to ownership of voting shares and certain other matters relevant to the enforcement of the restrictions. Suncor is prohibited from accepting any subscription for, and issuing or registering a transfer of, any voting shares if a contravention of the individual ownership restrictions results.

Suncor's Articles, as required by the *Petro-Canada Public Participation Act*, also include provisions requiring Suncor to maintain its head office in Calgary, Alberta; prohibiting Suncor from selling, transferring or otherwise disposing of all or substantially all of its assets in one transaction, or several related transactions, to any one person or group of associated persons, or to non-residents, other than by way of security only in connection with the financing of Suncor; and requiring Suncor to ensure (and to adopt, from time to time, policies describing the manner in which Suncor will fulfill the requirement to ensure) that any member of the public can, in either official language of Canada (English and French), communicate with and obtain available services from Suncor's head office and any other facilities where Suncor determines there is significant demand for communication with, and services from, that facility in that language.

Ratings

The following table shows the ratings issued by the rating agencies noted therein as of December 31, 2009. The credit ratings are not recommendations to purchase, hold or sell the debt securities inasmuch as such ratings do not comment as to the

market price or suitability for a particular investor. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant.

	Moody's Investors Service (Moody's)	Standard & Poor's (S&P)	Dominion Bond Rating Service (DBRS)
Outlook	Stable	Stable	Stable
Senior unsecured	Baa2	BBB+	A (low)
Commercial Paper	—	A-1 (Low)	R-1 (low)

Dominion Bond Rating Service's (DBRS) credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. A rating of A (low) by DBRS is the third highest of ten categories and is assigned to debt securities considered to be of satisfactory credit quality. Protection of interest and principal is still substantial, but the degree of strength is less than with AA rated entities. Entities in the A category are considered to be more susceptible to adverse economic conditions and have greater cyclical tendencies than higher rated companies. The assignment of a "(high)" or "(low)" modifier within each rating category indicates relative standing within such category. The "high" and "low" grades are not used for the AAA or D catagories.

Moody's credit ratings are on a long-term debt rating scale that ranges from AAA to C, which represents the range from highest to lowest quality of such securities rated. A rating of Baa2 by Moody's is the fourth highest of nine categories. Obligations rated Baa are subject to moderate credit risk. They are considered medium-grade and as such may possess certain speculative characteristics. Moody's appends numerical modifiers 1, 2 or 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Standard and Poor's (S&P) credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. A rating of BBB+ by S&P is the fourth highest of ten categories and indicates that the obligor exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation. The addition of a plus (+) or minus (-) designation after a rating indicates the relative standing within a particular rating category.

DBRS's commercial paper credit ratings are on a short-term debt rating scale that ranges from R-1 (high) to D, which represent the range from highest to lowest quality of such securities rated. A rating of R-1 (low) by DBRS is the third highest of ten categories and is assigned to debt securities considered to be of satisfactory credit quality. The overall strength and outlook for key liquidity, debt, and profitability ratios is not normally as favourable as with higher rating categories, but these considerations are still respectable, and any qualifying negative factors that exist are considered manageable, and the entity is normally of sufficient size to have some influence in its industry.

S&P's commercial paper credit ratings are on a short-term debt rating scale that ranges from A-1 (High) to D, which represent the range from highest to lowest quality of such securities rated. A short-term obligation rated A-1 is rated as the highest of eight categories by Standard & Poor's. A short-term obligation rated "A-1 (Low)" is slightly more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher rating categories. However, the obliger's capacity to meet its financial commitment on the obligation is satisfactory. Obligations rated "A-1 (Low)" on the Canadian commercial paper rating scale would qualify for a rating of "A-2" on Standard & Poor's global short-term rating scale.

MARKET FOR OUR SECURITIES

Price Range and Trading Volume of Common Shares

Our common shares are listed on the Toronto Stock Exchange in Canada, and on the New York Stock Exchange in the United States.

Toronto Stock Exchange

	Price Range ($Cdn)		
	High	Low	Trading Volume (000's)
2009			
January	29.78	22.00	104,250
February	27.25	21.15	112,120
March	34.22	23.50	192,482
April	32.17	27.44	117,944
May	39.98	30.87	121,417
June	40.13	31.84	122,525
July	36.84	29.90	115,715
August [1]	37.30	33.38	108,182
September	39.84	32.76	115,893
October	40.79	34.66	94,602
November	39.24	34.72	100,098
December	39.50	35.33	83,079

New York Stock Exchange

	Price Range ($Cdn)		
	High	Low	Trading Volume (000's)
2009			
January	25.31	17.37	229,625
February	22.34	16.95	207,281
March	27.92	18.21	341,981
April	26.44	21.61	188,623
May	36.53	25.96	275,432
June	36.93	27.56	233,009
July	34.09	25.51	240,720
August [1]	35.05	30.41	135,886
September	37.31	29.60	164,879
October	39.62	31.84	160,307
November	37.37	32.18	153,070
December	37.80	33.38	123,552

(1) The merger with Petro-Canada occurred August 1, 2009

Prior Sales

Except as disclosed herein and other than the approximately 1,568,322,051 common shares issued pursuant to the merger of Suncor and Petro-Canada on August 1, 2009 (actual number subject to rounding), no securities of the company were issued in 2009. Approximately 621,141,900 common shares were issued to former Petro-Canada shareholders and approximately 937,180,151 common shares were issued to former (pre-merger) Suncor shareholders.

During the twelve months prior to the date of this AIF, Suncor issued common shares pursuant to the exercise of outstanding options and pursuant to Suncor's dividend reinvestment plan. For information in respect of such issuances, see Note 15 to Suncor's audited annual consolidated financial statements for the year ended December 31, 2009, which are incorporated by reference into this AIF.

DIRECTORS AND EXECUTIVE OFFICERS

Directors

The following individuals are directors of Suncor.

Name and Jurisdiction of Residence	Period Served and Independence	Principal Occupations During Past Five Years
Mel E. Benson [3][4] Alberta, Canada	Director since 2000 Independent	Mel Benson is president of Mel E. Benson Management Services Inc., an international management consulting firm based in Calgary, Alberta. In 2000, Mr. Benson retired from a major international oil company. Mr. Benson is a director of Tenax Energy Inc., a director of Winalta Homes Inc. and director of the Fort McKay Group of Companies, a community trust. He is active with several charitable organizations including Hull Family Services. He is also a member of the board of governors for the Northern Alberta Institute of Technology.
Brian A. Canfield [1][4] Washington, USA	Director since 1995 Independent	Brian Canfield is the chairman of TELUS Corporation, a telecommunications company. Beginning his career with TELUS as a telephone installer in 1956, Mr. Canfield rose through the corporate ranks to occupy positions as COO, President and CEO. Mr. Canfield is a member of the Order of Canada, a member of the Order of British Columbia and a fellow of the Institute of Corporate Directors. He was also the first businessperson to receive an honorary Doctorate of Technology from the BC Institute of Technology.
Dominic D`Alessandro [1][2] Ontario, Canada	Director since 2009 Independent	Dominic D'Alessandro was president and chief executive officer of Manulife Financial Corporation from 1994 to 2009 and is currently a director of CGI Group Inc. and Canadian Imperial Bank of Commerce. For his many business accomplishments, Mr. D'Alessandro was recognized as Canada's Most Respected CEO in 2004 and CEO of the Year in 2002, and was inducted into the Insurance Hall of Fame in 2008. Mr. D'Alessandro is an officer of the Order of Canada and has been appointed as a Commendatore of the Order of the Star of Italy. In 2009, he received the Woodrow Wilson Award for Corporate Citizenship and in 2005 was granted the Horatio Alger Award for community leadership. Mr. D'Alessandro is an FCA and holds a Bachelor of Science from Concordia University in Montreal. He has also been awarded honorary doctorates from York University, the University of Ottawa, Ryerson University and Concordia University.
John T. Ferguson [5] Alberta, Canada	Director since 1995 Independent	John Ferguson is founder and chairman of the board of Princeton Developments Ltd. and Princeton Ventures Ltd. Mr. Ferguson is also a director of Fountain Tire Ltd., the Royal Bank of Canada and Strategy Summit Ltd. In addition, he is a board member of the Alberta Bone and Joint Institute, an advisory member of the Canadian Institute for Advanced Research and chancellor emeritus and chairman emeritus of the University of Alberta. Mr. Ferguson is a fellow of the Alberta Institute of Chartered Accountants and of the Institute of Corporate Directors.
W. Douglas Ford [2][3] Florida, USA	Director since 2004 Independent	W. Douglas Ford was chief executive, refining and marketing for BP p.l.c. from 1998 to 2002 and was responsible for the refining, marketing and transportation network of BP as well as the aviation fuels business, the marine business and BP shipping. Mr. Ford currently serves as a director of USG Corporation and Air Products and Chemicals Inc. He is also a director of the Home Run Inn and a member of the board of trustees of the University of Notre Dame.
Richard L. George Alberta, Canada	Director since 1991 Non-independent, management	Richard George is the president and chief executive officer of Suncor Energy Inc. Mr. George is also a director of the Swiss offshore and onshore drilling company Transocean Ltd. He currently serves as the Canadian Chair of the North American Competitiveness Council and he chaired the 2008 Governor General's Canadian Leadership Conference. Mr. George was named a member of the Order of Canada in 2007.

Paul Haseldonckx [1][4] Essen, Germany	Director since 2002 (Petro-Canada 2002 to July 31, 2009) Independent	Paul Haseldonckx was a director of Petro-Canada and a member of the management board of Veba Oel AG, Germany's largest downstream company, including the ubiquitous Aral AG gas stations in Europe. Mr. Haseldonckx represented Veba's interests at the board of the Cerro Negro joint venture, an in situ oil sands development including an upgrader, during the construction and early production phase. Mr. Haseldonckx holds a Master of Science and completed Executive Programs at INSEAD, Fontainebleau and IMD, Lausanne.
John R. Huff [3][4] Texas, USA	Director since 1998 Independent	John Huff is chairman of Oceaneering International Inc., an oilfield services company. He also serves as director of BJ Services Company and KBR Inc.
Jacques Lamarre [3][4] Quebec, Canada	Director since 2009 Independent	Jacques Lamarre was the president and chief executive officer of SNC-Lavalin from 1996 to 2009. Mr. Lamarre is an officer of the Order of Canada and a founding member and past chair of the Commonwealth Business Council. He is also past chair of the Board of Directors of the Conference Board of Canada and a founding member of the World Economic Forum's Governors for Engineering & Construction. Currently, he serves as a director of The Royal Bank of Canada and P3 Canada and as a member of the Engineering Institute of Canada, Engineers Canada and the Ordre des ingénieurs du Québec. Mr. Lamarre holds a Bachelor of Arts and a Bachelor of Arts and Science in Civil Engineering from Laval University in Quebec City. He also completed Harvard University's Executive Development Program. In addition, Mr. Lamarre holds honorary doctorates from the University of Waterloo and the University of Moncton.
Brian MacNeill [1][2] Alberta, Canada	Director since 1995 (Petro-Canada 1995 to July 31, 2009) Independent	Brian MacNeill was a director and chairman of the board of Petro-Canada and is a Chartered Accountant, a Certified Public Accountant and holds a Bachelor of Commerce. He is a director of TELUS Corporation, West Fraser Timber Co. Ltd., Capital Power Corp and Oilsands Quest Inc. Mr. MacNeill is a member of the Canadian Institute of Chartered Accountants and the Financial Executives Institute. He is also a fellow of the Alberta Institute of Chartered Accountants and of the Institute of Corporate Directors. Mr. MacNeill is also a member of the Order of Canada.
Maureen McCaw [3][4] Alberta, Canada	Director since 2004 [5] (Petro-Canada 2004 to July 31, 2009) Independent	Maureen McCaw was a director of Petro-Canada and is senior vice president (Edmonton) of Leger Marketing, formerly Criterion Research Corp., a company she founded in 1986. Ms. McCaw holds a Bachelor of Arts from the University of Alberta and an Institute of Corporate Directors certification (ICD.D). In addition to being president of Tinnakilly Inc. and a director of the Edmonton International Airport, Women Building Futures and Royal Alexandria Hospital, she is also managing partner at Prism Ventures. She is a past chair of the Edmonton Chamber of Commerce and serves on a number of Alberta boards and advisory committees.
Michael W. O'Brien [1][2] Alberta, Canada	Director since 2002 Independent	Michael O'Brien served as executive vice president, corporate development, and chief financial officer of Suncor Energy Inc. before retiring in 2002. Mr. O'Brien is lead director of Shaw Communications Inc. In addition, he is past chair of the board of trustees for Nature Conservancy Canada, past chair of the Canadian Petroleum Products Institute and past chair of Canada's Voluntary Challenge for Global Climate Change.
James Simpson [2][3] California, USA	Director since 2004 (Petro-Canada 2004 to July 31, 2009) Independent	James Simpson was a director of Petro-Canada and is past president of Chevron Canada Resources (oil and gas). He serves as Lead Director for Canadian Utilities Limited and is on its Corporate Governance, Nomination, Compensation and Succession Committee and Risk Review Committee, as well as being the chairman for the Audit Committee. Mr. Simpson holds a Bachelor of Science and Master of Science, and graduated from the Program for Senior Executives at M.I.T.'s Sloan School of Business. He is also past chairman of the Canadian Association of Petroleum Producers and past vice chairman of the Canadian Association of the World Petroleum Congresses.

Eira M. Thomas [1][2] British Columbia, Canada	Director since 2006 Independent	Eira Thomas assumed the role of executive chairman of Stornoway Diamond Corporation, a mineral exploration company, on January 1, 2009 after serving as chief executive officer since July 2003. Previously, Ms. Thomas was president of Navigator Exploration Corporation and chief executive officer of Stornoway Ventures Ltd. She is also a director of Strongbow Exploration Inc., Fortress Minerals Corp., Ashton Mining of Canada Inc. and Lucara Diamond Corp. In addition, Ms. Thomas is a director of the University of Toronto (U of T) Alumni Association, Lassonde Advisory Board of the U of T, Prospectors and Developers Association of Canada and the Northwest Territories and Nunavut Chamber of Mines. She also is a member of the U of T President's Internal Advisory Council.

(1) Audit Committee

(2) Governance Committee

(3) Human Resources and Compensation Committee

(4) Environment, Health, Safety and Sustainable Development Committee

(5) As chairman, by standing invitation, Mr. Ferguson is considered an ex-officio member of all committees

Corporate Officers

The following individuals are the executive officers of Suncor.

Name and Jurisdiction of Residence	Office [1]
Richard L. George Alberta, Canada	President and Chief Executive Officer
Ron A. Brenneman Alberta, Canada	Executive Vice Chairman
Steve W. Williams Alberta, Canada	Chief Operating Officer
Bart Demosky Alberta, Canada	Chief Financial Officer
Kirk Bailey Alberta, Canada	Executive Vice President, Oil Sands
Neil J. Camarta Alberta, Canada	Executive Vice President, Natural Gas
Boris Jackman Ontario, Canada	Executive Vice President, Refining and Marketing
Kevin D. Nabholz Alberta, Canada	Executive Vice President, Major Projects
Jay Thornton Alberta, Canada	Executive Vice President, Energy Supply, Trading and Development
Terrence J. Hopwood Alberta, Canada	Senior Vice President and General Counsel
Sue Lee Alberta, Canada	Senior Vice President, Human Resources and Public Affairs
Mark Little Alberta, Canada	Senior Vice President, International and Offshore
Mike MacSween Alberta, Canada	Senior Vice President, In-Situ
Harry Roberts Alberta, Canada	Senior Vice President, Integration
Andrew Stephens Alberta, Canada	Senior Vice President, Business Services
Eric Axford Alberta, Canada	Senior Vice President, Operations Support
Janice B. Odegaard Alberta, Canada	Corporate Secretary

Notes:

(1) This information reflects the positions of officers as at December 31, 2009.

The percentage of common shares of Suncor owned beneficially, directly or indirectly, or over which control or direction is exercised by Suncor's directors and executive officers, as a group, is less than 1%.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

To the best of our knowledge, having made due inquiry, we confirm that, as at the date hereof:

(a) in the last ten years, no director or executive officer of Suncor is or has been a director or officer of another company or has owned a personal holding company that, while that person was acting in that capacity:

  (i) was the subject of a cease trade or similar order, or an order that denied the relevant issuer access to any exemption under Canadian securities legislation that was in effect for a period of more than 30 consecutive days;

  (ii) was subject to a cease trade order or an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days, after the director or executive officer ceased to be a director or executive officer, in the company and which resulted from an event that occurred while that person was acting in the capacity as a director or executive officer; or

  (iii) became bankrupt or made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets, other than Mr. Ford, a director of Suncor who is currently a director of USG Corporation, which was in bankruptcy protection until June, 2006 and who was also a director of United Airlines (until February 2006), which was in Chapter 11 bankruptcy protection until February, 2006.

(b) no director or executive officer of Suncor has:

  (i) been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or

  (ii) has been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision; and

(c) no director or executive officer of Suncor nor any personal holding company controlled by such person has become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director or executive officer.

Conflicts of Interest

No director or executive officer has any existing or potential direct or indirect material conflicts of interest in respect of any matter that has materially affected or will materially affect Suncor or any of its subsidiaries.

SUNCOR EMPLOYEES

The following table shows the distribution of employees among our business units and corporate office for the past two years.

	As at December 31,	
	2009[3]	2008
Oil Sands	4,616	3,903
Natural Gas	786	198
International & East Coast Canada	582	—
Refining and Marketing	3,347	1,112
Corporate [1]	3,647	1,585
Total [2]	12,978	6,798

Notes:

(1) Corporate employees include employees from our Major Projects group, which supports our business units, and employees from our Energy Supply, Trading and Development group.

(2) In addition to our employees, we also use independent contractors to supply a range of services.

(3) Includes employees added as a result of the merger with Petro-Canada.

Approximately 35% of the company's employees were covered by collective bargaining agreements in 2009.

The Communications, Energy and Paperworkers Union (CEP) Local 707 represent approximately 2,900 Oil Sands employees. A new collective agreement with the union was entered into effective May 1, 2007. The terms of the agreement include a wage increase of 7% in the first year and 6% in each of the following two years, as well as an initial lump sum payment. Approximately 22% of legacy Petro-Canada's employees were covered by collective bargaining agreements in 2009. Approximately 1,100 employees of legacy Petro-Canada's unionized employees (8% of the company's employees) were members of the CEP in 2009, which represents refinery, marketing, gas plant and offshore production workers. Three-year collective bargaining agreements with most CEP locals will expire in 2010.

Employee associations represent approximately 230 of Refining and Marketing's Sarnia refinery, London terminal and Sun-Canadian Pipe Line Company employees. In 2008, a four-year agreement that will be renegotiated in 2012 was signed with the Sarnia employee association. In 2006, a three-year agreement was signed with the Canadian Auto Workers Union (CAW) at the London terminal, and expired March 1, 2009. In January 2009, management received formal notification from CAW of its intention to bargain. The agreement with the employee association of Sun-Canadian Pipe Line Company was signed in 1993, and is renewed automatically each year unless terminated by written notice by either party at least 60 days prior to the anniversary date of the agreement. No notice has been received or given to date, and management believes the agreement will be automatically renewed on its anniversary. A collective agreement at legacy Petro-Canada's Montreal refinery was reached in December 2008, following a 13-month company-initiated work stoppage.

The United Steel Workers Union (USW) represents approximately 250 employees at Refining and Marketing's Commerce City, Colorado refining facilities. In February 2009, USW ratified a three-year contract which will expire in January 2012. Negotiations between legacy Petro-Canada and the union representing employees on the Terra Nova FPSO commenced well in advance of the contract expiry and a tentative agreement was reached in early 2009.

RELIANCE ON EXEMPTIVE RELIEF

We report our oil and gas reserves data in accordance with, and are relying on, the terms of the following Dual Decision Document: In the Matter of the Securities Legislation of Alberta and In the Matter of the Process for Exemptive Relief Applications in Multiple Jurisdictions and In the Matter of Suncor Energy Inc., November 16, 2009 which came into effect on December 28, 2009 (the "Decision Document").

Our reserves data consists of net proved working interest oil and gas reserve quantities relating to oil and gas operations, estimated as at December 31, 2009, using constant dollar cost and pricing assumptions for the first day of each month for the previous 12 months, and the related standardized measure.

Our estimates of reserves and related standardized measure of discounted future net cash flows (the "standardized measure") were evaluated or reviewed in accordance with the standards set out in the Canadian Oil and Gas Evaluation Handbook modified to the extent necessary to reflect the terminology and standards of U.S. disclosure requirements, including:

- the information required by the United States Financial Accounting Standards Board, including Topic 932;
- the information required by Subpart 1200 of Regulation S-K as promulgated by the SEC under the SEC final rule Modernization of Oil and Gas Reporting (December 31, 2008); and

- certain other information required in accordance with US disclosure practices.

If we had been reporting our reserves data in accordance with NI 51-101 and had not been relying on the terms of the Decision Document, we would have been required to report the following:

- proved and probable working interest oil and gas reserve quantities relating to oil and gas operations, gross and net, using forecast prices and costs for each of proved developed producing reserves, proved developed non-producing reserves, proved undeveloped reserves, proved reserves (in total), probable reserves (in total) and proved plus probable reserves (in total); and

- future net revenue attributable to the reserves categories referred to above, estimated using forecast prices and costs, before and after deducting future income tax expenses, calculated without discount and using discount rates of 5%, 10%, 15% and 20% on an aggregate and certain per unit value basis (10% discount), as well as certain elements of future net revenue calculation without discount.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate

The Audit Committee Mandate is attached as Schedule "B" to this AIF.

Composition of the Audit Committee

The Audit Committee is comprised of Mr. Canfield (Chairman), Mr. D'Alessandro, Mr. MacNeill, Mr. O'Brien, Mr. Haseldonckx and Ms. Thomas. All members are independent and financially literate. The education and expertise of each member is described under the heading "Directors and Executive Officers".

For the purpose of making appointments to the company's Audit Committee, and in addition to the independence requirements, all directors nominated to the Audit Committee must meet the test of financial literacy as determined in the judgment of the board of directors. Also, at least one director so nominated must meet the test of financial expert as determined in the judgment of the Board of Directors. The designated financial experts on the Audit Committee are Michael W. O'Brien and Dominic D'Alessandro.

Financial Literacy

Financial literacy can be generally defined as the ability to read and understand a balance sheet, an income statement and a cash flow statement. In assessing a potential appointee's level of financial literacy, the board of directors must evaluate the totality of the individual's education and experience including:

- the level of the person's accounting or financial education, including whether the person has earned an advanced degree in finance or accounting;

- whether the person is a professional accountant, or the equivalent, in good standing, and the length of time that the person actively has practiced as a professional accountant, or the equivalent;

- whether the person is certified or otherwise identified as having accounting or financial experience by a recognized private body that establishes and administers standards in respect of such expertise, whether that person is in good standing with the recognized private body, and the length of time that the person has been actively certified or identified as having this expertise;

- whether the person has served as a principal financial officer, controller or principal accounting officer of a corporation that, at the time the person held such position, was required to file reports pursuant to securities laws, and if so, for how long;

- the person's specific duties while serving as a public accountant, auditor, principal financial officer, controller, principal accounting officer or position involving the performance of similar functions;

- the person's level of familiarity and experience with all applicable laws and regulations regarding the preparation of financial statements that must be included in reports filed under securities laws;

- the level and amount of the person's direct experience reviewing, preparing, auditing or analyzing financial statements that must be included in reports filed under provisions of securities laws;

- the person's past or current membership on one or more audit committees of companies that, at the time the person held such membership, were required to file reports pursuant to provisions of securities laws;

- the person's level of familiarity and experience with the use and analysis of financial statements of public companies; and

- whether the person has any other relevant qualifications or experience that would assist him or her in understanding and evaluating the corporation's financial statements and other financial information and to make knowledgeable and thorough inquiries whether:
    - the financial statements fairly present the financial condition, results of operations and cash flows of the corporation in accordance with generally accepted accounting principles; and
    - the financial statements and other financial information, taken together, fairly present the financial condition, results of operations and cash flows of the corporation.

Audit Committee Financial Expert

An "Audit Committee Financial Expert" means a person who, in the judgment of the corporation's Board of Directors, has the following attributes:

a. an understanding of Canadian generally accepted accounting principles and financial statements;

b. the ability to assess the general application of such principles in connection with the accounting for estimates, accruals, and reserves;

c. experience preparing, auditing or analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by Suncor's financial statements, or experience actively supervising one or more persons engaged in such activities;

d. an understanding of internal controls and procedures for financial reporting; and

e. an understanding of audit committee functions.

A person shall have acquired the attributes referred to in items (a) through (e) inclusive above through:

a. education and experience as a principal financial officer, principal accounting officer, controller, public accountant or auditor or experience in one or more positions that involve the performance of similar functions;

b. experience actively supervising a principal financial officer, principal accounting officer, controller, public accountant, auditor or person performing similar functions;

c. experience overseeing or assessing the performance of companies or public accountants with respect to the preparation, auditing or evaluation of financial statements; or

d. other relevant experience.

Audit Committee Pre-Approval Policies for Non Audit Services

Our Audit Committee has considered whether the provision of services other than audit services is compatible with maintaining the auditors' independence and has a policy governing the provision of these services. A copy of our policy relating to Audit Committee approval of fees paid to our auditors, in compliance with the *Sarbanes Oxley Act of 2002* and applicable Canadian law, is attached as Schedule "A" to this AIF.

Fees Paid to Auditors

Fees payable to PricewaterhouseCoopers LLP in 2009 and 2008 are detailed below:

($)	2009	2008
Audit Fees	4,307,000	1,600,000
Audit-Related Fees	807,000	442,000
Tax Fees	—	7,000
All other Fees	164,000	13,000
Total	5,278,000	2,062,000

The nature of each category of fees is described below.

Audit Fees

Audit fees were paid for professional services rendered by the auditors for the audit of Suncor's annual financial statements or services provided in connection with statutory and regulatory filings or engagements.

Audit-Related Fees

Audit-related fees were paid for professional services rendered by the auditors for preparation of reports on specified procedures as they relate to joint venture audits and attest services not required by statute or regulation.

Tax Fees

Tax fees were paid for international tax planning, advice and compliance.

All Other Fees

Fees disclosed under "All Other Fees" were paid for subscriptions to auditor-provided and supported tools as well as externally-sourced, direct or indirect, internal audit services in legacy Petro-Canada businesses.

None of the services described under the captions "Audit-related Fees", "Tax Fees" and "All Other Fees" were approved by the Audit Committee pursuant to paragraph (c)(7)(i)(C) of Rule 2-01 of Regulation S-X.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings to which we are a party or of which any of our property is the subject, nor are there any proceedings known by us to be contemplated that involves a claim for damages exceeding 10% of our current assets. In addition, there have not been any (a) penalties or sanctions imposed against the company by a court relating to securities legislation or by a securities regulatory authority during our financial year, (b) penalties or sanctions imposed by a court or regulatory body against the company that would likely be considered important to a reasonable investor in making an investment decision, or (c) settlement agreements entered into by the company before a court relating to securities legislation or with a securities regulatory authority during your financial year.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director, executive officer, or any person or company that beneficially owns or controls or directs, directly or indirectly, more than 10% of our securities or any associate or affiliate of these persons has, or has had, any material interests in any transaction or any proposed transaction that has materially affected or is reaonsonably expected to materially affect us or any of our affiliates, within the three most recently completed financial years or during the current financial year.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for our common shares is Computershare Trust Company of Canada at its principal offices in Calgary, Montreal, Toronto and Vancouver and Computershare Trust Company Inc. in Denver, Colorado.

MATERIAL CONTRACTS

Other than the arrangement agreement entered into between Suncor Energy Inc. and Petro-Canada on March 22, 2009, of which a full summary of the particulars was included in the Joint Information and Proxy Circular of Suncor Energy Inc. and Petro-Canada dated April 29, 2009 (the Information Circular), as filed on SEDAR at www.sedar.com, described under the heading "*The Arrangement – The Arrangement Agreement*" on pages 60 to 67 of the Information Circular, which section of the Information Circular is incorporated by reference into this AIF, during the year ended December 31, 2009, we have not entered into any contracts, nor are there any contracts still in effect, that are material to our business, other than contracts entered into in the ordinary course of business.

INTERESTS OF EXPERTS

Reserve and resource estimates contained in this AIF are based upon reports prepared by GLJ Petroleum Consultants Ltd, Sproule Associates Ltd. and RPS Energy Plc., Suncor's Independent Reserve Engineering Evaluators. The 2009 Consolidated Financial Statements of the Company have been audited by PricewaterhouseCoopers LLP, Suncor's auditors. As at the date hereof, none of the partners, employees or consultants of GLJ, Sproule or RPS, respectively, as a group, through registered or beneficial interests, directly or indirectly, held, or are entitled to receive more than 1% of any class of our outstanding securities, including the securities of our associates and affiliates, and PricewaterhouseCoopers LLP has advised Suncor's Audit Committee that they are independent with respect to Suncor within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

DISCLOSURE PURSUANT TO THE REQUIREMENTS OF THE NEW YORK STOCK EXCHANGE

As a Canadian issuer listed on the New York Stock Exchange (the NYSE), we are not required to comply with most of the NYSE rules and listing standards and instead may comply with domestic requirements. As a foreign private issuer, we are only required to comply with three of the NYSE rules (i) have an audit committee that satisfies the requirements of the United States *Securities Exchange Act of 1934*; (ii) the Chief Executive Officer must promptly notify the NYSE in writing after an executive officer becomes aware of any material non-compliance with the applicable NYSE Rules; and (iii) provide a brief description of any significant differences between our corporate governance practices and those followed by U.S. companies listed under the NYSE. The company has disclosed in the corporate governance section of its website at www.suncor.com that, in certain instances, it is not required to obtain shareholder approval for material amendments to equity compensation plans and that Suncor, while in compliance with the independence requirements of applicable securities laws in Canada (specifically National Instrument 52-110 *Audit Committees*) and the U.S. (specifically Rule 10A-3 of the *Securities Exchange Act of 1934*), it has not adopted the director independence standards contained in Section 303A.02 of the NYSE's Listed Company Manual. Except as described, the company is in compliance with the NYSE corporate governance standards in all other significant respects.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities, securities authorized for issuance under equity compensation plans and interests of insiders in material transactions, where applicable, is contained in our most recent management proxy circular for our most recent annual meeting of our shareholders that involved the election of directors. Additional financial information is provided in our 2009 Consolidated Financial Statements and MD&A for our most recently completed financial year.

Further information about Suncor, filed with Canadian securities commissions and the SEC, including periodic quarterly and annual reports and the Annual Information Form (AIF/40-F) is available online on SEDAR at www.sedar.com and www.sec.gov. In addition, our Standards of Business Conduct Code is available online at www.suncor.com. Information contained in or otherwise accessible through our website does not form part of this AIF, and is not incorporated into the AIF by reference.

SCHEDULE "A"

*****Approved and Accepted April 28, 2004*****

SUNCOR ENERGY INC.
POLICY AND PROCEDURES FOR PRE-APPROVAL OF AUDIT AND NON-AUDIT SERVICES

Pursuant to the *Sarbanes-Oxley Act of 2002* and Multilateral Instrument 52-110, the Securities and Exchange Commission and the Ontario Securities Commission respectively has adopted final rules relating to audit committees and auditor independence. These rules require the Audit Committee of Suncor Energy Inc ("Suncor") to be responsible for the appointment, compensation, retention and oversight of the work of its independent auditor. The Audit Committee must also pre-approve any audit and non-audit services performed by the independent auditor or such services must be entered into pursuant to pre-approval policies and procedures established by the Audit Committee pursuant to this policy.

I. STATEMENT OF POLICY

The Audit Committee has adopted this Policy and Procedures for Pre-Approval of Audit and Non-Audit Services (the "Policy"), which sets forth the procedures and the conditions pursuant to which services proposed to be performed by the independent auditor will be pre-approved. The procedures outlined in this Policy are applicable to all Audit, Audit-Related, Tax Services and All Other Services provided by the independent auditor.

II. RESPONSIBILITY

Responsibility for the implementation of this Policy rests with the Audit Committee. The Audit Committee delegates its responsibility for administration of this policy to management. The Audit Committee shall not delegate its responsibilities to pre-approve services performed by the independent auditor to management.

III. DEFINITIONS

For the purpose of these policies and procedures and any pre-approvals:

a) "Audit services" include services that are a necessary part of the annual audit process and any activity that is a necessary procedure used by the auditor in reaching an opinion on the financial statements as is required under generally accepted auditing standards ("GAAS"), including technical reviews to reach audit judgment on accounting standards;

The term "audit services" is broader than those services strictly required to perform an audit pursuant to GAAS and include such services as:

i) the issuance of comfort letters and consents in connections with offerings of securities;

ii) the performance of domestic and foreign statutory audits;

iii) Attest services required by statute or regulation;

iv) Internal control reviews; and

v) Assistance with and review of documents filed with the Canadian Securities administrators, the Securities and Exchange Commission and other regulators having jurisdiction over Suncor and its subsidiaries, and responding to comments from such regulators;

b) "Audit-related services" are assurance (e.g. due diligence services) and related services traditionally performed by the external auditors and that are reasonably related to the performance of the audit or review of financial statements and not categorized under "audit fees" for disclosure purposes.

"Audit-related services" include:

i) employee benefit plan audits, including audits of employee pension plans;

ii) due diligence related to mergers and acquisitions;

iii) consultations and audits in connection with acquisitions, including evaluating the accounting treatment for proposed transactions;

iv) internal control reviews;

v) attest services not required by statute or regulation; and

vi) consultations regarding financial accounting and reporting standards;

Non-financial operational audits are not "audit-related" services;

c) "Tax services" include but are not limited to services related to the preparation of corporate and/or personal tax filings, tax due diligence as it pertains to mergers, acquisitions and/or divestitures and tax planning;

d) "All other services" consist of any other work that is neither an Audit service, nor an Audit-Related service nor a Tax service, the provision of which by the independent auditor is not expressly prohibited by Rule 2-01(c)(7) of Regulation S-X under the Securities and Exchange Act of 1934, as amended. (See Appendix A for a summary of the prohibited services.)

IV. GENERAL POLICY

The following general policy applies to all services provided by the independent auditor:

- All services to be provided by the independent auditor will require specific pre-approval by the Audit Committee. The Audit Committee will not approve engaging the independent auditor for services which can reasonably be classified as "tax services" or "all other services" unless a compelling business case can be made for retaining the independent auditor instead of another service provider.

- The Audit Committee will not provide pre-approval for services to be provided in excess of twelve months from the date of the pre-approval, unless the Audit Committee specifically provides for a different period.

- The Audit Committee has delegated authority to pre-approve services with an estimated cost not exceeding $100,000 in accordance with this Policy to the Chairman of the Audit Committee. The delegate member of the Audit Committee must report any pre-approval decision to the Audit Committee at its next meeting.

- The Chairman of the Audit Committee may delegate his authority to pre-approve services to another sitting member of the Audit Committee provided that the recipient has also been delegated the authority to act as Chairman of the Audit Committee in the Chairman's absence. A resolution of the Audit Committee is required to evidence the Chairman's delegation of authority to another Audit Committee member under this policy.

- The Audit Committee will, from time to time, but no less than annually, review and pre-approve the services that may be provided by the independent auditor.

- The Audit Committee must establish pre-approval fee levels for services provided by the independent auditor on an annual basis. On at least a quarterly basis, the Audit Committee will be provided with a detailed summary of fees paid to the independent auditor and the nature of the services provided and a forecast of fees and services that are expected to be provided during the remainder of the fiscal year.

- The Audit Committee will not approve engaging the independent auditor to provide any prohibited non-audit services as set forth in Appendix A.

- The Audit Committee shall evidence their pre-approval for services to be provided by the independent auditor as follows:

  a) In situations where the Chairman of the Audit Committee pre-approves work under his delegation of authority, the Chairman will evidence his pre-approval by signing and dating the pre-approval request form, attached as Appendix B. If it is not practicable for the Chairman to complete the form and transmit it to the company prior to engagement of the independent audit, the Chairman may provide verbal or email approval of the engagement, followed up by completion of the request form at the first practical opportunity.

  b) In all other situations, a resolution of the Audit Committee is required.

- All audit and non-audit services to be provided by the independent auditors shall be provided pursuant to an engagement letter that shall:

  a) be in writing and signed by the auditors

  b) specify the particular services to be provided

  c) specify the period in which the services will be performed

  d) specify the estimated total fees to be paid, which shall not exceed the estimated total fees approved by the Audit Committee pursuant to these procedures, prior to application of the 10% overrun.

  e) include a confirmation by the auditors that the services are not within a category of services the provision of which would impair their independence under applicable law and Canadian and U.S. generally accepted accounting standards.

- The Audit Committee pre-approval permits an overrun of fees pertaining to a particular engagement of no greater than 10% of the estimate identified in the associated engagement letter. The intent of the overrun authorization is to ensure on an interim basis only, that services can continue pending a review of the fee estimate and if required, further Audit Committee approval of the overrun. If an overrun is expected to exceed the 10% threshold, as soon as the overrun is identified, the Audit Committee or its designate must be notified and an additional pre-approval obtained prior to the engagement continuing.

V. RESPONSIBILITIES OF EXTERNAL AUDITORS

To support the independence process, the independent auditors will:

a) Confirm in each engagement letter that performance of the work will not impair independence;

b) Satisfy the Audit Committee that they have in place comprehensive internal policies and processes to ensure adherence, world-wide, to independence requirements, including robust monitoring and communications;

c) Provide communication and confirmation to the Audit Committee regarding independence on at least a quarterly basis;

d) Maintain registration by the Canadian Public Accountability Board and the U.S. Public Company Accounting Oversight Board;

e) Review their partner rotation plan and advise the Audit Committee on an annual basis.

In addition, the external auditors will:

a) Provide regular, detailed fee reporting including balances in the "Work in Progress" account;

b) Monitor fees and notify the Audit Committee as soon as a potential overrun is identified.

VI. DISCLOSURES

Suncor will, as required by applicable law, annually disclose its pre-approval policies and procedures, and will provide the required disclosure concerning the amounts of audit fees, audit-related fees, tax fees and all other fees paid to its outside auditors in its filings with the Securities and Exchange Commission.

* * *

Appendix A

Prohibited Non-Audit Services

An external auditor is not independent if, at any point during the audit and professional engagement period, the auditor provides the following non-audit services to an audit client.

Bookkeeping or other services related to the accounting records or financial statements of the audit client. Any service, unless it is reasonable to conclude that the results of these services will not be subject to audit procedures during an audit of Suncor's financial statements, including:

- Maintaining or preparing the audit client's accounting records;
- Preparing Suncor's financial statements that are filed with the Securities and Exchange Commission ("SEC") or that form the basis of financial statements filed with the SEC; or
- Preparing or originating source data underlying Suncor's financial statements.

Financial information systems design and implementation. Any service, unless it is reasonable to conclude that the results of these services will not be subject to audit procedures during an audit of Suncor's financial statements, including:

- Directly or indirectly operating, or supervising the operation of, Suncor's information system or managing Suncor's local area network; or
- Designing or implementing a hardware or software system that aggregates source data underlying the financial statements or generates information that is significant to Suncor's financial statements or other financial information systems taken as a whole.

Appraisal or valuation services, fairness opinions or contribution-in-kind reports. Any appraisal service, valuation service or any service involving a fairness opinion or contribution-in-kind report for Suncor, unless it is reasonable to conclude that the results of these services will not be subject to audit procedures during an audit of Suncor's financial statements.

Actuarial services. Any actuarially-oriented advisory service involving the determination of amounts recorded in the financial statements and related accounts for Suncor other than assisting Suncor in understanding the methods, models, assumptions, and inputs used in computing an amount, unless it is reasonable to conclude that the results of these services will not be subject to audit procedures during an audit of Suncor's financial statements.

Internal audit outsourcing services. Any internal audit service that has been outsourced by Suncor that relates to Suncor's internal accounting controls, financial systems, or financial statements, unless it is reasonable to conclude that the result of these services will not be subject to audit procedures during an audit of Suncor's financial statements.

Management functions. Acting, temporarily or permanently, as a director, officer, or employee of Suncor, or performing any decision-making, supervisory, or ongoing monitoring function for Suncor.

Human resources.

- Searching for or seeking out prospective candidates for managerial, executive, or director positions;
- Engaging in psychological testing, or other formal testing or evaluation programs;
- Undertaking reference checks of prospective candidates for an executive or director position;
- Acting as a negotiator on Suncor's behalf, such as determining position, status or title, compensation, fringe benefits, or other conditions of employment; or
- Recommending, or advising Suncor to hire a specific candidate for a specific job (except that an accounting firm may, upon request by Suncor, interview candidates and advise Suncor on the candidate's competence for financial accounting, administrative, or control positions.)

Broker-dealer, investment adviser or investment banking services. Acting as a broker-dealer (registered or unregistered), promoter, or underwriter, on behalf of Suncor, making investment decisions on behalf of Suncor or otherwise having discretionary authority over Suncor's investments, executing a transaction to buy or sell Suncor's investment, or having custody of Suncor's assets, such as taking temporary possession of securities purchased by Suncor.

Legal services. Providing any service to Suncor that, under circumstances in which the service is provided, could be provided only by someone licensed, admitted, or otherwise qualified to practice law in the jurisdiction in which the service is prohibited.

Expert services unrelated to the audit. Providing an expert opinion or other expert service for Suncor, or Suncor's legal representative, for the purpose of advocating Suncor's interest in litigation or in a regulatory or administrative proceeding or investigation. In any litigation or regulatory or administrative proceeding or investigation, an accountant's independence shall not be deemed to be impaired if the accountant provides factual accounts, including testimony, of work performed or explains the positions taken or conclusions reached during the performance of any service provided by the accountant for Suncor.

Appendix B

Pre-approval Request Form

NATURE OF WORK	ESTIMATED FEES (Cdn $)
Total	

Date

Signature

SCHEDULE "B"

AUDIT COMMITTEE MANDATE

The Audit Committee

The by-laws of Suncor Energy Inc. provide that the Board of Directors may establish Board committees to whom certain duties may be delegated by the Board. The Board has established, among others, the Audit Committee, and has approved this mandate, which sets out the objectives, functions and responsibilities of the Audit Committee.

Objectives

The Audit Committee assists the Board of Directors by:

- monitoring the effectiveness and integrity of the Corporation's financial reporting systems, management information systems and internal control systems, and by monitoring financial reports and other financial matters.
- selecting, monitoring and reviewing the independence and effectiveness of, and where appropriate replacing, subject to shareholder approval as required by law, external auditors, and ensuring that external auditors are ultimately accountable to the Board of Directors and to the shareholders of the Corporation.
- reviewing the effectiveness of the internal auditors, excluding the Operations Integrity Audit department, which is specifically within the mandate of the Environment, Health, Safety & Sustainable Development Committee (references throughout this mandate to "Internal Audit" shall not include the Operations Integrity Audit department); and
- approving on behalf of the Board of Directors certain financial matters as delegated by the Board, including the matters outlined in this mandate.

The Committee does not have decision-making authority, except in the very limited circumstances described herein or where and to the extent that such authority is expressly delegated by the Board of Directors. The Committee conveys its findings and recommendations to the Board of Directors for consideration and, where required, decision by the Board of Directors.

Constitution

The Terms of Reference of Suncor's Board of Directors set out requirements for the composition of Board Committees and the qualifications for committee membership, and specify that the Chair and membership of the committees are determined annually by the Board. As required by Suncor's by-laws, unless otherwise determined by resolution of the Board of Directors, a majority of the members of a committee constitute a quorum for meetings of committees, and in all other respects, each committee determines its own rules of procedure.

Functions and Responsibilities

The Audit Committee has the following functions and responsibilities:

Internal Controls

1. Inquire as to the adequacy of the Corporation's system of internal controls, and review the evaluation of internal controls by Internal Auditors, and the evaluation of financial and internal controls by external auditors.
2. Review management's monitoring of compliance with the Corporation's Standards of Business Conduct Code.
3. Establish procedures for the confidential submission by employees of complaints relating to any concerns with accounting, internal control, auditing or Standards of Business Conduct Code matters, and periodically review a summary of complaints and their related resolution.
4. Review the findings of any significant examination by regulatory agencies concerning the Corporation's financial matters.
5. Periodically review management's governance processes for information technology resources, to assess their effectiveness in addressing the integrity, the protection and the security of the Corporation's electronic information systems and records.
6. Review the management practices overseeing officers' expenses and perquisites.

External and Internal Auditors

7. Evaluate the performance of the external auditors and initiate and approve the engagement or termination of the external auditors, subject to shareholder approval as required by applicable law.

8. Review the audit scope and approach of the external auditors, and approve their terms of engagement and fees.

9. Review any relationships or services that may impact the objectivity and independence of the external auditor, including annual review of the auditor's written statement of all relationships between the auditor (including its affiliates) and the Corporation; review and approve all engagements for non-audit services to be provided by external auditors or their affiliates.

10. Review the external auditor's quality control procedures including any material issues raised by the most recent quality control review or peer review and any issues raised by a government authority or professional authority investigation of the external auditor, providing details on actions taken by the firm to address such issues.

11. Review and approve the appointment or termination of the Director, Internal Audit, and annually review a summary of the remuneration and performance of the Director, Internal Audit.

12. Review the Internal Audit Department Charter, and the plans, activities, organizational structure and qualifications of the Internal Auditors, and monitor the department's performance and independence.

13. Provide an open avenue of communication between management, the Internal Auditors or the external auditors, and the Board of Directors.

Financial Reporting and other Public Disclosure

14. Review the external auditor's management comment letter and management's responses thereto, and inquire as to any disagreements between management and external auditors or restrictions imposed by management on external auditors. Review any unadjusted differences brought to the attention of management by the external auditor and the resolution thereof.

16. Review with management and the external auditors the financial materials and other disclosure documents referred to in paragraph 16, including any significant financial reporting issues, the presentation and impact of significant risks and uncertainties, and key estimates and judgements of management that may be material to financial reporting including alternative treatments and their impacts.

17. Review and approve the Corporation's interim consolidated financial statements and accompanying management's discussion and analysis ("MD&A"). Review and make recommendations to the Board of Directors on approval of the Corporation's annual audited financial statements and MD&A, Annual Information Form and Form 40-F. Review other material annual and quarterly disclosure documents or regulatory filings containing or accompanying audited or unaudited financial information.

18. Review and approve the Corporation's policy on external communication and disclosure of material information, including the form and generic content of any quarterly earnings guidance and of any financial disclosure provided to investment analysts and rating agencies.

19. Review any change in the Corporation's accounting policies.

20. Review with legal counsel any legal matters having a significant impact on the financial reports.

Oil and Gas Reserves

20. Review with reasonable frequency Suncor's procedures for:

    (A) the disclosure, in accordance with applicable law, of information with respect to Suncor's oil and gas activities including procedures for complying with applicable disclosure requirements;

    (B) providing information to the qualified reserves evaluators ("Evaluators") engaged annually by Suncor to evaluate Suncor's reserves data for the purpose of public disclosure of such data in accordance with applicable law.

21. Annually approve the appointment and terms of engagement of the Evaluators, including the qualifications and independence of the Evaluators; review and approve any proposed change in the appointment of the Evaluators, and the reasons for such proposed change including whether there have been disputes between the Evaluators and management.

22. Annually review Suncor's reserves data and the report of the Evaluators thereon; annually review and make recommendations to the Board of Directors on the approval of (i) the content and filing by the company of a statement of reserves data ("Statement") and the report thereon of management and the directors to be included in or filed with the Statement, and (ii) the filing of the report of the Evaluators to be included in or filed with the Statement, all in accordance with applicable law.

Risk Management

23. Periodically review the policies and practices of the Corporation respecting cash management, financial derivatives, financing, credit, insurance, taxation, commodities trading and related matters. Oversee the Board's risk management governance model by conducting periodic reviews with the objective of appropriately reflecting the principal risks of the Corporation's business in the mandate of the Board and its committees.

Pension Plan

24. Review the assets, financial performance, funding status, investment strategy and actuarial reports of the Corporation's pension plan including the terms of engagement of the plan's actuary and fund manager.

Security

25. Review on a summary basis any significant physical security management, IT security or business recovery risks and strategies to address such risks.

Other Matters

27. Conduct any independent investigations into any matters which come under its scope of responsibilities.

28. Review any recommended appointees to the office of Chief Financial Officer.

29. Review and/or approve other financial matters delegated specifically to it by the Board of Directors.

Reporting to the Board

30. Report to the Board of Directors on the activities of the Audit Committee with respect to the foregoing matters as required at each Board meeting and at any other time deemed appropriate by the Committee or upon request of the Board of Directors.

Approved by resolution of the Board of Directors on August 1, 2009. (1)

---

(1) Previously revised on February 25, 2009

SCHEDULE "C"

MODIFIED FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Form 51-101F3, as modified in accordance with exemptions from National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") contained in Suncor Energy Inc., Re, 2009 ABASC 571 dated effective December 28, 2009, *In the Matter of Suncor Energy Inc.* (the "Decision Document").

Terms to which a meaning is ascribed in the Decision Document have the same meaning in this form.

Management of Suncor Energy Inc. (the "company") are responsible for the preparation and disclosure of information with respect to the company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) proved and probable oil and gas reserve quantities relating to oil and gas operations, estimated as at December 31, 2009 using an average constant dollar cost and pricing assumptions as of the first day of each calendar month in 2009, and the related standardized measure; and

(b) the Standardized Measure of Discounted Future Net Cash Flows relating to proved and probable oil and gas reserves.

GLJ Petroleum Consultants Ltd., Sproule Associates Limited and RPS Energy Inc., independent qualified reserves evaluators, have evaluated the company's reserves data. The report of the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this report.

The Audit Committee of the Board of Directors of the company has:

(a) reviewed the company's procedures for providing information to the independent qualified reserves evaluators;

(b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluators.

The Audit Committee of the Board of Directors has reviewed the company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Audit Committee, approved:

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(b) the filing of the report of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

Reserves data are estimates only and are not exact quantities. Because reserves data are based on judgments regarding future events, actually results will vary and such variations may be material.

