SUNCOR ENERGY INC
Form 40-F
March 01, 2012

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, 2011
Commission File Number:	No. 1-12384

SUNCOR ENERGY INC.
(Exact name of registrant as specified in its charter)

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

150 - 6th Avenue S.W.
Box 2844
Calgary, Alberta, Canada T2P 3E3
(403) 296-8000

(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, 2011 there were 1,558,636,368 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 1, 2012

TABLE OF CONTENTS

ADVISORIES

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. On August 1, 2009, Suncor completed its merger with Petro-Canada, referred to in this document as the "merger". References to the "Board of Directors" or the "Board" mean the Board of Directors of Suncor Energy Inc., unless the context otherwise requires.

All financial information is reported in Canadian dollars, unless otherwise noted. Production volumes are presented on a working-interest basis, before royalties, unless otherwise noted. Certain amounts in prior years may have been reclassified to conform to the current year's presentation.

References to our 2011 audited Consolidated Financial Statements mean Suncor's audited Consolidated Financial Statements prepared in accordance with Canadian generally accepted accounting principles (GAAP), the notes and the auditors' report, as at and for each year in the two-year period ended December 31, 2011. References to our MD&A mean Suncor's Management's Discussion and Analysis, dated February 23, 2012.

Unless otherwise noted, all financial information has been prepared in accordance with Canadian GAAP, which is within the framework of International Financial Reporting Standards (IFRS).

This AIF 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 document in the Risk Factors section, many of which are beyond the company's control. Users of this information are cautioned that actual results may differ materially. Refer to the Advisory Forward-Looking Information section of this AIF for information on other risk factors and the material assumptions underlying our forward-looking information.

Information contained in or otherwise accessible through Suncor's website www.suncor.com does not form a part of this AIF, and is not incorporated into the AIF by reference.

GLOSSARY OF TERMS AND ABBREVIATIONS

Common Industry Terms

Products

Hydrocarbons are solids, liquids or gas made up of compounds of carbon and hydrogen, in varying proportions.

Crude oil is a mixture of pentanes (lighter hydrocarbons) and heavier hydrocarbons that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons, but does not include liquids obtained in the processing of natural gas.

> **Bitumen or heavy crude oil** is a naturally occurring viscous mixture, consisting mainly of pentanes and heavier hydrocarbons, which may not be recoverable at a commercial rate in its naturally occurring viscous state through a well without using enhanced recovery methods. After it is extracted, bitumen or heavy crude oil may be upgraded into crude oil and other petroleum products.
>
> **Conventional crude oil** is crude oil produced through wells by standard industry recovery methods.
>
> **Oil sands** are naturally occurring deposits of sand or sandstone, or other sedimentary rocks that contain bitumen.
>
> **Synthetic crude oil** (SCO) is a mixture of hydrocarbons derived by upgrading bitumen from oil sands. SCO 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 synthetic crude oil**, while SCO with higher sulphur content is referred to as **sour synthetic crude oil**.
>
> **West Texas Intermediate** is a type of crude oil used as a benchmark in oil pricing, and is the underlying commodity of futures contracts on the New York Mercantile Exchange (NYMEX).

Natural gas is a mixture of lighter hydrocarbons, which at atmospheric conditions of temperature and pressure is in a gaseous state.

Conventional natural gas is natural gas produced from all geological strata, including associated, non-associated and solution gas, but excluding coal bed methane and shale gas.

Non-associated gas is an accumulation of natural gas in a reservoir where there is no crude oil. **Associated gas** is the gas cap overlying a crude oil accumulation in a reservoir.

Solution gas is natural gas dissolved in crude oil in a reservoir.

Natural gas liquids (NGLs) are 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.

Oil and gas exploration and development processes

Development costs are costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves.

Exploration costs are costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves.

Field is a defined geographical area consisting of one or more pools containing hydrocarbons.

Glory hole is an excavation into the sea floor designed to protect wellhead equipment from icebergs, and which typically contains multiple wellheads.

Reservoir is 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.

Wells:

Development wells are 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.

Dry wells are exploratory or development wells found to be incapable of producing either oil or gas in sufficient quantities to justify the completion as an oil or gas well.

Exploratory wells are drilled in a territory without existing proved reserves, with the intention to discover commercial reservoirs or deposits of crude oil and/or natural gas. Exploratory wells include **appraisal wells**, which are drilled to measure the commercial potential (i.e. size and quality) of a hydrocarbon discovery. Before development, an offshore discovery is likely to need several appraisal wells.

Service wells are drilled or completed for the purpose of supporting production in an existing field, such as wells drilled for observation or wells drilled for the injection of gas or water.

Stratigraphic wells are drilling efforts, geologically directed, to obtain information pertaining to a specific geologic condition, such as **core hole drilling** on oil sands leases, and are usually drilled without the intention of being completed for production.

Production processes

Capacity is the annual average output that may be achieved from a processing facility, such as an upgrader, refinery or natural gas processing plant, under ideal operating conditions and in accordance with current design specifications.

Downstream refers to the refining of crude oil or synthetic crude oil and the selling and distribution of refined products in retail and wholesale channels.

Feedstock generally refers either to i) the bitumen required in the production of synthetic crude oil for the company's oil sands operations; or ii) crude oil and/or other components required in the production of refined products for the company's downstream operations.

In situ or "in place" refers to methods of extracting bitumen or heavy crude oil from deep deposits of oil sands by means other than surface mining.

Overburden is the material overlying oil sands that must be removed before mining, which consists of muskeg, glacial deposits and sand.

Production Sharing Contracts (PSC) are a common type of contract signed between a government and a resource extraction company that states how much of the resource produced each party will receive and which parties are responsible for the development and operation of the resource. An **Exploration and Production Sharing Agreement (EPSA)** is a form of Production Sharing Contract, which also states which parties are responsible for exploration activities.

Steam-assisted gravity drainage (SAGD) is an enhanced oil recovery technology for producing heavy crude oil and bitumen. It is an advanced form of steam stimulation in which a pair of horizontal wells are drilled into the oil reservoir, one a few metres above the other. Low pressure steam is continuously injected into the upper wellbore to heat the oil and reduce its viscosity, causing the heated oil to drain into the lower wellbore, from which it is pumped out.

Steam-to-oil ratio (SOR) is a metric used to quantify the efficiency of an in situ oil recovery process, which measures the cubic metres of steam required to produce one cubic metre of oil. The lower the ratio, the higher the efficiency of the use of steam.

Utilization is the average use of capacity, and includes the impact of planned and unplanned facility outages and maintenance. More specifically, **refinery utilization** is the amount of crude oil and natural gas plant liquids run through crude distillation units, expressed as a percentage of the capacity of these units.

Upgrading is the two-stage process by which