"RICHARD L. GEORGE"

RICHARD L. GEORGE
President and Chief Executive Officer

"BART DEMOSKY"

BART DEMOSKY
Chief Financial Officer

"JOHN T. FERGUSON"

JOHN T. FERGUSON
Chairman of the Board of Directors

"BRIAN A. CANFIELD"

BRIAN A. CANFIELD
Chairman of the Audit Committee

March 5, 2010

SCHEDULE "D"

MODIFIED FORM 51-101F2
REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES EVALUATORS

Report on Reserves Data

Suncor Energy Inc.
P.O. Box 38
112 - 4th Avenue S.W.
Calgary, AB T2P 2V5

To: The Board of Directors of Suncor Energy Inc. (the "Company")

Re: Form 51-101F2, as modified in accordance with exemptions from National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") contained in Suncor Energy Inc., Re, 2009 ABASC 571 dated effective December 28, 2009, *In the Matter of Suncor Energy Inc.* (the "Decision Document")

We are providing this report in accordance with the terms of the Decision Document and any capitalized terms, not otherwise defined in this report, shall have the same meaning as set out in the Decision Document.

We have evaluated and reviewed the Company's reserves data as at December 31, 2009. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2009, estimated using constant prices and costs.

The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation and review.

We carried out our evaluation or review in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society) modified to the extent necessary to reflect the terminology and standards of US Disclosure Requirements.

Those standards require that we plan and perform an evaluation or review to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation or review also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook as modified to the extent necessary to reflect the terminology and standards of US Disclosure Requirements.

The following tables sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved and proved plus probable reserves, estimated using constant prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated and reviewed by us for the year ended December 31, 2009, and

identifies the respective portions thereof that we have evaluated or reviewed and reported on to the Company's Board of Directors:

Proved Reserves						
			Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) ($ millions)			
Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Audit/Evaluation/Review Report	Location of Reserves (Country or Foreign Geographic Area)	Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	December 31, 2009	Canada	—	14,258	18	14,276
Sproule Associates Limited	December 31, 2009	Canada & United States	—	4,438	—	4,438
RPS Energy Ltd.	December 31, 2009	International	—	3,480	1,476	4,938
Totals			—	22,176 (93.7%)	1,494 (6.3%)	23,652 (100%)

Proved plus Probable Reserves						
			Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) ($ millions)			
Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Audit/Evaluation/Review Report	Location of Reserves (Country or Foreign Geographic Area)	Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	December 31, 2009	Canada	—	18,879	20	18,899
Sproule Associates Limited	December 31, 2009	Canada & United States	—	7,601	—	7,601
RPS Energy Ltd.	December 31, 2009	International	—	5,687	3,038	8,725
Totals			—	32,167 (91.3%)	3,058 (8.7%)	35,225 (100%)

In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined by, and are in accordance with, the COGE Handbook as modified to the extent necessary to reflect the terminology and standards of US Disclosure Requirements. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

We have no responsibility to update our reports referred to in above for events and circumstances occurring after their respective preparation dates.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd.

"Dana B. Laustsen"

Dana B. Laustsen, P.Eng
Executive Vice-President
March 5, 2010

Sproule Associates Limited

"R. Keith MacLeod"

R. Keith MacLeod, P.Eng
President
March 5, 2010

RPS Energy Plc

"Dr. Graeme Simpson"

Dr. Graeme Simpson
Director, Advisory
March 5, 2010

SCHEDULE "E"

REPORT OF GLJ PETROLEUM CONSULTANTS LTD.

GLJ Petroleum Consultants

Principal Officers:
Harry Jung, P. Eng.
President, C.E.O.
Dana B. Laustsen, P. Eng.
Executive V.P., C.O.O.
Keith M. Braaten, P. Eng.
Executive V.P.

Officers / Vice Presidents:
Terry L. Aarsby, P. Eng.
Jodi L. Anhorn, P. Eng.
Neil I. Dell, P. Eng.
David G. Harris, P. Geol.
Myron J. Hladyshevsky, P. Eng.
Bryan M. Joa, P. Eng.
John H. Stilling, P. Eng.
Douglas R. Sutton, P. Eng.
James H. Willmon, P. Eng.

March 5, 2010
Project 1099570

The Board of Directors of Suncor Energy Inc.
Suncor Energy Inc.
P.O. Box 38
112 – 4th Avenue S.W.
Calgary, AB T2P 2V5

Dear Board Members:

Re: Third Party Report on Reserves

This report was prepared to satisfy requirements contained in Item 1202(a)(8) of U.S. Securities and Exchange Commission Regulation S-K and to provide the qualifications of the technical persons responsible for overseeing the reserve estimation process.

The numbering of items below corresponds to the requirements set out in Item 1202(a)(8) of Regulation S-K. Terms to which a meaning is ascribed in *Regulation S-K* and *Regulation S-X* have the same meaning in this report.

i. We have prepared an independent evaluation of certain reserves of Suncor Energy Inc. (the "Company") for the management and the board of directors of the Company. The primary purpose of our evaluation report was to provide estimates of reserves information in support of the Company's year-end reserves reporting requirements under U.S. and Canadian securities laws, specifically Regulation S-K, and for other internal business and financial needs of the Company.

ii. We have evaluated and reviewed certain reserves of the Company as at December 31, 2009. The completion (transmittal) date of our report is March 5, 2010.

iii. The attached table sets forth the total net after royalty reserves under constant prices and costs covered by our report by geographic area, and the proportion of the Company covered. All of the Company reserves covered by our report are located in Western Canada. We evaluated essentially all of the Company reserves covered by our report. We express no opinion on the portion of the Company's reserves that we did not evaluate

iv. Our report covered approximately 81% of the Company's total proved and total probable oil equivalent reserves, respectively. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") with the necessary modifications to reflect definitions and standards under the U.S. Financial Accounting Standards Board policies (the "FASB Standards") and the legal requirements under the U.S. Securities and Exchange Commission ("SEC requirements").

The royalty obligations on the oil sands mining and in-situ properties are determined on a bitumen project basis. Where subsequent upgrading of the bitumen is recognized in the reserves, the synthetic crude oil (SCO) reserves reflect both the yield on bitumen and product value differences. As a consequence of differences in revenue, the royalty percent is lower on an SCO basis than it is on bitumen.

The economic evaluations were prepared on a before income tax basis and only consider a portion of the Company's abandonment and reclamation obligations associated with the properties we evaluated. Costs relating to greenhouse gas (GHG) emissions were included for the Syncrude operation; they were not included for Suncor operated oil sands properties, in recognition of the level at which such costs have been reported and budgeted.

Data used in our evaluation were obtained from regulatory agencies, public sources and from Company personnel and Company files. In the preparation of our report we have accepted as presented, and have relied, without independent verification, upon a variety of information furnished by the Company such as interests and burdens, recent production, product transportation and marketing and sales agreements, historical revenue, capital costs, operating expense data, budget forecasts, capital cost estimates and well data for recently drilled wells. If in the course of our evaluation, the validity or sufficiency of any material information was brought into question, we did not rely on such information until such concerns were satisfactorily resolved.

The Company has warranted in a representation letter to us that, to the best of the Company's knowledge and belief, all data furnished to us was accurate in all material respects, and no material data relevant to our evaluation was omitted.

A field examination of all the evaluated properties was not performed nor was it considered necessary for the purposes of our report.

In our opinion, estimates provided in our report have, in all material respects, been determined in accordance with the applicable industry standards, and results provided in our report and summarized herein are appropriate for inclusion in filings under U.S. and Canadian securities laws, specifically Regulation S-K.

v. As required under SEC Regulation S-K, reserves are those quantities of oil and gas that are estimated to be economically producible under existing economic conditions. As specified, in determining economic production, constant product reference prices have been based on a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the effective date of our report. In our economic analysis, operating and capital costs are those costs estimated as applicable at the effective date of our report, with no future escalation. Where deemed appropriate, the capital costs and revised operating costs associated with the implementation of committed projects designed to modify specific field operations in the future may be included in economic projections.

vi. Our report has been prepared assuming the continuation of existing regulatory and fiscal conditions subject to the guidance in the COGE Handbook and SEC regulations. Notwithstanding that the Company currently has regulatory approval to produce the reserves identified in our report, there is no assurance that changes in regulation will not occur; such changes, which cannot reliably be predicted, could impact the Company's ability to recovery the estimated reserves.

vii. Oil and gas reserves estimates have an inherent degree of associated uncertainty the degree of which is affected by many factors. Reserves estimates will vary due to the limited and imprecise nature of data upon which the estimates of reserves are predicated. Moreover, the methods and data used in estimating reserves are often necessarily indirect or analogical in character rather than direct or deductive. Furthermore, the persons involved in the preparation of reserves estimates and associated information are required, in applying geosciences, engineering and evaluation principles, to make numerous unbiased judgments based upon their educational background, professional training, and professional experience. The extent and significance of the judgments to be made are, in themselves, sufficient to render reserves estimates inherently imprecise. Reserves estimates may change substantially as additional data becomes available and as economic conditions impacting oil and gas prices and costs change. Reserves estimates will also change over time due to other factors such as knowledge and technology, fiscal and economic conditions, and contractual, statutory and regulatory provisions.

viii. In our opinion, the reserves information evaluated by us have, in all material respects, been determined in accordance with all appropriate industry standards, methods and procedures applicable for the Company's filing of reserves information under U.S. and Canadian securities laws, specifically Regulation S-K.

ix. A summary of the Company reserves evaluated by us for item iii is attached.

GLJ is a private firm established in 1972 whose business is the provision of independent geological and engineering services to the petroleum industry. GLJ is among the largest evaluation firms in North America with approximately 70 professional engineering and geoscience personnel. GLJ evaluate the reserves of the four producing oil sands mining operations for various owners, and also prepare in-situ evaluations for a significant number of owners. Mr. Laustsen and Mr. Willmon were responsible for overseeing GLJ's reserves estimation process, with Mr. Laustsen addressing the In-Situ reserves, and Mr. Willmon addressing the Mining and North America Conventional Onshore reserves. Both responsible individuals are qualified, independent reserves evaluators as defined in COGEH, are registered Practicing Professional Engineers in the Province of Alberta, have in excess of 32 years of practical experience in petroleum engineering, and have been employed at GLJ as evaluators/auditors since 1982.

We trust this meets your current requirements.

Yours truly,

GLJ PETROLEUM CONSULTANTS LTD.

"James H. Willmon"

James H. Willmon, P. Eng.
Vice President

"Dana B. Laustsen"

Dana B. Laustsen, P. Eng.
Executive Vice President

GLJ Petroleum Consultants

Suncor Energy Inc.
SEC Net After Royalty Reserves Covered by GLJ Petroleum Consultants
Effective December 31, 2009

	Total Proved Reserves				
Location	**Oil & NGL MMbbl**	**SCO [1] MMbbl**	**Bitumen [2] MMbbl**	**Natural Gas Bcf**	**Oil Equivalent [3] MMbbl**
Mining		1,899			1,899
In Situ		506	411		917
NACO [4]	4			363	65
Total GLJ Coverage	4	2,405	411	363	2,881
Total Company Reserves [5]	294	2,565	411	1,692	3,552
Portion of Total Covered by GLJ	1%	94%	100%	21%	81%

	Total Probable Reserves				
Location	**Oil & NGL MMbbl**	**SCO [1] MMbbl**	**Bitumen [2] MMbbl**	**Natural Gas Bcf**	**Oil Equivalent [3] MMbbl**
Mining		524			524
In Situ		397	1,344		1,741
NACO [4]	2			117	22
Total GLJ Coverage	2	921	1,344	117	2,287
Total Company Reserves [5]	246	1,100	1,344	830	2,828
Portion of Total Covered by GLJ	1%	84%	100%	14%	81%

Notes:

1. Synthetic Crude Oil; liquid sales volumes after upgrading
2. portion of the in-situ bitumen production not forecast to be upgraded
3. Oil equivalence factors: Oil& NGL, SCO and Bitumen 1 bbl/bbl, Natural Gas 6 Mcf/bbl
4. North America Conventional Onshore; 97% evaluated, with balance reviewed
5. supplied by the company to derive portion of total covered by GLJ

SCHEDULE "F"

REPORT OF SPROULE ASSOCIATES LIMITED

Ref.: 0468.17530

March 5, 2010

The Board of Directors of Suncor Energy Inc.
Suncor Energy Inc.
P.O. Box 38
112 Fourth Avenue SW
Calgary AB T2P 2V5

Re: Evaluation of Certain Petroleum & Natural Gas Reserves of Suncor Energy Inc.
(As of December 31, 2009)

Dear Sirs:

At your request, we have independently evaluated certain proved and probable oil, natural gas, and natural gas liquids reserves of Suncor Energy Inc. ("Suncor"), as of December 31, 2009, in the properties located in the following regions:

East Coast, Canada;
North America Conventional Onshore; and
In Situ, Canada.

The purpose of this report is to summarize the results of our independent evaluations, to be included as an exhibit for Suncor's annual filings in accordance with U.S. and Canadian security laws and pursuant to the Securities and Exchange Commission ("SEC"), Modernization of Oil and Gas Reporting; Final Rule, December 31, 2008.

Summary of Conclusions

Our evaluation of these reserves was conducted during the period of September 2009 through January 2010. The results of our work are summarized in Table 1.

Table 1
Summary of Reserves Evaluated by Sproule
As of December 31, 2009

Geographical Area	Company Net Proved Reserves (After Royalty)					
	Oil & NGLs	SCO	Natural Gas	Total BOE	Portion Evaluated	Portion Reviewed
	MMbbl	MMbbl	Bcf	MMbbl	%	%
East Coast	67	0	0	67	100	0
North America Conventional Onshore	38	0	913	190	100	0
In Situ	0	160	0	160	100	0
Total	**105**	**160**	**913**	**417**		
Grand Total Suncor*	**294**	**2565**	**1692**	**3552**		
Proportion of Total Suncor Reserves	**36%**	**6%**	**54%**	**12%**		

Geographical Area	Company Net Probable Reserves (After Royalty)					
	Oil & NGLs	SCO	Natural Gas	Total BOE	Portion Evaluated	Portion Reviewed
	MMbbl	MMbbl	Bcf	MMbbl	%	%
East Coast	99	0	0	99	100	0
North America Conventional Onshore	13	0	376	76	100	0
In Situ	0	179	0	179	100	0
Total	**112**	**179**	**376**	**354**		
Grand Total Suncor*	**246**	**1100**	**830**	**2828**		
Proportion of Total Suncor Reserves	**46%**	**16%**	**45%**	**13%**		

* provided by Suncor

Assumptions, Data, Methods & Procedures

This report has been prepared by Sproule Associates Limited ("Sproule") using current geological and engineering knowledge, techniques and computer software. It has been prepared within the Code of Ethics of the Association of Professional Engineers, Geologists and Geophysicists of Alberta ("APEGGA"). For this evaluation, Sproule used the reserves evaluation model, Value Navigator (ValNav). This report adheres, in all material aspects, to the SEC, Modernization of Oil and Gas Reporting; Final Rule, December 31, 2008. Sproule used the methods and procedures that it considered necessary to prepare this report, as follows:

Reserves and Production

The oil and natural gas reserves were estimated volumetrically, from production decline curve analyses, using analogy techniques, or by material balance methods. Volumetric reserves were estimated using the net pay encountered at the wellbore and an assigned drainage area, or, where sufficient well data were available, using reservoir volumes calculated from isopach maps of net pay. Reservoir rock and fluid property data were obtained from available core analyses, well logs, PVT data, gas analyses, and published information, either from the pool in question or from a similar reservoir producing from the same zone. Reservoir pressures were derived from drillstem and AOF test data, pressure surveys, and published reports. Recovery factors for oil reserves were selected either from the results of detailed reservoir analyses, or by comparing the reservoir under study with similar reservoirs that have more firmly established recovery factors from extended production histories. Recovery factors for gas reserves were estimated by taking into consideration well depths, deliverability characteristics, product prices, and operating cost information.

The solution gas reserves were estimated based on current producing gas-oil ratios (GORs) and estimates of future oil production or volumetric calculations. Similarly, the natural gas by-product reserves were based on current recoveries and estimates of future gas production.

Forecasts of net revenue were prepared by predicting annual production from the reserves, and product prices. Annual production was forecast taking into account historical production trends of Suncor's producing wells, applicable regulatory conditions, existing or anticipated contract rates, and by comparison with other wells in the vicinity producing from similar reservoirs.

Historical Data, Interests and Burdens

All historical production, revenue and expense data, product prices actually received, and other data that were obtained from Suncor or from public sources, were accepted as represented, without any further investigation by Sproule Associates Limited.

Property descriptions, details of interests held, and well data, as supplied by Suncor, were accepted as represented. No investigation was made into either the legal titles held or any operating agreements in place relating to the subject properties.

Lessor and overriding royalties and other burdens were obtained from Suncor. No further investigation was undertaken by Sproule Associates Limited.

Operating Expenses

Suncor provided Sproule with recent revenue statements to determine certain economic parameters.

Capital Expenses

Capital expenses were based the capital program provided by Suncor, or on estimates by Sproule.

Abandonment

Well abandonment and disconnect costs were included for the North American Conventional Onshore and the In Situ properties. For these areas, our evaluation does not include well-site or facility reclamation costs. No abandonment costs were incorporated by Sproule for the East Coast property.

Economic Assumptions

This evaluation utilized constant prices and costs which were consistent with the new SEC guidance, which incorporates a twelve month average pricing mechanism. The prices used were supplied by Suncor, reviewed by Sproule for reasonableness and were accepted as represented.

Regulatory Considerations

In the conduct of our evaluation, we reviewed the ability of the booked reserves to be developed, produced and/or recovered based on current regulations existing in the jurisdictions where the assets reside. This review yielded no concerns with respect to Suncor's ability to develop, produce and/or recover the reserves as booked in the selected entities reported and reviewed. Down-spacing requirements or plans have already been approved or have significant offsetting precedents to indicate that such down-spacing requirements have a high degree of certainty to be approved when applied for.

Uncertainties of Forward-Looking Statements & Reserves Estimates

This report contains forward-looking statements including or incorporating expectations of future production revenues and capital expenditures. Information concerning reserves may also be deemed to be forward-looking as estimates involve the implied assessment that the reserves described can be profitably produced in future. These statements are based on current expectations that involve a number of risks and uncertainties, which could cause actual results to differ from those anticipated. These risks include, but are not limited to: the underlying risks of the oil and gas industry (i.e., corporate commitment, regulatory approval, operational risks in development, exploration and production); potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserves estimations; the uncertainty of estimates and projections relating to production; costs and expenses; health, safety and environmental factors; commodity prices; and exchange rate fluctuation.

The analysis of individual entities and properties as reported herein was conducted within the context and scope of an evaluation of a unique group of properties in aggregate. Use of this report outside of this scope may not be appropriate.

Actual future production may require that estimated trends be significantly altered. Reserve estimates from volumetric calculations and from analogies are often less certain than reserve estimates based on well performance obtained over a period during which a substantial portion of the reserves was produced.

The accuracy of reserves estimates and associated economic analysis is, in part, a function of the quality and quantity of available data and of engineering and geological interpretation and judgment. Given the data provided at the time this report was prepared, the estimates presented herein are considered reasonable. However, they should be accepted with the understanding that reservoir and financial performance subsequent to the date of the estimates may necessitate revision. These revisions may be material.

No limitations and/or restrictions were placed upon Sproule by the officials of Suncor in our independent reserves evaluation.

Sproule has no responsibility to update this evaluation for events and circumstances occurring after the date of this report.

Suncor provided all technical data, revenue and expense statements, budget and development strategy prior to December 31, 2009. Any information with a date of occurrence after December 31, 2009 was not considered in the evaluation.

Evaluator's Qualifications

The people primarily responsible for the evaluation were Doug W.C. Ho, P.Eng., VP Engineering – Unconventional; Matthew J. O'Blenes, P.Eng, Senior Associate – Canada; Scott W. Pennell, P.Eng., Supervisor – Unconventional Gas; and Cameron P. Six, P.Eng., Manager Engineering – Canada. Sproule's executive endorsement of the Report was provided by R. Keith MacLeod, P.Eng., President. The persons responsible for the preparation of the report are qualified reserves evaluators and auditors and are completely independent from Suncor in accordance with National Instrument 51-101.

Exclusivity

This report is solely for the information of Suncor and for the information and assistance of its independent public accountants in connection with their review of, and report upon, the financial statements of Suncor. Also, Sproule hereby provides permission for this report to be included as an exhibit for Suncor's annual filings in accordance with applicable U.S. and Canadian securities laws. This report should not be used, circulated or quoted for any other purpose without the express written consent of the undersigned or except as required by law. Our work papers and data are in our files and available for review upon request.

If you have any questions regarding the above, or if we can be of further assistance, please call us.

Sproule Associates Limited

Certification

Report Preparation

The report entitled "Evaluation of Certain Reserves of Suncor Energy Inc., (As of December 31, 2009)" was prepared by the following Sproule personnel:

"Doug W. C. Ho"

Doug W. C. Ho, P.Eng.
Vice-President, Engineering – Unconventional
05 / 03 /2010 dd/mm/yr

"Matthew J. O'Blenes"

Matthew J. O'Blenes, P.Eng.
Senior Associate
05 / 03 /2010 dd/mm/yr

"Scott W. Pennell"

Scott W. Pennell, P.Eng.
Supervisor, Unconventional Gas
05 / 03 /2010 dd/mm/yr

"Cameron P. Six"

Cameron P. Six, P.Eng.
Manager, Engineering – Canada
05 / 03 /2010 dd/mm/yr

Sproule Executive Endorsement

This report has been reviewed and endorsed by the following Executive of Sproule:

"R. Keith MacLeod"

R. Keith MacLeod, P.Eng.
President
05 / 03 /2010 dd/mm/yr

Permit to Practice

Sproule Associates Limited is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and our permit number is P00417.

Enclosure(s)
MJO-RKM
P:\Suncor 17530 WC 2009\Report – SEC summary all Regions\Suncor 2009 Summary for SEC March 5 2010.doc

SCHEDULE "G"

REPORT OF RPS ENERGY LTD.

Goldsworth House, Denton Way, Goldsworth Park, Woking, Surrey, GU2I 3LG, United Kingdom
T +44 (0)1483 746500 **F** +44 (0)1483 746505 **E** rpsenergy@rpsgroup.com **W** www.rpsgroup.com

March 5, 2010 Project Ref: ECV1516

Suncor Energy Inc.
P.O. Box 38
112 – 4 th Avenue S.W.
Calgary, AB T2P 2V5
Canada

To: The Board of Directors of Suncor Energy Inc.

INDEPENDENT EVALUATION AND REVIEW OF SUNCOR ENERGY'S RESERVES AS OF DECEMBER 31, 2009

At the request of Suncor Energy Inc. ("Suncor"), RPS Energy ("RPS") evaluated Suncor's reserves of oil, natural gas and natural gas liquids (NGLs), in selected "International" oil and gas properties, as of 31 st December, 2009. In addition, RPS carried out a review of Suncor's estimates of its reserves of oil, natural gas and natural gas liquids (NGLs) in its remaining "International" oil and gas properties. This letter summarizes the context, performance and findings of the RPS evaluation and review.

Context of Evaluation and Review

Suncor is a Canadian company which has securities that are traded on the Toronto Stock Exchange (TSX) and on the New York Stock Exchange (NYSE). Therefore, it must comply with Canadian securities laws, and is also subject to securities laws of the United States.

Canada's National Instrument 51-101 (NI 51-101), "Standards for Disclosure for Oil and Gas Activities", sets out Suncor's reserves reporting requirements. Suncor has applied for an exemption and received approval to disclose reserves in accordance with US Securities and Exchange Commission (SEC) rules (effective December 28 , 2009; in effect for 1 year):

- Citation: Suncor Energy Inc., Re. 2009 ABASC 571 Date: 20091116

Although Suncor uses its own staff to prepare some of its reserves estimates, its internal corporate governance practices require that independent qualified reserves evaluators or auditors must be used to confirm the quality of the company's reserves evaluation policies, practices and procedures. The objective of these activities is to provide the management and directors of Suncor with assurance that the reserves which have been estimated internally are materially correct.

Suncor has specified that for the year ending December 31, 2009 three of its "International" fields would be evaluated by an independent qualified reserves evaluator; for the remainder of its "International" fields the reserves have been evaluated by Suncor, with the results being reviewed by the independent qualified reserves evaluator. It is in this context, that RPS was retained by Suncor to evaluate the company's reserves in the selected properties, as of December 31, 2009, and to review the company's own estimates of reserves in the remaining"International" properties.

Suncor's "International"properties fall into two Geographical Areas ("North Sea" which covers the UK and Netherlands and "Other International"; which covers Libya, Syria and Trinidad & Tobago), and we understand from Suncor Energy that these properties represent approximately 7% of Suncor Energy's Net After Royalty reserves (when expressed as barrels of oil equivalent).

Applicable Reserves Definitions

As of the 1 st of January 2010 the SEC has issued new rules governing reporting oil and gas producing activities for companies with a financial year ending on or after December 31, 2009. RPS has used the following documents to interpret these rules and referenced collectively as SEC Rules 2009:

a) Modernization of Oil and Gas Reporting (29/12/08)
http://www.sec.gov/rules/final/2008/33-8995.pdf

b) Compliance and Disclosure Interpretations (26/10/09)
http://www.sec.gov/divisions/corpfin/guidance/regs-kinterp.htm

c) Staff Accounting Bulletin No 113 (29/10/09)
http://www.sec.gov/interps/account/sab113.htm

The reported reserve volumes evaluated by RPS have been estimated in accordance with the standards set out in those documents.

The reported reserve volumes evaluated by Suncor have been reviewed by RPS against the same standards, and the reserves are determined in a manner and standard consistent with RPS practice.

Reserve Information

Suncor provided RPS with (i) access to basic data and documentation pertaining to the "International" oil and gas properties being evaluated by RPS (ii) all Reserve Information prepared by Suncor in respect of its "International" oil and gas fields being reviewed by RPS, and (iii) access to Suncor personnel who might have information relevant to the evaluation or review of such basic data, documentation and Reserve Information.

Conduct of the Evaluation and Review

For the purpose of this Evaluation and Review, RPS's Primary Evaluators were Roy Wikramaratna and Graeme Simpson, whose qualifications are as follows:

- Roy Wikramaratna is a Principal Advisor and manager of the specialist reservoir engineering group at RPS's Winfrith office, with over 30 years experience in oil reservoir engineering and groundwater resource evaluation. He is a Member of the Energy Institute (MEI) and a Chartered Engineer (registration 569043) registered with the Engineering Council, UK.

- Graeme Simpson is a Director of RPS, with over 30 years of experience in exploration and production geoscience, with a major operator, in academia and through consultancy. He has a PhD in Geology. He is a Certified Petroleum Geologist (number 5926) with the American Association of Petroleum Geologists and a Chartered Geologist. He is a member of the SPEE, and chairs the SPEE European Chapter.

RPS carried out its evaluation and reviews in accordance with generally accepted petroleum engineering and evaluation principles as set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers ("SPE Standards"). The evaluations undertaken by RPS used a mix of performance based and volumetric methods as judged appropriate for each particular accumulation for the purposes of this report.

Our examination included such tests and procedures as we considered necessary under the circumstances to render the opinion set forth herein.

We are independent with respect to Suncor Energy as provided in the SPE Standards.

It should be understood that the RPS evaluation and review does not constitute a complete reserve study of the oil and gas properties of Suncor Energy. In the conduct of our report, we have not independently verified the accuracy and completeness of information and data furnished by Suncor Energy with respect to ownership interests, oil and gas production, costs of operation and development, product prices, and agreements relating to current and future operations and sales of production.

If, in the course of our examination the validity or sufficiency of any of information or data was brought into question, we did not rely on such information or data until we had satisfactorily resolved our concerns thereto or had independently verified such information or data.

Throughout its work, RPS endeavoured to reconcile with Suncor any differences of opinion that it may have held with Suncor on the estimates of reserves.

Key Findings of Evaluation and Review

RPS have carried out independent evaluations of proved reserves and probable reserves for three of Suncor's "International" fields, and have undertaken reviews of Suncor's internal evaluations for the remaining Suncor "International" fields. The results of these evaluations and reviews are summarised in Table 1 (for Net After Royalty Reserves), which show the resulting proved reserves and probable reserves (for Oil and NGL combined and for Gas) by geographic area. The proved reserves and probable reserves for each of the individual fields evaluated by RPS have been evaluated in accordance with the SEC Guidance detailed above under "Applicable Reserves Definitions"; reviews carried out by RPS for fields evaluated by Suncor have been undertaken against the same SEC Guidance. The estimated reserves for the individual fields have been summed arithmetically within each geographic area, in accordance with SEC guidance, to give the numbers that have been quoted in Table 1. The percentages of Suncor Energy's total proved reserves (which sum to 3552 MMboe) and probable reserves (which sum to 2828 MMboe), expressed as barrels of oil equivalent, that were evaluated and reviewed by RPS in each category are also shown in Table 1. It should be noted that due to the effects of rounding, the numbers shown in Table 1 might not add up exactly in all cases.

In respect of the fields where the reserves were reviewed, RPS has conducted a high-level assessment of reserves data and information provided by Suncor, supplemented by detailed discussions with Suncor reserves management and other staff, and concluded that the final reserves data were plausible (in the sense defined in the COGE Handbook, Volume 1, section 12.2).

Requested Warranties

In addition to providing the findings of its evaluation and review, RPS makes the following warranties, which were requested of it by Suncor.

(a) Neither RPS, nor its Shareholders and Officers have or have had any direct or indirect interest, nor do they expect to receive any direct or indirect interest in any securities of Suncor.

(b) No limitations and/or restrictions were placed upon RPS by officials of Suncor in its independent evaluations and reviews of the International and Offshore Business Unit Reserves Reported Volumes of Suncor.

(c) There has been no information obtained by RPS from January 1, 2010 to the date of this letter that would have material effect on the various amounts and classifications of reserves reported upon.

(d) RPS consents to this summary report being filed with Suncor's Annual Disclosure Requirements.

Very truly yours,

"Dr. Graeme Simpson"
Dr. Graeme Simpson
Director, Advisory
Attachment

Table 1
Summary of Reserves Evaluated and Reviewed by RPS Energy
(as of December 31, 2009)

Geographical Area	Company Net Proved Reserves (After Royalty)					
	Oil & NGLs	SCO	Natural Gas	Total BOE*	Portion Evaluated	Portion Reviewed
	MMbbl	MMbbl	Bcf	MMbbl	%	%
North West Europe	141	0	29	146	79%	21%
Other International	45	0	387	109	16%	84%
Total	**185**	**0**	**415**	**255**	**52%**	**48%**
Grand Total Suncor**	**294**	**2565**	**1692**	**3552**		
Proportion of Total Suncor Reserves	**63%**	**0%**	**25%**	**7%**		

Geographical Area	Company Net Probable Reserves (After Royalty)					
	Oil & NGLs	SCO	Natural Gas	Total BOE*	Portion Evaluated	Portion Reviewed
	MMbbl	MMbbl	Bcf	MMbbl	%	%
North West Europe	73	0	72	85	71%	29%
Other International	60	0	265	105	8%	92%
Total	**133**	**0**	**337**	**189**	**36%**	**64%**
Grand Total Suncor**	**246**	**1100**	**830**	**2828**		
Proportion of Total Suncor Reserves	**54%**	**0%**	**41%**	**7%**		

* Conversion factors to barrels of oil equivalent: all liquids 1bbl/boe; natural gas 6Mcf/boe=6Bcf/MMboe

** Data provided by Suncor

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

A. Undertaking

Suncor Energy Inc. (the "Registrant") undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the staff of the Securities and Exchange Commission ("SEC"), and to furnish promptly, when requested to do so by the SEC staff, information relating to the securities in relation to which the obligation to file an annual report on Form 40-F arises, or transactions in said securities.

B. Consent to Service of Process

The Registrant has filed previously with the SEC a Form F-X in connection with the Common Shares.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

See page 55 and page 56 of Exhibit 99-1, and page 29 of Exhibit 99.2.

AUDIT COMMITTEE FINANCIAL EXPERT

See pages 71 and 72 of Annual Information Form.

CODE OF ETHICS

See page 74 of Annual Information Form.

FEES PAID TO PRINCIPAL ACCOUNTANT

See page 72 of Annual Information Form.

AUDIT COMMITTEE PRE-APPROVAL POLICIES

See Schedule "A" of Annual Information Form.

APPROVAL OF NON-AUDIT SERVICES

See Schedule "A" of Annual Information Form.

OFF-BALANCE SHEET ARRANGEMENTS

See page 16 of Exhibit 99-2.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

See page 14 of Exhibit 99-2.

IDENTIFICATION OF THE AUDIT COMMITTEE

See page 71 of Annual Information Form.

SIGNATURES

Pursuant to the requirements of the Exchange Act, the registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized.

SUNCOR ENERGY INC.

DATE: March 5, 2010

PER: /s/ BART DEMOSKY

Bart Demosky
Chief Financial Officer

EXHIBIT INDEX

Exhibit No.	Description
99-1	Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2009, including reconciliation to U.S. GAAP (Note 23)
99-2	Management's Discussion and Analysis for the fiscal year ended December 31, 2009, dated February 26, 2010
99-3	Consent of PricewaterhouseCoopers LLP
99-4	Consent of GLJ Petroleum Consultants Ltd.
99-5	Consent of Sproule Associates Ltd.
99-6	Consent of RPS Energy Plc
99-7	Certificate of President and Chief Executive Officer Pursuant to Exchange Act Rules 13a-14(a) or 15d-14(a)
99-8	Certificate of the Chief Financial Officer Pursuant to Exchange Act Rules 13a-14(a) or 15d-14(a)
99-9	Certificate of the President and Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as Enacted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99-10	Certificate of the Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Enacted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

QuickLinks

ANNUAL INFORMATION FORM
UNDERTAKING AND CONSENT TO SERVICE OF PROCESS
DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING
AUDIT COMMITTEE FINANCIAL EXPERT
CODE OF ETHICS
FEES PAID TO PRINCIPAL ACCOUNTANT
AUDIT COMMITTEE PRE-APPROVAL POLICIES
APPROVAL OF NON-AUDIT SERVICES
OFF-BALANCE SHEET ARRANGEMENTS
TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS
IDENTIFICATION OF THE AUDIT COMMITTEE
SIGNATURES
EXHIBIT INDEX

QuickLinks -- Click here to rapidly navigate through this document

EXHIBIT 99-1

Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2009, including reconciliation to U.S. GAAP (Note 23)

MANAGEMENT'S STATEMENT
OF RESPONSIBILITY FOR FINANCIAL REPORTING

The management of Suncor Energy Inc. is responsible for the presentation and preparation of the accompanying consolidated financial statements of Suncor Energy Inc. on pages 59 to 100 and all related financial information contained in this Annual Report, including Management's Discussion and Analysis.

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles. They include certain amounts that are based on estimates and judgments relating to matters not concluded by year-end. Financial information presented elsewhere in this Annual Report is consistent with that contained in the consolidated financial statements.

In management's opinion, the consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the significant accounting policies adopted by management as summarized on pages 59 to 63. If alternate accounting methods exist, management has chosen those policies it deems the most appropriate in the circumstances. In discharging its responsibilities for the integrity and reliability of the financial statements, management maintains and relies upon a system of internal controls designed to ensure that transactions are properly authorized and recorded, assets are safeguarded against unauthorized use or disposition and liabilities are recognized. These controls include quality standards in hiring and training of employees, formalized policies and procedures, a corporate code of conduct and associated compliance program designed to establish and monitor conflicts of interest, the integrity of accounting records and financial information among others, and employee and management accountability for performance within appropriate and well-defined areas of responsibility.

The system of internal controls is further supported by the professional staff of an internal audit function who conduct periodic audits of the company's financial reporting.

The company retains independent petroleum consultants, GLJ Petroleum Consultants Ltd., Sproule Associates Limited and RPS Energy Plc, to conduct independent evaluations of the company's oil and gas reserves and resources.

The Audit Committee of the Board of Directors, currently composed of six independent directors, reviews the effectiveness of the company's financial reporting systems, management information systems, internal control systems and internal auditors. It recommends to the Board of Directors the external auditors to be appointed by the shareholders at each annual meeting and reviews the independence and effectiveness of their work. In addition, it reviews with management and the external auditors any significant financial reporting issues, the presentation and impact of significant risks and uncertainties, and key estimates and judgments of management that may be material for financial reporting purposes. The Audit Committee appoints the independent petroleum consultants. The Audit Committee meets at least quarterly to review and approve interim financial statements prior to their release, as well as annually to review Suncor's annual financial statements and Management's Discussion and Analysis, Annual Information Form/Form 40-F, and annual reserves and resource estimates, and recommend their approval to the Board of Directors. The internal auditors and PricewaterhouseCoopers LLP have unrestricted access to the company, the Audit Committee and the Board of Directors.





Richard L. George
President and
Chief Executive Officer

Bart Demosky
Chief Financial Officer

February 26, 2010

The following report is provided by management in respect of the Company's internal control over financial reporting (as defined in Rule13a-15(f) under the U.S. Securities Exchange Act of 1934):

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

1. Management is responsible for establishing and maintaining adequate internal control over the Company's financial reporting.

2. On August 1, 2009, Suncor completed its merger with Petro-Canada. As permitted by the Securities and Exchange Commission, management has excluded Petro-Canada from its evaluation of the effectiveness of Suncor's internal control over financial reporting as of December 31, 2009. Assets attributable to Petro-Canada as of August 1, 2009 represented approximately 50% of Suncor's total assets as of August 1, 2009, and revenues attributable to Petro-Canada for the period August 1, 2009 to December 31, 2009 represented approximately 25% of Suncor's total revenues for the year ended December 31, 2009.

3. Management has used the Committee of Sponsoring Organizations of the Treadway Commission (COSO) framework in Internal Control — Integrated Framework to evaluate the effectiveness of the Company's internal control over financial reporting.

4. Management has assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2009, and has concluded that such internal control over financial reporting was effective as of that date. Additionally, based on this assessment, management determined that there were no material weaknesses in internal control over financial reporting as of December 31, 2009. Because of inherent limitations, systems of internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

5. The effectiveness of the Company's internal control over financial reporting as of December 31, 2009 has been audited by PricewaterhouseCoopers LLP, independent auditors, as stated in their report which appears herein.





Richard L. George
President and
Chief Executive Officer

Bart Demosky
Chief Financial Officer

February 26, 2010

INDEPENDENT AUDITORS' REPORT

TO THE SHAREHOLDERS OF SUNCOR ENERGY INC.

We have completed integrated audits of Suncor Energy Inc's 2009, 2008 and 2007 consolidated financial statements and of its internal control over financial reporting as at December 31, 2009. Our opinions, based on our audits, are presented below.

Consolidated financial statements

We have audited the accompanying consolidated balance sheets of Suncor Energy Inc. ("the company") as at December 31, 2009 and December 31, 2008, and the related consolidated statements of earnings, comprehensive income, changes in shareholders' equity and of cash flows for each of the years in the three year period ended December 31, 2009. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits of the company's financial statements as at December 31, 2009 and 2008 and for each of the years in the three year period ended December 31, 2009 in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. A financial statement audit also includes assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the company as at December 31, 2009 and December 31, 2008 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2009 in accordance with Canadian generally accepted accounting principles.

Internal control over financial reporting

We have also audited the company's internal control over financial reporting as at December 31, 2009, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

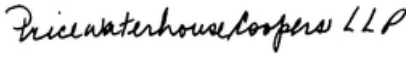
We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As described in Management's Report on Internal Control over Financial Reporting, management has excluded Petro-Canada from its assessment of internal control over financial reporting as at December 31, 2009 because it was acquired by the company in a purchase business combination during 2009. We have also excluded Petro-Canada from our audit of internal control over financial reporting. Assets attributable to Petro-Canada as of August 1, 2009 represented approximately 50% of the company's total assets as of August 1, 2009, and revenues attributable to Petro-Canada for the period August 1, 2009 to December 31, 2009 represented approximately 25% of the company's total revenues for the year ended December 31, 2009.

In our opinion, the company maintained, in all material respects, effective internal control over financial reporting as at December 31, 2009 based on criteria established in Internal Control – Integrated Framework issued by the COSO.



PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta

February 26, 2010

SUNCOR ENERGY INC.
SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Principles of Consolidation and the Preparation of Financial Statements

These consolidated financial statements are prepared and reported in Canadian dollars in accordance with generally accepted accounting principles (GAAP) in Canada, which differ in some respects from GAAP in the United States. These differences are quantified and explained in note 23.

The consolidated financial statements include the accounts of Suncor Energy Inc. and its subsidiaries and the company's proportionate share of the assets, liabilities, equity, revenues, expenses and cash flows of its joint ventures (the "company"). Subsidiaries are defined as entities in which the company holds a controlling interest, is the general partner or where it is subject to the majority of expected losses or gains.

The timely preparation of financial statements requires that management make estimates and assumptions, and use judgment regarding assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur. Significant estimates used in the preparation of the financial statements include, but are not limited to, asset retirement obligations, income taxes, employee future benefits, valuation of derivative instruments, the estimates of oil and natural gas reserves and related depreciation, depletion and amortization, and the valuation of goodwill.

Certain prior period comparative figures have been reclassified to conform to the current period presentation.

(b) Revenues

Revenue from the sale of crude oil, natural gas, natural gas liquids, purchased products and refined petroleum products is recorded when title passes to the customer and collection is reasonably assured. Revenue from oil and natural gas production is recorded net of royalties payable to governments and other mineral interest owners and revenue from properties in which the company has an interest with other producers is recognized on the basis of the company's net working interest. Inter-segment sales of crude oil and natural gas are accounted for at market values and included, for segmented reporting, in revenues of the segment making the transfer and expenses of the segment receiving the transfer. Inter-segment amounts are eliminated on consolidation.

International operations conducted pursuant to exploration and production-sharing agreements (EPSAs) are reflected in the Consolidated Financial Statements based on the company's working interest in such operations. Under the EPSAs, the company and other non-governmental partners, if any, pay all exploration costs and a pro-rata share of costs to develop and operate the concessions. Each EPSA establishes specific terms for the company to recover these costs (Cost Recovery Oil) and to share in the production profits (Profit Oil). Cost Recovery Oil is determined in accordance with a formula that is generally limited to a specified percentage of production during each fiscal year. Profit Oil is that portion of production remaining after deducting Cost Recovery Oil and is shared between the joint venture partners and the government of each country. Cost Recovery Oil, Profit Oil and amounts in respect of all income taxes payable by the company under the laws of the respective country are reported as sales revenue. All other government stakes, other than income taxes, are considered to be royalty interests.

(c) Transportation Costs

Transportation costs billed to customers are classified as revenues with the related transportation costs classified as transportation in the Consolidated Statements of Earnings.

(d) Foreign Currency Translation

The International operating segment, the United States operations of our refining and marketing and natural gas businesses, and our corporate self-insurance operations are classified as self-sustaining and are translated into Canadian dollars using the current rate method. Assets and liabilities are translated at the period-end exchange rate, while revenues and expenses are translated using average exchange rates during the period. Translation gains or losses are included in other comprehensive income (loss) in the Consolidated Statements of Comprehensive Income.

Otherwise, monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars at rates of exchange in effect at the end of the period. The resulting exchange gains and losses are included in earnings. With the exception of balances pertaining to self-sustaining operations, other assets and related depreciation, depletion and amortization, other liabilities, revenues and expenses are translated at rates of exchange in effect at the respective transaction dates. The resulting exchange gains and losses are included in earnings.

(e) Income Taxes

Suncor follows the liability method of accounting for income taxes. Future income taxes are recorded for the effect of any difference between the accounting and income tax basis of an asset or liability, using enacted or substantively enacted income tax rates. Accumulated future income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted with the adjustment being recognized in net earnings in the period that the change occurs. Investment tax credits are recorded as an offset to the related expenditures.

(f) Earnings Per Share

Basic earnings per share are calculated by dividing the net earnings by the weighted-average number of common shares outstanding. Diluted earnings per share reflect the potential dilution that would occur if stock options, excluding stock options with a cash payment alternative were exercised. The treasury stock method is used in calculating diluted earnings per share, which assumes that any proceeds received from the exercise of in-the-money stock options would be used to purchase common shares at the average market price for the period. A liability and expense is recorded for stock options with a cash payment alternative. Accordingly, the potential issuance of common shares associated with these stock options is not included in the calculation of diluted earnings per share.

(g) Cash and Cash Equivalents

Cash and cash equivalents consist primarily of cash in banks, term deposits, certificates of deposit and all other highly liquid investments with a maturity at the time of purchase of three months or less.

(h) Inventories

Inventories of crude oil and refined products, other than inventories held for trading purposes are valued at the lower of cost (using the first-in, first-out (FIFO) method) and net realizable value. Costs include direct and indirect expenditures incurred in bringing an item or product to its existing condition and location. Materials and supplies are valued at the lower of average cost and net realizable value.

Inventories held for trading purposes in the company's energy supply and trading operations are carried at fair value less costs to sell and any changes in fair value are recognized as gains or losses within Energy Supply and Trading Activities revenue in the Consolidated Statements of Earnings.

(i) Investments

Investments in companies over which the company has significant influence are accounted for using the equity method.

(j) Property, Plant and Equipment

Cost

Property, plant and equipment are recorded at cost.

The company follows the successful efforts method of accounting for the exploration and development expenditures of oil and gas producing activities. Under the successful efforts method, acquisition costs of proved and unproved properties are capitalized. Costs of unproved properties are transferred to proved properties when proved reserves are confirmed. Exploration costs, including geological and geophysical costs, are expensed as incurred. Exploratory drilling costs are initially capitalized. If it is determined that a specific well does not contain proved reserves, the related capitalized exploratory drilling costs are charged to expense, as dry hole costs, at that time.

Development costs, including the costs of developing production facilities, which include the costs of wellhead equipment, development drilling costs, applicable geological and geophysical costs, gas plants and handling facilities, offshore platforms and subsea structures, upgraders, extraction plants and the costs of acquiring or constructing support facilities and equipment are capitalized. Costs incurred to operate and maintain wells and equipment and to lift oil and gas to the surface are expensed as operating costs.

Development of oil sands mining activities are capitalized when costs are recoverable and directly result in an identifiable future benefit.

Costs incurred after the inception of operations are expensed. Planned major maintenance and expenditures that increase capacity or extend the useful lives of assets are capitalized.

Interest Capitalization

Interest costs relating to major capital projects in progress are capitalized as part of property, plant and equipment. Capitalization of interest ceases when the capital asset is substantially complete and ready for its intended productive use. Capitalization of

interest is suspended while an asset is in safe mode. Capitalized interest cannot exceed the actual interest incurred during the period.

Leases

Leases that transfer substantially all the benefits and risks of ownership to the company are recorded as capital leases and classified as property, plant and equipment with offsetting long-term debt. All other leases are classified as operating leases under which leasing costs are expensed in the period incurred.

Depreciation, Depletion and Amortization

Depreciation and depletion of property, plant and equipment for oil and gas producing properties follow successful efforts accounting. Acquisition costs of unproved properties for natural gas and conventional crude are amortized over the lease term until proved reserves are confirmed. Exploration drilling and development costs are depleted over the remaining proved developed reserves. Proved property acquisition costs are depleted over the remaining proved reserves.

Mine and mobile equipment costs are depleted on unit-of-production basis over proved developed reserves or depreciated on a straight-line basis over periods ranging from two to 20 years, while mining extraction and upgrading facilities and other property and equipment, including leases in service, are depreciated on a straight-line basis over periods ranging from four to 40 years. Gas plants, central processing facilities of in-situ oil sands activities, and support facilities and equipment are depreciated on a straight-line basis over their useful lives, which range from 3 years to 30 years.

Capital expenditures associated with significant development projects are not depleted until facilities are substantially complete and ready for their intended productive use.

Depreciation of property, plant and equipment in the refining and marketing operations are provided on a straight-line basis over the useful lives of assets. The refineries and lubricants plant and additions thereto are depreciated over an average of 30 years, service stations and related equipment over four to 20 years and pipeline facilities and other equipment over three to 40 years.

Depreciation, depletion and amortization rates for all capitalized costs associated with all of the company's activities are reviewed, at least annually, or when events or conditions occur that impact capitalized costs, reserves or estimated service lives.

The cost of major maintenance shutdowns is capitalized and amortized on a straight-line basis over the period to the next shutdown, which varies from three to nine years.

Impairment

Property, plant and equipment are reviewed for impairment whenever events or conditions indicate that their net carrying amount may not be recoverable from estimated undiscounted future cash flows. If it is determined that the estimated net recoverable amount is less than the net carrying amount, a write-down to the asset's fair value is recognized during the period, with a charge to earnings.

Disposals and Abandonments

Gains or losses on disposals of non-oil and gas property, plant and equipment are recognized in earnings. For oil and gas property, plant and equipment, gains or losses on significant disposals or disposal of an entire property are recognized in earnings. All other disposals and abandonments of oil and gas property, plant and equipment are charged to depreciation, depletion and amortization expense.

(k) Business Combinations and Goodwill

Acquisitions are accounted for using the purchase method in accordance with Canadian Institute of Chartered Accountants ("CICA") Handbook section 1581. Under this method, the purchase consideration of the combination is allocated to the identifiable assets, liabilities and contingent liabilities on the basis of fair value as of the date of acquisition.

Goodwill, which is not amortized, is the excess of the purchase price over such fair value and is assigned to the appropriate reporting units. The carrying value of goodwill is assessed for impairment annually or more frequently as economic events dictate, by comparing the fair value of the reporting unit to its carrying value, including goodwill. If the fair value of the reporting unit is less than its carrying value, goodwill impairment is recognized as the excess of the carrying value of the goodwill over the fair value of the goodwill.

(l) Intangible Assets

Intangible assets, other than goodwill, include acquired customers lists and brand value and are stated at the amount initially recognized, less accumulated amortization. Intangible assets with a finite life are amortized over their expected useful lives which range from five to 10 years, while intangible assets with an indefinite useful life are not subject to amortization. Expected useful

lives of intangible assets are reviewed on an annual basis and, if necessary, changes in useful lives are accounted for prospectively.

The carrying values of intangible assets with a finite life are reviewed for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. Intangible assets with an indefinite useful life are assessed for impairment annually, or more frequently as economic events dictate that carrying value may be less than fair value. If it is determined that the estimated net recoverable amount or fair value is less than the net carrying amount, a write-down is recognized during the period, with a charge to earnings.

(m) Asset Retirement Obligations

A liability is recognized for future retirement obligations associated with the company's property, plant and equipment. The fair value of the Asset Retirement Obligation (ARO) is recorded on a discounted basis. This amount is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the company settles the obligation. Changes in the estimated obligation resulting from revisions to the estimated timing or amount of undiscounted cash flows are recognized as a change in the asset retirement obligation and related asset. Actual expenditures incurred are charged against the accumulated obligation.

(n) Stock-Based Compensation Plans

Under the company's common stock-based compensation plans (see note 15), stock-based awards are granted to executives, employees and non-employee directors. Compensation expense is recorded in the Consolidated Statements of Earnings as operating, selling and general expense.

For common share options granted to employees and non-employee directors on or after January 1, 2003, the expense is based on the fair values of the option at the time of grant and is recognized in the Consolidated Statements of Earnings over the estimated vesting periods of the respective options. A corresponding increase is recorded as contributed surplus in the Consolidated Statements of Changes in Shareholders' Equity. Consideration paid to the company on exercise of options is credited to share capital.

Stock-based compensation awards that are to be settled in cash or have the option to settle in cash or shares are measured using the intrinsic value method at each period end. A liability and expense are recorded over the vesting period in the amount by which the then current market price exceeds the option exercise price. The expense is recognized in the Consolidated Statements of Earnings. When awards are surrendered for cash, the cash settlement paid reduces the outstanding liability. When awards are exercised for common shares, consideration paid by the holder and the previously recognized liability associated with the stock options are recorded as common shares.

For employees eligible to retire prior to the vesting date, the compensation expense is recognized over the shorter period. In instances where an employee is eligible to retire at the time of grant, the full expense is recognized immediately.

(o) Employee Future Benefits

The company's employee future benefit programs consist of defined benefit and defined contribution pension plans, as well as other post-retirement benefits as described in note 14.

The estimated future cost of providing defined benefit pension and other post-retirement benefits is actuarially determined using management's best estimates of demographic and financial assumptions, and such cost is accrued proportionately from the date of hire of the employee to the date the employee becomes fully eligible to receive the benefits. The discount rate used to determine accrued benefit obligations is based on a year-end market rate of interest for high-quality corporate debt instruments with cash flows that match the timing and amount of expected benefit payments.

Company contributions to the defined contribution plan are expensed as incurred.

(p) Financial Instruments

All financial instruments are initially recognized at fair value on the balance sheet. The company has classified each financial instrument into one of the following categories: held-for-trading financial assets and liabilities, loans and receivables, held-to-maturity financial assets, and other financial liabilities. Subsequent measurement of financial instruments is based on their classification.

Held-for-trading financial assets and liabilities are subsequently measured at fair value with changes in those fair values recognized in net earnings. Loans and receivables, held-to-maturity financial assets and other financial liabilities are subsequently measured at amortized cost using the effective interest method.

The company classifies cash and cash equivalents as held-for-trading financial assets, accounts receivable as loans and receivables, and accounts payable and accrued liabilities, short-term notes payable, long-term debt and other liabilities as other financial liabilities. The company combines transaction costs and premiums or discounts directly attributable to the issuance of long-term debt with the fair value of the debt and amortizes these amounts to earnings using the effective interest method, with the exception of the portion of debt that has related financial hedges, which is accounted for under the fair value hedge methodology outlined below.

The estimated fair values of financial instruments have been determined based on the company's assessment of available market information and appropriate valuation methodologies based on industry accepted third-party models.

Derivative Financial Instruments

The company may use derivative financial instruments to manage certain exposures to fluctuations in interest rates, commodity prices, foreign exchange rates, as well as for trading purposes. Derivative contracts for trading and non-trading activities are required to be recorded on the balance sheet at fair value. Derivative contracts that the company accounts for as designated hedges are assessed at each reporting date to determine if the relationship between the derivative and the underlying hedged exposure is still effective, and to quantify any ineffectiveness in the relationship.

If the derivative is designated as a fair value hedge, changes in the fair value of the derivative and changes in the fair value of the hedged item attributable to the hedged risk are recognized in net earnings. If the derivative is designated as a cash flow hedge, the effective portions of the changes in fair value of the derivative are initially recorded in other comprehensive income and are recognized in net earnings when the hedged item is realized. Ineffective portions of changes in the fair value of hedging instruments are recognized in net earnings immediately for both fair value and cash flow hedges.

Gains or losses arising from hedging activities, including the ineffective portion, are reported in the same caption as the hedged item. The determination of hedge effectiveness and the measurement of hedge ineffectiveness for cash flow hedges are based on internally derived valuations that utilize observable market data. The company uses these valuations to estimate the fair values of the underlying physical commodity contracts.

Derivative contracts not accounted for as designated hedges are recorded on the balance sheet at fair value, with any change in fair value immediately recorded as a net gain or loss in net earnings.

(q) Recent Accounting Pronouncements

Business Combinations

In January 2009, the CICA issued section 1582 "Business Combinations" to replace section 1581. The CICA concurrently issued section 1601 "Consolidated Financial Statements" and section 1602 "Non-Controlling Interests" which replace section 1600 "Consolidated Financial Statements". Prospective application of the standards is effective for fiscal years beginning on or after January 1, 2011, with early adoption permitted. The new standards revise guidance on the determination of the carrying amount of the assets acquired and liabilities assumed, goodwill and accounting for non-controlling interests at the time of a business combination. The company applied section 1581 to the Petro-Canada business combination; however the company will continue to consider the application of section 1582 to business combinations in 2010.

CONSOLIDATED STATEMENTS OF EARNINGS

For the years ended December 31 ($ millions)	**2009**	2008 (restated)	2007 (restated)
Revenues			
Operating revenues (notes 4 and 22)	**18 658**	18 179	15 193
Less: Royalties	**(1 199)**	(890)	(691)
Operating revenues (net of royalties)	**17 459**	17 289	14 502
Energy supply and trading activities (notes 4 and 5)	**7 577**	11 320	2 782
Interest and other income (note 2e)	**444**	28	30
	25 480	28 637	17 314
Expenses			
Purchases of crude oil and products	**7 383**	7 582	6 414
Operating, selling and general (note 15)	**6 641**	4 186	3 450
Energy supply and trading activities (notes 4 and 5)	**7 381**	11 323	2 870
Transportation	**427**	246	160
Depreciation, depletion and amortization	**2 306**	1 049	864
Accretion of asset retirement obligations	**155**	64	48
Exploration (note 21)	**268**	90	95
Loss on disposal of assets	**66**	13	7
Project start-up costs	**51**	35	68
Financing expenses (income) (note 6)	**(487)**	917	(211)
	24 191	25 505	13 765
Earnings Before Income Taxes	**1 289**	3 132	3 549
Provisions for (Recovery of) Income Taxes (note 7)			
Current	**868**	514	382
Future	**(725)**	481	184
	143	995	566
Net Earnings	**1 146**	2 137	2 983
Net Earnings Per Common Share (dollars) (note 8)			
Basic	**0.96**	2.29	3.23
Diluted	**0.95**	2.26	3.17
Cash dividends	**0.30**	0.20	0.19

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years ended December 31 ($ millions)	**2009**	2008	2007
Net earnings	**1 146**	2 137	2 983
Other comprehensive income (loss), net of tax (notes 4 and 20)			
Change in foreign currency translation adjustment	**(332)**	350	(195)
Gain on derivative contracts designated as cash flow hedges	**2**	—	5
Comprehensive Income	**816**	2 487	2 793

See accompanying Summary of Significant Accounting Policies and Notes.

CONSOLIDATED BALANCE SHEETS

As at December 31 ($ millions)	**2009 (note 2)**	2008 (restated) (note 1)
Assets		
Current assets		
Cash and cash equivalents	**505**	660
Accounts receivable (note 4)	**3 936**	1 580
Inventories (note 11)	**2 971**	909
Income taxes receivable	**587**	67
Future income taxes (note 7)	**332**	21
Total current assets	**8 331**	3 237
Property, plant and equipment, net (note 13)	**57 485**	28 882
Other assets (note 12)	**536**	388
Goodwill (note 2d)	**3 201**	21
Future income taxes (note 7)	**193**	—
Total assets	**69 746**	32 528
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt	**2**	2
Current portion of long-term debt	**25**	18
Accounts payable and accrued liabilities (notes 4, 14, 15 and 16)	**6 529**	3 326
Income taxes payable	**1 274**	81
Future income taxes (note 7)	**18**	111
Total current liabilities	**7 848**	3 538
Long-term debt (note 17)	**13 855**	7 866
Accrued liabilities and other (notes 4, 14, 15 and 16)	**5 062**	1 986
Future income taxes (note 7)	**8 870**	4 615
Shareholders' equity (see below)	**34 111**	14 523
Total liabilities and shareholders' equity	**69 746**	32 528

Commitments and contingencies (note 19)

SHAREHOLDERS' EQUITY

As at December 31 ($ millions)	**Number (thousands)**	**2009**	Number (thousands)	2008
Share capital	**1 559 778**	**20 053**	935 524	1 113
Contributed surplus		**526**		288
Accumulated other comprehensive income (loss) (notes 4 and 20)		**(233)**		97
Retained earnings		**13 765**		13 025
Total shareholders' equity		**34 111**		14 523

See accompanying Summary of Significant Accounting Policies and Notes.

Approved on behalf of the Board of Directors:



Richard L. George,
Director



Brian A. Canfield,
Director

February 26, 2010

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31 ($ millions)	**2009**	2008 (restated)	2007 (restated)
Operating Activities			
Net earnings	**1 146**	2 137	2 983
Adjustments for:			
Depreciation, depletion and amortization	**2 306**	1 049	864
Future income taxes	**(725)**	481	184
Accretion of asset retirement obligations	**155**	64	48
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**(858)**	919	(252)
Change in fair value of derivative contracts	**980**	(638)	6
Loss on disposal of assets	**66**	13	7
Stock-based compensation	**262**	(22)	148
Gain on effective settlement of pre-existing contract with Petro-Canada (note 2e)	**(438)**	—	—
Other	**(278)**	(7)	(18)
Exploration expenses	**183**	61	67
Cash flow from operating activities before changes in non-cash working capital	**2 799**	4 057	4 037
Decrease (increase) in non-cash working capital related to operating activities (note 10)	**(224)**	405	(144)
Cash flow from operating activities	**2 575**	4 462	3 893
Investing Activities			
Capital and exploration expenditures	**(4 246)**	(7 987)	(5 629)
Deferred outlays and other investments	**(30)**	(51)	(32)
Cash acquired through business combination (net) (note 2d)	**248**	—	—
Proceeds from disposals	**148**	33	9
Decrease (increase) in non-cash working capital related to investing activities	**(791)**	415	290
Cash flow used in investing activities	**(4 671)**	(7 590)	(5 362)
Net cash deficiency before financing activities	**(2 096)**	(3 128)	(1 469)
Financing Activities			
Decrease in short-term debt	**—**	(1)	(4)
Net proceeds from issuance of long-term debt	**—**	2 704	1 835
Net increase (decrease) in revolving-term debt	**2 325**	422	(171)
Issuance of common shares under stock option plan	**41**	190	62
Dividends paid on common shares	**(401)**	(180)	(162)
Deferred revenue	**—**	—	4
Cash flow provided by financing activities	**1 965**	3 135	1 564
Increase (Decrease) in Cash and Cash Equivalents	**(131)**	7	95
Effect of Foreign Exchange on Cash and Cash Equivalents	**(24)**	84	(47)
Cash and Cash Equivalents at Beginning of Period	**660**	569	521
Cash and Cash Equivalents at End of Period	**505**	660	569

See accompanying Summary of Significant Accounting Policies and Notes.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

For the years ended December 31 ($ millions)	Share Capital	Contributed Surplus	Accumulated Other Comprehensive Income (AOCI)	Retained Earnings
At December 31, 2006	794	100	(71)	8 261
Net earnings	—	—	—	2 983
Dividends paid on common shares	—	—	—	(162)
Issued for cash under stock option plans	74	(12)	—	—
Issued under dividend reinvestment plan	13	—	—	(13)
Stock-based compensation expense	—	103	—	—
Income tax benefit of stock option deductions in the U.S.	—	3	—	—
Adjustment to opening retained earnings arising from ineffective portion of cash flow hedges at January 1, 2007	—	—	—	5
Adjustment to opening AOCI arising from effective portion of cash flow hedges at January 1, 2007	—	—	8	—
Change in accumulated other comprehensive income (loss)	—	—	(190)	—
At December 31, 2007	881	194	(253)	11 074
Net earnings	—	—	—	2 137
Dividends paid on common shares	—	—	—	(180)
Issued for cash under stock option plans	226	(36)	—	—
Issued under dividend reinvestment plan	6	—	—	(6)
Stock-based compensation expense	—	120	—	—
Income tax benefit of stock option deductions in the U.S.	—	10	—	—
Change in accumulated other comprehensive income (loss)	—	—	350	—
At December 31, 2008	**1 113**	**288**	**97**	**13 025**
Net earnings	**—**	**—**	**—**	**1 146**
Dividends paid on common shares	**—**	**—**	**—**	**(401)**
Issued for cash under stock option plans	**57**	**(16)**	**—**	**—**
Issued under dividend reinvestment plan	**5**	**—**	**—**	**(5)**
Stock-based compensation expense	**—**	**103**	**—**	**—**
Issued for Petro-Canada acquisition (note 2c)	**18 878**	**—**	**—**	**—**
Fair value of Petro-Canada stock options exchanged for Suncor stock options (note 2c)	**—**	**147**	**—**	**—**
Income tax benefit of stock option deduction in the U.S.	**—**	**4**	**—**	**—**
Change in accumulated other comprehensive income (loss)	**—**	**—**	**(330)**	**—**
At December 31, 2009	**20 053**	**526**	**(233)**	**13 765**

See accompanying Summary of Significant Accounting Policies and Notes.

SCHEDULES OF SEGMENTED DATA (a)

For the Years Ended December 31 ($ millions)	Oil Sands			Natural Gas			East Coast Canada			International		
	2009	2008	2007	**2009**	2008	2007	**2009**	2008	2007	**2009**	2008	2007
EARNINGS												
Revenues (b)												
Operating revenues	**4 135**	8 045	6 160	**612**	696	541	**499**	—	—	**1 434**	—	—
Less: Royalties	**(645)**	(715)	(565)	**(85)**	(175)	(126)	**(217)**	—	—	**(252)**	—	—
Operating revenues (net of royalties)	**3 490**	7 330	5 595	**527**	521	415	**282**	—	—	**1 182**	—	—
Energy supply and trading activities	**—**	—	—	**—**	—	—	**—**	—	—	**—**	—	—
Intersegment revenues (c)	**2 609**	1 309	580	**154**	58	12	**159**	—	—	**—**	—	—
Interest and other income	**440**	—	—	**—**	—	—	**—**	—	—	**1**	—	—
	6 539	8 639	6 175	**681**	579	427	**441**	—	—	**1 183**	—	—
Expenses												
Purchases of crude oil and products	**325**	574	157	**—**	—	—	**33**	—	—	**—**	—	—
Operating, selling and general	**4 277**	3 203	2 439	**322**	160	155	**72**	—	—	**242**	—	—
Energy supply and trading activities	**—**	—	—	**—**	—	—	**—**	—	—	**—**	—	—
Transportation	**248**	229	138	**58**	17	15	**19**	—	—	**33**	—	—
Depreciation, depletion and amortization	**922**	580	462	**448**	225	189	**184**	—	—	**400**	—	—
Accretion of asset retirement obligations	**111**	55	40	**22**	8	7	**4**	—	—	**17**	—	—
Exploration	**10**	17	13	**127**	73	82	**4**	—	—	**127**	—	—
Loss (gain) on disposal of assets	**70**	36	1	**(20)**	(22)	(1)	**—**	—	—	**—**	—	—
Project start-up costs	**51**	35	60	**—**	—	—	**—**	—	—	**—**	—	—
Financing expenses (income)	**1**	—	—	**—**	—	—	**1**	—	—	**(1)**	—	—
	6 015	4 729	3 310	**957**	461	447	**317**	—	—	**818**	—	—
Earnings (loss) before income taxes	**524**	3 910	2 865	**(276)**	118	(20)	**124**	—	—	**365**	—	—
Income taxes	**33**	(1 035)	(391)	**77**	(29)	45	**(12)**	—	—	**(200)**	—	—
Net earnings (loss)	**557**	2 875	2 474	**(199)**	89	25	**112**	—	—	**165**	—	—
As at December 31												
TOTAL ASSETS	**37 553**	25 795	18 172	**5 003**	1 862	1 811	**4 771**	—	—	**9 913**	—	—

(a) Accounting policies for segments are the same as those described in the Summary of Significant Accounting Policies.

(b) There were no customers that represented 10% or more of the company's 2009, 2008 or 2007 consolidated revenues.

(c) Intersegment revenues are recorded at prevailing fair market prices and accounted for as if the sales were to third parties.

See accompanying Summary of Significant Accounting Policies and Notes.

For the Years Ended December 31 ($ millions)	Refining and Marketing			Corporate, Energy Trading and Eliminations			Total		
	2009	2008	2007	**2009**	2008	2007	**2009**	2008	2007
EARNINGS									
Revenues [b]									
Operating revenues	**11 962**	9 418	8 486	**16**	20	6	**18 658**	18 179	15 193
Less: Royalties	**—**	—	—	**—**	—	—	**(1 199)**	(890)	(691)
Operating revenues (net of royalties)	**11 962**	9 418	8 486	**16**	20	6	**17 459**	17 289	14 502
Energy supply and trading activities	**—**	—	—	**7 577**	11 320	2 782	**7 577**	11 320	2 782
Intersegment revenues [c]	**51**	—	(100)	**(2 973)**	(1 367)	(492)	**—**	—	—
Interest and other income	**—**	1	5	**3**	27	25	**444**	28	30
	12 013	9 419	8 391	**4 623**	10 000	2 321	**25 480**	28 637	17 314
Expenses									
Purchases of crude oil and products	**9 731**	8 472	6 847	**(2 706)**	(1 464)	(590)	**7 383**	7 582	6 414
Operating, selling and general	**1 279**	746	720	**449**	77	136	**6 641**	4 186	3 450
Energy supply and trading activities	**—**	—	—	**7 381**	11 323	2 870	**7 381**	11 323	2 870
Transportation	**87**	16	20	**(18)**	(16)	(13)	**427**	246	160
Depreciation, depletion and amortization	**323**	202	171	**29**	42	42	**2 306**	1 049	864
Accretion of asset retirement obligations	**1**	1	1	**—**	—	—	**155**	64	48
Exploration	**—**	—	—	**—**	—	—	**268**	90	95
Loss (gain) on disposal of assets	**16**	6	7	**—**	(7)	—	**66**	13	7
Project start-up costs	**—**	—	8	**—**	—	—	**51**	35	68
Financing expenses (income)	**4**	—	—	**(492)**	917	(211)	**(487)**	917	(211)
	11 441	9 443	7 774	**4 643**	10 872	2 234	**24 191**	25 505	13 765
Earnings (loss) before income taxes	**572**	(24)	617	**(20)**	(872)	87	**1 289**	3 132	3 549
Income taxes	**(139)**	19	(175)	**98**	50	(45)	**(143)**	(995)	(566)
Net earnings (loss)	**433**	(5)	442	**78**	(822)	42	**1 146**	2 137	2 983
As at December 31									
TOTAL ASSETS	**10 568**	3 795	4 065	**1 938**	1 076	461	**69 746**	32 528	24 509

SCHEDULES OF SEGMENTED DATA (a) (continued)

For the Years Ended December 31 ($ millions)	Oil Sands			Natural Gas			East Coast Canada			International		
	2009	2008	2007	**2009**	2008	2007	**2009**	2008	2007	**2009**	2008	2007
CASH FLOW BEFORE FINANCING ACTIVITIES												
Operating activities												
Net earnings (loss)	**557**	2 875	2 474	**(199)**	89	25	**112**	—	—	**165**	—	—
Adjustments for:												
Depreciation, depletion and amortization	**922**	580	462	**448**	225	189	**184**	—	—	**400**	—	—
Future income taxes	**(643)**	535	108	**(52)**	15	(43)	**12**	—	—	**(56)**	—	—
Accretion of asset retirement obligations	**111**	55	40	**22**	8	7	**4**	—	—	**17**	—	—
Unrealized (gain) loss on translation of U.S. dollar denominated long-term debt	**—**	—	—	**—**	—	—	**—**	—	—	**—**	—	—
Change in fair value of derivative contracts	**960**	(590)	10	**—**	—	2	**—**	—	—	**—**	—	—
Loss (gain) on disposal of assets	**70**	36	1	**(20)**	(22)	(1)	**—**	—	—	**—**	—	—
Stock-based compensation	**90**	54	86	**19**	4	7	**2**	—	—	**10**	—	—
Gain on effective settlement of pre-existing contract with Petro-Canada	**(438)**	—	—	**—**	—	—	**—**	—	—	**—**	—	—
Other	**(378)**	(38)	(16)	**(11)**	(13)	(2)	**21**	—	—	**19**	—	—
Exploration expenses	**—**	—	—	**122**	61	67	**—**	—	—	**61**	—	—
Cash flow from (used in) operating activities before changes in non-cash working capital	**1 251**	3 507	3 165	**329**	367	251	**335**	—	—	**616**	—	—
Decrease (increase) in operating working capital	**(202)**	934	564	**(9)**	43	19	**(34)**	—	—	**(35)**	—	—
Total cash from (used in) operating activities	**1 049**	4 441	3 729	**320**	410	270	**301**	—	—	**581**	—	—
Investing activities:												
Capital and exploration expenditures	**(2 807)**	(7 391)	(4 566)	**(320)**	(342)	(537)	**(123)**	—	—	**(543)**	—	—
Deferred outlays and other investments	**(36)**	(39)	(18)	**—**	—	—	**—**	—	—	**—**	—	—
Cash acquired through business combination (net)	**—**	—	—	**—**	—	—	**—**	—	—	**—**	—	—
Proceeds from disposals	**96**	—	3	**27**	26	5	**—**	—	—	**—**	—	—
Decrease (increase) in investing working capital	**(799)**	434	333	**(19)**	—	—	**(29)**	—	—	**60**	—	—
Total cash from (used in) investing activities	**(3 546)**	(6 996)	(4 248)	**(312)**	(316)	(532)	**(152)**	—	—	**(483)**	—	—
Net cash surplus (deficiency) before financing activities	**(2 497)**	(2 555)	(519)	**8**	94	(262)	**149**	—	—	**98**	—	—

(a) Accounting policies for segments are the same as those described in the Summary of Significant Accounting Policies.

See accompanying Summary of Significant Accounting Policies and Notes.

For the Years Ended December 31 ($ millions)	Refining and Marketing 2009	Refining and Marketing 2008	Refining and Marketing 2007	Corporate, Energy Trading and Eliminations 2009	Corporate, Energy Trading and Eliminations 2008	Corporate, Energy Trading and Eliminations 2007	Total 2009	Total 2008	Total 2007
CASH FLOW BEFORE FINANCING ACTIVITIES									
Operating activities									
Net earnings (loss)	**433**	(5)	442	**78**	(822)	42	**1 146**	2 137	2 983
Adjustments for:									
Depreciation, depletion and amortization	**323**	202	171	**29**	42	42	**2 306**	1 049	864
Future income taxes	**109**	(7)	77	**(95)**	(62)	42	**(725)**	481	184
Accretion of asset retirement obligations	**1**	1	1	**—**	—	—	**155**	64	48
Unrealized (gain) loss on translation of U.S. dollar denominated long-term debt	**—**	—	—	**(858)**	919	(252)	**(858)**	919	(252)
Change in fair value of derivative contracts	**(14)**	27	(6)	**34**	(75)	—	**980**	(638)	6
Loss (gain) on disposal of assets	**16**	6	7	**—**	(7)	—	**66**	13	7
Stock-based compensation	**35**	16	35	**106**	(96)	20	**262**	(22)	148
Gain on effective settlement of pre-existing contract with Petro-Canada	**—**	—	—	**—**	—	—	**(438)**	—	—
Other	**60**	8	(16)	**11**	36	16	**(278)**	(7)	(18)
Exploration expenses	**—**	—	—	**—**	—	—	**183**	61	67
Cash flow from (used in) operating activities before changes in non-cash working capital	**963**	248	711	**(695)**	(65)	(90)	**2 799**	4 057	4 037
Decrease (increase) in operating working capital	**(270)**	292	(247)	**326**	(864)	(480)	**(224)**	405	(144)
Total cash from (used in) operating activities	**693**	540	464	**(369)**	(929)	(570)	**2 575**	4 462	3 893
Investing activities:									
Capital and exploration expenditures	**(409)**	(226)	(449)	**(44)**	(28)	(77)	**(4 246)**	(7 987)	(5 629)
Deferred outlays and other investments	**(3)**	(11)	—	**9**	(1)	(14)	**(30)**	(51)	(32)
Cash acquired through business combination (net)	**—**	—	—	**248**	—	—	**248**	—	—
Proceeds from disposals	**25**	—	1	**—**	7	—	**148**	33	9
Decrease (increase) in investing working capital	**(4)**	(19)	(43)	**—**	—	—	**(791)**	415	290
Total cash from (used in) investing activities	**(391)**	(256)	(491)	**213**	(22)	(91)	**(4 671)**	(7 590)	(5 362)
Net cash surplus (deficiency) before financing activities	**302**	284	(27)	**(156)**	(951)	(661)	**(2 096)**	(3 128)	(1 469)

SUNCOR ENERGY INC.
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. CHANGES IN ACCOUNTING POLICIES AND DISCLOSURES

(a) Goodwill and Intangible Assets

On January 1, 2009, the company retroactively adopted Canadian Institute of Chartered Accountants (CICA) Handbook section 3064 "Goodwill and Intangible Assets." This new standard replaces section 3062 "Goodwill and Other Intangible Assets" and section 3450 "Research and Development Costs," and focuses on the criteria for asset recognition in the financial statements, including those internally developed. The impact of adopting this standard resulted in a change in the classification of our deferred maintenance shutdown costs that had previously been classified within other assets and amortized over the period to the next shutdown. At December 31, 2008, property, plant and equipment was increased by $566 million, with an equal and offsetting reduction to other assets.

(b) Credit Risk and the Fair Value of Financial Assets and Financial Liabilities

On January 1, 2009, the company adopted the recommendations of CICA Emerging Issues Committee Abstract 173 relating to the fair value of financial assets and liabilities. The Abstract requires that an entity's own credit risk and the credit risk of the counterparty are taken into account in determining the fair value of financial assets and liabilities, including derivative instruments. The Abstract is to be applied retroactively without restatement of prior periods. The company has evaluated the new abstract and concluded that the adoption of the new requirements did not have a material impact on Suncor's financial statements.

(c) Financial Instruments Disclosures

On December 31, 2009, the company prospectively adopted amendments to CICA Handbook section 3862 "Financial Instruments: Disclosures," requiring adoption for annual periods ending on or after September 30, 2009. The amendments require additional disclosures on fair value measurements of financial instruments and enhanced liquidity risk disclosure. These additional disclosures are provided in note 4.

2. BUSINESS COMBINATION WITH PETRO-CANADA

(a) Overview

In the first quarter of 2009, Suncor announced that it had agreed to merge with Petro-Canada. The transaction was accomplished through a plan of arrangement, which included a share exchange, pursuant to which holders of common shares of Petro-Canada received 1.28 common shares of Suncor for each common share of Petro-Canada held.

In the second and third quarters of 2009, the arrangement received approval from Suncor and Petro-Canada shareholders, the Alberta Court of Queen's Bench, and the Competition Bureau of Canada. The transaction closed August 1, 2009 and the merged company continues to operate as Suncor Energy Inc.

(b) Accounting for Business Combinations

The company has accounted for this business combination as prescribed by CICA Handbook section 1581 "Business Combinations." As the acquirer, the company is required to recognize Petro-Canada assets and liabilities as at August 1, 2009. The results of Petro-Canada operations are included in the consolidated financial statements of the company from August 1, 2009.

(c) Consideration and Purchase Price

Consideration offered to complete the merger included 621.1 million shares of Suncor with a value of $18,878 million, or $30.39 per share, that were issued to Petro-Canada shareholders and 7.1 million Suncor share options with a fair value of $147 million, that were exchanged for existing Petro-Canada share options. The replacement of stock options and other stock-based compensation plans that are accounted for as liabilities are not included in consideration (see note 15).

The total purchase price for the acquisition was $19,630 million, consisting of the following amounts:

($ millions)

621.1 million common shares issued to Petro-Canada shareholders	18 878
7.1 million Petro-Canada share options exchanged for share options of Suncor	147
Transaction costs	167
Effective settlement of pre-existing contract with Petro-Canada (note e)	438
Total purchase price	19 630

(d) Preliminary Allocation of Purchase Price

The following estimated fair values were assigned to the net assets of Petro-Canada as at August 1, 2009:

($ millions)

Current assets	4 645
Property, plant and equipment	27 407
Other assets	537
Total assets	32 589
Current liabilities	3 741
Long-term debt	4 410
Accrued liabilities and other	3 416
Future income taxes	4 570
Total liabilities	16 137
Net assets purchased	16 452
Goodwill	3 178
Total purchase price	19 630

The preliminary purchase price allocation is based on current best estimates by Suncor's management and is based principally on valuations prepared by independent valuation specialists.

Cash acquired was $248 million, net of transaction costs of $167 million.

Other assets includes $236 million for intangible assets, relating to the Petro-Canada brand, with an indefinite life, and customer lists, which will be amortized over their estimated useful lives.

The fair value for current liabilities includes $216 million for provisions for costs related to exiting certain activities of Petro-Canada and involuntary termination benefits. As at December 31, 2009, $118 million of actual expenses had been charged against these provisions.

$3,019 million of the goodwill has been allocated to the Oil Sands segment and the remaining $159 million has been allocated to the Refining and Marketing segment. No amount that is part of goodwill is expected to be deductible for tax purposes.

(e) Pre-Existing Contract with Petro-Canada

CICA Emerging Issues Committee Abstract 154 (EIC 154) *Accounting for Pre-existing Relationships between the Parties of a Business Combination* states that the consummation of a business combination between parties with a pre-existing relationship requires an evaluation to determine if a settlement of the related contract exists, and where the relationship is favourable to the acquirer, that the purchase cost of the acquisition be the sum of the consideration paid and the benefit from the settlement of the relationship. The benefit is measured as the lesser of the amount of any stated settlement provisions in the contract and the amount by which the contract is favourable, from the perspective of the acquirer, when compared to pricing for current market transactions for the same or similar items.

In 2003, Suncor entered into a fee-for-service contract where it agreed to upgrade bitumen supplied by Petro-Canada. The contract came into effect January 1, 2009. The contract processing fee included an escalation factor tied to the price of West Texas Intermediate (WTI) crude, which was intended to approximate changes in Canadian light/heavy differentials for crude oil. The contract terms included a take-or-pay volume commitment and no early settlement provisions.

Since 2003, crude prices have increased significantly and industry conditions for the supply and demand of upgraded bitumen have changed dramatically resulting in the contract being favourable to Suncor at the transaction closing date. A value of $438 million was assigned to the effective settlement of the contract, by comparing estimated future processing fees on the take-or-pay volume commitment to estimated Canadian light/heavy differentials using future pricing assumptions for WTI, synthetic crude and bitumen.

The deemed settlement amount of $438 million (net of income taxes of $nil) is included in the total purchase price of the acquisition and included in interest and other income in the Consolidated Statement of Earnings.

3. CHANGE IN SEGMENTED DISCLOSURES

As a result of the business combination described in note 2, the company has reclassified its operations into the following segments.

Oil Sands includes the company's operations in northeast Alberta to produce synthetic crude through the recovery and upgrading of bitumen from mining and in-situ development.

Natural Gas includes exploration and production of natural gas, crude oil and natural gas liquids, primarily in Western Canada.

The East Coast Canada segment comprises activity offshore Newfoundland and Labrador, and includes interests in the Hibernia, Terra Nova, White Rose and Hebron oilfields.

The International segment includes the exploration for, and production of, crude oil and natural gas in the United Kingdom, the Netherlands, Norway, Trinidad and Tobago, Libya and Syria.

Refining and Marketing includes the purchase and sale of crude oil, the refining of crude oil products, and the distribution and marketing of these and other purchased products through refineries located in Eastern and Western Canada and the U.S., as well as a lubricants plant located in Eastern Canada. Energy supply and trading activities that were previously included in the Refining and Marketing segment are now included within Corporate, Energy Trading and Eliminations.

The Corporate, Energy Trading and Eliminations includes third-party energy supply and trading activities, and activities not directly attributable to an operating segment.

All prior periods have been restated to conform to these segment definitions.

4. FINANCIAL INSTRUMENTS AND FINANCIAL RISK FACTORS

Derivatives are financial instruments that either imitate or counter the price movements of stocks, bonds, currencies, commodities and interest rates. Suncor uses derivatives to reduce (hedge) its exposure to fluctuations in commodity prices and foreign currency exchange rates and to manage interest rate or currency-sensitive assets and liabilities. Suncor also uses derivatives for trading purposes. When used in a trading activity, the company is attempting to realize a gain on the fluctuations in the market value of the derivative.

The recent merger has provided Suncor with the ability to capitalize on future trading opportunities due to increased transactional and trading capacity. The company determined that new transaction levels for certain physical trading commodity contracts exceeded the company's expected purchase, sale or usage requirements. Effective October 1, 2009, these contracts are now considered derivative financial instruments whereby realized and unrealized gains and losses, and the underlying settlement of these contracts is recognized and reported on a net basis in Energy Supply and Trading Activities revenue. The related inventory is carried at fair value less costs to sell, with changes in fair value recognized as gains or losses within Energy Supply and Trading Activities revenue.

Forwards and futures are contracts to purchase or sell a specific item at a specified date and price. When used as hedges, forwards and futures help to manage the exposure to losses that could result if commodity prices, foreign currency exchange rates, or interest rates change adversely.

An option is a contract where its holder, for a fee, has purchased the right (but not the obligation) to buy or sell a specified item at a fixed price during a specified period. Options used as hedges help to protect against adverse changes in commodity prices, interest rates, or foreign currency exchange rates.

A costless collar is a combination of two option contracts that limit the holder's exposure to changes in prices to within a specific range. The "costless" nature of this derivative is achieved by buying a put option (the right to sell) for consideration equal to the premium received from selling a call option (the right to purchase).

A swap is a contract where two parties exchange commodity, currency, interest or other payments in order to alter the nature of the payments. For example, fixed interest rate payments on debt may be converted to payments based on a floating interest rate.

Hedge accounting is a method for recognizing the gains, losses, revenues and expenses associated with the items in a hedging relationship at the time when the underlying transaction impacts earnings. Suncor has elected to use hedge accounting on certain derivatives linked to future commodity and financial transactions.

Financial Instruments

(a) Balance Sheet Financial Instruments

The company's financial instruments in the Consolidated Balance Sheets consist of cash and cash equivalents, accounts receivable, derivative contracts, substantially all current liabilities (except for the current portions of income taxes), long-term debt, and a portion of non-current accrued liabilities and other. Unless otherwise noted, carrying values reflect the current fair value of the company's financial instruments.

The estimated fair values of recognized financial instruments have been determined based on the company's assessment of available market information and appropriate valuation methodologies based on industry accepted third-party models; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

The company's fixed-term debt is accounted for under the amortized cost method, with the exception of the portion of debt that has related financial hedges which is accounted for under the fair value methodology discussed below. Upon initial recognition, the cost of the debt is its fair value, adjusted for any associated transaction costs. We do not recognize gains or losses arising from changes in the fair value of this debt until the gains or losses are realized. Gains or losses on our U.S. dollar denominated long-term debt resulting from changes in the exchange rate are recognized in the period in which they occur. At December 31, 2009, the carrying value of our fixed-term debt accounted for under the amortized cost method was $10.1 billion (December 31, 2008 – $6.7 billion) and the fair value at December 31, 2009 was $10.7 billion (December 31, 2008 – $5.4 billion).

(b) Hedges – Documented as Part of a Qualifying Hedge Relationship

Fair Value Hedges

The company periodically enters into derivative financial instrument contracts such as interest rate swaps as part of its risk management strategy to manage its exposure to benchmark interest rate fluctuations. The interest rate swap contracts involve an exchange of floating rate versus fixed rate interest payments between the company and investment grade counterparties. The differentials on the exchange of periodic interest payments are recognized in earnings as an adjustment to interest expense. The fair value of the underlying debt is adjusted by the fair value change in the derivative financial instrument with the offset to interest expense. At December 31, 2009, the company had interest rate swaps classified as fair value hedges outstanding for up to two years relating to $200 million of its fixed-rate debt. There was no ineffectiveness recognized on interest rate swaps designated as fair value hedges during the year ended December 31, 2009 (no ineffectiveness during the year ended December 31, 2008). The fair value of interest rate swap contracts outstanding at December 31, 2009 is detailed in note 17.

The company periodically enters into derivative contracts to hedge risks specific to individual transactions. The differentials between the fair value of the hedged transactions and the fair value of the derivative contracts are recognized in earnings as an adjustment to operating revenues. There was no earnings impact associated with hedge ineffectiveness on derivative contracts to hedge risks specific to individual transactions during the year ended December 31, 2009 (2008 – loss of $4 million, net of income taxes of $2 million).

Cash Flow Hedges

The company operates in a global industry where the market price of its petroleum and natural gas products is largely determined based on floating benchmark indices. The company periodically enters into derivative financial instrument contracts such as forwards, futures, swaps, options and costless collars to hedge against the potential adverse impact of changing market prices due to changes in the underlying indices. Specifically, the company manages crude sales price variability by entering into West Texas Intermediate (WTI) derivative transactions, and manages variability in market interest rates and foreign exchange rates during periods of debt issuance through the use of interest rate locks and foreign exchange forward contracts.

There was no earnings impact associated with realized and unrealized hedge ineffectiveness on derivative contracts designated as cash flow hedges during the years ended December 31, 2009 and December 31, 2008.

Certain derivative contracts do not require the payment of premiums or cash margin deposits prior to settlement. On settlement, these contracts result in cash receipts or payments by the company for the difference between the contract and market rates for the applicable dollars and volumes hedged during the contract term. Such cash receipts or payments offset corresponding decreases or increases in the company's sales revenues or crude oil purchase costs. For collars, if market rates are not different than, or are within the range of contract prices, the options contracts making up the collar will expire with no exchange of cash.

Fair Value of Hedging Derivative Financial Instruments

The fair value of hedging derivative financial instruments as recorded, is the estimated amount that the company would receive (pay) to terminate the hedging derivative contracts. Such amounts, which also represent the unrealized gain (loss) on the contracts, were as follows:

($ millions)	**December 31 2009**	December 31 2008
Revenue hedge swaps and collars [(b)]	**—**	(2)
Fixed to floating interest rate swaps [(a)]	**18**	25
Specific hedges of individual transactions [(b)]	**—**	(11)
Fair value of outstanding hedging derivative financial instruments	**18**	12

(a) As at December 31, 2009, $10 million is recorded in accounts receivable (2008 – $9 million) and $8 million is recorded in other assets (2008 – $16 million) in the Consolidated Balance Sheets.

(b) As at December 31, 2009, $nil is recorded in accounts payable and accrued liabilities (2008 – $13 million) in the Consolidated Balance Sheets.

Accumulated Other Comprehensive Income (AOCI)

A reconciliation of changes in AOCI attributable to derivative hedging activities for the year ending December 31 is as follows:

($ millions)	**2009**	2008
AOCI attributable to derivative hedging activities, beginning of the period, net of income taxes of $5 (2008 – $4)	**13**	13
Current year net changes arising from cash flow hedges, net of income taxes of $nil (2008 – $2)	**—**	(7)
Net unrealized hedging losses (gains) at the beginning of the year reclassified to earnings during the period, net of income taxes of $nil (2008 – $3)	**2**	7
AOCI attributable to derivative hedging activities, at December 31, net of income taxes of $5 (2008 – $5)	**15**	13

(c) Derivatives

Commodity Price Risk Derivatives

The company also periodically enters into derivative financial instruments such as options, basis swaps, and heat rate swaps that either do not qualify for hedge accounting treatment or hedges that the company has not elected to document as part of a qualifying hedge relationship. Changes in fair value of these derivative financial instruments are immediately recorded as a gain or loss in the same revenue or expense account where the hedged transaction is recorded. The earnings impact associated with these contracts for the year ended December 31, 2009, was a loss of $763 million, net of income taxes of $261 million (2008 – a gain of $348 million, net of income taxes of $142 million).

Significant contracts outstanding at December 31, 2009 were as follows:

Crude oil	Quantity (bpd)	Average Price [(1)] (US$/bbl)	Hedge Period
Purchased puts [(2)]	55 000	60.00	2010
Sold puts [(3)]	54 753	60.00	2010
Collars – floor	50 041	50.00	2010
Collars – cap	49 986	68.06	2010

(1) Average price for crude puts is US$ WTI per barrel at Cushing, Oklahoma.

(2) Premium paid was US$29.5 million.

(3) Premium received was US$213 million.

Energy Trading Derivatives

The company's Energy Trading group also uses physical and financial energy contracts, including swaps, forwards and options to earn trading and marketing revenues. These energy contracts are comprised of crude oil, natural gas and refined products contracts. Financial and physical energy trading activities are accounted for using the mark-to-market method, with the associated gains and losses and the underlying settlement of these contracts recognized and reported on a net basis in Energy Supply and Trading Activities Revenue in the Consolidated Statements of Earnings.

The earnings impact associated with these contracts for the year ended December 31, 2009, was a loss of $52 million, net of income taxes of $18 million (2008 – a gain of $90 million, net of income taxes of $37 million).

Fair Value of Non-Designated Derivative Financial Instruments

The fair values of the derivative assets and liabilities above are as follows:

($ millions)	**December 31 2009**	December 31 2008
Derivative assets [(a)]	**213**	635
Derivative liabilities [(b)]	**(572)**	(14)
Net derivative assets (liabilities)	**(359)**	621

(a) As at December 31, 2009, $213 million is recorded in accounts receivable (2008 – $376 million recorded in accounts receivable and $259 million recorded in other assets) in the Consolidated Balance Sheets.

(b) As at December 31, 2009, $572 million is recorded in accounts payable and accrued liabilities (2008 – $14 million) in the Consolidated Balance Sheets.

Change in fair value of net assets

($ millions)	**2009**
Fair value of contracts at December 31, 2008	621
Fair value of contracts realized during the period	**448**
Fair value of contracts entered into during the period	**(983)**
Changes in fair value during the period	**(445)**
Fair value of contracts outstanding at December 31, 2009	**(359)**

(d) Fair Value of Financial Instruments

To estimate fair value of financial instruments, the company uses quoted market prices when available, or industry accepted third-party models and valuation methodologies that utilize observable market data. In addition to market information, the company incorporates transaction specific details that market participants would utilize in a fair value measurement, including the impact of non-performance risk. The company characterizes inputs used in determining fair value using a hierarchy that prioritizes inputs depending on the degree to which they are observable. However, these fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction. The three levels of the fair value hierarchy are as follows:

- Level 1 – inputs represent quoted prices in active markets for identical assets or liabilities (for example, exchange-traded commodity derivatives). Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2 – inputs other than quoted prices included within Level 1 that are observable, either directly or indirectly, as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, market interest rates, and volatility factors, which can be observed or corroborated in the marketplace. The company obtains information from sources such as the New York Mercantile Exchange and independent price publications.
- Level 3 – inputs that are less observable, unavailable or where the observable data does not support the majority of the instrument's fair value.

In forming estimates, the company utilizes the most observable inputs available for valuation purposes. If a fair value measurement reflects inputs of different levels within the hierarchy, the measurement is categorized based upon the lowest level of input that is significant to the fair value measurement. The valuation of over-the-counter financial swaps and collars is based on similar transactions observable in active markets or industry standard models that primarily rely on market observable inputs. Substantially all of the assumptions for industry standard models are observable in active markets throughout the full term of the instrument. These are categorized as Level 2.

The following table presents the company's material assets and liabilities measured at fair value for each hierarchy level as of December 31, 2009:

($ millions)	Level 1	Level 2	Level 3	Total Fair Value
Designated hedge financial instruments	—	18	—	**18**
Other derivative financial instruments	(13)	(348)	2	**(359)**
Total	**(13)**	**(330)**	**2**	**(341)**

Financial Risk Factors

The company is exposed to a number of different financial risks arising from normal course business exposures, as well as the company's use of financial instruments. These risk factors include market risks relating to commodity prices, foreign currency risk and interest rate risk, as well as liquidity risk and credit risk.

The company maintains a formal governance process to manage its financial risks. Our Risk Management Committee (RMC) is charged with the oversight of the company's risk management for trading risk management activities which are defined as strategic hedging, optimization trading, marketing and speculative trading. The RMC, acting under board authority, meets regularly to monitor limits on risk exposures, review policy compliance and validate risk-related methodologies and procedures. All risk management activity is carried out by specialist teams that have the appropriate skills, experience and supervision with the appropriate financial and management controls, and is unchanged from the prior year.

1) Market Risk

Market risk is the risk or uncertainty arising from possible market price movements and their impact on the future performance of the business. The market price movements that could adversely affect the value of the company's financial assets, liabilities and expected future cash flows include commodity price risk (crude oil, natural gas and electricity price), foreign currency exchange risk and interest rate risk.

(a) Commodity Price Risk

The company's financial performance is closely linked to crude oil prices (including pricing differentials for various product types), and to a lesser extent, natural gas and electricity prices. The company's policies permit the use of various financial instruments in managing these price exposures. Our strategic crude oil hedging program gives management approval to fix a price or range of prices for portions of the total crude oil planned production for specified periods of time.

A key component of our overall business strategy is to produce sufficient natural gas to meet or exceed internal demands for natural gas purchased for consumption at our North American operations, thus creating a price hedge which reduces our exposure to natural gas price volatility. In addition, existing corporate policies also permit the hedging of natural gas exposures to manage regional price differentials and pricing indexes as identified.

Changes in commodity prices on our financial contracts would have the following impact on our net earnings and other comprehensive income for the year ended December 31, 2009:

Sensitivity Analysis

($ millions)	December 31, 2009 [1]	Change	Net Earnings	Other Comprehensive Income
Crude Oil	US$85.55/barrel			
Price increase		US$1.00/barrel	(18)	—
Price decrease		US$1.00/barrel	18	—
Natural Gas	US$5.81/mcf			
Price increase		US$0.10/mcf	(1)	—
Price decrease		US$0.10/mcf	1	—

(1) Prices represent the average of the forward strip prices at December 31, 2009.

(b) Foreign Currency Exchange Risk

The company is exposed to changes in foreign exchange rates as revenues, capital expenditures, or financial instruments may fluctuate due to changing rates. As crude oil, the company's primary product, is priced in U.S. dollars, fluctuations in US$/Cdn$ exchange rates may have a significant impact on revenues. The company's exposure is partially offset through the issuance of U.S. dollar denominated long-term debt (refer to note 17) and by sourcing capital projects in U.S. dollars. The company does not currently hedge foreign currency risk on estimated revenues. The effect of a $0.01 change in the December 31, 2009 US$/Cdn$ exchange rate would change after-tax earnings by approximately $75 million and after-tax other comprehensive income by approximately $40 million for the year ended December 31, 2009.

Where an operating unit has substantial exposure to capital expenditures in currencies other than the U.S. dollar, the company may hedge these risks through a combination of forward and option instruments. Transactions in the applicable financial market are executed consistent with established risk management policies.

(c) Interest Rate Risk

The company is exposed to interest rate risk as changes in interest rates may affect future cash flows and the fair values of its financial instruments. The primary exposure is related to our revolving-term debt (commercial paper, bankers' acceptances and London Interbank Offered Rate (LIBOR) loans). The company seeks to optimize this risk through the use of interest rate swaps by swapping fixed rates of interest for variable rates (see – Fair Value Hedges on page 75) and other derivative instruments.

To optimize the company's position with respect to interest expense, the company targets 30% to 50% of total debt to be exposed to floating interest rates. Over time this floating/fixed rate mix will fluctuate based on prevailing market conditions and management's assessment of overall risk.

The proportion of floating interest rate exposure inclusive of interest rate swaps at December 31, 2009 was 25% of total debt outstanding (December 31, 2008 – 15%). The weighted-average interest rate on total debt for the year ending December 31, 2009 was 5.6% (December 31, 2008 – 5.9%).

The company's cash flows are sensitive to changes in interest rates on the floating rate portion of the company's debt. If the interest rates applicable to floating rate instruments were to have increased by 1%, it is estimated that the company's cash flow for the year ended December 31, 2009 would decrease by approximately $34 million and earnings would decrease by approximately $27 million. This assumes that the amount and mix of fixed and floating rate debt remains unchanged from December 31, 2009, and that the change in interest rates is effective from the beginning of the year.

2) Liquidity Risk

Liquidity risk is the risk that an entity will encounter difficulty in meeting obligations associated with financial liabilities. The company believes that it has access to sufficient capital through internally generated cash flows and external sources (bank credit markets and debt capital markets), and to undrawn committed borrowing facilities to meet current spending forecasts.

Surplus cash is invested into a range of short-dated money market securities and the company seeks to ensure the security and liquidity of those investments. Investments are only permitted in high credit quality government or corporate securities. Diversification of these investments is supported through maintaining counterparty credit limits.

The following table shows the timing of cash outflows relating to trade and other payables and finance debt.

	December 31, 2009		December 31, 2008	
($ millions)	Trade and other payables [1]	Finance debt [2]	Trade and other payables [1]	Finance debt [2]
Within one year	**6 529**	**3 796**	3 181	1 378
1 to 3 years	**653**	**1 811**	335	1 377
3 to 5 years	**—**	**1 591**	—	822
Over 5 years	**—**	**18 900**	16	13 387
Total	**7 182**	**26 098**	3 532	16 964

(1) Includes the Fort Hills purchase obligation and the Libya EPSAs signature bonus.

(2) Finance debt includes principal and interest payments on long-term debt and capital lease payments.

3) Credit Risk

Credit risk is the risk that a customer or counterparty will fail to perform an obligation or fail to pay amounts due causing a financial loss. We have a credit policy that is designed to ensure there is a standard credit practice throughout the company to measure and monitor credit risk. The policy outlines delegation of authority, the due diligence process required to approve a new customer or counterparty and the maximum amount of credit exposure per single entity. Before transactions begin with a new customer or counterparty, its creditworthiness is assessed, a credit rating is assigned and a maximum credit limit is allocated. The assessment process is outlined in the credit policy and considers both quantitative and qualitative factors. The company constantly monitors the exposure to any single customer or counterparty along with the financial position of the customer or counterparty. If it is deemed that a customer or counterparty has become materially weaker, the company will work to reduce the credit exposure and lower the credit limit allocated. Regular reports are generated to monitor credit risk and the Credit Committee meets quarterly to ensure compliance with the credit policy and review the exposures.

A substantial portion of the company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risk. At December 31, 2009, substantially all of the company's trade receivables were current, and there were no counterparties that individually constituted more than 10% of the outstanding balance.

The company may be exposed to certain losses in the event that counterparties to derivative financial instruments are unable to meet the terms of the contracts. The company's exposure is limited to those counterparties holding derivative contracts with positive fair values at the reporting date. At December 31, 2009, the company's exposure was $231 million (December 31, 2008 – $659 million).

5. ENERGY SUPPLY AND TRADING ACTIVITIES

($ millions)	**December 31 2009**	December 31 2008	December 31 2007
Settlement of non-trading physical contracts [(1)]	**8 008**	11 295	2 931
Settlement of trading physical contracts [(1)]	**20**	—	—
Gains (losses) on trading derivatives [(1)]	**(70)**	127	(39)
Gains on inventory valuation [(1)]	**47**	—	—
Less: Intercompany eliminations	**(428)**	(102)	(110)
Energy Supply and Trading Activities Revenue	**7 577**	11 320	2 782
Settlement of non-trading physical contracts [(1)]	**7 929**	11 331	2 871
Less: Intercompany eliminations	**(548)**	(8)	(1)
Energy Supply and Trading Activities Expense	**7 381**	11 323	2 870

(1) As described in Note 4, certain physical trading strategies are no longer being used for the company's expected purchase, sale or usage requirements. Effective October 1, 2009, contracts within these strategies are now considered derivative financial instruments whereby realized and unrealized gains and losses, and the underlying settlement of these contracts, is recognized and reported on a net basis in Energy Supply and Trading Activities Revenue. Prior to October 1, 2009, the settlement of these contracts was recorded on a gross basis within Energy Supply and Trading Activity Revenue and Energy Supply and Trading Activity Expense.

6. FINANCING EXPENSES (INCOME)

($ millions)	**2009**	2008	2007
Interest on debt	**573**	352	189
Capitalized interest	**(136)**	(352)	(189)
Interest expense	**437**	—	—
Foreign exchange loss (gain) on long-term debt	**(858)**	919	(252)
Other foreign exchange (gain) loss	**(66)**	(2)	41
Total financing expenses (income)	**(487)**	917	(211)

Cash interest payments in 2009 totalled $581 million (2008 – $328 million; 2007 – $183 million).

7. INCOME TAXES

The assets and liabilities shown on Suncor's balance sheets are calculated in accordance with Canadian GAAP. Suncor's income taxes are calculated according to government tax laws and regulations, which results in different values for certain assets and liabilities for income tax purposes. These differences are known as ***temporary differences****, because eventually these differences will reverse.*

The amount shown on the balance sheets as ***future income taxes*** *represent income taxes that will eventually be payable or recoverable in future years when these temporary differences reverse.*

See below for more technical details and amounts.

The provision for income taxes reflects an effective tax rate that differs from the statutory tax rate. A reconciliation of the provision for income taxes is as follows:

($ millions)	**2009**	2008	2007
Earnings before income tax	**1 289**	3 132	3 549
Canadian statutory tax rate	**30.95%**	29.52%	32.14%
Statutory tax	**399**	925	1 141
Add (deduct) the tax effect of:			
Non-taxable component of capital gains and losses	**(133)**	136	(40)
Stock-based compensation and other permanent items	**42**	36	33
Assessments and adjustments	**(42)**	(48)	(1)
Effect of changes to statutory enacted rates	**(148)**	—	(427)
Impact of income tax rate adjustments on future income tax liabilities	**152**	—	—
Change in valuation allowance	**(59)**	—	—
Canadian tax rate differential	**(27)**	(113)	(145)
Foreign tax rate differential	**84**	12	23
Non-taxable gain on effective settlement of pre-existing contract with Petro-Canada (note 2(e))	**(105)**	—	—
Other	**(20)**	47	(18)
Provision for income taxes	**143**	995	566

At December 31, geographic distribution of current income tax provisions were as follows:

($ millions)	**2009**	2008	2007
Provision for (recovery of) Income Taxes:			
Current:			
Canada	**599**	493	271
Foreign	**269**	21	111
Future:			
Canada	**(702)**	515	142
Foreign	**(23)**	(34)	42
Total provision for income taxes	**143**	995	566

The provisions for current and future income taxes include tax recoveries (expenses), which are largely due to changes to income tax rates. These amounts have been allocated to the business segments as follows:

($ millions)	**2009**	2008	2007
Oil Sands	**103**	—	413
Natural Gas	**8**	—	39
East Coast Canada	**20**	—	—
Refining and Marketing	**19**	—	17
Corporate, Energy Trading and Eliminations	**(2)**	—	(42)
	148	—	427

In 2009, net income tax payments totalled $872 million (2008 – $638 million; 2007 – $152 million).

At December 31, future income taxes were comprised of the following:

($ millions)	**2009**	2008	2007
Future income tax liabilities:			
Property, plant and equipment	**9 670**	4 987	4 467
Risk management and energy trading	**—**	149	—
Other	**177**	48	86
Future income tax assets:			
Asset retirement obligations	**(813)**	(400)	(269)
Employee future benefits	**(352)**	(72)	(118)
Risk management and energy trading	**(113)**	—	—
Other Assets	**(206)**	(7)	37
Net Future income tax liabilities	**8 363**	4 705	4 203
Less: Current portion of future income tax (assets)/liabilities	**(314)**	90	(9)
Future income tax liabilities	**8 677**	4 615	4 212

Deferred distribution taxes associated with International business operations have not been recorded. Based on current plans, repatriation of funds in excess of foreign reinvestment will not result in material additional income tax expense.

Complex income tax issues, which involve interpretation of continually changing regulations, are encountered in computing the provision for income taxes. Management believes that adequate provisions have been made for all such outstanding issues and the resolution of these issues would not materially affect the financial position or results of operation of the company,

8. EARNINGS PER COMMON SHARE

The following is a reconciliation of basic and diluted net earnings per common share:

($ millions)	**2009**	2008	2007
Net earnings	**1 146**	2 137	2 983
(millions of common shares)			
Weighted-average number of common shares	**1 198**	932	922
Dilutive securities:			
Shares issued under stock-based compensation plans	**13**	13	20
Weighted-average number of diluted common shares	**1 211**	945	942
(dollars per common share)			
Basic earnings per share [(a)]	**0.96**	2.29	3.23
Diluted earnings per share [(b)]	**0.95**	2.26	3.17

Note: An option will have a dilutive effect under the treasury stock method only when the average market price of the common stock during the period exceeds the exercise price of the option.

(a) Basic earnings per share is the net earnings attributable to common shareholders divided by the weighted-average number of common shares.

(b) Diluted earnings per share is the net earnings attributable to common shareholders divided by the weighted-average number of diluted common shares.

9. CASH AND CASH EQUIVALENTS

($ millions)	**2009**	2008
Cash	**205**	30
Short-term investments	**300**	630
	505	660

10. CHANGES IN NON-CASH WORKING CAPITAL RELATING TO OPERATING ACTIVITIES

Non-cash working capital is comprised of current assets and current liabilities, other than cash and cash equivalents, future income taxes and the current portion of long-term debt.

The (increase) decrease in non-cash working capital is comprised of:

($ millions)	**2009** [1]	2008	2007
Operating activities			
Accounts receivable	**123**	226	(374)
Inventories	**(585)**	103	(223)
Accounts payable and accrued liabilities	**282**	186	207
Income taxes payable/receivable	**(44)**	(110)	246
	(224)	405	(144)

(1) Balances do not include amounts acquired from Petro-Canada as a result of the merger, but do reflect the changes in these working capital accounts subsequent to August 1, 2009.

11. INVENTORIES

($ millions)	**2009**	2008
Crude oil	**781**	459
Refined products	**1 303**	247
Materials, supplies and merchandise	**532**	203
Energy trading commodity inventories [1]	**355**	—
Total	**2 971**	909

(1) As described in note 4, certain physical trading commodity contracts are no longer being used for the company's expected purchase, sale or usage requirements. Inventories related to these derivative contracts are now recorded at fair value less costs to sell with the associated gains and losses and the underlying settlement of the inventory recorded on a net basis in Energy Supply and Trading Activities revenue.

During 2009, inventories of $14.9 billion (2008 – $15.7 billion) were expensed. There were no write-downs of inventories in 2009 (2008 – $40 million) and no reversals of write-downs were recorded in 2009 and 2008.

12. OTHER ASSETS

($ millions)	**2009**	2008
Unrealized mark-to-market gains on commodity derivatives	**6**	273
Intangible assets [1]	**233**	—
Investments	**148**	23
Other	**149**	92
Total	**536**	388

(1) In 2009, $236 million of intangible assets were acquired through the business combination with Petro-Canada. $166 million of these assets relate to the Petro-Canada brand and have an indefinite life, and $70 million relate to customer lists which will be amortized over their estimated useful lives which range from five to ten years. Amortization expense recognized for the year ended December 31, 2009 related to intangible assets was $4 million (2008 – nil).

13. PROPERTY, PLANT AND EQUIPMENT

($ millions)	2009 Cost	2009 Accumulated Provision	2008 Cost	2008 Accumulated Provision
Oil Sands				
Oil and gas properties	**5 224**	**448**	2 021	285
Plant and equipment	**19 012**	**3 677**	14 184	2 988
Assets not subject to depreciation or depletion[1]	**12 551**	**—**	11 107	—
	36 787	**4 125**	27 312	3 273
Natural Gas				
Oil and gas properties	**5 925**	**1 613**	2 584	1 213
Plant and equipment	**351**	**118**	219	100
Assets not subject to depreciation or depletion[1]	**24**	**—**	211	—
	6 300	**1 731**	3 014	1 313
East Coast Canada			—	—
Oil and gas properties	**3 463**	**207**	—	—
Plant and equipment	**49**	**1**	—	—
Assets not subject to depreciation or depletion[1]	**1 360**	**—**	—	—
	4 872	**208**	—	—
International				
Oil and gas properties	**4 130**	**271**	—	—
Plant and equipment	**53**	**31**	—	—
Assets not subject to depreciation or depletion[1]	**4 294**	**—**	—	—
	8 477	**302**	—	—
Refining and Marketing				
Plant and equipment	**8 312**	**1 654**	4 049	1 313
Assets not subject to depreciation or depletion[1]	**503**	**—**	215	—
	8 815	**1 654**	4 264	1 313
Corporate	**419**	**165**	329	138
	65 670	**8 185**	34 919	6 037
Net property, plant and equipment		**57 485**		28 882

(1) Consists of work in progress, development assets, and assets under construction which are not currently being depreciated or depleted.

At December 31, 2009, capital leases at a net cost of $225 million (December 31, 2008 – $91 million) and $48 million are included in the assets of Oil Sands and East Coast Canada, respectively.

14. EMPLOYEE FUTURE BENEFITS LIABILITY

*Suncor employees are eligible to receive certain pension, health care and insurance benefits when they retire under the terms of the company's defined benefit and defined contribution plans. The related **Benefit Obligation** or commitment that Suncor has to employees and retirees at December 31, 2009, was $3 279 million (2008 – $955 million).*

*As required by government regulations, Suncor sets aside funds with an independent trustee to meet certain of the defined benefit pension obligations. The company funds its unregistered supplementary pension plan and supplementary senior executive retirement plan on a voluntary basis. The amount and timing of future funding for these supplementary plans is subject to capital availability and is at the company's discretion. At the end of December 2009, **Plan Assets** to meet the **Benefit Obligation** were $2 072 million (2008 – $613 million).*

*The excess of the **Benefit Obligation** over **Plan Assets** of $1 207 million (2008 – $342 million) represents the **Net Unfunded Obligation**.*

The company also provides a number of defined contribution plans, including a U.S. 401(k) savings plan, that provide for an annual contribution of 5% to 8% of each participating employee's pensionable earnings.

Defined Benefit Pension Plans and Other Post-Retirement Benefits

The company's defined benefit pension plans provide non-indexed pension benefits at retirement based on years of service and final average earnings. These obligations are met through funded registered retirement plans and through unregistered supplementary pensions and senior executive retirement plans that are voluntarily funded through retirement compensation arrangements, and/or paid directly to recipients. Company contributions to the funded plans are deposited with independent trustees who act as custodians of the plans' assets, as well as the disbursing agents of the benefits to recipients. Plan assets are managed by a pension committee on behalf of beneficiaries. The committee retains independent managers and advisors.

Funding of the registered retirement plans complies with applicable regulations that require actuarial valuations of the pension funds at least once every three years in Canada, depending on funding status, and every year in the United States. The most recent valuation for the Canadian plans was performed as at December 31, 2009 and the next required valuation will be as of December 31, 2012.

The company's other post-retirement benefits programs are unfunded and include certain health care and life insurance benefits provided to retired employees and eligible surviving dependants.

The expense and obligations for both funded and unfunded benefits are determined in accordance with Canadian GAAP and actuarial principles. Obligations are based on the projected benefit method of valuation that includes employee service to date and present pay levels, as well as a projection of salaries and service to retirement.

Defined Benefit Obligations and Funded Status

The following table presents information about obligations recognized in the Consolidated Balance Sheets and the funded status of the plans at December 31:

	Pension Benefits		Other Post-Retirement Benefits	
($ millions)	**2009**	2008	**2009**	2008
Change in benefit obligation				
Benefit obligation at beginning of year	**806**	901	**149**	162
Plan acquisition upon merger [(a)]	**1 912**	—	**265**	—
Service costs	**64**	56	**6**	4
Interest costs	**96**	49	**15**	9
Plan participants' contributions	**17**	9	**—**	—
Foreign exchange	**(13)**	8	**(4)**	4
Actuarial (gain) loss	**59**	(168)	**1**	(27)
Benefits paid	**(86)**	(49)	**(8)**	(3)
Benefit obligation at end of year [(b)(e)]	**2 855**	806	**424**	149
Change in plan assets [(c)]				
Fair value of plan assets at beginning of year	**613**	684	**—**	—
Plan acquisition upon merger	**1 255**	—		—
Actual return (loss) on plan assets	**175**	(107)	**—**	—
Employer contributions	**105**	72	**—**	—
Foreign exchange	**(7)**	4	**—**	—
Plan participants' contributions	**17**	9	**—**	—
Benefits paid	**(86)**	(49)	**—**	—
Fair value of plan assets at end of year [(e)]	**2 072**	613	**—**	—
Net unfunded obligation	**(783)**	(193)	**(424)**	(149)
Items not yet recognized in earnings:				
Unamortized net actuarial loss [(d)]	**50**	123	**8**	12
Unamortized past service costs	**9**	—	**(14)**	(17)
Accrued benefit liability	**(724)**	(70)	**(430)**	(154)
Current liability	**(30)**	(37)	**(3)**	(3)
Long-term liability	**(701)**	(40)	**(427)**	(151)
Long-term asset	**7**	7	**—**	—
Total accrued benefit liability	**(724)**	(70)	**(430)**	(154)

(a) The valuation of accrued benefit obligations for plans acquired through the business combination with Petro-Canada assumed a discount rate of 5.25%, a rate of compensation increase of 3.00% and an expected return on plan assets rate of 6.75%.

(b) Obligations are based on the following assumptions:

(percent)	Pension Benefit Obligations 2009	Pension Benefit Obligations 2008	Other Post-Retirement Benefits Obligations 2009	Other Post-Retirement Benefits Obligations 2008
Discount rate	**5.85**	6.50	**6.00**	6.50
Rate of compensation increase	**3.90**	5.00	**4.00**	4.75

Assumed health care cost trend rates may have a significant effect on the amounts reported for other post-retirement benefit obligations. A one percent change in assumed health care cost trend rates would have the following effects:

($ millions)	1% increase	1% decrease
Increase (decrease) to total of service and interest cost components of net periodic post-retirement health care benefit cost	2	(2)
Increase (decrease) to the health care component of the accumulated post-retirement benefit obligation	34	(28)

(c) Pension plan assets are not the company's assets and therefore are not included in the Consolidated Balance Sheets.

(d) The unamortized net actuarial loss represents annually calculated differences between actual and projected plan performance. These amounts are amortized as part of the net periodic benefit cost over the expected average remaining service life of employees of 7 years for pension benefits (2008 – 11 years; 2007 – 11 years), and over the expected average future service life to full eligibility age of 11 years for other post-retirement benefits (2008 – 11 years; 2007 – 12 years).

(e) The company uses a measurement date of December 31 to value the plan assets and accrued benefit obligation.

The above benefit obligation at year-end includes partially funded and unfunded plans, as follows:

($ millions)	Pension Benefits 2009	Pension Benefits 2008	Other Post-Retirement Benefits 2009	Other Post-Retirement Benefits 2008
Partially funded plans	**2 855**	806	**—**	—
Unfunded plans	**—**	—	**424**	149
Benefit obligation at end of year	**2 855**	806	**424**	149

Benefit Plans Expense

($ millions)	Pension Benefits 2009	Pension Benefits 2008	Pension Benefits 2007	Other Post-Retirement Benefits 2009	Other Post-Retirement Benefits 2008	Other Post-Retirement Benefits 2007
Current service costs	**64**	56	51	**6**	4	4
Interest costs	**96**	49	45	**15**	9	8
Actual (return) loss on plan assets [(i)]	**(175)**	107	(7)	**—**	—	—
Actuarial (gain) loss	**59**	(168)	(28)	**1**	(27)	(4)
Pension expense before adjustments for the long-term nature of employee future benefit costs	**44**	44	61	**22**	(14)	8
Difference between actual and expected return on plan assets [(i)]	**98**	(152)	(35)	**—**	—	—
Difference between actual and recognized actuarial losses	**(36)**	188	51	**3**	33	10
Difference between actual and recognized past service costs	**2**	2	2	**(3)**	(3)	(3)
Defined benefit plans expense [(ii)]	**108**	82	79	**22**	16	15
Defined contribution plans expense	**28**	15	13	**—**	—	—
Total benefit plans expense	**136**	97	92	**22**	16	15

(i) The expected return on plan assets is the expected long-term rate of return on plan assets for the year. It is based on plan assets at the beginning of the year that have been adjusted on a weighted-average basis for contributions and benefit payments expected for the year. The expected return on plan assets is included in the net periodic benefit cost for the year to which it relates, while the difference between it and the actual return realized on plan assets in the same year is amortized over the expected average remaining service life of employees of 7 years for pension benefits.

To estimate the expected long-term rate of return on plan assets, the company considered the current level of expected returns on the fixed income portion of the portfolio, the historical level of the risk premium associated with other asset classes in which the portfolio is invested and the expectation for future returns on each asset class. The expected return for each asset class was weighted based on the policy asset mix to develop an expected long-term rate of return on asset assumption for the portfolio.

(ii) Defined benefit plans pension expense is based on the following assumptions:

(percent)	Pension Benefit Expense **2009**	2008	2007	Other Post-Retirement Benefits Expense **2009**	2008	2007
Discount rate	**6.50**	5.25	5.00	**6.00**	5.25	5.00
Expected return on plan assets	**6.70**	6.50	6.50	**N/A**	N/A	N/A
Rate of compensation increase	**3.90**	5.00	5.00	**4.00**	4.75	4.75

Plan Assets and Investment Objectives

The company's long-term investment objective is to secure the defined pension benefits while managing the variability and level of its contributions. The portfolio is rebalanced periodically as required, while ensuring that the maximum equity content is 65% at any time. Plan assets are restricted to those permitted by legislation, where applicable. Investments are made through pooled, mutual, segregated or exchange traded funds.

The company's weighted-average pension plan asset allocation based on market values as at December 31, 2009 and 2008, and the target allocation for 2010, are as follows:

Asset Category	Target Allocation % 2010	Plan Assets % **2009**	2008
Equities	57	**59**	57
Fixed income	43	**41**	43
Total	100	**100**	100

Equity securities do not include any direct investments in Suncor shares.

Cash Flows

The company expects that cash contributions to its defined benefit pension plans in 2010 will be $133 million. Expected benefit payments from all of the plans are as follows:

	Pension Benefits	Other Post-Retirement Benefits
2010	136	18
2011	145	19
2012	153	21
2013	163	23
2014	170	24
2015 – 2019	963	141
Total	1 730	246

15. SHARE CAPITAL

Authorized

Common Shares

The company is authorized to issue an unlimited number of common shares without nominal or par value.

Preferred Shares

The company is authorized to issue an unlimited number of preferred shares in series, without nominal or par value.

Issued

	Common Shares	
	Number (thousands)	Amount ($ millions)
Balance as at December 31, 2006	919 888	794
Issued for cash under stock option plans	5 388	74
Issued under dividend reinvestment plan	290	13
Balance as at December 31, 2007	925 566	881
Issued for cash under stock options plan	9 823	226
Issued under dividend reinvestment plan	135	6
Balance as at December 31, 2008	935 524	1 113
Shares issued to Petro-Canada shareholders (note 2)	**621 142**	**18 878**
Issued for cash under stock options plan	**2 968**	**57**
Issued under dividend reinvestment plan	**144**	**5**
Balance as at December 31, 2009	**1 559 778**	**20 053**

Stock-Based Compensation

A stock option gives the holder the right, but not the obligation, to purchase common shares at a predetermined price over a specified period of time.

After the date of grant, employees and non-employee directors that hold options must earn the right to exercise them. The holder must fulfill a time requirement for service to the company, at which time the option is considered vested. Certain options are subject to accelerated vesting should the company meet predetermined performance criteria.

The predetermined price at which an option can be exercised is equal to or greater than the market price of the common shares on the date the option is granted.

Certain stock options with a cash payment alternative (CPA) entitle the holder to surrender vested options for cancellation in return for a direct cash payment based on the excess of the then current market price of the underlying common share over the option exercise price or for a common share in the company at the option exercise price.

A stock appreciation right unit (SAR) entitles the holder to receive a cash payment equal to the difference between the stated exercise price and the market price of the company's common shares on the date the vested option is surrendered.

A performance share unit (PSU) is a time-vested award entitling employees to receive cash to varying degrees contingent upon the company's shareholder return relative to a peer group of companies.

A restricted share unit (RSU) is a time-vested award entitling employees to receive cash based on the company's share price at time of vesting.

A deferred share unit (DSU) is a notional share unit, redeemable for cash or a common share for a period of time after a unitholder ceases employment or Board membership. The DSU plan is only for executives and members of the company's Board of Directors.

(a) Stock Option Plans:

(i) SunShare 2012 Performance Stock Option Plan

Granting of options under this plan ended on July 31, 2009. The company granted 1,204,000 options in 2009 (2008 – 2,637,000, 2007 – 15,686,000) to all eligible permanent full-time and part-time employees, both executive and non-executive, under its SunShare 2012 performance stock option plan. On January 1, 2010, 25% of the outstanding options vested and the remaining 75% of outstanding options may vest on January 1, 2013 if certain specified performance targets are met. All unvested options at January 1, 2013, which have not previously expired or been cancelled will automatically expire.

(ii) Executive Stock Plan

Granting of options under this plan ended on July 31, 2009. Under this plan, the company granted 711,000 common share options in 2009 (2008 – 895,000; 2007 – 958,000) to non-employee directors and certain executives and other senior employees of the company. Options granted have a 10-year life and vest annually over a three-year period.

(iii) Key Contributor Stock Option Plan

Granting of options under this plan ended on July 31, 2009. Under this plan, the company granted 571,000 common share options in 2009 (2008 – 2,375,000; 2007 – 2,370,000) to non-insider senior managers and key employees. Options granted have a 10-year life and vest annually over a three-year period.

(iv) Petro-Canada Stock Options ("Adjusted Options")

Granting of options under this plan ended on July 31, 2009. In conjunction with the business combination transaction described in note 2, each outstanding option issued under this plan to purchase Petro-Canada common shares was exchanged on August 1, 2009 for 1.28 options to purchase Suncor common shares, for a total of 29.9 million options outstanding at August 1, 2009. The same exchange ratio was applied to the exercise price of these options.

The Adjusted Options, issued to officers and certain employees, have a term of ten years if granted prior to 2004 and seven years if granted subsequent to 2003. Holders of options granted after 2003 are entitled to exercise the options in exchange for a cash payment alternative (CPA). A total of 22.8 million of the Adjusted Options outstanding on August 1, 2009 had a CPA and are recorded in accrued liabilities and other on the Consolidated Balance Sheets, based on their intrinsic value at each period end. All Adjusted Options vest over periods of up to four years.

(v) Suncor Energy Inc. Stock Options

This plan replaces the pre-merger stock option plans of legacy Petro-Canada and Suncor. The company granted 4,000 options under this plan, which came into effect on August 1, 2009. Outstanding options that are cancelled, expire or are terminated or otherwise result in no underlying common share being issued will be available for issuance as options under this plan. Options granted have a seven-year life and vest annually over a three-year period.

The following tables cover all common share options granted by the company for the years indicated:

	Number (thousands)	Range of Exercise Prices Per Share ($)	Weighted-Average Exercise Price Per Share ($)
Outstanding, December 31, 2006	39 618	3.89 – 50.90	19.24
Granted	21 104	35.28 – 53.51	46.68
Exercised	(5 388)	3.89 – 46.06	11.38
Forfeited/expired	(1 334)	12.66 – 50.87	32.84
Outstanding, December 31, 2007	54 000	5.06 – 53.51	30.31
Granted	5 907	23.30 – 69.97	50.78
Exercised	(9 823)	5.06 – 50.86	19.69
Forfeited/expired	(3 682)	12.31 – 67.58	41.72
Outstanding, December 31, 2008	46 402	5.06 – 69.97	34.55
Granted	**2 490**	**20.99 – 49.67**	**35.78**
Adjusted options issued to Petro-Canada stock option holders	**29 900**	**8.22 – 44.27**	**28.05**
Exercised	**(2 870)**	**5.06 – 36.68**	**13.69**
Forfeited/expired	**(3 898)**	**13.31 – 71.12**	**40.48**
Outstanding, December 31, 2009	**72 024**	**7.84 – 72.68**	**32.52**
Exercisable, December 31, 2009	**42 755**	**7.84 – 72.68**	**26.16**

Common shares authorized for issuance by the Board of Directors that remain available for the granting of future options, at December 31:

(thousands of common shares)	**2009**	2008	2007
	15 942	12 345	14 570

The following table is an analysis of outstanding and exercisable common share options as at December 31, 2009:

	Outstanding			Exercisable	
Exercise Prices ($)	Number (thousands)	Weighted-Average Remaining Contractual Life (years)	Weighted-Average Exercise Price Per Share ($)	Number (thousands)	Weighted-Average Exercise Price Per Share ($)
7.84 – 12.99	2 476	1	10.03	2 476	10.03
13.00 – 17.99	13 984	2	14.18	13 984	14.18
18.00 – 29.99	15 157	4	22.31	10 788	22.93
30.00 – 44.99	17 736	4	38.91	10 863	39.72
45.00 – 49.99	21 216	5	47.45	4 557	46.51
50.00 – 72.68	1 455	5	57.62	87	52.75
Total	72 024	4	32.52	42 755	26.16

Fair Value of Options Granted

The fair values of all legacy Suncor common share options granted during the period and Adjusted Options granted in 2003 are estimated as at the grant date using the Monte Carlo simulation approach for the SunShare 2012 option plan and the Black-Scholes option-pricing model for all other option plans. Adjusted Options which have a CPA granted subsequent to 2003 are accounted for based on the intrinsic value at each period end. The weighted-average fair values of the options granted during the various periods and the weighted-average assumptions used in their determination are as noted below:

	2009	2008	2007
Annual dividend per share	**$0.30**	$0.20	$0.19
Risk-free interest rate	**2.31%**	3.35%	4.22%
Expected life	**5 years**	6 years	6 years
Expected volatility	**47%**	30%	30%
Weighted-average fair value per option	**$10.28**	$13.86	$14.89

(b) Petro-Canada Stock Appreciation Rights ("Adjusted SARs")

Grants under this plan ended on July 31, 2009. In conjunction with the business combination described in note 2, each outstanding SAR issued under this plan was exchanged with 1.28 SARs resulting in the addition of 15,353,000 SARs at August 1, 2009. SARS have a seven-year life and vest annually over a four-year period.

Changes in the number of Adjusted SARs outstanding were as follows:

	Number (thousands)	Range of Exercise Prices Per Share ($)	Weighted-Average Exercise Price Per Share ($)
Shares issued to Petro-Canada shareholders (note 2)	**15 353**	**19.13 – 46.13**	**28.74**
Exercised	**(306)**	**19.13 – 39.41**	**35.01**
Forfeited/expired	**(982)**	**19.13 – 46.13**	**28.28**
Outstanding, December 31, 2009	**14 065**	**19.13 – 46.13**	**28.63**
Exercisable, December 31, 2009	**2 740**	**19.13 – 46.13**	**35.45**

The following table summarizes outstanding and exercisable Adjusted SARs as at December 31, 2009:

	Outstanding			Exercisable	
Exercise Prices ($)	Number (thousands)	Weighted-Average Remaining Contractual Life (years)	Weighted-Average Exercise Price Per Share ($)	Number (thousands)	Weighted-Average Exercise Price Per Share ($)
19.13 – 25.00	6 177	6	19.45	7	20.81
25.01 – 35.00	3 538	4	34.31	1 637	34.33
35.01 – 40.00	4 212	5	36.84	1 040	36.87
40.01 – 46.13	138	5	43.83	56	43.65
Total	14 065	5	28.63	2 740	35.45

(c) Deferred Share Units (DSUs)

The company had 2,616,000 DSUs outstanding at December 31, 2009 (1,903,000 at December 31, 2008). In conjunction with the business combination described in note 2, each outstanding Petro-Canada DSU was adjusted by 1.28, resulting in the addition of 1,008,000 DSUs at August 1, 2009. DSUs were granted to certain executives under the company's former employee long-term incentive program. Members of the Board of Directors receive one-half, or at their option, all of their compensation in the form of DSUs. DSUs are only redeemable at the time a unitholder ceases employment or Board membership, as applicable.

In 2009, 443,000 DSUs were redeemed for cash consideration of $16 million (2008 – 473,000 redeemed for cash consideration of $30 million; 2007 – 40,000 redeemed for cash consideration of $2 million). Over time, DSU unitholders are entitled to receive additional DSUs equivalent in value to future notional dividend reinvestments.

(d) Performance Share Units (PSUs)

During 2009, the company issued 1,149,000 PSUs (2008 – 795,000; 2007 – 830,000) under its Performance Share Unit Compensation Plan. In conjunction with the business combination described in note 2, each outstanding Petro-Canada PSU was adjusted by 1.28, resulting in the addition of 945,000 PSUs at August 1, 2009. PSUs vest and are settled in cash approximately three years after the grant date to varying degrees (0%, 50%, 100% and 150%) contingent upon Suncor's performance (performance factor). Performance is measured by reference to the company's total shareholder return (stock price appreciation and dividend income) relative to a peer group of companies. Expense related to the PSUs is accrued based on the price of common shares at the end of the period and the anticipated performance factor. This expense is recognized on a straight-line basis over the term of the grant.

(e) Restricted Share Units (RSUs)

In 2009, the company issued 2,715,000 RSUs (2008 – 1,078,000) under the share unit portion of its new employee stock-based compensation plan ("SunShare 2012"). In conjunction with the business combination described in note 2, each outstanding Petro-Canada RSU was adjusted by 1.28, resulting in the addition of 1,018,000 RSUs at August 1, 2009.

Stock-Based Compensation Expense (Recovery)

The following table summarizes the stock based compensation expense (recovery) recorded for all plans within operating, selling and general expense on the Consolidated Statements of Earnings:

($ millions)	**2009**	2008	2007
Stock option plans	**148**	120	103
Adjusted SARs	**35**	—	—
Performance share units (PSUs)	**30**	(30)	60
Restricted share units (RSUs)	**50**	8	—
Deferred share units (DSUs)	**30**	(51)	21
Total stock based compensation expense	**293**	47	184

16. ACCRUED LIABILITIES AND OTHER

($ millions)	**2009**	2008
Asset retirement obligations [(a)]	**2 888**	1 444
Employee future benefits liability (note 14)	**1 128**	191
Stock-based compensation plans [(b)]	**219**	67
Deferred revenue	**94**	161
Other long-term financial liabilities [(c)]	**602**	—
Other	**131**	123
Total	**5 062**	1 986

(a) Asset Retirement Obligations (ARO)

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the total obligations associated with the retirement of property, plant and equipment.

($ millions)	**2009**	2008
Asset retirement obligations, beginning of year	**1 600**	1 072
Liabilities incurred	**253**	38
Petro-Canada liabilities acquired during the year (note 2) [(1)]	**1 605**	—
Changes in estimates	**(145)**	560
Liabilities settled	**(248)**	(134)
Accretion of asset retirement obligations	**155**	64
Foreign exchange	**(20)**	—
Asset retirement obligations, end of year	**3 200**	1 600
Less: Current portion	**(312)**	(156)
	2 888	1 444

(1) The majority of the asset retirement obligation liability acquired as a result of the merger with Petro-Canada was discounted at August 1, 2009 using the company's long-term credit-adjusted risk-free rate at that time of 6.5%.

The total undiscounted amount of estimated future cash flows required to settle the obligations at December 31, 2009, was approximately $8.3 billion (2008 – $3.5 billion). Substantially all of the liability recognized in 2009 was discounted using the company's long-term credit-adjusted risk-free rate of 6.2% (2008 – 9.0%). The credit-adjusted risk-free rate used reflects the expected timeframe of the related liability. Payments to settle the ARO occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed fifty years. The current portion of asset retirement obligations is included in accounts payable and accrued liabilities.

A significant portion of the company's assets, including the upgrading facilities at the oil sands operation and the downstream refineries, have retirement obligations for which the fair value cannot be reasonably determined because the assets currently have an indeterminate life. The asset retirement obligation for these assets will be recorded in the first period in which the lives of the assets are determinable.

(b) Stock Based Compensation Plans

The portion of the stock based compensation plans expected to be paid within one year is shown within current liabilities and amounts to an additional $10 million (2008 – $8 million). See note 15 for further information on our liability-based stock-based compensation awards.

(c) Other Long-Term Financial Liabilities

As part of the business combination described in Note 2, the company assumed an obligation relating to Petro-Canada's acquisition of an additional 5% interest in the Fort Hills project in 2007 from another partner in the project. To pay for this investment the company will fund $375 million of expenditures in excess of its working interest. Upon the acquisition of Petro-Canada, this obligation was revalued using an estimated payout pattern for the funding, discounted using the company's estimated cost of debt. At December 31, 2009, the carrying amount of the Fort Hills obligation was $322 million.

The company also assumed the remaining US$500 million obligation for a signature bonus relating to Petro-Canada's ratification of six Exploration and Production Sharing Agreements in Libya in 2008, payable in several instalments to be paid through 2013. Upon the acquisition of Petro-Canada, this obligation was revalued using the company's estimated cost of debt.

At December 31, 2009, the carrying amount of the Libya obligation was $511 million, of which the current portion is $231 million and is recorded in accounts payable and accrued liabilities.

17. LONG-TERM DEBT AND CREDIT FACILITIES

($ millions)	**2009**	2008
Fixed-term debt, redeemable at the option of the company		
6.85% Notes, denominated in U.S. dollars, due in 2039 (US$750) (i)	**785**	918
6.80% Notes, denominated in U.S. dollars, due in 2038 (US$900)	**972**	—
6.50% Notes, denominated in U.S. dollars, due in 2038 (US$1150)	**1 204**	1 408
5.95% Notes, denominated in U.S. dollars, due in 2035 (US$600)	**578**	—
5.95% Notes, denominated in U.S. dollars, due in 2034 (US$500)	**523**	612
5.35% Notes, denominated in U.S. dollars, due in 2033 (US$300)	**266**	—
7.15% Notes, denominated in U.S. dollars, due in 2032 (US$500)	**523**	612
6.10% Notes, denominated in U.S. dollars, due in 2018 (US$1250) (i)	**1 308**	1 531
6.05% Notes, denominated in U.S. dollars, due in 2018 (US$600)	**643**	—
5.00% Notes, denominated in U.S. dollars, due in 2014 (US$400) (ii)	**429**	—
4.00% Notes, denominated in U.S. dollars, due in 2013 (US$300)	**313**	—
7.00% Debentures, denominated in U.S. dollars, due in 2028 (US$250)	**271**	—
7.875% Debentures, denominated in U.S. dollars, due in 2026 (US$275)	**325**	—
9.25% Debentures, denominated in U.S. dollars, due in 2021 (US$300)	**402**	—
5.39% Series 4 Medium Term Notes, due in 2037	**600**	600
5.80% Series 4 Medium Term Notes, due in 2018 (iii)	**700**	700
6.70% Series 2 Medium Term Notes, due in 2011 (iv)	**500**	500
	10 342	6 881
Revolving-term debt, with interest at variable rates		
Commercial paper (v), bankers' acceptances and LIBOR loans (interest rate at December 31, 2009 – 0.7%, 2008 – 2.2%)	**3 244**	934
Total unsecured long-term debt	**13 586**	7 815
Secured long-term debt	**13**	13
Capital leases (vi)	**326**	103
Fair value of interest swaps	**18**	25
Deferred financing costs	**(63)**	(72)
	13 880	7 884
Current portion of long-term debt		
Capital leases (vii)	**(14)**	(9)
Fair value of interest swaps	**(11)**	(9)
Total current portion of long-term debt	**(25)**	(18)
Total long-term debt	**13 855**	7 866

(i) In June 2008, the company issued 6.10% Notes with a principal amount of US$1.25 billion and 6.85% Notes with a principal amount of US$750 million under an amended US$3.65 billion debt shelf prospectus. These notes bear interest, which is paid semi-annually, and mature on June 1, 2018, and June 1, 2039, respectively. The net proceeds received were added to our general funds, which were used for our working capital needs, sustaining capital expenditures, growth capital expenditures and to repay outstanding commercial paper borrowings.

(ii) These notes, acquired on August 1, 2009 under the merger with Petro-Canada, were originally issued by PC Financial Partnership, a wholly-owned finance subsidiary of Petro-Canada. Suncor has fully and unconditionally guaranteed the notes.

(iii) In May 2008, the company issued 5.80% Medium Term Notes with a principal amount of $700 million under an outstanding $2,000 million debt shelf prospectus. These notes bear interest, which is paid semi-annually, and mature on May 22, 2018. The net proceeds received were added to our general funds to repay outstanding commercial paper, which originally funded our working capital needs, sustaining capital expenditures and growth capital expenditures.

(iv) The company has entered into interest rate swap transactions. The swap transactions result in an average effective interest rate that is different from the stated interest rate of the related underlying long-term debt instruments.

Description of Swap Transaction	Principal Swapped ($ millions)	Swap Maturity	Effective Interest Rate 2009	2008
Swap of 6.70% Medium Term Notes to floating rates	200	2011	2.0%	4.8%

(v) The company is authorized to issue commercial paper to a maximum of $2.5 billion having a term not to exceed 365 days. Commercial paper is supported by available committed credit facilities, (see Credit facilities below).

(vi) Interest rates on capital leases range from 4.7% to 13.4%, and maturity dates range from 2012 to 2037.

Credit facilities

During 2009, the company acquired $4,524 million of available credit facilities in the merger with Petro-Canada. At December 31, 2009, the company had available credit facilities of $8,188 million, of which $4,208 million was unutilized, as follows:

($ millions)	**2009**
Facility that is fully revolving for 364 days, has a term period of one year and expires in 2010	**61**
Facility that is fully revolving for a period of four years and expires in 2013	**209**
Facilities that are fully revolving for a period of five years and expire in 2013	**7 320**
Facilities that can be terminated at any time at the option of the lenders	**598**
Total available credit facilities	**8 188**
Credit facilities supporting outstanding revolving-term debt	**(3 244)**
Credit facilities supporting standby letters of credit	**(736)**
Total unutilized credit facilities	**4 208**

Certain of the notes and debentures of the company were acquired in the merger described in note 2 and were accounted for at their fair value at the date of acquisition, which was higher than the principal amount. The difference between the fair value and the principal amount of these debts of $121 million is being amortized over the remaining life of the debt acquired.

18. CAPITAL STRUCTURE FINANCIAL POLICIES

The company's primary capital management objective is to maintain a solid investment-grade credit rating profile. This objective affords the company the financial flexibility and access to the capital it requires to execute on its growth objectives.

The company monitors capital through two key ratios: net debt to cash flow from operations [(1)] and total debt to total debt plus shareholders' equity.

Net debt to cash flow from operations is calculated as short-term debt plus total long-term debt less cash and cash equivalents divided by cash flow from operations for the year then ended.

Total debt to total debt plus shareholders' equity is calculated as short-term debt plus total long-term debt divided by short-term debt plus total long-term debt plus shareholders' equity.

Financial covenants associated with the company's various banking and debt arrangements are reviewed regularly and controls are in place to maintain compliance with these covenants. The company complied with all financial covenants for the years ended December 31, 2009 and 2008.

The company's strategy during 2009, which was unchanged from 2008, was to maintain the measure set out in the following schedule. The company believes that achieving our capital target helps to provide the company access to capital at a reasonable cost by maintaining solid investment-grade credit ratings. The company operates in a cyclical business environment and ratios may periodically fall outside of management targets.

At December 31, ($ millions)	Capital Measure Target	**2009**	2008
Components of ratios			
Short-term debt		**2**	2
Current portion of long-term debt		**25**	18
Long-term debt		**13 855**	7 866
Total debt		**13 882**	7 886
Cash and equivalents		**505**	660
Net debt		**13 377**	7 226
Shareholders' equity		**34 111**	14 523
Total capitalization (total debt + shareholders' equity)		**47 993**	22 409
Cash flow from operations [(1)]		**2 799**	4 057
Net debt/cash flow from operations	<2.0 times	**4.8**	1.8
Total debt/total debt plus shareholders' equity		**29%**	35 %

The increase in debt levels as a result of the merger with Petro-Canada on August 1, 2009 has caused our net debt/cash flow from operations measure for the year ended December 31, 2009 to increase significantly, as the calculation only includes five months of cash flow from operations relating to legacy Petro-Canada operations.

(1) Cash flow from operations is expressed before changes in non-cash working capital. Cash flow from operations is the same measure as the cash flow from operating activities before changes in working capital measure that is included in the Consolidated Statements of Cash Flows.

19. COMMITMENTS, CONTINGENCIES, VARIABLE INTEREST ENTITIES, AND GUARANTEES

(a) Operating Commitments

($ millions)	Pipeline Capacity, Energy Services and Delivery Obligations[1]	Operating Leases
2010	714	376
2011	708	212
2012	707	160
2013	688	114
2014	647	101
Later years	7 538	759
Total	11 002	1 722

(1) Includes annual tolls payable under transportation service agreements with major pipeline companies to use a portion of their pipeline capacity and tankage, as applicable, for transportation of product within Canada and the United States.

Suncor has commitments under long-term energy agreements to obtain a portion of the power and the steam generated by certain cogeneration facilities owned by a major third-party energy company and obligations associated with reimbursing BG Gas Marketing for gas quantities as outlined in the Trinidad LNG Sales Contract.

In addition to the operating commitments quantified in the above table, we have other obligations for goods and services and raw materials entered into in the normal course of business, which may terminate on short notice. Commodity purchase obligations for which an active, highly liquid market exists, and which are expected to be re-sold shortly after purchase, are one example of excluded items.

Crude Oil

At December 31, 2009, Suncor had purchase commitments relating to crude oil predominately for refinery supply. Crude oil commitments consisted of market price evergreen contracts for a total volume of 245,000 barrels per day of crude oil (2008 – 182,000 bbls/day), of which most have industry standard thirty-day cancellation clauses.

Natural Gas

At December 31, 2009, Suncor had purchase commitments relating to natural gas for physical trading. Natural gas commitments consist of fixed price contracts with a total volume of 7 million GJ (2008 – 8 million GJ) within a price range of Cdn $4.51 – $7.05 per GJ (2008 – $5.80-$9.47 per GJ) and having terms extending to October 2010 (2008 – December 2009), as well as market price contracts for a total volume of 60 million GJ (2008 – 17 million GJ) with terms extending to October 2015 (2008 – October 2009).

Refined Products

At December 31, 2009, Suncor's significant purchase commitments relating to finished products at its refineries consisted of market price contracts for a total volume of 5,429 millions of litres and having terms extending to 2012.

(b) Contingencies

The company is subject to various regulatory and statutory requirements relating to the protection of the environment. These requirements, in addition to contractual agreements and management decisions, result in the recognition of estimated asset retirement obligations. Estimates of asset retirement obligation costs can change significantly based on such factors as operating experience and changes in legislation and regulations.

The company reduces exposure to some operational risks by maintaining a comprehensive insurance program at limits and deductible amounts that management believes to be acceptable.

The company carries property damage and business interruption insurance with varying coverage limits and deductible amounts based on the asset. As of December 31, 2009, Suncor's insurance program includes a coverage limit of up to US$1.35 billion for

oil sands risks, up to US$1.25 billion for offshore risks and up to US$420 million for refining risks. These limits are all net of deductible amounts or waiting periods and subject to certain price and volume caps. The company also has primary property insurance for US$250 million that covers all of Suncor's assets.

Suncor believes its liability, property and business interruption insurance is appropriate to its business, although such insurance will not provide coverage in all circumstances or fully protect against prolonged outages. In the future, the insurance program may change due to market conditions or other business considerations.

The company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. The company believes that any liabilities that might arise pertaining to such matters would not have a material effect on its consolidated financial position.

Costs attributable to these commitments and contingencies are expected to be incurred over an extended period of time and to be funded from the company's cash flow from operating activities. Although the ultimate impact of these matters on net earnings cannot be determined at this time, the impact may be material.

(c) Variable Interest Entities

CICA Accounting Guideline 15, *Consolidation of Variable Interest Entities* (VIEs), provides criteria for the identification of VIEs and further criteria for determining what entity, if any, should consolidate them. Entities in which equity investors do not have the characteristic of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinate financial support are subject to consolidation by a company if that company is deemed the primary beneficiary. The primary beneficiary is the party that is subject to a majority of the risk of loss from the VIEs activities, or is entitled to receive a majority of the VIE's residual returns, or both. The company has determined that certain retail licensee and wholesale marketer agreements would constitute VIEs, even though the company has no ownership in these entities. The company, however, is not the primary beneficiary and, therefore, consolidation is not required. In certain of the retail licensee arrangements, the company has provided loan guarantees. Management is of the opinion that the company's maximum exposure to loss from these arrangements would not be significant.

(d) Guarantees and Off-Balance Sheet Arrangements

At December 31, 2009, the company had various indemnification agreements with third parties as described below.

The company has agreed to indemnify holders of all notes and debentures and the company's credit facility lenders (see note 17) for added costs relating to taxes, assessments or other government charges or conditions, including any required withholding amounts. Similar indemnity terms apply to certain facility and equipment leases.

There is no limit to the maximum amount payable under the indemnification agreements described above. The company is unable to determine the maximum potential amount payable as government regulations and legislation are subject to change without notice. Under these agreements, the company has the option to redeem or terminate these contracts if additional costs are incurred.

20. ACCUMULATED OTHER COMPREHENSIVE INCOME

The components of accumulated other comprehensive income (loss), net of income taxes, are as follows:

As at December 31 ($ millions)	**2009**	2008
Unrealized foreign currency translation adjustment	**(248)**	84
Unrealized gains on derivative hedging activities	**15**	13
Total	**(233)**	97

21. SUPPLEMENTAL INFORMATION

($ millions)	**2009**	2008	2007
Geographic areas			
Revenues			
Canada	**20 184**	23 742	13 262
U.S.	**4 010**	4 794	3 943
Other	**1 286**	101	109
	25 480	28 637	17 314
Total assets			
Canada	**54 259**	29 178	21 615
U.S.	**5 239**	2 840	2 556
Other	**10 248**	510	338
	69 746	32 528	24 509
Exploration expenses			
Geological and geophysical	**85**	29	28
Dry hole costs	**173**	61	67
Other	**10**	—	—
Total	**268**	90	95
Allowance for doubtful accounts	**16**	4	3

22. SUBSEQUENT EVENTS

A fire on February 9, 2010 damaged portions of one of the company's oil sands upgraders. An assessment of the damage and expected schedule for repairs has been completed, and repairs are currently underway. The company expects the damaged upgrader to return to production in early April 2010. Based on the damage assessment and repair schedule, and applicable waiting periods and deductibles, the company does not expect insurance to play a significant role in mitigating losses from this incident.

On February 9, 2010, Suncor entered into an agreement to sell certain natural gas properties located in northeast British Columbia for proceeds of $390 million. The sale is expected to close in March 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.

23. DIFFERENCES BETWEEN CANADIAN AND U.S. GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The consolidated financial statements have been prepared in accordance with Canadian GAAP. The application of United States GAAP (U.S. GAAP) would have the following effects on net earnings and comprehensive income as reported:

($ millions)	Notes	**2009**	2008	2007
Net earnings as reported, Canadian GAAP		**1 146**	2 137	2 983
Adjustments				
Transaction costs and provisions	(a)	**(302)**	—	—
Stock-based compensation expense	(b)	**41**	(7)	15
Energy supply and trading activities (inventory valuation)	(e)	**(47)**	—	—
Income tax expense	(a,b,e)	**80**	1	(6)
Net earnings, U.S. GAAP		**918**	2 131	2 992
Pension and post-retirement obligation, net of income taxes of $22 (2008 – $20; 2007 – $8)	(c)	**43**	43	17
Other comprehensive income (loss) items		**(330)**	350	(190)
Comprehensive income, U.S. GAAP		**631**	2 524	2 819

Per common share (dollars)	**2009**	2008	2007
Net earnings per share, U.S. GAAP			
Basic	**0.77**	2.29	3.24
Diluted	**0.76**	2.26	3.18

The application of U.S. GAAP would have the following effects on the consolidated balance sheets as reported:

		December 31, 2009		December 31, 2008	
	Notes	As Reported	U.S. GAAP	As Reported	U.S. GAAP
Current assets	(a,e)	**8 331**	**8 318**	3 237	3 237
Property, plant and equipment, net		**57 485**	**57 485**	28 882	28 882
Other assets	(d)	**536**	**599**	388	460
Goodwill	(a)	**3 201**	**5 762**	21	21
Future income taxes		**193**	**210**	—	—
Total assets		**69 746**	**72 374**	32 528	32 600
Current liabilities	(a,b)	**7 848**	**7 881**	3 538	3 538
Long-term borrowings	(d)	**13 855**	**13 918**	7 866	7 938
Accrued liabilities and other	(b,c)	**5 062**	**5 119**	1 986	2 094
Future income taxes	(a,b,c)	**8 870**	**8 840**	4 615	4 579
Share capital	(b)	**20 053**	**22 908**	1 113	1 201
Contributed surplus	(b)	**526**	**546**	288	313
Retained earnings	(a,b,e)	**13 765**	**13 431**	13 025	12 919
Accumulated other comprehensive income (loss)	(c)	**(233)**	**(269)**	97	18
Total liabilities and shareholders' equity		**69 746**	**72 374**	32 528	32 600

Certain prior period comparative figures have been reclassified to conform to the current presentation.

(a) Business Combination with Petro-Canada

Under U.S. GAAP, the total purchase price for the acquisition was $22,225 million. U.S. GAAP requires the 621.1 million Suncor shares offered as consideration to complete the merger to be valued at $34.84 per share, which was the Suncor Share price as at the transaction close date of August 1, 2009. Under Canadian GAAP the share price is that value as at the merger announcement date. In addition, transaction costs of $124 million (net of income taxes of $43 million) are not permitted to be included in consideration under U.S. GAAP, and are expensed instead.

Under Canadian GAAP, the transaction costs were netted against cash acquired in the business combination and presented as part of cash flow from investing activities in the Consolidated Statements of Cash Flows. Under U.S. GAAP the $124 million of transaction costs would be included in net earnings and thus be presented as a reduction in cash flow from operating activities.

The fair value of current liabilities assumed by Suncor in the business combination under Canadian GAAP includes $160 million (net of income taxes of $56 million) for provisions for severance and other costs associated with exiting certain activities of Petro-Canada that cannot be recognized at the time of the merger under U.S. GAAP and instead must be expensed as incurred. As at December 31, 2009, $99 million (net of income taxes of $36 million) of amounts related to these provisions had been incurred, for which $12 million (net of income taxes of $4 million) remains in current liabilities under U.S. GAAP.

As per note (b), under U.S. GAAP stock-based compensation awards recognized as liabilities are measured using different methods than Canadian GAAP. At August 1, 2009, the value of CPAs, SARs, RSUs and PSUs calculated using methods prescribed by U.S. GAAP was $126 million (net of income taxes of $43 million) greater than the value calculated using methods prescribed under Canadian GAAP.

As a result of these differences in accounting for this business combination, the resulting value for goodwill under U.S. GAAP is $5,762 million, of which $5,474 million would be allocated to the Oil Sands segment and the remaining $288 million would be allocated to the Refining and Marketing segment.

(b) Stock-Based Compensation

Under Canadian GAAP, the company's stock options with a cash payment alternatives (CPAs), stock appreciation rights (SARs), performance share units (PSUs) and restricted share units (RSUs) are measured using an intrinsic approach, which is a fair-value technique not permitted under U.S. GAAP. For U.S. GAAP, our CPAs and SARs have been measured at fair value using the Black-Scholes option-pricing model, while our PSUs and RSUs have been measured using a Monte Carlo Simulation approach to

determine fair value. The impact on net earnings for the year ended December 31, 2009 is a recovery of previously recognized stock-based compensation expense of $31 million, net of income taxes of $10 million (2008 — expense of $2 million, net of income taxes $1 million; 2007 — recovery of $17 million, net of income taxes of $6 million).

Under Canadian GAAP, compensation expense related to common share options granted prior to January 1, 2003 ("pre-2003 options") is not recognized in the Consolidated Statements of Earnings. U.S. GAAP requires the recognition of expense related to the company's pre-2003 options. There was no additional compensation expense to recognize in 2009, as the remaining expense for pre-2003 options was recognized in 2008 (2008 — $4 million, 2007 — $8 million). There was no impact on income taxes.

(c) Accounting for Defined Benefit Pension and Other Post-Retirement Plans

U.S. GAAP requires the company recognize the over funded or under funded status of a defined benefit post-retirement plan as an asset or liability on the balance sheet, with changes to funded status in the year recorded through comprehensive income, net of income taxes. Canadian GAAP currently does not require the company to recognize the funded status of these plans in the Consolidated Balance Sheet. In 2009, other comprehensive income under U.S. GAAP would increase by $43 million, net of income taxes of $22 million (2008 – $43 million, net of income taxes of $20 million).

(d) Deferred Financing Costs

Effective January 1, 2007, under Canadian GAAP, deferred financing costs on long-term debt are included in the carrying value of the related debt. Under U.S. GAAP, these costs are recorded as a deferred charge. As a result, $63 million would have been reclassified from long-term debt to deferred charges and other at December 31, 2009 (December 31, 2008 – $72 million).

(e) Inventory

U.S. GAAP requires inventory to be measured at the lower of cost or net realizable value and does not permit the measurement of held for trading inventories at fair value less costs to sell. As a result, the value of energy trading inventories at December 31, 2009 is lower by $47 million, with the difference in valuation charged to energy supply and trading activities revenue ($32 million, net of income taxes of $15 million).

(f) Cash Flow Information

Other than described in note (a), the application of U.S. GAAP would not have a material effect on cash flow from total operating, investing, or financing activities on the Consolidated Statement of Cash Flows.

Recently Adopted Accounting Standards

Codification

Effective September 15, 2009 the U.S. Financial Accounting Standards Board (FASB) introduced the FASB Accounting Standards Codification (Codification) as the source of authoritative U.S. GAAP for financial statements issued for annual periods ending after the effective date. The Codification did not affect the application of U.S. GAAP to the company's U.S. GAAP financial statements.

Business Combinations

In December 2007, the FASB amended Topic 805 "Business Combinations" and Topic 810 "Consolidations" which are effective for all business combinations occurring on or after January 1, 2009. These standards require the identifiable assets acquired and liabilities assumed in a business combination to be recorded at fair value and most of the related acquisition and restructuring costs to be expensed. The impact to Suncor has been quantified in section (a) above.

Oil and Gas Reporting Requirements

In January 2010, the FASB amended Topic 932 "Extractive Industries Oil and Gas" to align the oil and gas reserve estimation and disclosure requirements of Topic 932 with the changes implemented by the Securities and Exchange Commission Final Rule, Modernization of Oil and Gas Reporting Requirements.

The amendments expand the definition of an oil and gas producing activity to include resources extracted through mining activities, coal beds and shale. The new rules also permit the use of new technologies to determine proved reserves, if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes. The new rules will also require companies to report their oil and gas reserves based on annual average prices determined by the prices in effect on the first day of each month, rather than year-end prices. The amendments are effective for December 31, 2009.

Recently Issued Accounting Standards

Consolidations

In June 2009, the FASB issued amendments to Topic 810 "Consolidations" to improve financial reporting for enterprises involved with variable interest entities (VIEs). The amendments change how a company determines when these entities should be consolidated, replacing the quantitative-based risks and rewards calculation with an approach that is primarily qualitative. The amendments are effective for January 1, 2010. The company does not anticipate changes to its reporting for VIEs as a result of these amendments.

QUARTERLY SUMMARY (unaudited)

FINANCIAL DATA [1]

($ millions, except per share amounts)	For the Quarter Ended Mar 31 2009	June 30 2009	Sept 30 2009	Dec 31 2009	Total Year 2009	For the Quarter Ended Mar 31 2008	June 30 2008	Sept 30 2008	Dec 31 2008	Total Year 2008
Revenues (net of royalties)	**4 633**	**4 768**	**8 443**	**7 636**	**25 480**	5 538	7 640	8 507	6 952	28 637
Net earnings (loss)										
Oil Sands	**(110)**	**(307)**	**738**	**236**	**557**	695	751	854	575	2 875
Natural Gas	**(10)**	**(28)**	**(111)**	**(50)**	**(199)**	19	52	18	—	89
East Coast Canada	**—**	**—**	**39**	**73**	**112**	—	—	—	—	—
International	**—**	**—**	**32**	**133**	**165**	—	—	—	—	—
Refining and Marketing	**118**	**106**	**51**	**158**	**433**	78	102	(11)	(174)	(5)
Corporate, Energy Trading and Eliminations	**(187)**	**178**	**180**	**(93)**	**78**	(84)	(76)	(46)	(616)	(822)
	(189)	**(51)**	**929**	**457**	**1 146**	708	829	815	(215)	2 137
Per common share										
Net earnings (loss) attributable to common shareholders										
– basic	**(0.20)**	**(0.06)**	**0.69**	**0.29**	**0.96**	0.77	0.89	0.87	(0.24)	2.29
– diluted	**(0.20)**	**(0.06)**	**0.68**	**0.29**	**0.95**	0.75	0.87	0.86	(0.24)	2.26
Cash dividends	**0.05**	**0.05**	**0.10**	**0.10**	**0.30**	0.05	0.05	0.05	0.05	0.20
Cash flow from (used in) operations										
Oil Sands	**480**	**174**	**242**	**355**	**1 251**	924	1 232	1 030	321	3 507
Natural Gas	**53**	**42**	**74**	**160**	**329**	84	122	98	63	367
East Coast Canada	**—**	**—**	**130**	**205**	**335**	—	—	—	—	—
International	**—**	**—**	**163**	**453**	**616**	—	—	—	—	—
Refining and Marketing	**222**	**198**	**275**	**268**	**963**	173	237	19	(181)	248
Corporate, Energy Trading and Eliminations	**46**	**(119)**	**(310)**	**(312)**	**(695)**	(31)	(61)	(1)	28	(65)
	801	**295**	**574**	**1 129**	**2 799**	1 150	1 530	1 146	231	4 057

(1) The financial data includes the results of post-merger Suncor from August 1, 2009. As such, the amounts reflect results 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 2008 results of legacy Suncor.

QUARTERLY SUMMARY (unaudited) (continued)

OPERATING DATA

	For the Quarter Ended				Total Year	For the Quarter Ended				Total Year
	Mar 31 2009	**June 30 2009**	**Sept 30 2009**	**Dec 31 2009**	**2009**	Mar 31 2008	June 30 2008	Sept 30 2008	Dec 31 2008	2008
OIL SANDS										
Production [a]										
Total production (excluding Syncrude)	**278.0**	**301.0**	**305.3**	**278.9**	**290.6**	248.0	174.6	245.6	243.8	228.0
Firebag [b]	**42.4**	**48.3**	**54.3**	**51.1**	**49.1**	34.6	34.7	40.4	39.7	37.4
Mackay River [b]	**—**	**—**	**26.5*** **	**31.7**	**29.7*** **	—	—	—	—	—
Syncrude	**—**	**—**	**37.4*** **	**39.3**	**38.5*** **	—	—	—	—	—
Sales [a]										
Light sweet crude oil	**108.8**	**99.4**	**89.6**	**100.8**	**99.6**	96.2	68.2	48.1	95.7	77.0
Diesel	**22.8**	**25.3**	**36.9**	**31.4**	**29.1**	28.0	21.2	10.9	19.1	19.8
Light sour crude oil	**102.7**	**150.5**	**146.8**	**142.4**	**135.7**	120.8	91.8	157.4	144.2	128.7
Bitumen	**9.1**	**10.5**	**14.3**	**13.0**	**11.8**	0.1	0.3	2.6	3.1	1.5
Total sales	**243.4**	**285.7**	**287.6**	**287.6**	**276.2**	245.1	181.5	219.0	262.1	227.0
Average sales price [1], [c]										
Light sweet crude oil*	**54.64**	**65.83**	**71.99**	**77.71**	**67.26**	100.93	122.12	125.70	63.69	98.66
Other (diesel, light sour crude oil and bitumen)*	**48.80**	**62.71**	**67.51**	**72.93**	**64.18**	93.09	120.52	114.74	59.77	95.14
Total*	**52.78**	**63.79**	**68.91**	**74.61**	**65.29**	96.22	122.39	117.14	61.20	96.33
Total	**59.14**	**59.00**	**61.70**	**64.81**	**61.26**	96.16	121.12	116.32	61.53	95.96
Syncrude average sales price [1], [c]	**—**	**—**	**75.17**	**78.81**	**77.36**	—	—	—	—	—
Cash operating costs and Total operating costs – Total Operations (excluding Syncrude) [d]										
Cash costs	**30.65**	**29.65**	**30.65**	**35.10**	**31.50**	25.10	40.10	27.80	35.35	31.45
Natural gas	**3.00**	**1.65**	**1.55**	**3.40**	**2.40**	5.00	8.75	4.30	4.05	5.25
Imported bitumen	**0.05**	**—**	**0.05**	**0.20**	**0.05**	1.45	2.00	1.90	1.90	1.80
Cash operating costs [2]	**33.70**	**31.30**	**32.25**	**38.70**	**33.95**	31.55	50.85	34.00	41.30	38.50
Project start-up costs	**0.65**	**0.35**	**0.45**	**0.50**	**0.45**	0.30	0.90	0.35	0.30	0.40
Total cash operating costs [3]	**34.35**	**31.65**	**32.70**	**39.20**	**34.40**	31.85	51.75	34.35	41.60	38.90
Depreciation, depletion and amortization	**7.30**	**7.20**	**7.60**	**10.00**	**8.00**	5.75	8.30	6.70	7.50	6.95
Total operating costs [4]	**41.65**	**38.85**	**40.30**	**49.20**	**42.40**	37.60	60.05	41.05	49.10	45.85
Cash operating costs and Total operating costs – Syncrude [d]****										
Cash costs	**—**	**—**	**29.50**	**29.65**	**29.60**	—	—	—	—	—
Natural gas	**—**	**—**	**2.10**	**3.45**	**2.90**	—	—	—	—	—
Cash operating costs [5]	**—**	**—**	**31.60**	**33.10**	**32.50**	—	—	—	—	—
Project start-up costs	**—**	**—**	**—**	**—**	**—**	—	—	—	—	—
Total cash operating costs [6]	**—**	**—**	**31.60**	**33.10**	**32.50**	—	—	—	—	—
Depreciation, depletion and amortization	**—**	**—**	**12.70**	**11.80**	**12.15**	—	—	—	—	—
Total operating costs [7]	**—**	**—**	**44.30**	**44.90**	**44.65**	—	—	—	—	—
Cash operating costs and Total operating costs – In-situ Bitumen Production Only [c]										
Cash costs	**10.50**	**11.15**	**10.25**	**11.35**	**10.90**	14.60	10.10	10.75	16.55	13.00
Natural gas	**7.90**	**5.25**	**4.30**	**6.05**	**5.70**	14.10	14.55	11.30	9.65	12.30
Cash operating costs [5]	**18.40**	**16.40**	**14.55**	**17.40**	**16.60**	28.70	24.65	22.05	26.20	25.30
In-situ start-up costs	**3.35**	**1.50**	**0.65**	**1.25**	**1.30**	0.35	1.65	0.80	—	0.65
Total cash operating costs [6]	**21.75**	**17.90**	**15.20**	**18.65**	**17.90**	29.05	26.30	22.85	26.20	25.95
Depreciation, depletion and amortization	**7.10**	**6.00**	**5.95**	**6.65**	**6.35**	6.75	6.70	5.40	6.55	6.35
Total operating costs [7]	**28.85**	**23.90**	**21.15**	**25.30**	**24.25**	35.80	33.00	28.25	32.75	32.30

Footnotes and definitions, see page 113.

QUARTERLY SUMMARY (unaudited) (continued)

OPERATING DATA (continued)

	For the Quarter Ended				Total Year	For the Quarter Ended				Total Year
	Mar 31 2009	**June 30 2009**	**Sept 30 2009**	**Dec 31 2009**	**2009**	Mar 31 2008	June 30 2008	Sept 30 2008	Dec 31 2008	2008
NATURAL GAS										
Gross production										
Natural gas [e]										
Western Canada	**200**	**192**	**477**	**620**	**374**	209	205	197	195	202
U.S. Rockies	**—**	**—**	**40**	**54**	**24**	—	—	—	—	—
Natural gas liquids and crude oil [a]										
Western Canada	**3.1**	**3.2**	**8.3**	**10.8**	**6.4**	3.3	3.4	2.6	3.1	3.1
U.S. Rockies	**—**	**—**	**2.4**	**4.2**	**1.7**	—	—	—	—	—
Total gross production [f]										
Western Canada	**219**	**211**	**527**	**685**	**412**	229	226	213	213	220
U.S. Rockies	**—**	**—**	**54**	**79**	**34**	—	—	—	—	—
Average sales price [1]										
Natural gas [g]										
Western Canada	**5.63**	**3.56**	**2.79**	**3.99**	**3.70**	7.30	9.62	9.10	6.90	8.23
U.S. Rockies	**—**	**—**	**3.01**	**4.62**	**3.93**	—	—	—	—	—
Natural gas [g]*										
Western Canada	**5.61**	**3.52**	**2.77**	**3.99**	**3.68**	7.31	9.68	9.14	6.84	8.25
U.S. Rockies	**—**	**—**	**3.01**	**4.62**	**3.93**	—	—	—	—	—
Natural gas liquids and crude oil [c]										
Western Canada	**39.03**	**41.39**	**53.28**	**60.06**	**52.97**	64.14	86.14	96.88	39.31	70.89
U.S. Rockies	**—**	**—**	**67.08**	**74.19**	**71.62**	—	—	—	—	—
EAST COAST CANADA ***										
Production [a]										
Terra Nova	**—**	**—**	**16.0**	**24.0**	**20.8**	—	—	—	—	—
Hibernia	**—**	**—**	**28.5**	**26.3**	**27.2**	—	—	—	—	—
White Rose	**—**	**—**	**5.1**	**13.3**	**10.0**	—	—	—	—	—
Total production	**—**	**—**	**49.6**	**63.6**	**58.0**	—	—	—	—	—
Average sales price [1]	**—**	**—**	**75.22**	**77.71**	**76.86**	—	—	—	—	—
INTERNATIONAL ***										
Production [h]										
North Sea										
Buzzard	**—**	**—**	**29.4**	**59.9**	**47.8**	—	—	—	—	—
Other U.K.	**—**	**—**	**11.4**	**18.2**	**15.5**	—	—	—	—	—
The Netherlands sector of the North Sea	**—**	**—**	**13.8**	**12.9**	**13.2**	—	—	—	—	—
Total North Sea	**—**	**—**	**54.6**	**91.0**	**76.5**	—	—	—	—	—
Other International										
Libya	**—**	**—**	**42.7**	**26.0**	**32.6**	—	—	—	—	—
Trinidad & Tobago	**—**	**—**	**11.3**	**12.0**	**11.7**	—	—	—	—	—
Total Other International	**—**	**—**	**54.0**	**38.0**	**44.3**	—	—	—	—	—
Total production	**—**	**—**	**108.6**	**129.0**	**120.8**	—	—	—	—	—
Average sales price [1] – North Sea [i]	**—**	**—**	**68.67**	**71.46**	**71.63**	—	—	—	—	—
Average sales price [1] – Other International [i]	**—**	**—**	**62.40**	**59.04**	**61.25**	—	—	—	—	—

Footnotes and definitions, see page 113.

QUARTERLY SUMMARY (unaudited) (continued)

OPERATING DATA (continued)

	For the Quarter Ended				Total Year	For the Quarter Ended				Total Year
	Mar 31 2009	**June 30 2009**	**Sept 30 2009**	**Dec 31 2009**	**2009**	Mar 31 2008	June 30 2008	Sept 30 2008	Dec 31 2008	2008
REFINING AND MARKETING										
Eastern North America										
Refined product sales [j]										
Transportation fuels										
Gasoline										
– retail	**3.8**	**4.0**	**12.5**	**16.5**	**9.3**	3.9	3.9	3.8	3.9	3.9
– other	**4.4**	**4.7**	**5.8**	**6.5**	**5.3**	3.8	4.0	4.3	5.0	4.0
Distillate	**5.1**	**5.4**	**10.3**	**13.9**	**8.8**	4.8	5.6	5.2	5.4	5.2
Total transportation fuel sales	**13.3**	**14.1**	**28.6**	**36.9**	**23.4**	12.5	13.5	13.3	14.3	13.1
Petrochemicals	**1.0**	**1.0**	**1.7**	**1.2**	**0.8**	0.6	0.9	1.0	1.0	0.8
Asphalt	**0.8**	**0.7**	**2.4**	**2.0**	**1.5**	0.6	0.7	0.6	0.5	0.6
Other	**0.5**	**1.0**	**3.0**	**1.9**	**2.0**	0.8	1.1	1.2	0.5	1.0
Total refined product sales	**15.6**	**16.8**	**35.7**	**42.0**	**27.7**	14.5	16.2	16.1	16.3	15.5
Crude oil supply and refining										
Processed at refineries [j]	**11.3**	**11.8**	**25.5**	**28.3**	**29.6**	9.9	11.5	11.6	11.2	11.0
Utilization of refining capacity (%)	**84**	**87**	**94**	**83**	**87**	89	103	104	101	99
Western North America										
Refined product sales [j]										
Transportation fuels										
Gasoline										
– retail	**0.7**	**0.6**	**3.8**	**5.0**	**2.6**	0.7	0.6	0.7	0.7	0.7
– other	**7.5**	**8.3**	**12.3**	**13.4**	**10.4**	7.0	7.8	7.2	7.1	7.3
Distillate	**5.4**	**5.0**	**11.8**	**15.6**	**9.5**	5.6	5.9	5.4	5.5	5.6
Total transportation fuel sales	**13.6**	**13.9**	**27.9**	**34.0**	**22.5**	13.3	14.3	13.3	13.3	13.6
Asphalt	**1.2**	**1.4**	**1.7**	**0.9**	**1.3**	1.6	1.0	1.3	1.0	1.2
Other	**1.0**	**1.8**	**4.6**	**6.0**	**3.4**	1.1	1.6	1.3	0.9	1.2
Total refined product sales	**15.8**	**17.1**	**34.2**	**40.9**	**27.2**	16.0	16.9	15.9	15.2	16.0
Crude oil supply and refining										
Processed at refineries [j]	**14.2**	**15.6**	**27.8**	**33.4**	**33.6**	13.1	14.5	13.5	13.6	13.7
Utilization of refining capacity (%)	**96**	**106**	**100**	**96**	**97**	92	102	95	95	96

Footnotes and definitions, see page 113.

QUARTERLY SUMMARY (unaudited) (continued)

OPERATING DATA (continued)

	For the Quarter Ended				Total Year	For the Quarter Ended				Total Year
	Mar 31 2009	**June 30 2009**	**Sept 30 2009**	**Dec 31 2009**	**2009**	Mar 31 2008	June 30 2008	Sept 30 2008	Dec 31 2008	2008
NETBACKS										
Natural Gas[g]										
Western Canada										
Average price realized [8]	**5.77**	**3.88**	**3.76**	**5.05**	**4.58**	8.23	11.20	10.98	6.99	9.35
Royalties	**(1.14)**	**0.33**	**(0.24)**	**(0.72)**	**(0.49)**	(1.84)	(2.52)	(2.70)	(1.60)	(2.17)
Operating costs	**(1.65)**	**(1.71)**	**(1.90)**	**(1.77)**	**(1.79)**	(1.41)	(1.66)	(1.87)	(1.46)	(1.60)
Operating netback	**2.98**	**2.50**	**1.62**	**2.56**	**2.30**	4.98	7.02	6.41	3.93	5.58
Depreciation, depletion and amortization	**(2.97)**	**(2.92)**	**(2.73)**	**(2.62)**	**(2.74)**	(2.85)	(2.68)	(3.08)	(2.98)	(2.89)
Administrative expenses and other	**(0.78)**	**(1.63)**	**(1.60)**	**(1.09)**	**(1.29)**	(0.88)	(0.92)	(1.95)	(1.23)	(1.23)
Earnings before income taxes	**(0.77)**	**(2.05)**	**(2.71)**	**(1.15)**	**(1.73)**	1.25	3.42	1.38	(0.28)	1.46
U.S. Rockies										
Average price realized [8]	**—**	**—**	**5.20**	**7.15**	**6.35**	—	—	—	—	—
Royalties	**—**	**—**	**(0.82)**	**(1.13)**	**(1.01)**	—	—	—	—	—
Operating costs	**—**	**—**	**(1.79)**	**(1.83)**	**(1.82)**	—	—	—	—	—
Operating netback	**—**	**—**	**2.59**	**4.19**	**3.52**	—	—	—	—	—
Depreciation, depletion and amortization	**—**	**—**	**(3.20)**	**(3.44)**	**(3.35)**	—	—	—	—	—
Administrative expenses and other	**—**	**—**	**(0.47)**	**(0.66)**	**(0.58)**	—	—	—	—	—
Earnings before income taxes	**—**	**—**	**(1.08)**	**0.09**	**(0.41)**	—	—	—	—	—
Total Natural Gas										
Average price realized [8]	**5.77**	**3.88**	**3.89**	**5.26**	**4.71**	8.23	11.20	10.98	6.99	9.35
Royalties	**(1.14)**	**0.33**	**(0.29)**	**(0.76)**	**(0.53)**	(1.84)	(2.52)	(2.70)	(1.60)	(2.17)
Operating costs	**(1.65)**	**(1.71)**	**(1.89)**	**(1.78)**	**(1.79)**	(1.41)	(1.66)	(1.87)	(1.46)	(1.60)
Operating netback	**2.98**	**2.50**	**1.71**	**2.72**	**2.39**	4.98	7.02	6.41	3.93	5.58
Depreciation, depletion and amortization	**(2.97)**	**(2.92)**	**(2.78)**	**(2.70)**	**(2.79)**	(2.85)	(2.68)	(3.08)	(2.98)	(2.89)
Administrative expenses and other	**(0.78)**	**(1.63)**	**(1.49)**	**(1.05)**	**(1.23)**	(0.88)	(0.92)	(1.95)	(1.23)	(1.23)
Earnings before income taxes	**(0.77)**	**(2.05)**	**(2.56)**	**(1.03)**	**(1.63)**	1.25	3.42	1.38	(0.28)	1.46

Footnotes and definitions, see page 113.

QUARTERLY SUMMARY (unaudited) (continued)

OPERATING DATA (continued)

	For the Quarter Ended				Total Year	For the Quarter Ended				Total Year
	Mar 31 2009	**June 30 2009**	**Sept 30 2009**	**Dec 31 2009**	**2009**	Mar 31 2008	June 30 2008	Sept 30 2008	Dec 31 2008	2008
NETBACKS (continued)										
East Coast Canada[c]										
Average price realized [8]	**—**	**—**	**77.85**	**79.69**	**79.07**	—	—	—	—	—
Royalties	**—**	**—**	**(21.02)**	**(25.26)**	**(23.82)**	—	—	—	—	—
Operating costs	**—**	**—**	**(13.36)**	**(7.89)**	**(9.76)**	—	—	—	—	—
Operating netback	**—**	**—**	**43.47**	**46.54**	**45.49**	—	—	—	—	—
Depreciation, depletion and amortization	**—**	**—**	**(17.48)**	**(26.56)**	**(23.47)**	—	—	—	—	—
Administrative expenses and other	**—**	**—**	**(0.52)**	**(1.33)**	**(1.05)**	—	—	—	—	—
Earnings before income taxes	**—**	**—**	**25.47**	**18.65**	**20.97**	—	—	—	—	—
International										
North Sea[c]										
Average price realized [8]	**—**	**—**	**72.06**	**71.46**	**71.63**	—	—	—	—	—
Operating costs	**—**	**—**	**(14.04)**	**(8.08)**	**(9.78)**	—	—	—	—	—
Operating netback	**—**	**—**	**58.02**	**63.38**	**61.85**	—	—	—	—	—
Depreciation, depletion and amortization	**—**	**—**	**(24.54)**	**(34.63)**	**(31.76)**	—	—	—	—	—
Administrative expenses and other	**—**	**—**	**(7.61)**	**(4.62)**	**(5.48)**	—	—	—	—	—
Earnings before income taxes	**—**	**—**	**25.87**	**24.13**	**24.61**	—	—	—	—	—
Other International										
North Africa/Near East[c]										
Average price realized [8]	**—**	**—**	**76.02**	**79.97**	**78.19**	—	—	—	—	—
Royalties	**—**	**—**	**(46.46)**	**(32.12)**	**(39.88)**	—	—	—	—	—
Operating costs	**—**	**—**	**(2.21)**	**(6.03)**	**(4.05)**	—	—	—	—	—
Operating netback	**—**	**—**	**27.35**	**41.82**	**34.26**	—	—	—	—	—
Depreciation, depletion and amortization	**—**	**—**	**(2.31)**	**(7.70)**	**(4.89)**	—	—	—	—	—
Administrative expenses and other	**—**	**—**	**(5.21)**	**(10.15)**	**(7.57)**	—	—	—	—	—
Earnings before income taxes	**—**	**—**	**19.83**	**23.97**	**21.80**	—	—	—	—	—
Other International										
Northern Latin America[g]										
Average price realized [8]	**—**	**—**	**2.09**	**2.58**	**2.42**	—	—	—	—	—
Royalties	**—**	**—**	**(1.58)**	**(0.10)**	**(0.69)**	—	—	—	—	—
Operating costs	**—**	**—**	**(0.46)**	**(0.13)**	**(0.26)**	—	—	—	—	—
Operating netback	**—**	**—**	**0.05**	**2.35**	**1.47**	—	—	—	—	—
Depreciation, depletion and amortization	**—**	**—**	**(0.79)**	**(1.84)**	**(1.44)**	—	—	—	—	—
Administrative expenses and other	**—**	**—**	**0.12**	**0.04**	**0.08**	—	—	—	—	—
Earnings before income taxes	**—**	**—**	**(0.62)**	**0.55**	**0.11**	—	—	—	—	—
Total International[i]										
Average price realized [8]	**—**	**—**	**67.42**	**67.96**	**67.86**	—	—	—	—	—
Royalties	**—**	**—**	**(19.25)**	**(6.52)**	**(11.17)**	—	—	—	—	—
Operating costs	**—**	**—**	**(8.22)**	**(6.99)**	**(7.44)**	—	—	—	—	—
Operating netback	**—**	**—**	**39.95**	**54.45**	**49.25**	—	—	—	—	—
Depreciation, depletion and amortization	**—**	**—**	**(13.74)**	**(27.02)**	**(22.27)**	—	—	—	—	—
Administrative expenses and other	**—**	**—**	**(5.79)**	**(5.29)**	**(5.46)**	—	—	—	—	—
Earnings before income taxes	**—**	**—**	**20.42**	**22.14**	**21.52**	—	—	—	—	—

Footnotes and definitions, see page 113.

FIVE-YEAR FINANCIAL SUMMARY (unaudited)

($ millions)	**2009**	2008	2007	2006	2005
Revenues (net of royalties)					
Oil Sands	**6 539**	8 639	6 175	6 457	3 559
Natural Gas	**681**	579	427	451	530
East Coast Canada	**441**	—	—	—	—
International	**1 183**	—	—	—	—
Refining and Marketing	**12 013**	9 419	8 391	7 209	6 351
Corporate, Energy Trading and Eliminations	**4 623**	10 000	2 321	859	328
	25 480	28 637	17 314	14 976	10 768
Net earnings (loss)					
Oil Sands	**557**	2 875	2 474	2 775	986
Natural Gas	**(199)**	89	25	106	155
East Coast Canada	**112**	—	—	—	—
International	**165**	—	—	—	—
Refining and Marketing	**433**	(5)	442	224	228
Corporate, Energy Trading and Eliminations	**78**	(822)	42	(136)	(115)
	1 146	2 137	2 983	2 969	1 254
Cash flow from (used in) operations					
Oil Sands	**1 251**	3 507	3 165	3 902	1 961
Natural Gas	**329**	367	251	279	412
East Coast Canada	**335**	—	—	—	—
International	**616**	—	—	—	—
Refining and Marketing	**963**	248	711	423	449
Corporate, Energy Trading and Eliminations	**(695)**	(65)	(90)	(58)	(193)
	2 799	4 057	4 037	4 546	2 629
Capital and exploration expenditures					
Oil Sands	**2 807**	7 391	4 566	2 463	2 013
Natural Gas	**320**	342	537	458	365
East Coast Canada	**123**	—	—	—	—
International	**543**	—	—	—	—
Refining and Marketing	**409**	226	449	745	789
Corporate, Energy Trading and Eliminations	**44**	28	77	27	63
	4 246	7 987	5 629	3 693	3 230
Total assets	**69 476**	32 528	24 509	18 959	15 335
Ending capital employed [(A)]					
Short-term and long-term debt, less cash and cash equivalents	**13 377**	7 226	3 248	1 849	2 868
Shareholders' equity	**34 111**	14 523	11 896	9 084	6 130
	47 488	21 749	15 144	10 933	8 998
Less capitalized costs related to major projects in progress	**(13 365)**	(6 583)	(4 148)	(2 649)	(2 938)
	34 123	15 166	10 996	8 284	6 060
Total Suncor employees (number at year-end)	**12 978**	6 798	6 465	5 766	5 152

Footnotes and definitions, see page 108.

FIVE-YEAR FINANCIAL SUMMARY (unaudited) (continued)

	2009	2008	2007	2006	2005
Dollars per common share					
Net earnings attributable to common shareholders	**0.96**	2.29	3.23	3.23	1.37
Cash dividends	**0.30**	0.20	0.19	0.15	0.12
Cash flow from operations	**2.34**	4.36	4.38	4.95	2.88
Ratios					
Return on capital employed (%) [(B), (C)]	**2.6**	22.5	29.3	40.0	21.2
Return on capital employed (%) [(C), (D)]	**1.8**	16.3	21.5	30.1	15.4
Return on shareholders' equity (%) [(E)]	**5.1**	16.2	28.4	39.0	22.7
Debt to debt plus shareholders' equity (%) [(F)]	**28.9**	35.2	24.3	20.7	33.1
Net debt to cash flow from operations (times) [(G)]	**4.8**	1.8	0.8	0.4	1.1
Interest coverage – cash flow basis (times) [(H)]	**7.2**	13.0	23.4	30.6	17.9
Interest coverage – net earnings basis (times) [(I)]	**3.0**	8.9	18.8	25.5	13.5

(A) Capital employed – the sum of shareholders' equity plus short-term debt and long-term debt less cash and cash equivalents, less capitalized costs related to major projects in progress (as applicable).

(B) Net earnings adjusted for after-tax financing expenses (income) for the twelve-month period ended; divided by average capital employed. Average capital employed is the sum of shareholders' equity and short-term debt plus long-term debt less cash and cash equivalents less capitalized costs related to major projects in progress (as applicable), on a weighted-average basis. Return on capital employed (ROCE) for Suncor operating segments is calculated in a manner consistent with consolidated ROCE. For a detailed annual reconciliation of this non-GAAP financial measure see page 53 of MD&A.

(C) The increase in capital employed as a result of the merger with Petro-Canada has caused our return on capital employed measure to decrease significantly, as the calculation only includes five months of results relating to legacy Petro-Canada operations.

(D) If capital employed were to include capitalized costs related to major projects in progress, the return on capital employed would be as stated on this line.

(E) Net earnings as a percentage of average shareholders' equity. Average shareholders' equity is the sum of total shareholders' equity at the beginning and end of the year divided by two.

(F) Short-term debt plus long-term debt; divided by the sum of short-term debt, long-term debt and shareholders' equity.

(G) Short-term debt plus long-term debt less cash and cash equivalents; divided by cash flow from operations for the year then ended. The increase in debt levels as a result of the merger with Petro-Canada has caused our net debt/cash flow from operations measure to increase significantly, as the calculation only includes five months of cash flow from operations relating to legacy Petro-Canada operations.

(H) Cash flow from operations plus current income taxes and interest expense; divided by the sum of interest expense and capitalized interest.

(I) Net earnings plus income taxes and interest expense; divided by the sum of interest expense and capitalized interest.

SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION (unaudited)

	2009	2008	2007	2006	2005
OIL SANDS					
Production [a]	**290.6**	228.0	235.6	260.0	171.3
Sales [a]					
Light sweet crude oil	**99.6**	77.0	101.7	110.5	73.3
Diesel	**29.1**	19.8	25.0	28.2	15.6
Light sour crude oil	**135.7**	128.7	102.3	118.2	59.8
Bitumen	**11.8**	1.5	5.7	6.2	16.6
	276.2	227.0	234.7	263.1	165.3
Average sales price [c]					
Light sweet crude oil*	**67.26**	98.66	78.03	71.98	49.93
Other (diesel, light sour crude oil and bitumen)*	**64.18**	95.14	70.86	65.17	56.90
Total*	**65.29**	96.33	74.07	68.03	62.68
Total	**61.26**	95.96	74.01	68.03	53.81
Cash operating costs – total operations (excluding Syncrude) [2],[d]	**33.95**	38.50	27.80	21.70	24.55
Total cash operating costs – total operations (excluding Syncrude) [3],[d]	**34.40**	38.90	28.75	22.10	24.65
Total operating costs – total operations (excluding Syncrude) [4],[d]	**42.40**	45.85	34.15	26.15	29.95
Cash operating costs – Syncrude [5],[d]****	**32.50**	—	—	—	—
Total cash operating costs – Syncrude [6],[d]****	**32.50**	—	—	—	—
Total operating costs – Syncrude [7],[d]****	**44.65**	—	—	—	—
Cash operating costs – In-situ bitumen production [5],[d]	**16.60**	25.30	20.75	17.30	22.20
Total cash operating costs – In-situ bitumen production [6],[d]	**17.90**	25.95	20.75	19.00	23.20
Total operating costs – In-situ bitumen production [7],[d]	**24.25**	32.30	26.95	24.55	28.10
Ending capital employed excluding major projects in progress [k]	**16 141**	9 352	6 605	5 039	4 468
Return on capital employed (%)	**4.2**	35.5	43.0	53.1	23.0
Return on capital employed (%) **	**2.5**	21.8	27.9	39.8	16.5

Footnotes and definitions, see page 113.

SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION (unaudited) (continued)

	2009	2008	2007	2006	2005
NATURAL GAS					
Gross production					
Natural gas [e]					
Western Canada	**374**	202	196	191	190
U.S. Rockies	**24**	—	—	—	—
Natural gas liquids and crude oil [a]					
Western Canada	**6.4**	3.1	3.1	3.0	3.2
U.S. Rockies	**1.7**	—	—	—	—
Total [g]					
Western Canada	**412**	220	215	209	209
U.S. Rockies	**34**	—	—	—	—
Average sales price					
Natural gas [g]					
Western Canada	**3.70**	8.23	6.32	7.15	8.57
U.S. Rockies	**3.93**	—	—	—	—
Natural gas [g]*					
Western Canada	**3.68**	8.25	6.27	6.95	8.59
U.S. Rockies	**3.93**	—	—	—	—
Natural gas liquids and crude oil – conventional [c]					
Western Canada	**52.97**	70.89	56.64	51.93	54.24
U.S. Rockies	**71.62**	—	—	—	—
Ending capital employed [k]	**3 349**	1 152	1 153	857	562
Return on capital employed (%)	**(8.4)**	7.7	2.5	14.9	30.7

Footnotes and definitions, see page 113.

SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION (unaudited) (continued)

	2009	2008	2007	2006	2005
EAST COAST CANADA* **					
Production [a]					
Terra Nova	**20.8**	—	—	—	—
Hibernia	**27.2**	—	—	—	—
White Rose	**10.0**	—	—	—	—
Total production	**58.0**	—	—	—	—
Average sales price	**76.86**	—	—	—	—
Ending capital employed excluding major projects in progress [k]	**2 142**	—	—	—	—
Return on capital employed (%)	**10.7**	—	—	—	—
Return on capital employed (%)*	**6.5**	—	—	—	—
INTERNATIONAL* **					
Production [h]					
North Sea					
Buzzard	**47.8**	—	—	—	—
Other U.K.	**15.5**	—	—	—	—
The Netherlands sector of the North Sea	**13.2**	—	—	—	—
Total North Sea	**76.5**				
Other International					
Libya	**32.6**	—	—	—	—
Trinidad & Tobago	**11.7**	—	—	—	—
Total Other International	**44.3**	—	—	—	—
Total production	**120.8**	—	—	—	—
Average sales price – North Sea [c]	**71.63**	—	—	—	—
Average sales price – Other International [i]	**61.25**	—	—	—	—
Ending capital employed excluding major projects in progress [k]	**2 828**	—	—	—	—
Return on capital employed (%)	**11.5**	—	—	—	—
Return on capital employed (%)*	**7.5**	—	—	—	—

Footnotes and definitions, see page 113.

SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION (unaudited) (continued)

	2009	2008	2007	2006	2005
REFINING AND MARKETING					
Eastern North America					
Refined product sales [j]					
Transportation fuels					
Gasoline					
Retail	**9.3**	3.9	4.5	4.6	4.5
Other	**5.3**	4.0	4.3	3.8	3.9
Distillate	**8.8**	5.2	5.4	3.9	4.2
Total transportation fuel sales	**23.4**	13.1	14.2	12.3	12.6
Petrochemicals	**0.8**	0.8	0.9	0.9	0.7
Asphalt	**1.5**	0.6	0.3	—	—
Other	**2.0**	1.0	2.2	1.9	1.9
Total refined product sales	**27.7**	15.5	17.6	15.1	15.2
Crude oil supply and refining					
Processed at refineries [j]	**29.6**	11.0	10.9	8.6	10.6
Utilization of refining capacity (%)	**87**	99	98	78	95
Western North America					
Refined product sales [j]					
Transportation fuels					
Gasoline					
Retail	**2.6**	0.7	0.7	0.7	0.7
Other	**10.4**	7.3	7.3	6.8	6.2
Distillate	**9.5**	5.6	5.2	4.6	4.1
Total transportation fuel sales	**22.5**	13.6	13.2	12.1	11.0
Asphalt	**1.3**	1.2	1.4	1.2	1.6
Other	**3.4**	1.2	1.3	1.1	1.1
Total refined product sales	**27.2**	16.0	15.9	14.4	13.7
Crude oil supply and refining					
Processed at refineries [j]	**33.6**	13.7	14.2	13.1	12.1
Utilization of refining capacity (%)	**97**	96	99	92	98
Ending capital employed excluding major projects in progress [k]	**8 304**	2 974	2 489	1 938	907
Return on capital employed (%)	**7.5**	1.8	20.0	19.3	27.5
Return on capital employed (%)**	**7.5**	1.8	17.4	12.2	17.6
Retail outlets(number at year-end)	**1 813**	427	419	417	417

Prior year capital employed measures have not been restated for the movement of energy trading activities to Corporate, Energy Trading and Eliminations.

Footnotes and definitions, see page 113.

SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION (unaudited) (continued)

Definitions

(1) Average sales price – This operating statistic is calculated before royalties (where applicable) and net of related transportation costs and excludes the realized impact of hedging activities unless stated.

(2) Cash operating costs – Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes), accretion expense and the cost of bitumen imported from third parties. Per barrel amounts are based on total production volumes. For a reconciliation of this non-GAAP financial measure see Management's Discussion and Analysis.

(3) Total cash operating costs – Include cash operating costs as defined above and cash start-up costs. Per barrel amounts are based on total production volumes.

(4) Total operating costs – Include total cash operating costs as defined above and non-cash operating costs. Per barrel amounts are based on total production volumes.

(5) Cash operating costs – In-situ bitumen production – Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes) and accretion expense. Per barrel amounts are based on in-situ production volumes only.

(6) Total cash operating costs – In-situ bitumen production – Include cash operating costs – In-situ bitumen production as defined above and cash start-up operating costs. Per barrel amounts are based on in-situ production volumes only.

(7) Total operating costs – In-situ bitumen production – Include total cash operating costs – In-situ bitumen production as defined above and non-cash operating costs. Per barrel amounts are based on in-situ production volumes only.

(8) Average price realized – This operating statistic is calculated before transportation costs and royalties and excludes the impact of hedging activities.

Explanatory Notes

* Excludes the impact of realized hedging activities.

** If capital employed were to include capitalized costs related to major projects in progress, the return on capital employed would be as stated on this line.

*** For the three months ended September 30, 2009, and the twelve months ended December 31, 2009, operating summary information reflects results of operations since the merger with Petro-Canada on August 1, 2009.

**** Users are cautioned that the Syncrude costs per barrel measure may not be fully comparable to similar information calculated by other entities (including Suncor's own cash costs per barrel excluding Syncrude) due to differing treatments for operations and capital costs among producers.

(a) thousands of barrels per day
(b) thousands of barrels of bitumen per day
(c) dollars per barrel
(d) dollars per barrel rounded to the nearest $0.05
(e) millions of cubic feet per day
(f) millions of cubic feet equivalent per day
(g) dollars per thousand cubic feet equivalent
(h) thousands of barrels of oil equivalent per day
(i) dollars per barrel of oil equivalent
(j) thousands of cubic metres per day
(k) $ millions

Metric conversion

Crude oil, refined products, etc. – $1m^3$ (cubic metre) = approx. 6.29 barrels

SHARE TRADING INFORMATION (unaudited)

Common shares are listed on the Toronto Stock Exchange and New York Stock Exchange under the symbol SU.

	For the Quarter Ended				For the Quarter Ended			
	Mar 31 2009	**June 30 2009**	**Sept 30 2009**	**Dec 31 2009**	Mar 31 2008	June 30 2008	Sept 30 2008	Dec 31 2008
Share ownership								
Average number outstanding, weighted monthly (thousands) [(a)]	**936 550**	**937 005**	**1 349 263**	**1 559 512**	926 216	928 572	930 393	931 524
Share price (dollars)								
Toronto Stock Exchange								
High	**34.22**	**40.13**	**39.84**	**40.79**	56.14	73.10	62.37	43.78
Low	**21.15**	**27.44**	**29.90**	**34.66**	40.92	47.78	39.61	18.80
Close	**28.14**	**35.37**	**37.40**	**37.21**	49.61	59.20	44.00	23.72
New York Stock Exchange – US$								
High	**27.92**	**36.93**	**37.31**	**39.62**	56.73	74.28	61.99	41.12
Low	**16.95**	**21.61**	**25.51**	**31.84**	39.67	46.31	38.00	14.52
Close	**22.21**	**30.34**	**34.56**	**35.31**	52.61	68.56	51.64	19.02
Shares traded (thousands)								
Toronto Stock Exchange	**408 851**	**361 886**	**339 790**	**277 779**	219 094	226 392	266 381	396 680
New York Stock Exchange	**778 887**	**697 065**	**541 485**	**436 930**	342 938	371 303	458 534	720 851
Per common share information (dollars)								
Net earnings attributable to common shareholders	**(0.20)**	**(0.06)**	**0.69**	**0.29**	0.77	0.89	0.87	(0.24)
Cash dividends	**0.05**	**0.05**	**0.10**	**0.10**	0.05	0.05	0.05	0.05

(a) The company had approximately 3,028 holders of record of common shares as at January 31, 2010.

Information for Security Holders Outside Canada

Cash dividends paid to shareholders resident in countries with which Canada has an income tax convention are usually subject to Canadian non-resident withholding tax of 15%. The withholding tax rate is reduced to 5% on dividends paid to a corporation if it is a resident of the United States that owns at least 10% of the voting shares of the company.

QuickLinks

EXHIBIT 99-1

Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2009, including reconciliation to U.S. GAAP (Note 23)

QuickLinks -- Click here to rapidly navigate through this document

EXHIBIT 99-2

**Management's Discussion and Analysis for the fiscal year ended December 31, 2009,
dated February 26, 2010**

MANAGEMENT'S DISCUSSION AND ANALYSIS

February 26, 2010

This Management's Discussion and Analysis (MD&A) contains forward-looking information based on Suncor's current expectations, estimates, projections and assumptions. This information is subject to a number of risks and uncertainties, including those discussed in this MD&A and Suncor's other disclosure documents, many of which are beyond the company's control. Users of this information are cautioned that actual results may differ materially. For information on material risk factors and assumptions underlying our forward-looking information, see page 54.

This MD&A should be read in conjunction with Suncor's December 31, 2009 audited Consolidated Financial Statements and the accompanying notes. All financial information is reported in Canadian dollars (Cdn$) and in accordance with Canadian generally accepted accounting principles (GAAP), unless noted otherwise. The financial measures operating earnings, cash flow from operations, return on capital employed (ROCE) and cash and total operating costs per barrel referred to in this MD&A are not prescribed by GAAP and are discussed in Non-GAAP Financial Measures on page 52 and 53.

In order to provide shareholders with full disclosure relating to potential future capital expenditures, we have provided cost estimates for projects that, in some cases, are still in the early stages of development. These costs are preliminary estimates only. The actual amounts are expected to differ and these differences may be material. For a further discussion of our significant capital projects, see the Significant Capital Project Update on page 15.

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.

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. For further information with respect to the merger transaction, please refer to note 2 of the December 31, 2009 audited Consolidated Financial Statements and the accompanying notes.

The consolidated financial statements include the results of post-merger Suncor from August 1, 2009. As such, amounts disclosed in this MD&A reflect results 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 from 2008 and 2007 reflect solely the results of legacy Suncor.

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

Barrels of oil equivalent (boe) may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet (mcf) of natural gas: one barrel of crude oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

The tables and charts in this document form an integral part of this MD&A.

Additional information about Suncor and legacy Petro-Canada filed with Canadian securities commissions and the United States Securities and Exchange Commission (SEC), including periodic quarterly and annual reports and the Annual Information Form filed with the SEC under cover of Form 40-F, is available on-line at www.sedar.com, www.sec.gov and our website www.suncor.com. Information contained in or otherwise accessible through our website does not form a part of this MD&A and is not incorporated into the MD&A by reference.

SUNCOR OVERVIEW AND STRATEGIC PRIORITIES

Suncor Energy Inc. is an integrated energy company headquartered in Calgary, Alberta. We operate five businesses:

- **Oil Sands**, 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. The company has a 12% ownership interest in the Syncrude oil sands mining and upgrading joint venture, also located near Fort McMurray, Alberta.

- **Natural Gas**, located primarily in Western Canada, explores for, acquires, develops and produces natural gas, natural gas liquids and crude oil. The sale of natural gas production offsets Suncor's purchases for internal consumption at our North American operations. Suncor is currently divesting certain non-core assets as we focus the strategy of this business.

- **East Coast Canada**, comprised of oil development activity offshore of Newfoundland and Labrador. The company has a strong position in every major oil development off Canada's east coast, including Hibernia, White Rose, Terra Nova and Hebron.

- **International**, which includes activities in key core areas such as the North Sea (including the United Kingdom, the Netherlands and Norway sectors), Libya, Syria, and offshore Trinidad and Tobago. Suncor is currently divesting certain non-core assets as we focus the strategy of this business.

- **Refining and Marketing**, includes refineries located in Alberta, Quebec, Ontario and Colorado, which produce and market the company's refined products to retail, commercial and industrial customers. Refining and Marketing also owns and operates a lubricants business in Ontario, which manufactures, blends and markets high quality products world-wide, interests in pipelines and terminals, and a network of retail service stations across Canada and the state of Colorado.

In addition, the company engages in third-party energy marketing and trading activities, and has investments in renewable energy opportunities, including Canada's largest ethanol plant by volume and partnerships in four wind power projects.

Suncor's strategic priorities are:

- Maintaining financial strength and flexibility through disciplined cost, capital and debt management, and stewardship of the balance sheet.

- Increasing our return on capital employed through targeting capital budgets to high-return, near-term projects.

- Focusing on plant and process reliability, efficiency and cost management as part of operational excellence initiatives.

- Developing our oil sands resource base through mining and in-situ technology and supplementing our bitumen production with third-party supply.

- Expanding oil sands mining, in-situ and upgrading facilities to increase crude oil production and improving reliability by providing flexible bitumen feed and upgrading options.

- Integrating oil sands production into the North American energy market through Suncor's refineries and third-party refineries to reduce vulnerability to supply and demand imbalances.

- Focusing on our East Coast Canada and International assets, which provide steady low-cost cash flows and offer stability during low commodity cycles to support our core oil sands operations.

- Reducing risk associated with commodity price volatility by producing natural gas volumes that offset purchases for internal consumption.

- Advancing environmental and social performance by closely managing impact to air, water and land while also earning continued stakeholder support for our ongoing operations and growth plans.

- Maintaining a strong focus on employee, contractor and community health and safety.

2009 Overview

Key milestones and developments over the course of 2009 and early 2010 included:

Challenging economic environment to start the year. Low benchmark commodity prices significantly impacted earnings. We took action to protect our future revenues by entering into derivative contracts. As prices recovered later in 2009, we realized large losses as the settlement prices were lower than benchmark prices.

Capital spending plans were reduced. As cash flows were reduced, and the credit markets dried up, Suncor revised its spending plans down to $3 billion, and deferred a number of capital projects. Costs related to keeping these projects in "safe mode" totalled approximately $380 million in 2009.

Completed a merger with Petro-Canada on August 1, 2009. This resulted in Suncor becoming Canada's largest energy company by market capitalization, and provided Suncor with a number of key benefits:

- **Steady production from established assets in East Coast Canada and International that will support Suncor's growth through the commodity cycle.** Total production volumes from these two segments averaged approximately 178,000 bpd over the last five months of 2009.

- **Additional refining capacity provides options for expanding oil sands production.** Increased refining capacity from 178,000 bpd to 433,000 bpd. Observed performance improvements at our Edmonton refinery have enabled us to upwardly revise our nameplate capacity to 443,000 bpd. Sales of refined petroleum products during the final five months of 2009 averaged 84.8 million litres per day.

- **Solid hedge for natural gas usage at our North American operations.** Total production from our Natural Gas business segment averaged 677 mmcfe/d for the final five months of the year.

- **Synergy opportunities**(1). Operating synergies of approximately $400 million on an annualized basis have been identified. We expect that synergies will start to exceed merger and integration costs by the end of 2010, when we start realizing the full benefits of the merger. We also expect to achieve annual capital efficiencies of approximately $1 billion through elimination of redundant spending and targeting capital budgets to high- return, near-term projects.

Improved Oil Sands operational reliability. Annual production from our Oil Sands business segment averaged 290,600 bpd in 2009, compared to 228,000 bpd in 2008, with record production in November and cash operating costs (excluding Syncrude) averaging $33.95 per barrel during 2009, compared to $38.50 per barrel in 2008. However, fires in our Oil Sands operations in December 2009 and February 2010 have negatively impacted volumes.

Growth capital restarts. In November, Suncor announced 2010 capital spending plans that included restarting construction of our Firebag Stage 3 in-situ oil sands project.

Planned divestments. As part of its strategic business alignment, Suncor began the process of divesting a number of non-core natural gas assets, all Trinidad and Tobago assets and certain non-core North Sea assets, including all assets in The Netherlands. Announced sales to date include substantially all of our oil and gas producing assets in the U.S. Rockies, non-core natural gas properties in Northeast British Columbia, and all Trinidad and Tobago assets. The effective close date of the U.S. Rockies sale was March 1, 2010. The other sales are expected to close in the first quarter of 2010 and are subject to customary closing conditions and regulatory approvals. The proceeds of these sales, expected to be between $2 billion and $4 billion, are planned to go towards reducing the company's debt. Net debt at year-end 2009 was $13.4 billion.

---

(1) Synergy estimates are based on certain assumptions that management currently believes are reasonable, including but not limited to: reduced operating costs due to restructuring synergies, acceleration of timing of planned capital projects and resulting revenues, reduced capital costs relating to divested assets and cash flow from divested assets. Please see Legal Notice – Forward-Looking Information on page 54.

SELECTED FINANCIAL INFORMATION

Annual Financial Data

Year ended December 31 ($ millions except per share)	**2009**	2008	2007
Revenue (net of royalties)	**25 480**	28 637	17 314
Net earnings	**1 146**	2 137	2 983
Total assets	**69 746**	32 528	24 509
Long-term debt	**13 880**	7 884	3 814
Dividends on common shares	**401**	180	162
Net earnings attributable to common shareholders per share – basic	**0.96**	2.29	3.23
Net earnings attributable to common shareholders per share – diluted	**0.95**	2.26	3.17
Cash dividends per share	**0.30**	0.20	0.19

Outstanding Share Data

At December 31, 2009 (thousands)	
Number of common shares	1 559 778
Number of common share options	72 024
Number of common share options – exercisable	42 755

Industry Indicators

(Average for the year)	**2009**	2008	2007
West Texas Intermediate (WTI) crude oil US$/barrel at Cushing	**61.80**	99.65	72.30
Dated Brent crude oil US$/barrel at Sullom Voe	**61.50**	97.00	72.50
Dated Brent/Maya FOB price differential US$/barrel	**5.00**	13.15	12.65
Canadian 0.3% par crude oil Cdn$/barrel at Edmonton	**65.80**	103.05	76.65
Edmonton Light/Western Canadian Select price differential Cdn$/barrel	**6.65**	19.90	24.05
Light/heavy crude oil differential US$/barrel WTI at Cushing less Western Canadian Select at Hardisty	**9.70**	20.10	22.25
Natural gas US$/thousand cubic feet (mcf) at Henry Hub	**4.00**	8.95	6.90
Natural gas (Alberta spot) Cdn$/mcf at AECO	**4.15**	8.15	6.60
New York Harbour 3-2-1 crack (1) US$/barrel	**7.80**	9.10	13.70
Chicago 3-2-1 crack (1) US$/barrel	**7.75**	10.40	16.85
Seattle 3-2-1 crack (1) US$/barrel	**11.40**	11.80	19.55
Gulf Coast 3-2-1 (1) US$/barrel	**7.10**	9.45	13.30
Exchange rate: US$/Cdn$	**0.88**	0.94	0.93

(1) 3-2-1 crack spreads are industry indicators measuring the margin on a barrel of oil for gasoline and distillate. They are calculated by taking two times the gasoline margin at a certain location plus one times the distillate margin at that same location and dividing by three.

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. The comparative figures reflect solely the 2008 and 2007 results of legacy Suncor. For further information with respect to the merger transaction, please refer to note 2 of the December 31, 2009 audited Consolidated Financial Statements and the accompanying notes.

CONSOLIDATED FINANCIAL ANALYSIS

This analysis provides an overview of our consolidated financial results for 2009 compared to 2008. For a detailed analysis, see the various business segment discussions.

Net Earnings

Our net earnings were $1.146 billion in 2009, compared with $2.137 billion in 2008 (2007 – $2.983 billion). The decrease in net earnings is due primarily to lower price realizations, as average benchmark commodity prices were significantly weaker in 2009 compared to 2008, losses on commodity derivatives used for risk management compared to gains in the prior year, and costs incurred related to placing certain growth projects into safe mode due to market conditions earlier in the year.

These factors were partially offset by higher production from our existing oil sands assets resulting from improved operational performance, upstream production and refined product sales volumes resulting from the merger with Petro-Canada, unrealized foreign exchange gains on our U.S. denominated long-term debt due to the stronger Canadian dollar and a gain from the deemed settlement of the bitumen processing contract with Petro-Canada upon close of the merger (See note 2(e) to the December 31, 2009 audited Consolidated Financial Statements).

Revenues were $25.480 billion in 2009, compared with $28.637 billion in 2008 (2007 – $17.314 billion). The decrease was primarily due to the following factors:

- Operating revenues were adversely impacted by significantly weaker benchmark prices in 2009. In addition, losses on commodity price risk derivatives which we had initiated when commodity prices hit a low point early in 2009, also negatively affected operating revenues as prices recovered later in the year.

- Royalties increased to $1.199 billion in 2009 from $890 million in 2008, due primarily to royalty expense on additional production resulting from the merger with Petro-Canada, as well as increased production in legacy Suncor's oil sands operations. This was partially offset by lower commodity prices. For a discussion of Crown royalties, see pages 16 to 18.

- Energy trading revenues decreased to $7.577 billion in 2009, compared to $11.320 billion in 2008. Lower trading revenues partly resulted from decreased commodity prices. In addition, after the merger with Petro-Canada, we determined that certain physical trading commodity contracts exceeded the company's expected purchase, sale or usage requirements, and effective October 1, 2009, gains and losses on these contracts have been reported on a net basis. Had we continued reporting on a gross basis, energy supply and trading revenues would have been approximately $2 billion larger in 2009.

Partially offsetting these decreases were the following:

- Total upstream production and sales volumes were higher during 2009, mainly as a result of the merger with Petro-Canada, as well as improved reliability in legacy Suncor's oil sands operations. After completion of the merger with Petro-Canada, Suncor's total upstream production during the final five months of 2009 averaged 635,200 boe per day. Upstream production from legacy Suncor's oil sands and natural gas operations averaged 325,600 boe per day in 2009, compared to 264,700 boe per day in 2008.

- Other income included a $438 million gain related to the effective settlement of a pre-existing bitumen processing contract with Petro-Canada. For further details on this one-time item, see note 2(e) to the Consolidated Financial Statements on page 73.

- Stronger price realizations for sales of our oil sands sweet blend and diesel product relative to WTI positively impacted operating revenue.

The cost to purchase crude oil and crude oil products was $7.383 billion in 2009, compared to $7.582 billion in 2008 (2007 – $6.414 billion). The decrease was primarily due to the following:

- Lower benchmark crude oil prices. This had the largest impact on product purchases for our Refining and Marketing business, as average WTI prices were approximately 38% lower than in 2008.

- Decreased purchases of third-party product in our Oil Sands segment, primarily due to a reduction of planned and unplanned shutdowns, as 2008 results reflected higher purchases of diesel and bitumen to meet customer commitments. In addition, in 2008 Suncor purchased larger volumes of product from third parties to upgrade at Suncor facilities.

Partially offsetting these decreases was the following:

- Increased purchases in our Refining and Marketing segment due to the addition of refining assets as a result of the merger with Petro-Canada.

Operating, selling and general expenses were $6.641 billion in 2009 compared with $4.186 billion in 2008 (2007 – $3.450 billion). The primary reasons for the increase were:

- The addition of Petro-Canada operations and the related operating, selling and general expenses; and higher production and sales volumes in legacy Suncor operations.
- Higher planned maintenance expenditures at our oil sands operations related to the implementation of reliability and operational efficiency initiatives.
- Incurred costs related to placing our growth projects into safe mode as a result of the company revising its 2009 capital budget due to market conditions earlier in the year.
- One-time costs related to a number of merger and integration activities.

Partially offsetting these increases was the following:

- Decreased energy input costs, resulting mainly from significantly lower natural gas prices. The average benchmark AECO price in 2009 was down almost 50% compared to 2008.

Transportation costs were $427 million in 2009, compared to $246 million in 2008 (2007 – $160 million). The increase in transportation costs was primarily due to the additional production and sales volumes as a result of the merger with Petro-Canada.

Depreciation, depletion and amortization (DD&A) was $2.306 billion in 2009, compared to $1.049 billion in 2008 (2007 – $864 million). The increase primarily reflects the addition of assets as a result of the merger.

Financing income was $487 million in 2009, compared with expense of $917 million in 2008 (2007 – income of $211 million). The decrease in financing expense was primarily due to foreign exchange gains on our U.S. dollar denominated long-term debt in 2009, compared to losses in 2008. This was partially offset by additional debt acquired through the merger with Petro-Canada, and by interest costs that were not capitalized during 2009 as a number of growth projects were in safe mode during the period.

Income tax expense was $143 million in 2009 (11% effective tax rate), compared to $995 million in 2008 (32% effective tax rate) and $566 million in 2007 (16% effective tax rate). The lower effective tax rate for 2009 compared to 2008 is primarily a result of foreign exchange gains on our U.S. dollar denominated long-term debt being taxed at a lower capital gains rate, no tax assessed on the gain on effective settlement of the pre-existing contract with Petro-Canada, and tax filing reconciliations.

Cash Flow from Operations

Cash flow from operations was $2.799 billion in 2009, compared to $4.057 billion in 2008 (2007 – $4.037 billion). The decrease in cash flow from operations was primarily due to the same factors that impacted earnings. Cash flow from operations is a non-GAAP measure that the company uses to evaluate operating performance. See page 52 and 53 for discussion of non-GAAP financial measures.

Dividends

Total dividends paid during 2009 were $0.30 per share, compared with $0.20 per share in 2008 (2007 – $0.19 per share). Suncor's Board of Directors periodically reviews the dividend policy, taking into consideration the company's capital spending profile, financial position, financing requirements, cash flow and other relevant factors.

Quarterly Financial Data

	2009 Three months ended				2008 Three months ended			
($ millions except per share)	**Dec 31**	**Sept 30**	**June 30**	**Mar 31**	Dec 31	Sept 30	June 30	Mar 31
Revenues (net of royalties)	**7 636**	**8 443**	**4 768**	**4 633**	6 952	8 507	7 640	5 539
Net earnings (loss)	**457**	**929**	**(51)**	**(189)**	(215)	815	829	708
Net earnings (loss) attributable to common shareholders per share								
Basic	**0.29**	**0.69**	**(0.06)**	**(0.20)**	(0.24)	0.87	0.89	0.77
Diluted	**0.29**	**0.68**	**(0.06)**	**(0.20)**	(0.24)	0.86	0.87	0.75

Variations in quarterly net earnings (loss) during 2009 and 2008 were due to a number of factors:

- Additional upstream production and refined product sales volumes resulting from the merger with Petro-Canada, impacting the third and fourth quarter of 2009.
- Changes in benchmark commodity prices throughout 2009 and 2008. WTI averaged US$61.80 per barrel (bbl) in 2009, compared to US$99.65/bbl in 2008, while AECO averaged Cdn$4.15/mcf in 2009, compared to Cdn$8.15/mcf in 2008.
- Oil sands production and sales volumes decreased during periods of planned and unplanned maintenance.
- Cash operating costs varied due to changes in oil sands production levels, the timing and amount of maintenance activities, and the price and volume of natural gas used for energy in oil sands operations.
- Exchange rate fluctuations impacted the realized commodity prices on our products sold in U.S. dollars, affecting the Canadian dollar revenues earned. Changes in the exchange rate also led to unrealized gains/losses on our U.S. dollar denominated long-term debt.
- Crown royalties varied as a result of changes in commodity prices, changes in production and the extent and timing of eligible capital and operating expenditures.
- Refined product prices fluctuated as a result of global and regional supply and demand, as well as seasonal demand variations.
- Improved reliability in legacy Suncor's refineries, resulting in increased refined product sales and margins.

For further analysis of quarterly results, refer to Suncor's quarterly reports to shareholders available on our website.

Operating Earnings

Operating earnings is a non-GAAP measure that the company uses to evaluate operating performance, which management believes allows better comparability between periods. Operating earnings is calculated by adjusting net earnings for significant one-time items and items that are not indicative of operating performance. See page 52 for a discussion of non-GAAP financial measures.

Year ended December 31 ($ millions, after-tax)	**2009**	2008	2007
Net earnings as reported	**1 146**	2 137	2 983
Change in fair value of commodity derivatives used for risk management	**499**	(372)	—
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**(798)**	852	(215)
Mark-to-market valuation of stock-based compensation	**124**	(107)	35
Project start-up costs	**40**	24	49
Impact of income tax rate adjustments on future income tax liabilities (1)	**4**	—	(427)
Costs related to deferral of growth	**300**	—	—
Gain on effective settlement of pre-existing contract with Petro-Canada (2)	**(438)**	—	—
Impact of recording acquired inventory at fair value (3)	**97**	—	—
Merger and integration costs	**151**	—	—
Losses and adjustments on significant disposals (4)	**81**	—	—
Operating earnings	**1 206**	2 534	2 425

(1) In the third quarter of 2009, a $152 million increase in the future income tax liabilities resulted from a revised provincial allocation for income tax purposes due to the merger with Petro-Canada. This was partially offset for the year ended December 31, 2009 by a reduction to the Ontario income tax rate in the fourth quarter of 2009, resulting in a $148 million decrease in the future income tax liabilities. See note 7 to the Consolidated Financial Statements.

(2) Impact from deemed settlement value assigned to bitumen processing contract with Petro-Canada upon close of merger. See note 2 to the Consolidated Financial Statements.

(3) Inventory acquired through the merger at fair value was sold during the third quarter of 2009, resulting in a one-time negative impact to earnings.

(4) Includes loss recognized when a highway interchange constructed by Suncor was transferred to the Provincial government of Alberta, and fair value adjustments to assets acquired in the merger.

Operating earnings were $1.206 billion in 2009, compared to $2.534 billion in 2008 (2007 – $2.425 billion). The decrease in operating earnings is due primarily to lower price realizations, as average benchmark commodity prices were significantly weaker in 2009 compared to 2008. In addition, we realized losses on our risk management derivative contracts, as settlement prices were lower than market prices in the latter part of 2009 as commodity prices improved. These factors were partially offset by the increased upstream production and refined product sales volumes resulting from the merger with Petro-Canada, and improved operational performance from our existing oil sands assets.

LIQUIDITY AND CAPITAL RESOURCES

Our capital resources consist primarily of cash flow from operations and available lines of credit. As a result of the merger with Petro-Canada, we added approximately $4.2 billion in unutilized credit facilities and $415 million in cash.

We believe we will have the capital resources to fund our planned capital spending program and to meet current working capital requirements through cash flow from operations and our committed credit facilities, assuming our current production outlook and other business plan assumptions are met. Our cash flow from operations depends on a number of factors, including commodity prices, production/sales levels, refining and marketing margins, operating expenses, taxes, royalties, and foreign exchange rates. If additional capital is required, we believe adequate additional financing will be available in the debt capital markets at commercial terms and rates. Our spending is subject to change due to factors such as internal and regulatory approvals and capital availability. Refer to the discussion under Risk Factors Affecting Performance on page 20 for additional factors that may have an impact on our ability to fund our capital requirements.

To significantly reduce current debt levels in 2010, the company is targeting to apply the proceeds from the announced divestment program. The expected proceeds of $2 billion to $4 billion will be used to repay debt as the transactions are completed, subject to the financial and operational factors outlined previously, as internally generated cash flow will be used to fund our capital program.

Financing Activities

Management of debt levels continues to be a priority given our long-term growth plans. We believe a phased and flexible approach to existing and future growth projects should assist us in maintaining our ability to manage project costs and debt levels.

At December 31, 2009, our net debt (short-term debt, current portion of long-term debt and long-term debt less cash and cash equivalents) was $13.377 billion, compared to $7.226 billion at December 31, 2008. The increase in debt levels was primarily a result of the debt acquired from the merger with Petro-Canada, in addition to an increase in the drawn credit facilities that supported our capital spending program. The merger also caused our net debt/cash flow from operations measure to increase significantly, as the calculation only includes five months of cash flow from operations relating to legacy Petro-Canada operations.

Interest expense on debt continues to be influenced by the composition of our debt portfolio, and we are currently benefiting from short-term floating interest rates which remain at low levels compared to historical short-term rates. To manage fixed versus floating rate exposure, we have entered into interest rate swaps with investment grade counterparties. At December 31, 2009, we had $200 million of fixed-rate to variable-rate interest swaps (December 31, 2008 – $200 million).

During the fourth quarter of 2009, we reduced our committed bilateral credit facility from $855 million to $61 million, reduced our Canadian-based demand bilateral credit facilities from $588 million to $413 million, and we increased our commercial paper program from $1.5 billion to $2.5 billion. Unutilized lines of credit at December 31, 2009 were $4.208 billion.

Excluding cash and cash equivalents, short-term debt, the current portion of long-term debt and future income taxes, Suncor had an operating working capital deficiency of $309 million at December 31, 2009, compared to a deficiency of $851 million at December 31, 2008. The reduced deficiency was primarily due to increased inventory levels as a result of the merger with Petro-Canada.

We are subject to financial and operating covenants related to our public market and bank debt. Failure to meet the terms of one or more of these covenants may constitute an Event of Default as defined in the respective debt agreements, potentially resulting in accelerated repayment of one or more of the debt obligations.

We are in compliance with our financial covenant that requires consolidated debt to not be more than 60% of our total capitalization. At December 31, 2009, our consolidated debt to total capitalization was 28.9% (where consolidated debt is short-term debt plus current portion of long-term debt plus long-term debt, and total capitalization is consolidated debt plus shareholders' equity). We are also currently in compliance with all operating covenants. In addition, a limited number of our derivative financial instrument agreements contain provisions linked to debt ratings that may result in settlement of the outstanding transactions should our debt ratings fall below investment grade status.

All of our debt ratings are currently investment grade. Suncor's current long-term senior debt ratings are BBB+, with a Stable Outlook from Standard & Poor's ("S&P"); A(low), with a Stable Trend from Dominion Bond Rating Service ("DBRS"); and Baa2, with a Stable Outlook from Moody's Investors Service. Suncor's current commercial paper ratings are A-1 (Low) from S&P and R-1 (low) from DBRS.

The preceding paragraphs contain forward-looking information regarding our liquidity and capital resources based on factors and assumptions discussed above and on page 20. Users of this information are cautioned that our actual liquidity and capital resources may vary materially from our expectations. See the discussion with respect to forward-looking information on page 54.

Aggregate Contractual Obligations

In the normal course of business, the company is obligated to make future payments. These obligations represent contracts and other commitments that are known and non-cancellable.

		Payments Due by Period			
($ millions)	Total	2010	2011-2012 (aggregate)	2013-2014 (aggregate)	Later Years
Fixed-term debt and revolving-term debt [1]	13 586	3 244	500	742	9 100
Interest payments on fixed-term debt	12 197	651	1 255	1 219	9 072
Capital leases	711	35	68	72	536
Employee future benefits [2]	1 976	154	338	380	1 104
Asset retirement obligations [3]	8 280	318	468	352	7 142
Operating lease agreements, pipeline capacity, energy services commitments and delivery obligations [4]	12 724	1 090	1 787	1 550	8 297
Other long-term obligations [5]	1 146	382	568	139	57
Total	50 620	5 874	4 984	4 454	35 308

In addition to the enforceable and legally binding obligations quantified in the above table, we have other obligations for goods and services and raw materials entered into in the normal course of business, which may terminate on short notice. Commodity purchase obligations for which an active, highly liquid market exists, and which are expected to be re-sold shortly after purchase, are one example of excluded items.

(1) Includes $8.075 billion of U.S. and $1.800 billion of Canadian dollar denominated debt that is redeemable at our option. Maturities range from 2011 to 2039. Interest rates vary from 4.00% to 9.25%. We entered into interest rate swap transactions maturing in 2011 that resulted in an average effective interest rate in 2009 of 1.97% on $200 million of our Medium Term Notes. Approximately $3.244 billion of revolving-term debt with an effective interest rate of 0.74% was issued and outstanding at December 31, 2009.

(2) Represents the undiscounted expected funding by the company to its pension plans as well as benefit payments to retirees for other post-retirement benefits.

(3) Represents the undiscounted amount of legal obligations associated with site restoration on the retirement of assets with determinable lives.

(4) Includes annual tolls payable under transportation service agreements with major pipeline companies to use a portion of their pipeline capacity and tankage, as applicable, for transportation of product within Canada and the United States. In addition, includes commitments under long-term energy agreements to obtain a portion of the power and the steam generated by certain cogeneration facilities owned by a major third-party energy company and obligations associated with reimbursing BG Gas Marketing for gas quantities in the Trinidad LNG Sales Contract.

(5) Includes Libya Exploration and Production Sharing Agreements (EPSA) signature bonus and Fort Hills purchase obligation. See note 16 to the Consolidated Financial Statements.

Significant Capital Project Update

In November 2009, Suncor's Board of Directors approved a $5.5 billion capital spending plan for 2010. Approximately $1.5 billion will be directed toward growth project funding, primarily at the company's oil sands operations, while $4 billion in spending is targeted to sustaining existing operations.

The majority of growth spending will be directed toward the Firebag Stage 3 in-situ oil sands expansion, which was approximately 50 per cent complete before being deferred in early 2009. Suncor now expects the project to begin production in the second quarter of 2011, with volumes then beginning ramp up toward design capacity of approximately 68,000 bpd of bitumen over a period of approximately 18 months. Spending will also be directed to Firebag Stage 4 to support a target of first bitumen production in the fourth quarter of 2012. Stage 4 also has a design capacity of 68,000 bpd.

Growth capital will also be directed toward completing a naphtha unit in one of our upgraders and to expansion of Suncor's St. Clair Ethanol Plant. International growth plans include commitments in Libya and investments planned to bring the Ebla gas project in Syria into production in the second quarter of 2010.

Capital plans and sequencing for other projects in Suncor's growth portfolio are under evaluation with a further update expected in the fourth quarter of 2010.

Suncor spent $4.2 billion on capital and exploration expenditures in 2009, compared to $8.0 billion in 2008 (2007 – $5.6 billion). A summary of the progress on our significant projects under construction to support both our growth and sustaining needs is provided below. All projects listed below have received Board of Directors approval. The estimates and target completion dates do not include project commissioning and start-up.

The company continues to incur costs related to placing certain growth projects into "safe mode" as a result of the company revising its 2009 capital budget due to market conditions earlier in the year. Safe mode is defined as the costs of 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 projects into safe mode, pre-tax costs of $382 million were incurred in 2009. Further safe mode costs of $150 million to $200 million on a pre-tax basis, including costs related to the remobilization of growth projects placed into safe mode, are expected to be incurred in 2010.

Project	Business Segment	Plan	Cost Estimate $ millions[1]	Estimate % Accuracy[1]	Spent to date $ millions	Target Completion date
Firebag sulphur plant	Oil Sands	Support emission abatement plan at Firebag; capacity to support Stages 1-6	404	N/A	415	Complete
Steepbank extraction plant	Oil Sands	New location and technologies aimed at improving operational performance	980	N/A	1 015	Complete
Ebla gas project	International	Development of gas fields and construction of gas treatment plant	1 196	+7/-3	1 080	Q2 2010
Buzzard enhancement project [2]	International	Installation of equipment to handle high sulphur content	339	+15/-10	163	Q4 2010
Firebag Stage 3	Oil Sands	Expansion is expected to increase bitumen supply	3 638	+10/-10	2 780	Q2 2011
Naphtha unit [3]	Oil Sands	Increases sweet product mix	850	+4/-4	670	Q3 2011
North Amethyst [2]	East Coast Canada	Extension to the White Rose field involving subsea tie-in	490	+10/-5	230	2012 [4]

(1) Cost estimates and estimate accuracy reflect budgets approved by Suncor's Board of Directors.

(2) Amounts represent Suncor's net share in the project.

(3) As a result of labour shortages and cost escalation, the cost estimate has been revised to $850 million +4/-4% (previously $650 million +10/-10%).

(4) Initial production is expected in the second quarter of 2010.

The preceding paragraphs and table contain forward-looking information and users of this information are cautioned that the actual timing, amount of the final capital expenditures and expected results, including target completion dates, for each of these projects may vary from the plans disclosed in the table. For a list of the

material risk factors that could cause actual timing, amount of the final capital expenditures and expected results to differ materially from those contained in the previous table, please see page 20. For additional information on risks, uncertainties and other factors that could cause actual results to differ, please see page 54.

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 project; updates from third parties on delivery of goods and services associated with the project; and estimates from major projects teams on completion of future phases of the project. We have assumed that commitments from third parties will be honoured and that material delays and increased costs related to the risk factors referred to above will not be encountered.

Guarantees, Variable Interest Entities and Off-Balance Sheet Arrangements

CICA Accounting Guideline 15, *Consolidation of Variable Interest Entities* (VIEs), provides criteria for the identification of VIEs and further criteria for determining what entity, if any, should consolidate them. Entities in which equity investors do not have the characteristic of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinate financial support are subject to consolidation by a company if that company is deemed the primary beneficiary. The primary beneficiary is the party that is subject to a majority of the risk of loss from the VIE's activities, or is entitled to receive a majority of the VIE's residual returns, or both. The company has determined that certain retail licensee and wholesale marketer agreements would constitute VIEs, even though the company has no ownership in these entities. The company, however, is not the primary beneficiary and, therefore, consolidation is not required. In certain of the retail licensee arrangements, the company has provided loan guarantees. Management is of the opinion that the company's maximum exposure to loss from these arrangements would not be significant.

The company has agreed to indemnify holders of all notes and debentures and the company's credit facility lenders (see note 17 to the Consolidated Financial Statements) for added costs relating to taxes, assessments or other government charges or conditions, including any required withholding amounts. Similar indemnity terms apply to certain facility and equipment leases.

There is no limit to the maximum amount payable under the indemnification agreements described above. The company is unable to determine the maximum potential amount payable as government regulations and legislation are subject to change without notice. Under these agreements, Suncor has the option to redeem or terminate these contracts if additional costs are incurred.

ROYALTIES

Oil Sands Crown Royalties

Under the Province of Alberta's generic oil sands royalty regime in effect to December 31, 2008 (1997 Generic Regime), Alberta Crown royalties for oil sands projects were payable at the rate of 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 at 1% of revenues should allowable costs exceed revenues as determined using the R-C Royalty Formula. The Alberta government has classified Suncor's current oil sands operations as two distinct "projects" for royalty purposes.

Royalties on our Firebag in-situ project were under the 1997 Generic Regime until the end of 2008, and assessed based on bitumen value. In December 2008, the government of Alberta enacted the New Royalty Framework which increased royalty rates from the 1997 Generic Regime to a sliding scale royalty of 25% to 40% of R-C, subject to minimum royalty of 1% to 9% of R, depending on oil price. In both cases, the sliding scale royalty moves with increases in WTI prices from Cdn$55/bbl to the maximum rate at a WTI price of Cdn$120/bbl.

The MacKay River in-situ project acquired with the merger of Suncor and Petro-Canada on August 1, 2009. Mackay River is also subject to royalties based on the New Royalty Framework.

Royalties on our base oil sands mining and associated upgrading operations are modified by Crown agreements and are assessed on the R-C royalty, subject to a minimum royalty, as follows:

- Based on upgraded product values until December 31, 2008 with the rates at 25% of R-C, subject to the 1% minimum royalty of R.
- Commencing January 1, 2009, a bitumen-based royalty applied pursuant to Suncor's exercise of its option to transition to the bitumen-based 1997 Generic Regime. The royalty rates were at 25% of R-C, subject to the 1% minimum royalty of R, but applied to a revised R-C, where R was based on bitumen value and C would exclude substantially all upgrading operating and related capital costs.

- From January 1, 2010 through December 31, 2015, pursuant to our January 2008 Royalty Amending Agreement (RAA) with the government of Alberta, the New Royalty Framework rates described above will apply to the bitumen royalty for current production levels, subject to a cap of 30% of R-C, and a minimum royalty of 1% to 1.2% of R. In addition, the Suncor RAA provides Suncor with a level of certainty for various matters, including the bitumen valuation methodology, allowed costs, royalty-in-kind and certain taxes.

In 2016 and subsequent years, the royalty rates for all of our oil sands operations will be the rates prescribed under the New Royalty Framework, unless it is amended or superseded prior to that time.

The following table sets forth an estimation of royalties on our oil sands operations (excluding Syncrude) in the years 2010 – 2013 for three price scenarios, and certain assumptions on which we have based our estimates for those price scenarios.

WTI Price/bbl US$	**60**	**80**	**100**
Natural gas (Alberta spot) Cdn$/mcf at AECO	5.75	7.50	9.50
Light/heavy oil differential of WTI at Cushing less Maya at the U.S. Gulf Coast US$	7.25	9.75	12.00
Differential of Maya at the U.S. Gulf Coast less Western Canadian Select at Hardisty, Alberta US$	4.50	6.00	7.50
US$/Cdn$ exchange rate	0.85	0.97	1.00
Crown Royalty Expense (based on percentage of total Oil Sands gross revenue (excluding Syncrude)) % [1] 2010-2013	4-6	9-11	12-14

(1) Reflects Crown's interim bitumen valuation methodology.

The previous table contains forward-looking information and users of this information are cautioned that actual Crown royalty expense may vary from the percentages disclosed in the table. The percentages disclosed in the table were developed using the following assumptions: current agreements with the Government of Alberta, royalty rates and other changes enacted effective January 1, 2009 by the Government of Alberta, current forecasts of production, capital and operating costs, and the forward estimates of commodity prices and exchange rates described in the table.

The following risk factors could cause actual royalty rates to differ materially from the rates contained in the foregoing table:

(i) The government of Alberta enacted new Bitumen Valuation Methodology (Ministerial) Regulations as part of the implementation of the New Royalty Framework effective January 1, 2009. These interim regulations determine the valuation of bitumen for 2009 and 2010. The final regulations are being developed by the Crown that will establish the bitumen valuation methodology for future years. For Suncor's mining operations, the bitumen valuation methodology is based on the terms of the Suncor RAA, which we believe places certain limitations on the interim bitumen valuation methodology as recently enacted. For the year 2009, Suncor filed a non-compliance notice with the Crown, citing that reasonable adjustments in the determination of the Suncor bitumen value were not considered by the Crown as permitted by the Suncor RAA. Royalty payments to the Crown for our mining operations were determined in accordance with the Suncor RAA and royalty expense was recorded under the Crown's interim bitumen valuation methodology, representing a negative difference of approximately $200 million. The Suncor RAA provides for a negotiation period with the Crown and, failing a negotiated settlement, an arbitration procedure is outlined. If a negotiated settlement or arbiter does not create a result in Suncor's favour, royalty payments could be significantly higher.

(ii) The government enacted the new Oil Sands Allowed Costs (Ministerial) Regulations as part of the implementation of the New Royalty Framework effective January 1, 2009. Further clarification of some Allowed Cost business rules is still expected. The terms of the Suncor RAA determine the royalty obligation through 2015 for the mining operations. However, potential changes to, and the interpretation of, the Allowed Cost regulations, could over time, have a significant impact on the amount of royalties payable.

(iii) Changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs for each oil sands project; changes resulting from regulatory audits of prior year filings; further changes to applicable royalty regimes

by the government of Alberta; changes in other legislation; and the occurrence of unexpected events all have the potential to have an impact on royalties payable to the Crown.

For further information on risk factors related to royalty rates, please see page 54 of Suncor's Annual Information Form dated March 5, 2010.

Syncrude Royalties

Syncrude oil sands project is also subject to the New Royalty Framework effective January 1, 2009 and has signed a Royalty Amending Agreement with the Crown. Syncrude has also filed a non-compliance notice with the Crown with respect to the valuation of bitumen for royalty purposes. The royalty adjustment amount for Suncor's share of the Syncrude project is not material.

Alberta Natural Gas Crown Royalties

In 2008, royalty rates on natural gas production in Alberta were capped at 30% for gas discovered in 1974 or later and 35% for gas discovered prior to 1974. These rates were subject to reduction if (i) gas prices dropped below $3.70/gigajoule ($3.89/mcf), (ii) a gas well qualified for a deep gas royalty holiday incentive, or (iii) a gas well qualified as a low productivity well. The New Royalty Framework, effective from January 1, 2009, is a sliding scale that is dependent on the production rate, depth of the well, and the market price for natural gas, up to a maximum royalty rate of 50%. The framework provides some royalty relief, under the Natural Gas Deep Drilling Program, for wells drilled beyond 2,500 metres true vertical depth, based on the total depth and whether the well is exploratory or developmental. On November 19, 2008, the government of Alberta announced the Transitional Royalty Program available for wells from 1,000 metres to 3,500 metres in measured depth. Companies can elect to be subject to the Transitional Royalty Program for qualifying wells which would cap the maximum royalty at 30%, however, these wells cannot also receive royalty relief from the Natural Gas Deep Drilling Program. The Transitional Royalty Program is available from 2009 to 2013 inclusive. After January 1, 2014, all wells are subject to the New Royalty Framework.

East Coast Canada Royalties

The following table sets forth an estimation of royalties on our East Coast Canada operations in 2010 for three price scenarios, and certain assumptions on which we have based our estimates for those price scenarios.

WTI Price/bbl US$	**60**	**80**	**100**
US$/Cdn$ exchange rate	0.85	0.97	1.00
Crown Royalty Expense (based on percentage of gross revenue) % **2010** – Crude (tiered royalty rates assessed on gross or net revenue)	29-31	31-33	32-34

The previous table contains forward-looking information and users of this information are cautioned that actual Crown royalty expense may vary from the percentages disclosed in the table. The percentages disclosed in the table were developed using the following assumptions: current agreements with the Government of Newfoundland and Labrador, current forecasts of production, capital and operating costs, and the forward estimates of commodity prices and exchange rates described in the table.

The following risk factors could cause actual royalty rates to differ materially from the rates contained in the foregoing table:

(i) The government of Newfoundland and Labrador and Suncor are in discussions to resolve several outstanding issues that impact current and prior years. Settlement of these issues could impact royalties payable to the Crown.

(ii) Changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs for each project; changes resulting from regulatory audits of prior year filings; further changes to applicable royalty regimes by the government of Newfoundland and Labrador; changes in other legislation; and the occurrence of unexpected events all have the potential to have an impact on royalties payable to the Crown.

CASH INCOME TAXES

We estimate we will have cash income taxes of approximately $800 million to $900 million during 2010. Cash income taxes are sensitive to crude oil and natural gas commodity price volatility and the timing of deductibility of capital expenditures for income tax purposes, among other things. This estimate is based on the following assumptions: current forecasts of production, capital and operating costs and the commodity prices and exchange rates described in the royalty estimate tables on page 17 and 18, assuming there are no changes to the current income tax regime. Our outlook on cash income taxes is a forward-looking

statement and users of this information are cautioned that actual cash income taxes may vary materially from our outlook.

DERIVATIVE FINANCIAL INSTRUMENTS

We periodically enter into derivative contracts such as forwards, futures, swaps, options and costless collars to hedge against the potential adverse impact of changing market prices due to changes in the underlying indices. We also use physical and financial energy derivatives to earn trading revenues.

Suncor accounts for its significant derivative financial instruments using the mark-to-market method. The contracts are recorded on the balance sheet at fair value at each period end, with any changes in fair value immediately recognized in net earnings.

To estimate fair value of financial instruments, the company uses quoted market prices when available, or models that utilize observable market data. In addition to market information, the company incorporates transaction specific details that market participants would utilize in a fair value measurement, including the impact of non-performance risk. The company characterizes inputs used in determining fair value using a hierarchy that prioritizes inputs depending on the degree to which they are observable. However, these fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

The fair value of our derivative financial instruments at December 31, were as follows:

($ millions)	**2009**	2008
Derivative financial instruments		
Assets	**231**	660
Liabilities	**(572)**	(27)
Net derivative financial instruments	**(341)**	633

Commodity Price Risk Management Activities

The company has hedged a portion of its forecasted U.S. dollar denominated crude oil sales subject to U.S. dollar West Texas Intermediate (WTI) price risk. For the full year 2010, we hold crude oil hedges for approximately 50,000 bpd at an equivalent WTI floor price of US$50.00 per barrel and a ceiling price of approximately US$68.00 per barrel.

In addition to our strategic crude oil hedging program, Suncor uses derivative contracts to hedge risks related to purchases and sales of natural gas and refined products, to manage exposure to interest rates, and to hedge risks specific to individual transactions.

Settlement of our commodity hedging contracts results in cash receipts or payments for the difference between the derivative contract and market rates for the applicable volumes hedged during the contract term. For accounting purposes, amounts received or paid on settlement are recorded as part of the related hedged sales or purchase transactions in the Consolidated Statements of Earnings.

Significant derivative contracts outstanding at December 31, 2009 were as follows:

Crude oil	Quantity (bpd)	Average Price[1] (US$/bbl)	Hedge Period
Purchased puts [2]	55 000	60.00	2010
Sold puts [3]	54 753	60.00	2010
Collars – floor	50 041	50.00	2010
Collars – cap	49 986	68.06	2010

(1) Average price for crude puts is US$ WTI per barrel at Cushing, Oklahoma.

(2) Total premium paid was US$29.5 million.

(3) Premium received was US$213 million.

The earnings impact associated with our commodity price risk derivatives for the twelve months ended December 31, 2009 was a net pretax loss of $1.025 billion (2008 – pretax gain of $465 million).

Energy Supply and Trading Activities

Suncor uses crude oil, natural gas and refined product derivative contracts to earn supply and trading revenues. The results of these supply and trading activities are reported as energy supply and trading revenues and expenses in the Consolidated Statements of Earnings. The net pretax loss associated with our energy trading activities in 2009 was $70 million (2008 – earnings of $127 million).

Risks Associated with Derivative Financial Instruments

Our price risk management strategies are subject to periodic management reviews to determine appropriate hedge requirements in light of our tolerance for exposure to market volatility as well as the need for stable cash flow to finance future growth.

We may be exposed to certain losses in the event that the counterparties to derivative financial instruments are unable to meet the terms of the contracts. We minimize this risk by entering into agreements with investment grade counterparties. Risk is also minimized through regular management review of the potential exposure to and credit ratings of such counterparties. Our exposure is limited to those counterparties holding

derivative contracts with net positive fair values at the reporting date.

Energy marketing and trading activities are governed by a separate risk management group which reviews and monitors practices and policies and provides independent verification and valuation of these activities.

For further details on our derivative financial instruments, including a sensitivity analysis of the effect of changes in commodity prices on our financial contracts and additional discussion of exposure to risks and our mitigation activities, see note 4 to the Consolidated Financial Statements on page 74.

RISK FACTORS AFFECTING PERFORMANCE

Our financial and operational performance is potentially affected by a number of factors including, but not limited to, commodity prices and exchange rates, environmental regulations, changes to royalty and income tax legislation, credit market conditions, stakeholder support for activities and growth plans, extreme weather, regional labour issues and other issues discussed within Risk Factors Affecting Performance for each of our business segments. A more detailed discussion of our risk factors is presented in our most recent Annual Information Form (AIF)/Form 40-F, filed with securities regulatory authorities. We are continually working to mitigate the impact of potential risks to our stakeholders. This process includes an entity-wide risk review. This internal review is completed annually to ensure all significant risks are identified and appropriately managed. Certain key risk factors are discussed below:

Integration Risk

The company completed the merger with Petro-Canada in order to strengthen its position in the oil and natural gas industry and to create the opportunity to realize certain benefits including, cost savings and other operational synergies. Achieving the benefits of the merger depends in part on the ability of Suncor to effectively capitalize on its scale, scope and leadership position in the oil sands industry, to realize the anticipated capital and operating synergies, to profitably sequence the growth prospects of its asset base and to maximize the potential of its improved growth opportunities and capital funding opportunities as a result of combining the businesses and operations of Suncor and Petro-Canada. A variety of factors, including the required dedication of substantial management effort, time and resources on integration matters, which may divert focus and resources from other strategic opportunities of Suncor, and those other risk factors set forth in this MD&A, may adversely affect the ability to achieve the anticipated benefits of the merger.

Commodity Prices and Exchange Rates

Our future financial performance remains closely linked to hydrocarbon commodity prices, which may be influenced by many factors including global and regional supply and demand, seasonality, worldwide political events and weather. These factors can cause a high degree of price volatility. For example, from 2007 to 2009, the monthly average price for benchmark WTI crude oil ranged from a low of US$39.26/bbl to a high of US$134.02/bbl. During the same three-year period, the natural gas AECO benchmark monthly average price ranged from a low of $2.70/mcf to a high of $11.39/mcf.

Crude oil prices are based on U.S. dollar benchmarks that result in our realized prices being influenced by the US$/Cdn$ currency exchange rate, thereby creating an element of uncertainty. Should the Canadian dollar strengthen compared to the U.S. dollar, the resulting negative effect on net earnings would be partially offset by foreign exchange gains on our U.S. dollar denominated debt. The opposite would occur should the Canadian dollar weaken compared to the U.S. dollar. Cash flow from operations is not impacted by the effects of currency fluctuations on our U.S. dollar denominated debt. We are also impacted to a lesser extent by exchange rate fluctuations between the Canadian dollar, the Euro and the British pound.

We mitigate some of the risk associated with changes in commodity prices through the use of derivative financial instruments (see page 19).

SENSITIVITY ANALYSIS (1)

	2009 Average	Change	Approximate Change in Cash Flow from Operations ($ millions)	Approximate Change in After-Tax Earnings ($ millions)
Oil Sands				
Realized crude oil price ($/barrel) (2)	61.26	US$1.00	86	65
Sales (bpd)	276 200	1 000	7	5
Natural Gas				
Realized natural gas price ($/mcf) (2)	3.70	Cdn$0.10	13	9
Natural gas sales (mmcf/d)	397.2	10	10	1
East Coast Canada				
Realized crude oil price ($/barrel) (2)	76.86	US$1.00	7	5
Sales (bpd)	58 000	1 000	4	3
International				
Realized crude oil price ($/barrel) (2)	76.11	US$1.00	9	7
Crude oil sales (bpd)	100 500	1 000	6	5
Realized natural gas price ($/mcf) (2)	4.18	US$0.10	1	1
Natural gas sales (mmcf/d)	116.2	10	4	4
Consolidated				
US$/Cdn$ exchange rate effect on U.S. denominated long-term debt	0.88	0.01		92

(1) The sensitivity analysis shows the main factors affecting Suncor's annual cash flow from operations and earnings based on actual 2009 operations. The table illustrates the potential financial impact of these factors applied to Suncor's 2009 results. A change in any one factor could compound or offset other factors.

(2) Includes the impact of hedging activities. See page 19.

Environmental Regulation and Risk

Environmental regulation affects nearly all aspects of our operations. These regulatory regimes are laws of general application that apply to us in the same manner as they apply to other companies and enterprises in the energy industry. The regulatory regimes require us to obtain operating licenses and permits in order to operate, and impose certain standards and controls on activities relating to mining, oil and gas exploration, development and production, and the refining, distribution and marketing of petroleum products and petrochemicals. Environmental assessments and regulatory approvals are generally required before initiating most new projects or undertaking significant changes to existing operations. In addition to these specific, known requirements, we expect future changes to environmental legislation, including anticipated legislation for air emissions (Criteria Air Contaminants (CACs) and Greenhouse Gases (GHGs)), will impose further requirements on companies operating in the energy industry.

Some of the issues that are, or may in future be, subject to environmental regulation include:

- the possible cumulative regional impacts of oil sands development;
- manufacture, import, storage, treatment and disposal of hazardous or industrial waste and substances;
- the need to reduce or stabilize various emissions to air;
- withdrawals, use of, and discharges to, water;
- issues relating to land reclamation, restoration and wildlife habitat protection;
- reformulated gasoline to support lower vehicle emissions; and
- U.S. implementation of regulation or policy to limit its purchases of oil to oil produced from conventional sources, or U.S. state or federal calculation and regulation of fuel lifecycle carbon content.

Changes in environmental regulation could have a potentially adverse effect on our financial results from the standpoint of product demand, product reformulation and quality, methods of production and distribution and costs. For example, requirements for cleaner-burning fuels could cause additional costs to be incurred, which may or may not be recoverable in the marketplace. The complexity and breadth of these issues make it extremely difficult to predict their future impact on us. Management anticipates capital expenditures and operating expenses could increase in the future as a result of the implementation of new and increasingly stringent environmental regulations. Compliance with environmental regulation can require

significant expenditures and failure to comply with environmental regulation may result in the imposition of fines and penalties, liability for clean-up costs and damages, and the loss of important permits and licenses.

Climate Change Legislation Suncor operates in jurisdictions that have regulated or have proposed to regulate industrial GHG emissions. Jurisdictions that currently regulate GHG emissions include Alberta and the European Union. Jurisdictions that have proposed to regulate GHG emissions include the U.S., British Columbia (B.C.), Quebec, Ontario and Canada. Those jurisdictions that have announced the intent to regulate GHG emissions generally support carbon pricing policies such as cap-and-trade systems and, in some cases, have also proposed implementing additional measures, including low carbon fuel standards. Suncor participates both directly and through industry associations in the consultation process on the design of proposed regulations, as well as efforts to harmonize regulations across jurisdictions within North America.

While these jurisdictions have not yet published details on their proposed regulations, or on their compliance mechanisms, many, most notably the U.S., have identified the importance of balancing the environment, economy and energy security when developing regulations. The Canadian government has also recently gone on record to state that its regulations will be consistent with U.S. regulations. While it is premature to predict what impact these anticipated regulations may have on the company and the broader oil and gas sector, the company will likely face increased capital and operating costs in order to comply with these regulations and these costs could be material. In addition, regulation based on life cycle analysis of fuel carbon content may impact markets for oil sands crude oils. Notwithstanding the current regulatory uncertainty, the company assumes that a price will be imposed on carbon dioxide and incorporates a range of potential carbon costs and regulatory outcomes into future capital planning.

In 2007, the Alberta government introduced the Climate Change and Emissions Management Amendment Act, which places intensity (emissions per unit of production) limits on facilities emitting more than 100,000 tonnes of carbon dioxide equivalent per year. Suncor's oil sands operations, the Edmonton Refinery and two Natural Gas Plants in Alberta are subject to this legislation. The act calls for intensity reductions of 12% from an approved baseline, commencing July 1, 2007.

In compliance with this new legislation, the company filed applications in December 2007 to establish baseline intensities for our Alberta facilities. In March 2010, the company must file compliance reports that demonstrate that each facility either met its intensity target for 2009, or took action to offset its emissions intensity. Compliance options available to the company include internal emission reductions, utilizing offset projects or contributing to a government climate change emission management fund.

For the compliance period of January 1 to December 31, 2009, the compliance costs to Suncor's Alberta facilities are estimated at between $3 million and $5 million. Final costs for 2009 will be determined when the company files its compliance report with the Province of Alberta in March 2010.

Suncor's operated facilities in the Netherlands North Sea are subject to the European Union Emissions Trading System and the associated National Allocation Plan. For the compliance period of January 1 to December 31, 2009, Suncor's facilities will have sufficient allocations for compliance.

There remains uncertainty around the outcome and impacts of climate change and other environmental regulations. We continue to actively work to mitigate our environmental impact, including taking action to reduce greenhouse gas emissions, investing in renewable forms of energy such as wind power and biofuels, accelerating land reclamation, installing new emission abatement equipment and pursuing other opportunities such as carbon capture and sequestration.

Tailings Management Another area of risk for Suncor is the reclamation of tailings ponds, which contain water, clay and residual bitumen produced through the extraction process. On October 15, 2009, Suncor applied to the Energy Resources Conservation Board (ERCB) and Alberta Environment (AENV) for permission to amend its existing and/or approved operations east of the Athabasca River to move from the currently adopted tailings management system, being the use of a consolidated tailings (CT) process to consolidate mature fine tailings (MFT), to Suncor's new Tailings Reduction Operations (TRO) strategy, based on MFT drying. This application is currently pending ERCB and AENV approval.

Regulatory Approvals Before proceeding with most major projects, we must obtain regulatory approvals. The regulatory approval process often involves stakeholder consultation, environmental impact assessments and public hearings, among other factors. Failure to obtain regulatory approvals, or failure to obtain them on a timely basis, could result in delays, abandonment, or restructuring of projects and increased costs, all of which could negatively impact future earnings and cash flow.

CRITICAL ACCOUNTING ESTIMATES

Critical accounting estimates are defined as estimates that are important to the portrayal of our financial position and operations, and require management to make judgments based on underlying assumptions about future events and their effects. These underlying assumptions are based on historical experience and other factors that management believes to be reasonable under the circumstances, and are subject to change as new events occur, as more industry experience is acquired, as additional information is obtained and as our operating environment changes. Critical accounting estimates are reviewed annually by the Audit Committee of the Board of Directors. The following are the critical accounting estimates used in the preparation of our Consolidated Financial Statements.

Asset Retirement Obligations (ARO)

We are required to recognize a liability for the future retirement obligations associated with our property, plant and equipment. An ARO liability is only recognized to the extent there is a legal obligation associated with the retirement of a tangible long-lived asset that we are required to settle as a result of an existing or enacted law, statute, ordinance, written or oral contract, or by legal construction of a contract under the doctrine of promissory estoppel. The ARO is based on estimated costs, taking into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible use of the site. Since these estimates are specific to the sites involved, there are many individual assumptions underlying our total ARO amount. These individual assumptions can be subject to change based on experience.

Each year-end cash flow estimates are re-evaluated and increases to the ARO are discounted to present value using a credit-adjusted risk-free discount rate. The ARO accretes over time until we settle the obligation, the effect of which is included in a separate line in the Consolidated Statements of Earnings entitled accretion of asset retirement obligations. The discount rate is adjusted as appropriate, to reflect long-term changes in market rates and outlook.

An ARO is not recognized for assets with an indeterminate useful life because the amount cannot be reasonably estimated. An ARO for these assets will be recorded in the first period in which the lives of the assets are determinable.

In connection with company and third-party reviews of ARO during 2009, we increased our estimated undiscounted total obligation to $8.3 billion from the previous estimate of $3.5 billion. The increase was mainly due to the addition of $4.7 billion in undiscounted ARO as a result of the merger with Petro-Canada. The estimated discounted total obligation at December 31, 2009 was $3.2 billion, compared to $1.6 billion at December 31, 2008.

Employee Future Benefits

We provide a range of benefits to our employees and retired employees, including pensions and other post-retirement benefits. The determination of obligations under our benefit plans and related expenses requires the use of actuarial valuation methods and assumptions. Assumptions typically used in determining these amounts include, as applicable, rates of employee turnover, future claim costs, discount rates, future salary and benefit levels, return on plan assets, mortality rates and future medical costs. The fair value of plan assets is determined using market values. Actuarial valuations are subject to management judgment. Management continually reviews these assumptions in light of actual experience and expectations for the future. Changes in assumptions are accounted for on a prospective basis. Employee future benefit costs are reported as part of operating, selling and general expenses in our Consolidated Statements of Earnings. The accrued benefit liability is reported as part of accrued liabilities and other in the Consolidated Balance Sheets.

The assumed rate of return on plan assets considers the current level of expected returns on the fixed income portion of the plan assets portfolio, the historical level of risk premium associated with other asset classes in the portfolio and the expected future returns on each asset class. The discount rate assumption is based on the year-end interest rate on high-quality bonds with maturity terms equivalent to the benefit obligations. The rate of compensation increases is based on management's judgment. The accrued benefit obligation and net periodic benefit cost for both pensions and other post-retirement benefits may differ significantly if different assumptions are used.

Property, Plant and Equipment and Depreciation, Depletion and Amortization

We account for our exploration and production related to our oil and gas producing activities using the successful efforts method. This policy was selected over the alternative of the full-cost method because we believe it provides timelier accounting of the success or failure of exploration and production activities.

The application of the successful efforts method of accounting requires management to determine the proper classification of activities designated as developmental or exploratory, which then determines the appropriate accounting treatment of the costs incurred. The results

from a drilling program can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Where it is determined that exploratory drilling will not result in commercial production, the drilling costs of the exploratory dry hole are written off and reported as part of exploration expenses in the Consolidated Statements of Earnings. Dry hole expense can fluctuate from year to year due to such factors as the level of exploratory spending, the level of risk sharing with third parties participating in the exploratory drilling and the degree of risk in drilling in particular areas.

Properties that are assumed to be productive may, over a period of time, actually deliver oil and gas in quantities different than originally estimated because of changes in reservoir performance. Such changes may require a test for the potential impairment of capitalized properties based on estimates of future cash flow from the properties. An impairment test may also be required as a result of other economic events. Estimates of future cash flows are subject to significant management judgment concerning oil and gas prices, production quantities, operating costs and future development costs. Where properties are assessed by management to be fully or partially impaired, the book value of the properties is reduced to fair value and either completely removed (written off) or partially removed (written down) in our records and reported as part of depreciation, depletion and amortization expenses, in the Consolidated Statements of Earnings.

Asset Impairment

Producing properties and significant unproved properties are assessed annually, or as economic events dictate, for potential impairment. Impairment is assessed by comparing the estimated net undiscounted future cash flows with the carrying value of the asset. The cash flows used in the impairment assessment require management to make assumptions and estimates about recoverable reserves, future commodity prices and operating costs. Changes in any of the assumptions, such as a downward revision in reserves, a decrease in future commodity prices or an increase in operating costs, could result in an impairment of an asset's carrying value.

Purchase Price Allocation

Business acquisitions are accounted for by the purchase method of accounting. Under this method, the purchase price is allocated to the assets acquired and the liabilities assumed based on the fair value at the time of the acquisition. The excess purchase price over the fair value of identifiable assets and liabilities acquired is goodwill. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of property, plant and equipment acquired generally require the most judgment and include estimates of reserves acquired (see Oil and Gas Reserves below), future commodity prices and discount rates. Changes in any of the assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill in the purchase price allocation. Future net earnings can be affected as a result of changes in future depreciation and depletion, asset impairment or goodwill impairment.

Income Taxes

The company follows the liability method of accounting for income taxes, whereby future income taxes are recognized based on the differences between the carrying amounts of assets and liabilities reported in the financial statements and their respective tax bases. The determination of the income tax provision is an inherently complex process, requiring management to interpret continually changing regulations and to make certain judgments. While income tax filings are subject to audits and reassessments, management believes adequate provision has been made for all income tax obligations. However, changes in the interpretations or judgments may result in an increase or decrease in the company's income tax provision in the future.

Contingencies

The company is involved in litigation and claims in the normal course of operations. Management is of the opinion that any resulting settlements would not materially affect the financial position of the company as at December 31, 2009. However, the determination of contingent liabilities relating to litigation and claims is a complex process that involves judgments as to the outcomes and interpretation of laws and regulations. Changes in the judgments or interpretations may result in an increase or decrease in the company's contingent liabilities in the future.

Oil and Gas Reserves

Reserves estimates, although not reported as part of the company's Consolidated Financial Statements, can have a significant effect on net earnings as a result of their impact on depreciation and depletion rates, asset impairments and goodwill impairments. Our oil and gas reserves are evaluated by independent qualified reserves evaluators. The estimation of reserves is an inherently complex process and involves the exercise of professional judgment.

Estimates are based on projected future rates of production, estimated commodity prices, engineering data and the timing of future expenditures, all of which are subject to uncertainty.

RESERVES ESTIMATES

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 our Annual Information Form dated March 5, 2010. 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 reserve. 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 can be material mainly due to differences in the stipulated product prices to be used for reserve evaluations. U.S. disclosure requirements mandate the use of an average of first day of the month price for the twelve months prior to the end of the reporting period, while Canadian securities regulatory authorities require a forecasted price. However this difference in pricing methodologies did not have a material impact on Suncor's 2009 reserves disclosure.

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 proved and probable reserve totals on a gross basis (before royalty) together, in addition to reporting them separately on a net basis (after royalty) 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, both in the Canadian oil sands, and 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, Syria, Libya, and Trinidad and Tobago.

For more information regarding our reserves and resource disclosure, please see "Reserve Estimates" in our Annual Information Form dated March 5, 2010, which section of the Annual Information Form is incorporated into this MD&A by reference.

Merger of Suncor and Petro-Canada

Effective August 1, 2009, Suncor Energy Inc. (as it existed at that time) 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 being 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 millions of barrels (MMbbls) of proved oil volumes on a net basis (after royalty) and 1,179 billion cubic feet (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.

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)

Reserve category	Reserves				Reserve category	Reserves			
	Oil & NGL	Natural Gas	SCO	Bitumen		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**	**1 229**	**—**	**—**	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)	**—**	**—**	**1 899**	**—**	Oil Sands Mining (8)	**—**	**—**	**287**	**—**
Total Developed	**186**	**1 351**	**2 051**	**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**	**1 336**
Oil Sands Mining (8)	**—**	**—**	**—**	**—**	Oil Sands Mining (8)	**—**	**—**	**237**	**—**
Total Undeveloped	**108**	**342**	**514**	**389**	**Total Undeveloped**	**136**	**483**	**744**	**1 336**
TOTAL PROVED	**294**	**1 693**	**2 565**	**411**	**TOTAL PROBABLE**	**247**	**830**	**1 100**	**1 344**

(1) Numbers in the above table are rounded to the nearest 1 MMbbls or 1 Bcf.

(2) The reserves data are based upon evaluations by GLJ Petroleum Consultants Ltd., Sproule Associates Limited, RPS Energy Plc 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 our Annual Information Form dated March 5, 2010.

(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) 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, see page 30 of our Annual Information Form dated March 5, 2010.

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						Totals	
	North Sea (4)		Other International (6), (7)		North America Onshore		East Coast Canada	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	Natural Gas
	(MMbbls)	(Bcf)	(MMbbls)	(Bcf)	(MMbbls)	(Bcf)	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)	(Bcf)
End of Year 2008 (10)	**—**	**—**	**—**	**—**	**9**	**734**	**—**	**2 565**	**148**	**2 316**	**5 038**	**734**
Revisions of previous estimates (8)	6	(18)	6	247	15	(52)	16	(1 587)	1 863	(72)	247	177
Sale of reserves in place	—	—	—	—	—	(6)	(3)	—	—	—	(3)	(6)
Purchase of reserves in place	215	98	276	618	47	1 498	213	437	—	638	1 826	2 214
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**	**1 206**	**68**	**2 080**	**225**	**1 399**	**2 010**	**2 794**	**6 995**	**3 387**
Proved & Probable Undeveloped Reserves End of year 2009	**105**	**50**	**89**	**1 065**	**19**	**309**	**114**	**1 160**	**1 977**	**264**	**3 728**	**1 424**

(1) Numbers in the above table are rounded to the nearest 1 MMbbls or 1 Bcf.

(2) The reserves data are based upon evaluations by GLJ Petroleum Consultants Ltd., Sproule Associates Limited, RPS Energy Plc 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 our Annual Information Form dated March 5, 2010.

(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 an oil and gas activities, Suncor has re-stated its mining opening balance which would have been previously reported under Mining Guide 7.

(10) The 2008 reserve data for legacy Suncor assets has been restated per SEC guidelines, this information was previously disclosed under NI 51-101. For more information, see page 30 of our Annual Information Form dated March 5, 2010.

(11) The production data in the 2009 reserve tables are estimates from the third party evaluators, and may not exactly match production shown elsewhere in this Annual Report and our Annual Information Form dated March 5, 2010. 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)

Besides 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]	Conventional (MMBOEs)	Mining (MMBOEs)	In-Situ (MMBOEs)	Total (MMBOEs)
Total Proved	751	2 203	1 177	4 131
Total Probable	606	591	2 232	3 429
Total Proved Plus Probable Reserves	**1 357**	**2 794**	**3 409**	**7 560**
Contingent Resources [2], [5], [6] – Best Estimate [3]	2 935	6 080	10 881	19 896
Remaining Recoverable Resources (unrisked) [4]	**4 292**	**8 874**	**14 290**	**27 456**

(1) Numbers in the above table are rounded to the nearest 1 million. 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. 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, among other things.

For a discussion of the properties and projects that are associated with our remaining recoverable resources, see our Annual Information Form dated March 5, 2010.

CONTROL ENVIRONMENT

Based on their evaluation as of December 31, 2009, our chief executive officer and chief financial officer concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the United States Securities Exchange Act of 1934 (the Exchange Act)) are effective to ensure that information required to be disclosed by us in reports that we file or submit to Canadian and U.S. securities authorities is recorded, processed, summarized and reported within the time periods specified in Canadian and U.S. securities laws. In addition, as of December 31, 2009, there were no changes in our internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) – 15d-15(f)) that occurred during 2009 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. We will continue to periodically evaluate our disclosure controls and procedures and internal control over financial reporting and will make any modifications from time-to-time as deemed necessary.

The company has undertaken a comprehensive review of the effectiveness of its internal control over financial reporting based on the Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). For the year ended December 31, 2009, based on that evaluation, the company's internal controls were found to be operating free of any material weaknesses.

On August 1, 2009, Suncor completed its merger with Petro-Canada. As permitted by the Securities and Exchange Commission, management has excluded Petro-Canada from its evaluation of the effectiveness of Suncor's internal control over financial reporting as of December 31, 2009. Assets attributable to Petro-Canada as of August 1, 2009 represented approximately 50% of Suncor's total assets as of August 1, 2009, and revenues attributable to Petro-Canada for the period August 1 – December 31, 2009 represented approximately 25% of Suncor's total revenues for the year ended December 31, 2009.

The effectiveness of our internal control over financial reporting as at December 31, 2009 was audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report, which is included in our audited Consolidated Financial Statements for the year ended December 31, 2009.

Based on their inherent limitations, disclosure control and procedures and internal controls over financial reporting may not prevent or detect misstatements and even those options determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

CHANGES IN ACCOUNTING POLICIES

(a) Goodwill and Intangible Assets

On January 1, 2009, the company retroactively adopted Canadian Institute of Chartered Accountants (CICA) Handbook section 3064 "Goodwill and Intangible Assets." This new standard replaces section 3062 "Goodwill and Other Intangible Assets" and section 3450 "Research and Development Costs," and focuses on the criteria for asset recognition in the financial statements, including those internally developed. The impact of adopting this standard resulted in a change in the classification of our deferred maintenance shutdown costs that had previously been classified within other assets and amortized over the period to the next shutdown. At December 31, 2008, property, plant and equipment was increased by $566 million, with an equal and offsetting reduction to other assets.

(b) Financial Instruments Disclosures

On September 30, 2009, the company prospectively adopted amendments to CICA Handbook section 3862 "Financial Instruments: Disclosures". The section has been amended to include additional disclosure requirements about fair value measurements of financial instruments and to enhance liquidity risk disclosure requirements. The additional disclosures required by these amendments are provided in note 4 to the December 31, 2009 audited Consolidated Financial Statements.

(c) Credit Risk and the Fair Value of Financial Assets and Financial Liabilities

On January 1, 2009, the company adopted the recommendations of CICA Emerging Issues Committee Abstract 173 relating to the fair value of financial assets and liabilities. The Abstract requires that an entity's own credit risk and the credit risk of the counterparty are taken into account in determining the fair value of financial assets and liabilities, including derivative instruments. The Abstract is to be applied retroactively without restatement of prior periods. The company has evaluated the new abstract and concluded that the adoption of the new requirements did not have a material impact on Suncor's financial statements.

(d) International Financial Reporting Standards

In February 2008, the Canadian Accounting Standards Board confirmed that International Financial Reporting Standards (IFRS) will replace Canadian GAAP in 2011 for publicly accountable enterprises. While IFRS uses a conceptual framework similar to Canadian GAAP, there are significant differences in accounting policies that must be evaluated.

The company has successfully completed the integration of the legacy Petro-Canada and Suncor's IFRS conversion projects. Key activities included integrating the project plans, reviewing the accounting documentation, aligning the IFRS accounting conclusions, and reviewing the design of the Information Technology dual reporting solutions.

The company is currently engaged in the implementation phase of its IFRS project and continues to be on target to meet the changeover date. Please see the following table for select project activities within the implementation phase and an assessment of progress. Note that new and revised IFRS developments will be monitored throughout the project but may result in changes to the project activities described below.

IFRS Conversion Project

Key Activity	Key Milestones	Status
Financial Statement Preparation: – Identify differences in Canadian GAAP/IFRS accounting policies. – Select Suncor's ongoing IFRS policies. – Develop financial statement format. – Quantify effects of change in initial IFRS disclosure and 2010 financial statements.	Senior management and steering committee sign-off for all key IFRS accounting policy choices to occur during 2009. Develop draft financial statement format to occur during 2009.	Completed integrated technical analysis of IFRS differences. Initial analysis of IFRS accounting policy choices completed and presented to senior management including an evaluation of IFRS 1 transition exemptions. Further analysis will be ongoing throughout 2010. Prepared initial draft pro-forma financial statements and continued to review draft disclosures for the merged company.
Training: Define and introduce appropriate level of IFRS expertise for each of the following: – Financial reporting group and operating accounting staff. – Suncor management. – Audit Committee.	Financial reporting group and operating accounting staff training to occur during 2009 as needed. Additional training will occur throughout the project as needs are reassessed. Suncor management and Audit Committee training scheduled to occur during 2009.	Training and communication sessions provided for senior management, Financial Reporting and key individuals within the Business. Education and training sessions will continue throughout the company in 2010. Regular reporting and training has continued for the company's senior executive management and the Audit Committee. IFRS disclosure in the financial statements and MD&A will be updated throughout the project.
Infrastructure: Confirm that business processes and systems are IFRS compliant, including: – Program upgrades/changes. – Gathering data for disclosures.	Confirm that systems can address 2010 dual reporting requirements by 2009 and identify areas requiring change. Confirmation that business processes and systems are IFRS compliant will occur throughout the project.	Development and initial testing of approved IFRS Information Technology solution is underway including creation of IFRS dual reporting accounts. Identified business process and implementation changes and initiated detailed implementation plans.
Control Environment: – For all accounting policy changes identified, assess control design and effectiveness implications. – Implement appropriate changes.	All key control and design effectiveness implications to be assessed as part of the key IFRS differences and accounting policy choices through 2009.	Completed preliminary review of control environment and do not anticipate material changes to internal and disclosure controls over financial reporting.
External Communications: Assess the effects of key IFRS related accounting policy and financial statement changes on external communications. In particular: – Confirm 2011 investor communications are IFRS compliant regarding guidance and and expected earnings. – Monitor and update MD&A communications package. – Confirm investor relations process can respond to IFRS-related queries.	Analyze and publish the effect of IFRS on the financial statements throughout the project.	IFRS disclosures in the MD&A are updated throughout the project. Vice President, Investor Relations is part of the IFRS Steering Committee.

The company has not yet determined the full effects of adopting IFRS. The company's preliminary view of the key areas where changes in accounting policies are expected that may impact the company's consolidated financial statements are listed below. The list and comments below should not be regarded as a complete list of changes that will result from the transition to IFRS. It is intended to highlight those areas the company believes to be most significant; however, analysis of changes is still in progress and not all decisions have been made where choices of accounting policies are available. At this stage, the company has not quantified the impacts expected on its consolidated financial statements for these differences.

Note that most adjustments required on transition to IFRS will be made retrospectively, against opening retained earnings in the first comparative balance sheet. Transitional adjustments relating to those standards where comparative figures are not required to be restated because they are applied prospectively will only be made as of the first day of the year of transition.

IFRS 1 "First-Time Adoption of International Financial Reporting Standards" provides entities adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions, in certain areas, to the general requirement for full retrospective application of IFRS. The company is analyzing the various accounting policy choices available and will implement those determined to be most appropriate in the company's circumstances.

Property, Plant & Equipment

International Accounting Standard (IAS) 16 "Property, Plant & Equipment" and Canadian GAAP contain the same basic principles, however there are some differences. IFRS requires that significant parts of an asset be depreciated separately and depreciation commences when the asset is available for use. IFRS also permits property, plant and equipment to be measured using the fair value model or the historical cost model. The company is not planning on adopting the fair value measurement model for its property, plant and equipment.

IFRS 1 contains an elective exemption where an entity may elect to reset as the new cost basis for property, plant and equipment, its fair value at the date of transition. The company is not planning on adopting this exemption and will continue to measure its property, plant and equipment at cost.

Impairment of Assets

Impairments under IAS 36 "Impairment of Assets" are based on discounted cash flows. Under Canadian GAAP, if an asset's estimated undiscounted future cash flows are below its carrying amount a writedown is required and is determined by the amount which the carrying amount exceeds the discounted cash flows. There is no undiscounted test under IFRS. This may result in more frequent write-downs where carrying values of assets were previously supported under Canadian GAAP on an undiscounted cash flow basis, but could not be supported on a discounted cash flow basis.

In addition, under IAS 36 a favorable change in the circumstance that resulted in an impairment of an asset, other than goodwill, would trigger the requirement for a redetermination of the amount of the impairment with any reversal being recognized in income to the extent the asset had previously been impaired. Under Canadian GAAP, impairments are not reversed.

Provisions, Contingent Liabilities and Contingent Assets

IAS 37 "Provisions, Contingent Liabilities and Contingent Assets," requires a provision to be recognized when: there is a present obligation as a result of a past transaction or event; it is probable that an outflow of resources will be required to settle the obligation; and a reliable estimate can be made of the obligation. "Probable" in this context means more likely than not. Under Canadian GAAP, the criterion for recognition in the financial statements is "likely," which is a higher threshold than "probable." Therefore, it is possible that there may be some contingent liabilities, which would meet the recognition criteria under IFRS that were not recognized under Canadian GAAP.

Other differences between IFRS and Canadian GAAP exist in relation to the measurement of provisions, such as the methodology for determining the best estimate where there is a range of equally possible outcomes (IFRS uses the mid-point of the range, whereas Canadian GAAP used the low-end of the range) and the requirement under IFRS for provisions to be discounted where material. In addition, IFRS requires changes to timing, cash flow estimates and discount rates be applied prospectively. Canadian GAAP is similar; however, changes to the discount rates for ARO are only applied to the incremental increases in the liability and not the entire liability.

Share-Based Payments

IFRS 2 "Share-based Payment," requires that cash-settled share-based payments to employees are measured (both initially and at each reporting period) based on the fair values of the awards. Canadian GAAP on the other hand requires that such payments be measured based on the intrinsic values of the awards. This difference is expected to impact the accounting measurement of some of Suncor's cash-settled employee incentive plans.

Income Taxes

Under IAS 12 "Income Taxes," current and deferred tax are normally recognized in the income statement, except to the extent that tax arises from (1) an item that has been recognized directly in equity, whether in the same or a different period, (2) a business combination or (3) a share-based payment transaction. If a deferred tax asset or liability is remeasured subsequent to initial recognition, the impact of remeasurement is recorded in earnings, unless it relates to an item originally recognized in equity, in which case the change would also be recorded in equity. The practice of tracking the remeasurement of taxes back to the item which originally triggered the recognition is commonly referred to as "backwards tracing." Canadian GAAP prohibits backwards tracing except on business combinations and financial reorganizations.

Employee Benefits

IAS 19 "Employee Benefits," requires the past service cost element of defined benefit plans to be expensed on an accelerated basis, with vested past service costs expensed immediately and unvested past service costs recognized on a straight line basis until the benefits become vested. Under Canadian GAAP, past service costs are generally amortized on a straight line basis over the expected average remaining service period of active employees in the plan. In addition, actuarial gains and losses are permitted under IAS 19 to be recognized directly in equity rather than through profit or loss. IFRS 1 also provides an option to recognize all cumulative actuarial gains and losses existing at the date of transition immediately in retained earnings.

RECENTLY ISSUED CANADIAN ACCOUNTING STANDARDS

Business Combinations

In January 2009, the CICA issued section 1582 "Business Combinations" to replace section 1581. The CICA concurrently issued section 1601 "Consolidated Financial Statements" and section 1602 "Non-Controlling Interests" which replace section 1600 "Consolidated Financial Statements." Prospective application of the standards is effective for fiscal years beginning on or after January 1, 2011, with early adoption permitted. The new standards revise guidance on the determination of the carrying amount of the assets acquired and liabilities assumed, goodwill and accounting for non-controlling interests at the time of a business combination. The company applied section 1581 to the Petro-Canada business combination; however, the company will continue to consider the application of section 1582 to business combinations in 2010.

OIL SANDS

Located in northeast Alberta, our oil sands business forms the foundation of our operations and represents the most significant portion of our assets. Our oil sands operations recover bitumen through mining and in-situ development and upgrade it into refinery feedstock, diesel fuel and byproducts. Our marketing plan also allows for sales of bitumen when market conditions are favourable or when operating conditions warrant. The majority of our oil sands assets are owned and operated solely by Suncor. Following the merger with Petro-Canada, our oil sands business also includes a 12% share in the Syncrude oil sands joint venture and a 60% share in the proposed Fort Hills oil sands project.

Oil sands strategy focuses on:

- Developing long-life leases with substantial bitumen resources in place.
- Sourcing low-cost bitumen supply through mining in-situ development and third-party supply agreements, and upgrading this bitumen supply into high value crude oil products.
- Increasing production capacity and improving reliability through staged expansion, continued focus on operational excellence and worksite safety.
- Reducing costs through the application of technologies, economies of scale, direct management of growth projects, strategic alliances with key suppliers and continuous improvement of operations.
- Pursuing new technology applications to increase production, mitigate costs and reduce environmental impacts.

HIGHLIGHTS

Summary of Results

Year ended December 31 ($ millions unless otherwise noted)	**2009**	2008	2007
Revenue (net of royalties)	**6 539**	8 639	6 175
Production (excluding Syncrude) (thousands of bpd)	**290.6**	228.0	235.6
Syncrude production (thousands of bpd) [1]	**38.5**	—	—
Average sales price (excluding Syncrude) ($/barrel)	**61.26**	95.96	74.01
Net earnings	**557**	2 875	2 474
Operating earnings [2]	**1 066**	2 522	2 137
Cash flow from operations [2],[3]	**1 251**	3 507	3 165
Total assets	**37 553**	25 795	18 172
Cash used in investing activities	**(3 546)**	(6 996)	(4 248)
Sales mix (light/heavy mix)	**47/53**	43/57	54/46
Cash operating costs (excluding Syncrude) ($/barrel) [2]	**33.95**	38.50	27.80
ROCE (%) [2], [4]	**4.2**	35.5	43.0
ROCE (%) [2], [5]	**2.5**	21.8	27.9

(1) Reflects results of operations since the merger with Petro-Canada on August 1, 2009.

(2) Non-GAAP measures. See pages 52 and 53.

(3) Calculation of this measure has been revised, and prior period comparative figures have been restated. See page 52.

(4) Excludes capitalized costs related to major projects in progress. Return on capital employed (ROCE) for our operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non-GAAP Financial Measures.

(5) Includes capitalized costs related to major projects in progress.

2009 Overview

- Low benchmark prices and losses on derivative contracts used for risk management purposes significantly reduced Oil Sands price realizations in 2009. The average WTI crude oil price was 38% lower in 2009 than in 2008. Derivative contracts entered into to protect our future revenues ended up negatively impacting our results when crude prices strengthened later in the year, and settlement prices were lower than benchmark prices.

- Production (excluding proportionate production share from Syncrude joint venture) averaged 290,600 bpd in 2009, compared to 228,000 bpd in 2008, with record production reported in November 2009. Production volumes were up year-over-year primarily as the result of improved upgrader reliability and increased bitumen supply. However, unplanned maintenance following a fire in December negatively impacted production, and a subsequent fire in February 2010 will reduce production volumes in 2010.

- Cash operating costs for our oil sands operations (excluding Syncrude) averaged $33.95 per barrel during 2009, compared to $38.50 per barrel in 2008. The lower costs in 2009 are primarily due to the increase in production and a decrease in natural gas prices and third-party bitumen purchases. These factors were partially offset by an increase in operational expenses primarily due to the inclusion of operating costs from MacKay River as a result of the merger with Petro-Canada.

- In response to market uncertainty at the beginning of 2009, a revised capital spending plan deferred Oil Sands growth projects. Although the 2010 capital plan announced in November 2009 has restarted construction of certain projects, the costs associated with keeping projects in "safe mode" totalled $380 million pre-tax in 2009.

Operating Earnings [1]

Year ended December 31 ($ millions, after-tax)	**2009**	2008	2007
Oil Sands net earnings as reported	**557**	2 875	2 474
Change in fair value of commodity derivatives used for risk management	**499**	(372)	—
Mark-to-market valuation of stock-based compensation	**28**	(5)	27
Project start-up costs	**40**	24	49
Impact of income tax rate reductions on opening future income tax liabilities [2]	**37**	—	(413)
Costs related to deferral of growth projects	**299**	—	—
Gain on effective settlement of pre-existing contract with Petro-Canada [3]	**(438)**	—	—
Impact of recording acquired inventory at fair value [4]	**5**	—	—
Losses and adjustments on significant disposals [5]	**39**		
Oil Sands operating earnings	**1 066**	2 522	2 137

(1) Non-GAAP measure. See page 52 for a discussion of operating earnings.

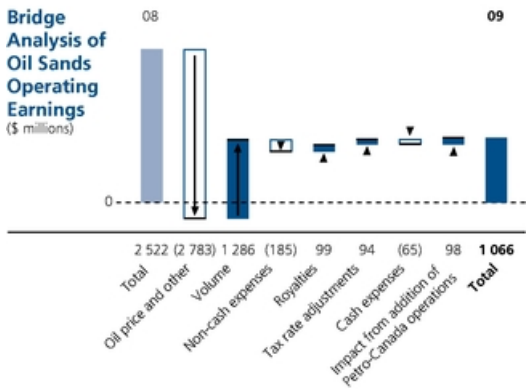
(2) In the third quarter of 2009, an increase in the future income tax liabilities resulted from a revised provincial allocation for income tax purposes due to the merger with Petro-Canada. This was partially offset for the year ended December 31, 2009 by a reduction to the Ontario income tax rate in the fourth quarter of 2009, resulting in a decrease in the future income tax liabilities. See note 7 to the Consolidated Financial Statements.

(3) Impact from deemed settlement value assigned to bitumen processing contract with Petro-Canada upon close of merger (see note 2 to the Consolidated Financial Statements).

(4) Inventory acquired through the merger at fair value was sold during the third quarter of 2009, resulting in a one-time negative impact to earnings

(5) Includes loss recognized when a highway interchange constructed by Suncor was transferred to the Provincial government of Alberta.

Net earnings were $557 million in 2009, compared to $2.875 billion in 2008 (2007 – $2.474 billion). Operating earnings for 2009 were $1.066 billion, compared to $2.522 billion in 2008 (2007 – $2.137 billion). Earnings decreased primarily as a result of lower average price realizations for oil sands crude products, partially offset by higher production and sales volumes.



The decrease in price realizations reflects significantly lower benchmark West Texas Intermediate (WTI) crude oil prices, as well as realized losses of approximately $315 million after-tax on risk management derivative contracts as the settlement prices were lower than benchmark prices for much of the year. This was partially offset by a decreased discount to WTI on our sweet crude blends and sour crude blends, increased sales of higher value sweet crude products, and a weaker Canadian dollar.

Oil Sands Production

Year ended December 31 Thousands of barrels per day	**2009**	2008	2007	2006	2005
Oil Sands production (excluding Syncrude)	**290.6**	228.0	235.6	260.0	171.3
Syncrude [1]	**38.5**	—	—	—	—

(1) Reflects our share of Syncrude production since the merger with Petro-Canada on August 1, 2009.

Oil Sands average production (excluding Syncrude) was 290,600 bpd in 2009, compared to 228,000 bpd in 2008. Production was higher in 2009 due mainly to improved upgrader reliability and increased bitumen supply. In addition, production in 2008 was negatively impacted by planned and unplanned maintenance shutdowns in our upgrading and extraction assets, as well as a regulatory cap on our Firebag in-situ operations, which was lifted in July 2008.

As a result of the merger, Suncor holds a 12% share in the Syncrude joint venture oil sands operations located close to Suncor's existing oil sands operations in Fort McMurray, Alberta, Canada. Syncrude operations contributed an additional average 38,500 bpd of sweet synthetic crude production in the last five months of 2009.

The merger with Petro-Canada 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 to July 31, 2009 as volumes processed by Suncor under a processing fee agreement. However, the addition of MacKay River has resulted in increased sales volumes for Oil Sands, as volumes under the processing agreement were not previously included in sales from January 1 to July 31, 2009.

Sales volumes in 2009 averaged 276,200 bpd, compared with 227,000 bpd in 2008. The increase was due primarily to increased production in legacy Suncor's oil sands operations and the addition of sales volumes from MacKay River as a result of the merger.

Production for 2009 was reduced due to unplanned maintenance activities following a December 2009 fire at one of our upgraders. Overall average production volumes in 2009 were impacted by approximately 7,600 barrels per day as a result of the fire. Repairs of the upgrader were completed and operations returned to normal in early February 2010.

Sales price realizations averaged $61.26 per barrel in 2009, compared with $95.96 per barrel in 2008. This was primarily due to a significant decrease in the average benchmark WTI crude oil price of about 38%. This was partially offset by a decreased discount to WTI on our sweet crude blends and sour crude blends and an increased proportion of higher priced sweet crude products in our sales mix.

Cash Expenses

Cash expenses increased year-over-year, primarily due to increased costs associated with higher production and sales volumes in 2009 as compared to 2008, as well as additional costs from Petro-Canada operations. These factors were partially offset by reduced energy input costs as a result of lower natural gas pricing and a decrease in purchases of third-party bitumen. Overall, increased cash expenses reduced operating earnings by $65 million.

Royalties

Alberta Crown royalties decreased in 2009 as compared to 2008, due primarily to lower benchmark WTI prices, partially offset by increased production. Oil Sands royalties are subject to completion of audits for 2009 and prior years. Changes to the estimated amounts previously recorded will be reflected in our financial statements on a prospective basis and may be significant. For a further discussion on Crown royalties, see pages 16 to 18.

Non-Cash Expenses

Non-cash expenses increased in 2009 as compared to 2008, primarily due to the addition of facilities for MacKay River and Syncrude as a result of the merger with Petro-Canada, as well as continued growth in the depreciable cost base after the commissioning of new assets throughout the year. Higher non-cash expenses decreased operating earnings by $185 million.

Tax Rate

As a result of decreases to the Oil Sands effective tax rate and taxable income in 2009 as compared to 2008, tax rate adjustments resulted in an increase to operating earnings of $94 million.

Cash Operating Costs

Cash operating costs (excluding Syncrude) increased to $3.599 billion in 2009, compared to $3.212 billion in 2008. On a per barrel basis, these costs decreased to $33.95 per barrel from $38.50 per barrel in 2008. The decrease in cash operating costs per barrel is a result of an increase in production and a decrease in natural gas input prices. These factors were partially offset by an increase in operational expenses due to the inclusion of operating costs from MacKay River as of August 1, 2009. Cash operating costs per barrel does not include costs related to deferral of growth projects.

Cash operating costs for our interest in Syncrude operations averaged $32.50 per barrel for the last five months of 2009. Users are cautioned that the Syncrude cash operating costs per barrel measure may not be fully comparable to similar information calculated by other entities (including Suncor's own cash operating costs per barrel excluding Syncrude) due to differing treatments for operating and capital costs among producers.

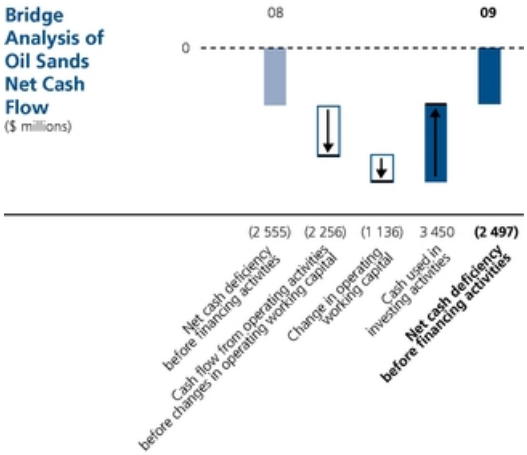
Refer to page 52 and 53 for further details on cash operating costs as a non-GAAP financial measure, including the calculation and reconciliation to GAAP measures.

Net Cash Deficiency Analysis

Cash flow from operations was $1.251 billion in 2009, compared to $3.507 billion in 2008 (2007 – $3.165 billion). The decrease was primarily due to the same factors that impacted operating earnings.

Cash flow used in investing activities decreased to $3.546 billion in 2009 from $6.996 billion in 2008 (2007 – $4.248 billion). The decrease was primarily due to reduced capital spending resulting from the deferral of the company's growth projects in response to economic conditions. During 2009, capital spending related primarily to our Steepbank extraction plant and Firebag sulphur plant.

These were the primary factors that resulted in a net cash deficiency of $2.497 billion in 2009, compared with $2.555 billion in 2008 (2007 – net cash deficiency of $519 million).



Future Expansion

In January 2009, in response to market uncertainty, we deferred a number of our growth projects, pending construction restart. On November 13, 2009, Suncor's Board of Directors approved the 2010 capital budget, and we resumed construction on key growth projects.

The majority of our planned growth spending in 2010 will be directed toward the Firebag Stage 3 in-situ oil sands expansion, which was approximately 50 per cent complete before being deferred in early 2009. The project is now expected 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. Spending will also be directed to Firebag Stage 4 to support a target of first bitumen production in the fourth quarter of 2012. Stage 4 also has a design capacity of 68,000 bpd. Remaining 2010 growth spending will be directed towards completion of a naphtha unit in one of our upgraders, which is intended to enhance product mix.

For further details, see the Significant Capital Project Update table on page 15.

The Oil Sands segment continued to incur costs related to placing certain growth projects into "safe mode" as a result of the company revising its 2009 capital budget due to market conditions earlier in the year. Safe mode is defined as the costs of 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. Further safe mode costs of $150 million to $200 million on a pre-tax basis, including costs related to remobilization of certain growth projects placed into safe mode, are expected to be incurred in 2010.

Planned Turnarounds

We have planned turnarounds scheduled for Upgrader 2 of approximately 45 days during the second quarter of 2010 and approximately 35 days during the third quarter of 2010.

February 2010 Fire

One of our oil sands upgraders was damaged by fire in early February. We have completed our assessment and repairs are currently underway. The company expects the damaged upgrader to return to production in early April 2010.

During the repair period, the company's second upgrader is expected to continue normal operations. Combined production of synthetic crude oil and bitumen sold directly to markets during this period is targeted at an average of approximately 210,000 barrels per day (bpd) in February and 230,000 bpd in March (these volumes do not include Suncor's proportionate production share from the Syncrude joint venture). Based on the damage assessment and repair schedule, and applicable waiting periods and deductibles, the company does not expect insurance to play a significant role in mitigating losses from this incident.

Risk Factors Affecting Performance

Our financial and operating performance is potentially affected by a number of factors, including, but not limited to, the following:

- Production reliability risk. Our ability to reliably operate our oil sands facilities in order to meet production targets.
- Our ability to finance oil sands growth and sustaining capital expenditures in a volatile commodity pricing environment. Also refer to Liquidity and Capital Resources on page 13.
- Bitumen supply. Ore grade quality, unplanned mine equipment and extraction plant maintenance, tailings storage and in-situ reservoir and equipment performance could impact 2010 production targets.
- Performance of recently commissioned facilities. Production rates while new equipment is being lined out are difficult to predict and can be impacted by unplanned maintenance.
- Ability to manage production operating costs. Operating costs could be impacted by inflationary pressures on labour, volatile pricing for natural gas used as an energy source in oil sands processes, and planned and unplanned maintenance. We continue to address these risks through such strategies as application of technologies that help manage operational workforce demand, offsetting natural gas purchases through internal production, investigation of technologies that mitigate reliance on natural gas as an energy source, and an increased focus on preventative maintenance.
- Our ability to complete projects both on time and on budget. This could be impacted by competition from other projects (including other Oil Sands projects) for goods and services and demands on infrastructure in Fort McMurray and the surrounding area (including housing, roads and schools). We continue to address these issues through a comprehensive recruitment and retention strategy, working with the community to determine infrastructure needs, designing oil sands expansion to reduce unit costs, seeking strategic alliances with service providers and maintaining a strong focus on engineering, procurement and project management.
- Potential changes in the demand for refinery feedstock and diesel fuel. Our strategy is to reduce the impact of this issue by entering into long-term supply agreements with major customers, expanding our customer base and offering a variety of blends of refinery feedstock to meet customer specifications.
- Volatility in crude oil and natural gas prices, foreign exchange rates and the light/heavy and sweet/sour crude oil differentials. We mitigate some of the risk associated with changes in commodity prices through the use of derivative financial instruments (see page 20).
- Logistical constraints and variability in market demand, which can impact crude movements. These factors can be difficult to predict and control.
- Changes to royalty and tax legislation and related agreements that could impact our business. While fiscal regimes in Alberta and Canada are generally stable relative to many global jurisdictions, royalty and tax treatments are subject to periodic review, the outcome of which is not predictable and could result in changes to the company's planned investments, and rates of return on existing investments.
- Our relationship with our trade unions. Work disruptions have the potential to adversely affect oil sands operations and growth projects. The Communications, Energy and Paperworkers Union Local 707 represents approximately 2,900 Oil Sands employees. The current collective agreement with the union expires on April 30, 2010. Negotiations are ongoing.

Additional risks impacting Suncor's general operations can be seen at Risk Factors Affecting Performance on page 20. Additional risks, assumptions and uncertainties are discussed on page 54 under Forward-Looking Information.

NATURAL GAS

Suncor's Natural Gas business, operating primarily in Western Canada, acts as a natural price hedge against the company's purchases of natural gas for internal consumption.

Natural gas strategy focuses on:

- Upgrading our asset portfolio by divesting non-core conventional assets.
- Achieving a lower cost structure.
- Improving return on capital employed, with a focus on improved capital efficiency.
- Moving from an exploration to an execution focus in order to reliably and cost effectively manage our internal consumption.

HIGHLIGHTS

Summary of Results

Year ended December 31 ($ millions unless otherwise noted)	**2009 [1]**	2008	2007
Revenue (net of royalties)	**681**	579	427
Western Canada gross production (mmcfe/d)	**412**	220	215
U.S. Rockies gross production (mmcfe/d)	**34**	—	—
Western Canada average natural gas sales price ($/mcf)	**3.70**	8.23	6.32
U.S. Rockies average natural gas sales price ($/mcf)	**3.93**	—	—
Net earnings (loss)	**(199)**	89	25
Operating earnings (loss) [2]	**(187)**	89	(12)
Cash flow from operations [2], [3]	**329**	367	251
Cash used in investing activities	**(312)**	(316)	(532)
Total assets	**5 003**	1 862	1 811
ROCE (%) [2], [4]	**(8.4)**	7.7	2.5

(1) Amounts for 2009 includes the results of five months of legacy Petro-Canada operations since the close of the merger on August 1, 2009.

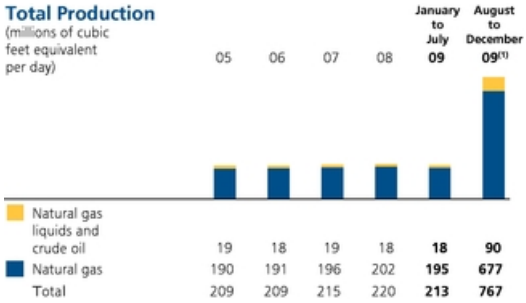
(2) Non-GAAP measures. See pages 52 and 53.

(3) Calculation of this measure has been revised, and prior period comparative figures have been restated. See page 52.

(4) ROCE for Suncor operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non-GAAP Financial Measures.

2009 Overview

- Low benchmark prices significantly reduced Natural Gas price realizations in 2009. The average natural gas spot price at AECO was approximately 50% lower in 2009 than in 2008.
- Post-merger production from Suncor's Natural Gas business during the last five months of 2009 averaged 767 million cubic feet equivalent (mmcfe) per day, comprised of 88% natural gas and 12% natural gas liquids and crude oil. Production from legacy Suncor's natural gas operations averaged 210 mmcfe per day in 2009 compared to 220 mmcfe per day in 2008.
- Suncor has begun the process of divesting of a number of non-core natural gas assets.
    - 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) before closing adjustments. The effective close date of the sale was March 1, 2010.
    - On February 9, 2010, Suncor entered into an agreement to sell certain non-core natural gas properties located in northeast British Columbia for proceeds of $390 million. The sale is expected to close in March 2010 and is subject to customary closing conditions and regulatory approvals.



(1) Reflects only the results of the five months of operations after the merger with Petro-Canada on August 1, 2009.

(2) In 2009, purchases represent all internal consumption within our North American operations, while in prior periods purchases for internal consumption were for our oil sands operations only.

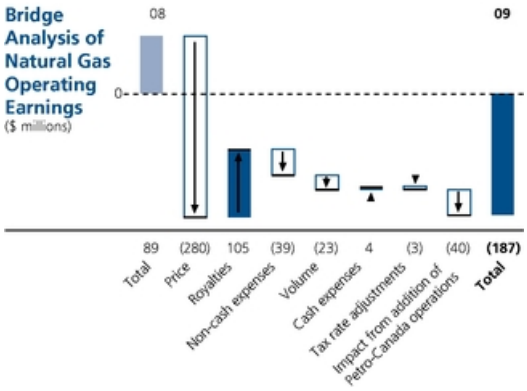
Operating Earnings [1]

Year ended December 31 ($ millions, after-tax)	**2009**	2008	2007
Natural Gas net earnings (loss) as reported	**(199)**	89	25
Mark-to-market valuation of stock-based compensation	**11**	—	2
Impact of income tax rate adjustments on future income tax liabilities [2]	**1**	—	(39)
Natural Gas operating earnings (loss)	**(187)**	89	(12)

(1) Non-GAAP measure. See page 52 for a discussion of operating earnings.

(2) In the third quarter of 2009, an increase in future income tax liabilities resulted from a revised provincial allocation for income tax purposes due to the merger with Petro-Canada. This was partially offset for the year ended December 31, 2009 by a reduction to the Ontario income tax rate in the fourth quarter of 2009, resulting in a decrease in future income tax liabilities. See note 7 to the Consolidated Financial Statements.

Natural Gas recorded a net loss of $199 million in 2009, compared to net earnings of $89 million in 2008 (2007 – net earnings of $25 million). The operating loss was $187 million in 2009, compared to operating earnings of $89 million in 2008 (2007 – operating loss of $12 million). The decrease in earnings was primarily due to significantly lower benchmark commodity prices, higher operating, selling and general and depreciation, depletion and amortization expense resulting from the merger with Petro-Canada, decreased legacy Suncor production due to shut-in volumes in the Elmworth area and the sale of certain non-core assets in the second quarter of 2009, lower sulphur revenue and higher dry hole costs. This was partially offset by lower royalty expense in 2009 compared to 2008 as a result of lower revenues, royalty credits and reduced rates due to the implementation of the Alberta New Royalty Framework.



The average realized price for natural gas was $3.71 per thousand cubic feet (mcf) in 2009, compared to an average of $8.23 per mcf in 2008, reflecting significantly lower benchmark natural gas prices. There was also a decrease in price realizations for crude oil and natural gas liquids, as well as sulphur, resulting from lower benchmark prices for those products in 2009. The net impact of the price variance was a decrease in operating earnings of $280 million.

Natural Gas Production

Year ended December 31 Average mmcfe per day	**09**	08	07	06	05
Legacy Suncor operations	**210**	220	215	209	209

Average mmcfe per day	**2009 [1]**
Legacy Petro-Canada Western Canada	**482**
Legacy Petro-Canada U.S. Rockies	**80**
Total legacy Petro-Canada Natural Gas production	**562**

(1) Production for 2009 is only the results of five months of operations since the merger with Petro-Canada on August 1, 2009

After completion of the merger with Petro-Canada, Suncor's natural gas production during the last five months of 2009 averaged 767 million cubic feet equivalent (mmcfe) per day, comprised of 88% natural gas and 12% natural gas liquids and crude oil. Production from legacy Suncor's natural gas operations averaged 210 mmcfe per day in 2009 compared to 220 mmcfe per day in 2008 which decreased primarily due to shut-in production in the Elmworth area as a result of low commodity prices and the sale of certain non-core assets during the second quarter of 2009.

Cash Expenses

Cash expenses decreased in 2009 as compared to 2008, primarily due to lower production from our legacy Suncor natural gas operations. Overall, decreased cash expenses increased operating earnings by $4 million.

Lifting and Administration Costs

($/mcfe)	05	06	07	08	**09 [1]**

Administration	0.42	0.67	0.70	0.56	**0.53**
Lifting	0.86	0.91	1.26	1.38	**1.35**
Total	1.28	1.58	1.96	1.94	**1.88**

(1) Amounts for 2009 includes the results of five months of legacy Petro-Canada operations since the close of the merger on August 1, 2009.

Non-Cash Expenses

Non cash expenses increased in 2009 as compared to 2008, primarily due to higher dry hole costs in 2009. Overall, increased non-cash expenses decreased operating earnings by $39 million.

Royalties

Royalties on production of natural gas, liquids and sulphur were $85 million ($0.53 per thousand cubic feet equivalent (mcfe)) in 2009, a decrease from $175 million

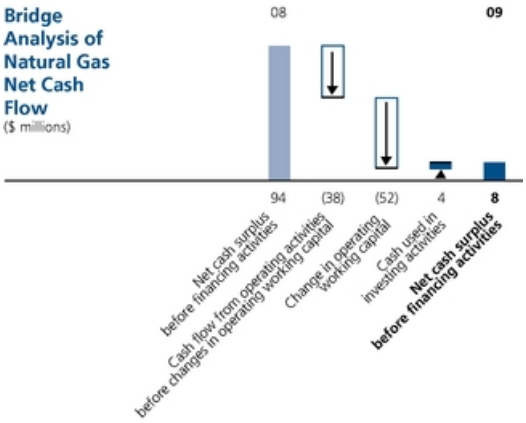
($2.17 per mcfe) in 2008 (2007 – $126 million; $1.61 per mcfe). The decrease in royalty expense for the year was due to significantly lower benchmark commodity prices, royalty credits and reduced rates due to the implementation of the Alberta New Royalty Framework, which was partially offset by increased royalty expense as a result of the merger. For a further discussion on Crown royalties, see page 18.

Overall, decreased royalties increased operating earnings by $105 million.

Net Cash Surplus (Deficiency) Analysis

Natural Gas net cash surplus was $8 million in 2009, compared with $94 million in 2008 (2007 – net cash deficiency of $262 million). Cash flow from operations decreased to $329 million, compared with $367 million in 2008 (2007 – $251 million), impacted by the same factors that affected net earnings, excluding the impact of dry hole costs.

Cash used in investing activities decreased to $312 million, compared with $316 million in 2008 (2007 – $532 million) primarily due to a decrease in drilling activity in 2009, partially offset by the inclusion of five months of Petro-Canada results.



Risk Factors Affecting Performance

Our financial and operating performance is potentially affected by a number of factors, including, but not limited to, the following:

- Consistently and competitively finding and developing reserves that can be brought on stream economically.
- Our ability to finance capital investment to replace reserves or increase processing capacity in a volatile commodity pricing and credit environment. Also refer to Liquidity and Capital Resources on page 13.
- Volatility in natural gas and liquids prices is not predictable and can significantly impact revenues.
- The accessibility and cost of mineral rights. Market demand influences the cost and available opportunities for mineral leases and acquisitions.
- Risk associated with a depressed market for asset sales, leading to losses on disposition.
- Risk in our ability to successfully change focus from a conventional to unconventional gas producer.
- Risks and uncertainties associated with consulting with stakeholders and obtaining regulatory approval for exploration and development activities in our operating areas. These risks could increase costs and/or cause delays to or cancellation of projects.
- Risks and uncertainties associated with weather conditions, which can shorten the winter drilling season and impact the spring and summer drilling program, which may result in increased costs and/or delays in bringing on new production.

Additional risks impacting Suncor's general operations can be seen at Risk Factors Affecting Performance on page 20. Additional risks, assumptions and uncertainties are discussed on page 54 under Forward-Looking Information.

EAST COAST CANADA

Suncor has a strong position in every major producing oil development off Canada's east coast. The company holds a 20% interest in Hibernia, a 27.5% interest in White Rose * and a 22.7% interest in Hebron, and is the operator of Terra Nova with a 34% ** interest.

The East Coast Canada strategy focuses on:

- Delivering top quartile operating performance and maximizing cash flow.
- Sustaining profitable production through reservoir extensions and add-ons.
- Pursuing high potential, near field development and exploration projects.

HIGHLIGHTS

Summary of Results

Year ended December 31 ($ millions unless otherwise noted)	2009 (1)
Revenue (net of royalties)	**441**
Production (bpd)	**58 000**
Average sales price ($/bbl)	**76.86**
Net earnings	**112**
Operating earnings (2)	**111**
Cash flow from operations (2)	**335**
Total assets	**4 771**
Cash used in investing activities	**(152)**
ROCE (%) (2), (3)	**10.7**
ROCE (%) (2), (4)	**6.5**

(1) Reflects the results of operations since the merger with Petro-Canada on August 1, 2009.

(2) Non-GAAP measures. See pages 52 and 53.

(3) Excludes capitalized costs related to major projects in progress. Return on capital employed (ROCE) for our operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non-GAAP Financial Measures.

(4) Includes capitalized costs related to major projects in progress.

2009 Overview

- Total production volume averaged 58,000 bpd in the last five months of 2009. Production was lower than capacity as a result of planned and unplanned maintenance, including the successful completion of the subsea tie-in of the North Amethyst extension at White Rose.
- Average crude sales price was $76.86 per barrel during the last five months of 2009. Sales price realizations were negatively impacted by low benchmark prices.

Operating Earnings (1)

Year ended December 31 ($ millions, after-tax)	2009 (1)
East Coast Canada net earnings as reported	**112**
Mark-to-market valuation of stock-based compensation	**2**
Impact of income tax rate reductions on opening future income tax liabilities (2)	**(20)**
Impact of recording acquired inventory at fair value (3)	**17**
East Coast Canada operating earnings	**111**

(1) Non-GAAP measure. See page 52 for a discussion of operating earnings.

(2) In the fourth quarter of 2009, a decrease in the future income tax liabilities resulted from a reduction to the Ontario income tax rate. See note 7 to the Consolidated Financial Statements.

(3) Inventory acquired through the merger at fair value was sold during 2009, resulting in a one-time negative impact to earnings.

Net earnings for East Coast Canada were $112 million in 2009, while operating earnings for 2009 were $111 million. Lower than capacity production as a result of planned and unplanned maintenance, as well as the tie-in of the North Amethyst extension at White Rose, adversely impacted earnings in the period.

East Coast Canada Net Production (1)

Five months ended December 31 Barrels per day	2009
Terra Nova	**20 800**
Hibernia	**27 200**
White Rose	**10 000**

Total East Coast Canada net production	**58 000**

(1) Production since the close of the merger on August 1, 2009

In the five months ended December 31, 2009, East Coast Canada production averaged 58,000 bpd. Terra Nova production averaged 20,800 bpd, with production impacted by planned and unplanned maintenance during August, September and early October. Production from Hibernia averaged 27,200 bpd for the five months ended December 31, 2009, with strong reservoir capability and facility reliability in the period. White Rose production averaged 10,000 bpd during the five months ended December 31, 2009, with production negatively impacted by planned downtime for maintenance and the tie-in of the North Amethyst extension during the period.

* Suncor holds a 26.125% interest in the White Rose North Amethyst and West White Rose extensions.

** Under the Terra Nova Development and Operating Agreement, a redetermination of working interests is required following payout. The owners have been working through a process to redetermine what the future working interests will be. This process is ongoing.

Sales volumes in the five months ended December 31, 2009 averaged 58,000 bpd, impacted by the same factors affecting production, and average realized crude oil price was $76.86 per barrel.

Non-cash expenses were impacted by an increase in the depreciable asset base for Hibernia, White Rose and Terra Nova as a result of the fair value allocation upon merger. Cash expenses were in line with expectations for the period.

Royalties

East Coast Canada royalties were $217 million ($23.82 per barrel) in 2009, averaging 33% of gross revenue. Terra Nova production was subject to a Tier I royalty of 30% of net revenue and a Tier II royalty of an incremental 12.5% of net revenue. White Rose production was subject to a Tier I royalty of 20% of net revenue and a Tier II royalty of 10% of net revenue. The royalty rate on Hibernia production increased from 5% of gross revenue to 30% of net revenue during 2009 based on the terms of the Hibernia Royalty Agreement and a Memorandum of Understanding. In addition, Hibernia production was subject to a federal government net profits interest of up to 10% of net revenue.

For a further discussion on Crown royalties, see page 18.

Net Cash Surplus Analysis

East Coast Canada's net cash surplus was $149 million in 2009. Cash flow from operations was $335 million in 2009, impacted by the same factors affecting earnings. Cash used in investing activities was $152 million primarily due to work performed on East Coast Canada growth projects, including the North Amethyst and Hibernia South extension projects.

Growth Update

Installation of subsea infrastructure is complete and development drilling continues for the North Amethyst portion of the White Rose Extensions, with first oil targeted during the second quarter of 2010. Development drilling of North Amethyst will continue through 2012.

Preliminary engineering and design activities continued for the Hebron project during 2009.

Drilling commenced during 2009 on the Hibernia South Extension project, in which the company holds a 19.5% interest, with production expected to begin in the first quarter of 2010. Final fiscal agreements were made between co-venturers and the Government of Newfoundland and Labrador in February 2010.

For further details, see the Significant Capital Project Update table on page 15.

Planned Turnarounds

During the second quarter of 2010, we have planned turnarounds scheduled of approximately 18 days for Terra Nova and 12 days for Hibernia. In addition, we have a planned turnaround scheduled for White Rose of approximately 20 days during the third quarter of 2010 and a planned turnaround during the fourth quarter of 2010 of approximately 10 days scheduled for Terra Nova.

Risk Factors Affecting Performance

Our financial and operating performance is potentially affected by a number of factors, including, but not limited to, the following:

- Consistently and competitively finding and developing reserves that can be brought on stream economically.
- Volatility in crude oil prices is not predictable and can significantly impact revenues.
- Performance after completion of maintenance not predictable and can significantly impact production rates.
- Risks and uncertainties associated with consulting with stakeholders and obtaining regulatory approval for exploration and development activities. These risks could increase costs and/or cause delays to or cancellation of projects and expansions to existing projects.
- Risks and uncertainties associated with weather conditions, which may result in increased costs and/or delays in bringing on new production.
- Our ability to finance capital investment to replace reserves or increase processing capacity in a volatile commodity pricing and credit environment. Also refer to Liquidity and Capital Resources on page 13.
- Risks associated with applicable legal and other regulatory requirements, including changes to tax, environmental and other legal and regulatory requirements, the outcome of which is not predictable and could result in changes to the company's planned investments, and rates of return on the company's existing investments.

Additional risks impacting Suncor's general operations can be seen at Risk Factors Affecting Performance on page 20. Additional risks, assumptions and uncertainties are discussed on page 54 under Forward-Looking Information.

INTERNATIONAL

Suncor has International activities in two core areas: the North Sea (the United Kingdom (U.K.), the Netherlands and Norway sectors) and Other International areas (Libya, Syria, and offshore Trinidad and Tobago).

The International strategy focuses on:

- Delivering top quartile operating performance and maximizing cash flow.
- Sustaining profitable production through reservoir extensions and add-ons.
- Pursuing high potential, near field development and exploration projects.
- Divesting non-core North Sea assets (The Netherlands and other U.K.), as well as Trinidad and Tobago.

HIGHLIGHTS

Summary of Results

Year ended December 31 ($ millions unless otherwise noted)	2009 [1]
Revenue (net of royalties)	**1 183**
North Sea net production (boe/d)	**76 500**
Other International net production (boe/d)	**44 300**
Average North Sea sales price ($/bbl)	**71.63**
Average Other International sales price ($/boe)	**61.25**
Net earnings	**165**
Operating earnings [2]	**223**
Cash flow from operations [2]	**616**
Total assets	**9 913**
Cash used in investing activities	**(483)**
ROCE (%) [2], [3]	**11.5**
ROCE (%) [2], [4]	**7.5**

(1) Reflects the results of operations since the merger with Petro-Canada on August 1, 2009.

(2) Non-GAAP measures. See pages 52 and 53.

(3) Excludes capitalized costs related to major projects in progress. Return on capital employed (ROCE) for our operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non-GAAP Financial Measures.

(4) Includes capitalized costs related to major projects in progress.

2009 Overview

- Net production volumes averaged 120,800 boe per day in the last five months of 2009.
- Production in the North Sea was lower than capacity as a result of planned maintenance shutdowns. 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.
- Production in Libya was adversely impacted by OPEC production quota constraints.
- Average sales price in the last five months of 2009 was $71.63 per barrel for the North Sea, and $61.25 per boe for Other International. The combined average sales price for the International segment in this period was $67.82 per boe.
- Suncor has announced plans to divest of a number of non-core assets from the International segment. The proposed divestments identified to date include all Trinidad and Tobago assets and certain non-core North Sea assets, including all assets in The Netherlands.

Operating Earnings [1]

Year ended December 31 ($ millions, after-tax)	2009
International net earnings as reported	**165**
Mark-to-market valuation of stock-based compensation	**8**
Impact of recording acquired inventory at fair value [2]	**8**
Losses and adjustments on significant disposals [3]	**42**
International operating earnings	**223**

(1) Non-GAAP measure. See page 52 for a discussion of operating earnings.

(2) Inventory acquired through the merger at fair value was sold during 2009, resulting in a one-time negative impact to earnings.

(3) Fair value adjustments to assets acquired in the merger with Petro-Canada.

Net earnings for International were $165 million in the five months ended December 31, 2009, while operating earnings for the same period were

$223 million. Lower than capacity production as a result of planned and unplanned maintenance, as well as OPEC quota constraints, adversely impacted earnings in the period. These factors were partially offset by improved price realizations.

International Net Production [1]

Five months ended December 31 Boe per day	2009
U.K. sector of the North Sea	**63 300**
The Netherlands sector of the North Sea	**13 200**
North Sea	**76 500**
Other International	**44 300**
Total International net production	**120 800**

(1) Production since the close of the merger with Petro-Canada on August 1, 2009

International net production averaged 120,800 boe per day in the five months ended December 31, 2009. Net production from the Buzzard development in the U.K. sector of the North Sea averaged 47,800 boe per day in the same period, impacted by a planned four-week shutdown during the third quarter of 2009. In the Netherlands sector of the North Sea, production was 13,200 boe per day for the five months ended December 31, 2009.

Other International consists of producing assets in Libya and Trinidad and Tobago. Production in Libya averaged 32,600 boe per day in the five months ended December 31, 2009, with production impacted by OPEC production quota constraints. Trinidad and Tobago offshore gas production averaged 11,700 boe per day in the same period, with high demand from the Atlantic liquefied natural gas terminal.

The average sales price for North Sea production was $71.63 per barrel in the five months ended December 31, 2009, while the average sales price for Other International was $61.25 per barrel of oil equivalent.

During 2009, planned maintenance shutdowns occurred at the Buzzard and Hanze facilities in the North Sea, resulting in reduced production. In late September 2009, planned turnaround and maintenance commenced at the Triton facility in the U.K. sector of the North Sea and was completed in early October, affecting overall production in 2009.

Cash Expenses

Cash expenses for 2009 were impacted by maintenance expenses incurred in the period, as well as the continued seismic program in Libya.

Non-Cash Expenses

Non-cash expenses were impacted by an increase in the depreciable base for assets as a result of the fair value allocation upon merger and dry hole costs incurred in the U.K. and The Netherlands.

Net Cash Surplus Analysis

International's net cash surplus was $98 million in 2009. Cash flow from operations was $616 million in 2009, impacted by the same factors affecting earnings. Cash used in investing activities was $483 million primarily due to work performed to advance International growth projects, including the Buzzard Enhancement project and Ebla Gas project.

Growth Update

Syria

The Ebla Gas Project remains on plan for first gas delivery in mid 2010 and 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 during the third quarter of 2009 and is currently being interpreted, while the 3D seismic survey of the Ash Shaer field was completed during the second quarter of 2009 and is also now being interpreted.

For further details, see the Significant Capital Project Update table on page 15.

Libya

Work has commenced on implementing the projects associated with the Libya Exploration and Production Sharing Agreements (EPSAs), with a focus on preparing the EPSA field development programs and progressing with the new exploration program. Work on the exploration program is progressing, with seven seismic surveys completed in 2009 and two seismic crews continue to acquire data in country. Seismic surveys completed in 2009 are being processed. Drilling of the first exploration well is expected to commence early in the second quarter of 2010.

Planned International Divestments

As part of its strategic business alignment and subject to Board of Directors approval, Suncor plans to divest of a number of non-core assets. The proposed divestments identified to date include all Trinidad and Tobago assets and certain non-core North Sea assets, including all assets in The Netherlands.

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.

Planned Turnarounds

During the second quarter of 2010, we have planned turnarounds of approximately 14 days for Buzzard, 14 days for Triton, 14 days for De Ruyter and 7 days for Hanze. In the third quarter of 2010, we have scheduled planned turnarounds of approximately 21 days for Triton and 7 days for Buzzard.

Risk Factors Affecting Performance

Our financial and operating performance is potentially affected by a number of factors, including, but not limited to, the following:

- Consistently and competitively finding and developing reserves that can be brought on stream economically.
- Volatility in commodity prices is not predictable and can significantly impact revenues. Current commodity prices are well below the average price realized in the last three years.
- Risks and uncertainties associated with consulting with stakeholders and obtaining regulatory approval for exploration and development activities in our operating areas. These risks could increase costs and/or cause delays to or cancellation of projects.
- Risks and uncertainties associated with operations in a number of foreign countries with different political, taxation, economic and social systems. These risks could decrease revenue, increase costs and/or cause delays to or nationalization, expropriation or cancellation of production and/or projects.
- Our ability to finance capital investment to replace reserves or increase processing capacity in a volatile commodity pricing and credit environment. Also refer to Liquidity and Capital Resources on page 13.
- Risks associated with applicable legal and other regulatory requirements, including changes to tax, environmental and other legal and regulatory requirements, the outcome of which is not predictable and could result in changes to the company's planned investments, and rates of return on the company's existing investments.

Additional risks impacting Suncor's general operations can be seen at Risk Factors Affecting Performance on page 20. Additional risks, assumptions and uncertainties are discussed on page 54 under Forward-Looking Information.

REFINING AND MARKETING

Refining and Marketing operates refineries in Edmonton, Alberta, Montreal, Quebec, Sarnia, Ontario and Commerce City, Colorado 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. In addition, Refining and Marketing 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 transport network and a robust bulk sales channel. Assets also include interests in pipelines and product terminals in Canada and the U.S.

Refining and Marketing's strategy is focused on:

- Enhancing the profitability of refining operations by improving reliability, product yields and enhancing operational flexibility to process a variety of feedstock, including crude oil streams from oil sands operations.
- Creating downstream market opportunities to capture greater long-term value from oil sands production.
- Increasing the profitability of our retail and wholesale networks.

HIGHLIGHTS

Summary of Results

Year ended December 31 ($ millions unless otherwise noted)	**2009**	2008	2007
Revenue	**12 013**	9 419	8 391
Refined product sales (millions of litres)			
Gasoline	**9 975**	5 819	6 132
Total	**19 672**	11 529	12 228
Net earnings (loss)	**433**	(5)	442
Operating earnings breakdown:			
Refining and product supply	**347**	(43)	396
Marketing	**152**	37	36
Total operating earnings (loss) [1]	**499**	(6)	432
Cash flow from operations [1],[2]	**963**	248	711
Total assets	**10 568**	4 687	4 846
Cash used in investing activities	**(391)**	(256)	(491)
ROCE (%) [1],[3]	**7.5**	1.8	20.0
ROCE (%) [1],[4]	**7.5**	1.8	17.4

(1) Non-GAAP measures. See pages 52 and 53.

(2) Calculation of this measure has been revised, and prior period comparative figures have been restated. See page 52.

(3) Excludes capitalized costs related to major projects in progress. Return on capital employed (ROCE) for our operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non-GAAP Financial Measures. Prior years have not been restated for the movement of energy trading activities to Corporate, Energy Trading and Eliminations.

(4) Includes capitalized costs related to major projects in progress.

2009 Overview

- Strong operational and positive financial performance despite a softening demand for petroleum products during 2009 as a result of poor economic conditions.
- After completion of the merger with Petro-Canada, Suncor's total sales of refined petroleum products during the last five months of 2009 averaged 84.8 million litres per day, including additional sales of 53.1 million litres per day resulting from the merger.
- Significant increase in refined product sales due to the addition of the Edmonton and Montreal refineries, national retail and wholesale businesses, and an international lubricants business as a result of the merger with Petro-Canada.
- 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.

Operating Earnings [1]

Year ended December 31 ($ millions, after-tax)	**2009**	2008	2007
Refining and Marketing net earnings (loss) as reported	**433**	(5)	442
Mark-to-market valuation of stock-based compensation	**17**	(1)	7
Impact of income tax rate reductions on opening future income tax liabilities [2]	**(19)**	—	(17)
Costs related to deferral of growth projects	**1**	—	—
Impact of recording acquired inventory at fair value [3]	**67**	—	—
Refining and Marketing operating earnings (loss)	**499**	(6)	432

(1) Non-GAAP measure. See page 52 for a discussion of operating earnings.

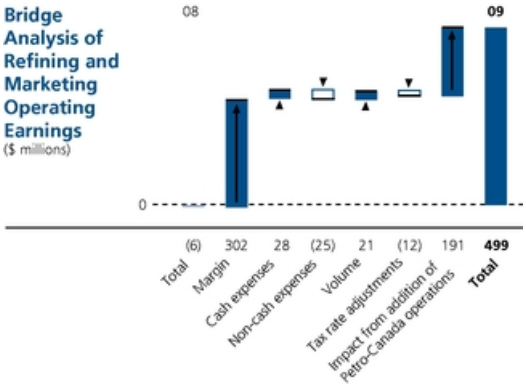
(2) In the fourth quarter of 2009, a decrease in the future income tax liabilities resulted from a reduction to the Ontario income tax rate. See note 7 to the Consolidated Financial Statements.

(3) Inventory acquired through the merger at fair value was sold during the third quarter of 2009, resulting in a one-time negative impact to earnings.

Refining and Marketing's net earnings increased to $433 million in 2009 from a net loss of $5 million in 2008 (2007 – net earnings of $442 million). Operating earnings were $499 million in 2009, compared to an operating loss of $6 million in 2008 (2007 – operating earnings of $432 million). The increase in earnings was primarily due to improved operational reliability at our existing Sarnia and Commerce City refineries that resulted in higher gross margins in 2009, compared to 2008 and the addition of assets associated with the company's merger with Petro-Canada in the third quarter of 2009, partially offset by the impact of lower overall demand for refined petroleum products associated with general economic conditions.

Refining and product supply contributed operating earnings of $347 million in 2009, up from an operating loss of $43 million in 2008. The increase was due to improved operational reliability at our existing Sarnia and Commerce City refineries and increased production resulting from the addition of the Edmonton and Montreal refineries, and the lubricants plant, as a result of the merger. These factors were partially offset by the impact of a weak business environment in 2009, resulting in softening demand for refined petroleum products.

Marketing contributed operating earnings of $152 million in 2009, up from $37 million in 2008, despite a weak business environment. The increase was due to the addition of the national Retail and Wholesale operations and the lubricants business as a result of the merger with Petro-Canada during the third quarter of 2009.



Volumes

After completion of the merger with Petro-Canada, Suncor's total sales of refined petroleum products during the last five months of 2009 averaged 84.8 million litres per day, including additional sales of 53.1 million litres per day resulting from the merger. Despite sales growth being constrained in 2009 by current economic conditions, total sales of refined petroleum products from legacy Suncor's refining and marketing operations averaged 32.6 million litres per day in 2009, compared to 31.5 million litres per day in 2008 reflecting improved refinery reliability.

Fuel Margins

Improved operational reliability at our existing Sarnia and Commerce City refineries resulted in higher gross margins in 2009, compared to 2008, as we were able to process more crude rather than purchasing refined product to meet customer commitments, which negatively impacted our margins in the comparative period.

Cash and Non-Cash Expenses

Cash expenses decreased $28 million in 2009, primarily due to lower input energy costs, as well as lower maintenance at the Sarnia and Commerce City refineries due to improved refinery reliability. Non-cash expenses increased by $25 million in 2009, primarily due to increased depreciation associated with recently completed projects and the cancellation of other partially completed projects. Overall, lower cash and non-cash expenses increased operating earnings by $3 million in 2009.

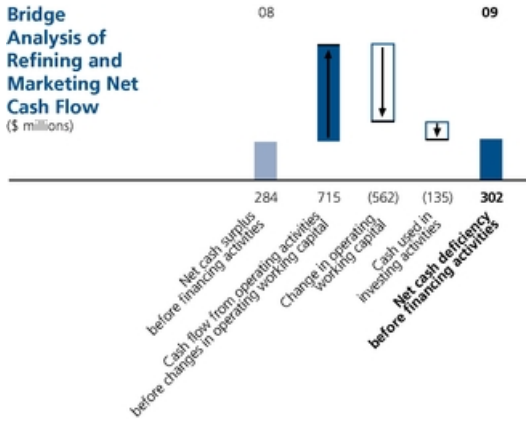
Refinery Utilization

Overall crude refinery utilization averaged 92% in 2009, with utilization for the legacy Suncor refineries averaging 96% compared to 97% in 2008. Although average utilization for the legacy Suncor refineries was down slightly from 2008, this was primarily due to an increase in capacity for both refineries effective January 1, 2009, offset by an increase in processed crude oil as a result of improved operational reliability.

Net Cash Surplus (Deficiency) Analysis

Refining and Marketing's net cash surplus was $302 million in 2009 compared to $284 million in 2008 (2007 – deficiency of $27 million). Cash flow from operations was $963 million in 2009 compared to $248 million in 2008 (2007 – $711 million). The decrease was primarily due to the same factors that impacted net earnings.

Cash used in investing activities was $391 million in 2009 compared to $256 million in 2008 (2007 – $491 million). The increase was due primarily to the addition of the Montreal and Edmonton refineries and lubricants plant as a result of the merger, as well as spending on sustaining and growth projects at our legacy Suncor refineries in 2009.



Risk Factors Affecting Performance

Our financial and operating performance is potentially affected by a number of factors, including, but not limited to, the following:

- Management expects that fluctuations in demand and supply for refined products, margin and price volatility, and market competition, including potential new market entrants, will continue to impact the business environment.
- There are certain risks associated with the execution of capital projects, including the risk of cost overruns. Numerous risks and uncertainties can affect construction schedules, including the availability of labour and other impacts of competing projects drawing on the same resources during the same time period.
- Our relationship with our trade unions. Hourly employees at our London, Ontario terminal operation, our Sarnia, Ontario refinery, our Commerce City, Colorado refinery, our Montreal refinery, certain of our lubricants operations, certain of our terminalling operations and at Sun-Canadian Pipeline Company Limited are represented by labour unions or employee associations. Any work interruptions involving our employees, and/or contract trades utilized in our projects or operations, could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Additional risks impacting Suncor's general operations can be seen at Risk Factors Affecting Performance on page 20. Additional risks, assumptions and uncertainties are discussed on page 54 under Forward-Looking Information.

CORPORATE, ENERGY TRADING AND ELIMINATIONS

Corporate, Energy Trading and Eliminations includes third-party energy supply and trading activities and activities not directly attributable to an operating segment. It also supports Suncor's sustainability goals by managing investment in wind energy projects and developing strategies to reduce greenhouse gas emissions.

Operating Earnings [1]

Year ended December 31 ($ millions, after-tax)	**2009**	2008	2007
Net earnings (loss) as reported	**78**	(822)	42
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**(798)**	852	(215)
Mark-to-market valuation of stock-based compensation	**58**	(101)	(1)
Impact of income tax rate adjustments on future income tax liabilities [2]	**5**	—	42
Merger and integration costs	**151**	—	—
Operating loss	**(506)**	(71)	(132)

(1) Non-GAAP measure. See page 52 for a discussion of operating earnings.

(2) In the third quarter of 2009, an increase in the future income tax liabilities resulted from a revised provincial allocation for income tax purposes due to the merger with Petro-Canada. This was partially offset for the year ended December 31, 2009 by a reduction to the Ontario income tax rate in the fourth quarter of 2009, resulting in a decrease in the future income tax liabilities. See note 7 of the Consolidated Financial Statements.

Corporate, Energy Trading and Eliminations net earnings were $78 million in 2009, compared to a net loss of $822 million in 2008 (2007 – net earnings of $42 million). Corporate, Energy Trading and Eliminations recorded an operating loss of $506 million in 2009, compared to $71 million in 2008 (2007 – $132 million). Results reflected higher net interest expense in 2009 due to additional debt acquired through the merger with Petro-Canada and $437 million of interest costs on debt used to finance growth projects. In 2009, these interest costs were expensed while growth projects were in safe mode, compared to 2008 when interest expense was capitalized. In addition, 2009 results reflected lower energy supply and trading earnings and an increase in profits eliminated on crude oil sales between upstream segments and Refining and Marketing, where this crude oil still resides in Refining and Marketing's inventories.

Summary of Results

Year ended December 31 ($ millions)	**2009**	2008	2007
Net earnings (loss)	**78**	(822)	42
Operating loss			
Corporate	**(457)**	(118)	(138)
Energy supply and trading	**44**	56	9
Group eliminations	**(93)**	(9)	(3)
Total operating loss	**(506)**	(71)	(132)
Cash flow used in operations	**(695)**	(65)	(90)
Total assets	**1 938**	184	(320)
Cash from (used in) investing activities	**213**	(22)	(91)
Renewable energy net earnings	**28**	28	31

Energy Supply and Trading Activities

Year ended December 31 ($ millions unless otherwise noted)	**2009**	2008	2007
Settlement of non-trading physical contracts	**8 008**	11 295	2 931
Settlement of trading physical contracts	**20**	—	—
Gains (losses) on trading derivatives	**(70)**	127	(39)
Gains on inventory valuation	**47**	—	—
Energy Supply and Trading Activities Revenue	**8 005**	11 422	2 892
Settlement of non-trading physical contracts	**(7 929)**	(11 331)	(2 871)
Operating, selling & general expense	**(13)**	(11)	(10)
Energy Supply and Trading Activities Earnings (pre-tax)	**63**	80	11

These activities involve marketing and trading of crude oil, natural gas, refined products and by-products, and the use of financial derivatives. These activities resulted in pre-tax earnings of $63 million in 2009 compared to $80 million in 2008 (2007 – $11 million). Marketing and trading profits were generated primarily by transporting crude oil to more attractive markets and by holding crude oil in storage to realize higher future prices. The lower earnings in 2009 are primarily attributable to financial derivatives designed to protect the value of physical positions. A portion of the gains on financial derivatives realized in 2008, on a fair value basis, are offset by losses on the physical positions realized in 2009. For further details on our energy supply and trading activities, see page 19.

Renewable Energy

Our renewable energy interests include four wind power projects and Canada's largest ethanol plant by production volume. Net earnings from renewable energy were $28 million in 2009, compared to $28 million in 2008 (2007 – $31 million).

Our four wind projects, located in Saskatchewan, Alberta and Ontario, have a total generating capacity of 147 megawatts, offsetting the equivalent of 284,000 tonnes of carbon dioxide (CO_2) per year.

The St. Clair Ethanol Plant has a current capacity of 200 million litres per year, offsetting the equivalent of 300,000 tonnes of CO_2 per year. A $120 million expansion of the ethanol plant currently underway, estimated to be completed in the first quarter of 2011, is expected to double the production capacity.

OUTLOOK

During 2010, management will focus on the following priorities:

- **Operational excellence.** Focusing on operational excellence to enhance personal and process safety management, environmental excellence and sustainability, reliability, and people.
- **Continue to focus on safety.** Continue efforts to identify and reduce potential process safety hazards and implement enhanced company-wide occupational hygiene and health standards.
- **Strengthen balance sheet.** Planned capital spending has been set at $5.5 billion for 2010, with expected near-term cash flow from operations as key criteria for investment. Applying proceeds from planned divestitures to reduce net debt is expected to contribute to a target of two-times cash flow from operations.
- **Continue efforts to reduce environmental impact intensity.** We expect to reclaim the industry's first tailings pond to a trafficable surface. As well, work will continue on developing accelerated reclamation technology.

Update to Production Outlook Issued February 4, 2010

One of our oil sands upgraders was damaged by fire in February 2010. Repairs are currently underway and the company expects the damaged upgrader to return to production in early April 2010.

During the repair period, the company's second upgrader is expected to continue normal operations. Combined production of synthetic crude oil and bitumen sold directly to markets during this period is targeted at an average of approximately 210,000 barrels per day (bpd) in February and 230,000 bpd in March (these volumes do not include Suncor's proportionate production share from the Syncrude joint venture). Accordingly, Suncor's production outlook issued on February 4, 2010 will be impacted and will be updated with the release of the company's first quarter results on May 4, 2010.

This update contains forward-looking statements identified by the word "targeted" and similar expressions that address expectations or projections about the future. Forward-looking statements are based on Suncor's current goals, expectations, estimates, projections and assumptions made in light of its experiences and the risks, uncertainties and other factors related to its business. Assumptions used to develop our production targets and outlook are based on year-to-date performance and management's best estimates for the remainder of the year.

Factors that could potentially impact Suncor's operations and financial performance in 2010 include:

- **Bitumen supply.** Ore grade quality, unplanned mine equipment and extraction plant maintenance, tailings storage and in-situ reservoir and facilities performance could impact 2010 production targets.
- **Performance of recently commissioned facilities.** Production rates while new equipment is being lined out are difficult to predict and can be impacted by unplanned maintenance.
- **Unplanned maintenance.** Production estimates could be impacted if unplanned work is required at any of our mining, production, upgrading, refining, pipeline or offshore assets.
- **Planned maintenance.** Production estimates could be impacted due to unexpected events impacting the timing or duration of planned maintenance.
- **Planned divestitures.** Our inability to execute planned divestitures could impact our debt management and capital expenditure plans.
- **Commodity prices.** Significant declines in natural gas commodity prices could result in the shut-in of some of our natural gas production.
- **Foreign operations.** Suncor's foreign operations and related assets are subject to a number of political, economic and socio-economic risks. Suncor's operations in Libya may be constrained by OPEC quotas.

For additional information on risk factors that could cause actual results to differ, please see page 20.

NON-GAAP FINANCIAL MEASURES

Certain financial measures referred to in this MD&A are not prescribed by Canadian generally accepted accounting principles (GAAP). 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. We include cash flow from operations (dollars and per share amounts), return on capital employed (ROCE), and cash and total operating costs per barrel data 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 Canadian GAAP.

Operating Earnings

Operating earnings (loss) represent net earnings (loss) excluding the change in fair value of commodity derivatives used for risk management purposes, unrealized foreign exchange gain (loss) on U.S. dollar denominated long term debt, mark-to-market valuation of stock-based compensation, impact of income tax rate adjustments on future income tax liabilities, costs related to start-up or deferral of growth projects, and impacts related to the merger with Petro-Canada. Operating earnings are used by the Company to evaluate operating performance. See page 12 for a reconciliation of consolidated net earnings to consolidated operating earnings.

Cash Flow from Operations per Common Share

Cash flow from operations is expressed before changes in non-cash working capital. Cash flow from operations is the same measure as the cash flow from operating activities before changes in working capital measure that is included in the Consolidated Financial Statements. Beginning in third quarter 2009, cash flow from operations adjusts for the impact of fair value changes on both the current and long-term portions of commodity derivatives and stock-based compensation (previously only adjusted the impact on the long-term portions). The company believes this provides more useful information to investors and allows better comparability between Suncor and other companies with similar adjustments for commodity derivatives and/or stock-based compensation. Prior period comparative figures have been restated. A reconciliation of net earnings to cash flow from operations is provided in the Schedules of Segmented Data, which are included in our Consolidated Financial Statements.

For the year ended December 31	**2009**	2008	2007
Cash flow from operations ($ millions)	**2 799**	4 057	4 037
Weighted number of shares outstanding – basic (millions of shares)	**1 198**	932	922
Cash flow from operations – basic ($ per share)	**2.34**	4.36	4.38

ROCE

For the year ended December 31 ($ millions, except ROCE)		2009	2008	2007
Adjusted net earnings				
Net earnings		**1 146**	2 137	2 983
Add: after-tax financing expenses (income)		**(509)**	852	(179)
	A	**637**	2 989	2 804
Capital employed – beginning of year				
Short-term and long-term debt, less cash and cash equivalents		**7 226**	3 248	1 849
Shareholders' equity		**14 523**	11 896	9 084
	B	**21 749**	15 144	10 933
Capital employed – end of year				
Short-term and long-term debt, less cash and cash equivalents		**13 377**	7 226	3 248
Shareholders' equity		**34 111**	14 523	11 896
	C	**47 488**	21 749	15 144
Average capital employed (1)	D	**35 128**	18 447	13 039
Average capitalized costs related to major projects in progress	E	**10 655**	5 149	3 454
ROCE (%) (2)	A/(D-E)	**2.6**	22.5	29.3

(1) Average capital employed for 2008 and 2007 is calculated on a simple-average basis (B+C)/2. In 2009, as a result of the significant capital employed that was acquired during the year due to the merger with Petro-Canada, average capital employed is now calculated on a monthly weighted-average basis.

(2) The increase in capital employed as a result of the merger with Petro-Canada has caused our return on capital employed measure to decrease significantly, as the calculation only includes five months of results relating to legacy Petro-Canada operations.

Oil Sands Operating Costs – Total Operations (1)

(unaudited)	2009 $ millions	2009 $/barrel	2008 $ millions	2008 $/barrel	2007 $ millions	2007 $/barrel
Operating, selling and general expenses	**4 277**		3 204		2 439	
Less: natural gas costs, inventory changes, stock-based compensation and other	**(400)**		(524)		(301)	
Less: Safe mode costs	**(380)**		—		—	
Less: non-monetary transactions	**(66)**		(111)		(102)	
Less: Syncrude-related operating, selling and general expenses	**(199)**		—		—	
Accretion of asset retirement obligations	**107**		55		40	
Cash costs	**3 339**	**31.50**	2 624	31.45	2 076	24.15
Natural gas	**252**	**2.40**	438	5.25	307	3.55
Imported bitumen (excluding other reported product purchases)	**8**	**0.05**	150	1.80	8	0.10
Cash operating costs	**3 599**	**33.95**	3 212	38.50	2 391	27.80
Project start-up costs	**51**	**0.45**	35	0.40	60	0.95
Total cash operating costs	**3 650**	**34.40**	3 247	38.90	2 451	28.75
Depreciation, depletion and amortization	**850**	**8.00**	580	6.95	462	5.40
Total operating costs	**4 500**	**42.40**	3 827	45.85	2 913	34.15
Production (thousands of barrels per day)		**290.6**		228.0		235.6

(1) Excludes Suncor's proportionate production share and operating costs from the Syncrude joint venture

Legal Notice – Forward-Looking Information

This Management's Discussion and Analysis contains certain forward-looking statements and other information that are based on Suncor's current expectations, estimates, projections and assumptions that were made by the company in light of its experience and its perception of historical trends. These statements and information are subject to a number of risks and uncertainties, many of which are beyond the company's control.

All statements and other information that address expectations or projections about the future, including statements about Suncor's strategy for growth, expected and future expenditures, commodity prices, costs, schedules, production volumes, operating and financial results and expected impact of future commitments, are forward-looking statements. Some of the forward-looking statements may be identified by words like "expects," "anticipates," "estimates," "plans," "scheduled," "intends," "believes," "projects," "indicates," "could," "focus," "vision," "goal," "outlook," "proposed," "target," "objective," "will" and similar expressions. These 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 Suncor. Suncor's actual results may differ materially from those expressed or implied by its forward-looking statements and readers are cautioned not to place undue reliance on them.

Suncor's production targets are based on our current expectations, estimates, projections and assumptions. Uncertainties in the estimating process and the impact of future events may cause actual results to differ, in some cases materially, from our estimates. Assumptions are based on management's experience and perception of historical trends, current conditions, anticipated future developments and other factors believed to be relevant. For a description of assumptions and risk factors specifically related to these production targets, see page 51.

Certain financial measures referred to in MD&A, namely operating earnings, cash flow from operations, return on capital employed (ROCE) and oil sands cash and total operating costs per barrel, are not prescribed by GAAP. 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 a further description of these measures please refer to pages 52 and 53.

The risks, uncertainties and other factors that could influence actual results include but are not limited to, those risks, uncertainties and other factors described throughout this MD&A and: market instability affecting Suncor's ability to borrow in the capital debt markets at acceptable rates; availability of third-party bitumen; success of hedging strategies; maintaining a desirable debt to cash flow ratio; changes in the general economic, market and business conditions; fluctuations in supply and demand for Suncor's products; commodity prices, interest rates and currency exchange rates; Suncor's 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; Suncor's inability to execute planned divestitures; political, economic and socio-economic risk associated with foreign operations (including OPEC production quotas); the accuracy of cost estimates, some of which are provided at the conceptual or other preliminary stage of projects and prior to commencement or conception of the detailed engineering needed to reduce the margin of error and increase the level of accuracy; the integrity and reliability of Suncor's capital assets; the cumulative impact of other resource development; the cost of compliance with current and future environmental laws; the accuracy of Suncor's reserve, resource and future production estimates and its success at exploration and development drilling and related activities; the maintenance of satisfactory relationships with unions, employee associations and joint venture partners; competitive actions of other companies, including increased competition from other oil and gas companies or 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); the ability and willingness of parties with whom we have material relationships to perform their obligations to us; the occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect Suncor; failure to realize anticipated synergies or cost savings associated with our merger with Petro-Canada; risks regarding the integration of Petro-Canada and incorrect assessments of the value of Petro-Canada. The foregoing important factors are not exhaustive.

Many of these risk factors are discussed in further detail throughout this MD&A and in Suncor's Annual Information Form/Form 40-F on file with Canadian securities commissions at www.sedar.com and the United States Securities and Exchange Commission (SEC) at www.sec.gov. Readers are also referred to the risk factors described in other documents that Suncor files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the company.

QuickLinks

EXHIBIT 99-2

Management's Discussion and Analysis for the fiscal year ended December 31, 2009, dated February 26, 2010

QuickLinks -- Click here to rapidly navigate through this document

EXHIBIT 99-3

Consent of PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
111 5th Avenue SW, Suite 3100
Calgary, Alberta
Canada T2P 5L3
Telephone +1 (403) 509 7500
Facsimile +1 (403) 781 1825

CONSENT OF INDEPENDENT ACCOUNTANTS

We hereby consent to inclusion in this Annual Report on Form 40-F and the incorporation by reference in the registration statements on Form S-8 (File No. 333-87604), Form S-8 (File No. 333-112234), Form S-8 (File No. 333-118648), Form S-8 (File No. 333-124415), Form S-8 (File No. 333-149532), Form S-8 (File No. 333-161021), Form S-8 (File No. 333-161029), Form F-9 (File No. 333-140797) and Form F-9 (File No. 333-151347) of Suncor Energy Inc., of our report dated February 26, 2010 relating to the consolidated financial statements and the effectiveness of internal control over financial reporting, which appears in the Annual Report to Shareholders.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta
March 5, 2010

QuickLinks

EXHIBIT 99-3

Consent of PricewaterhouseCoopers LLP

QuickLinks -- Click here to rapidly navigate through this document

EXHIBIT 99-4

Consent of GLJ Petroleum Consultants Ltd.

LETTER OF CONSENT

TO: Suncor Energy Inc.
The Securities and Exchange Commission
The Securities Regulatory Authorities of Each of the Provinces of Canada

Dear Sirs

Re: Suncor Energy Inc.

We refer to the Summary Reserves Report (the "Report") prepared by GLJ Petroleum Consultants Ltd. ("GLJ") dated March 5, 2010 which provides a summary of GLJ's proved and probable reserves evaluations and reviews pursuant to U.S. disclosure requirements of Suncor Energy Inc.'s mining leases, Firebag in-situ leases, Syncrude mining lease interests and North American onshore interests that were evaluated and North American onshore leases that were reviewed by GLJ as at December 31, 2009.

We hereby consent to the use of our name, reference to and excerpts from the said Report by Suncor Energy Inc. in its Annual Report on Form 40-F and the incorporation by reference in the registration statements on Form S-8 (File No. 333-87604), Form S-8 (File No. 333-112234), Form S-8 (File No. 333-118648), Form S-8 (File No. 333-124415), Form S-8 (File No. 333-149532), Form S-8 (File No. 333-161021), Form S-8 (File No. 333-161029), Form F-9 (File No. 333-140797) and Form F-9 (File No. 333-151347) of Suncor Energy Inc., of our Report.

We have read Suncor Energy Inc.'s Annual Information Form dated March 5, 2010 and the Form 40-F dated March 5, 2010 and have no reason to believe that there are any misrepresentations in the information contained therein that is derived from our Report or that are within our knowledge as a result of the services which we performed in connection with the preparation of the Report.

Yours very truly,

GLJ PETROLEUM CONSULTANTS LTD.

"GLJ PETROLEUM CONSULTANTS LTD."

Dana B. Laustsen, P. Eng.
Executive Vice-President

Dated: March 5, 2010
Calgary, Alberta
CANADA

QuickLinks

EXHIBIT 99-4

Consent of GLJ Petroleum Consultants Ltd.
LETTER OF CONSENT

QuickLinks -- Click here to rapidly navigate through this document

EXHIBIT 99-5

Consent of Sproule Associates Ltd.

LETTER OF CONSENT

TO: Suncor Energy Inc.
The Securities and Exchange Commission
The Securities Regulatory Authorities of Each of the Provinces of Canada

Dear Sirs

Re: Suncor Energy Inc.

We refer to the Summary Reserves Report (the "Report") prepared by Sproule Associates Limited ("Sproule") dated March 5, 2010 which provides a summary of Sproule's proved and probable reserves evaluations and reviews pursuant to U.S. disclosure requirements of Suncor Energy Inc.'s North American onshore interests, East Coast lease interests and MacKay River in-situ leases as at December 31, 2009.

We hereby consent to the use of our name, reference to and excerpts from the said Report by Suncor Energy Inc. in its Annual Report on Form 40-F and the incorporation by reference in the registration statements on Form S-8 (File No. 333-87604), Form S-8 (File No. 333-112234), Form S-8 (File No. 333-118648), Form S-8 (File No. 333-124415), Form S-8 (File No. 333-149532), Form S-8 (File No. 333-161021), Form S-8 (File No. 333-161029), Form F-9 (File No. 333-140797) and Form F-9 (File No. 333-151347) of Suncor Energy Inc., of our Report.

We have read Suncor Energy Inc.'s Annual Information Form dated March 5, 2010 and the Form 40-F dated March 5, 2010 and have no reason to believe that there are any misrepresentations in the information contained therein that is derived from our Report or that are within our knowledge as a result of the services which we performed in connection with the preparation of the Report.

Yours very truly,

SPROULE ASSOCIATES LTD.

"SPROULE ASSOCIATES LTD."

R. Keith MacLeod, P.Eng.
President

Dated: March 5, 2010
Calgary, Alberta
CANADA

QuickLinks

EXHIBIT 99-5

Consent of Sproule Associates Ltd.
LETTER OF CONSENT

QuickLinks -- Click here to rapidly navigate through this document

EXHIBIT 99-6

Consent of RPS Energy Ltd.

LETTER OF CONSENT

TO: Suncor Energy Inc.
The Securities and Exchange Commission
The Securities Regulatory Authorities of Each of the Provinces of Canada

Dear Sirs

Re: Suncor Energy Inc.

We refer to the Summary Reserves Report (the "Report") prepared by RPS Energy Ltd. ("RPS Energy") dated March 5, 2010 which provides a summary of RPS Energy's proved and probable reserves evaluations and reviews pursuant to U.S. disclosure requirements of reserves related to Suncor Energy Inc.'s international operations evaluated as at December 31, 2009.

We hereby consent to the use of our name, reference to and excerpts from the said Report by Suncor Energy Inc. in its Annual Report on Form 40-F and the incorporation by reference in the registration statements on Form S-8 (File No. 333-87604), Form S-8 (File No. 333-112234), Form S-8 (File No. 333-118648), Form S-8 (File No. 333-124415), Form S-8 (File No. 333-149532), Form S-8 (File No. 333-161021), Form S-8 (File No. 333-161029), Form F-9 (File No. 333-140797) and Form F-9 (File No. 333-151347) of Suncor Energy Inc., of our Report.

We have read Suncor Energy Inc.'s Annual Information Form dated March 5, 2010 and the Form 40-F dated March 5, 2010 and have no reason to believe that there are any misrepresentations in the information contained therein that is derived from our Report or that are within our knowledge as a result of the services which we performed in connection with the preparation of the Report.

Yours very truly,

RPS ENERGY LTD.

"RPS ENERGY LTD."

Dr. Graeme Simpson
Director, Advisory

Dated: March 5, 2010
Calgary, Alberta
CANADA

QuickLinks

EXHIBIT 99-6

Consent of RPS Energy Ltd.
LETTER OF CONSENT

QuickLinks -- Click here to rapidly navigate through this document

EXHIBIT 99-7

CERTIFICATION

I, RICHARD L. GEORGE, certify that:

1. I have reviewed this annual report on Form 40-F of the Issuer;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this annual report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

/s/ RICHARD L. GEORGE

Richard L. George
President and Chief Executive Officer

DATE: March 5, 2010

QuickLinks

EXHIBIT 99-7

CERTIFICATION

QuickLinks -- Click here to rapidly navigate through this document

EXHIBIT 99-8

CERTIFICATION

I, BART DEMOSKY, certify that:

1. I have reviewed this annual report on Form 40-F of the issuer;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this annual report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

/s/ BART DEMOSKY

Bart Demosky
Chief Financial Officer

DATE: March 5, 2010

QuickLinks

EXHIBIT 99-8

CERTIFICATION

QuickLinks -- Click here to rapidly navigate through this document

EXHIBIT 99-9

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ENACTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the annual report of Suncor Energy Inc. (the "Company") on Form 40-F for the fiscal year ending December 31, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, RICHARD L. GEORGE, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ RICHARD L. GEORGE

Richard L. George
President and Chief Executive Officer
Suncor Energy Inc.

DATE: March 5, 2010

QuickLinks

EXHIBIT 99-9

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ENACTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

QuickLinks -- Click here to rapidly navigate through this document

EXHIBIT 99-10

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ENACTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the annual report of Suncor Energy Inc. (the "Company") on Form 40-F for the fiscal year ending December 31, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, BART DEMOSKY, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ BART DEMOSKY

Bart Demosky
Chief Financial Officer
Suncor Energy Inc.

DATE: March 5, 2010

QuickLinks

EXHIBIT 99-10

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ENACTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002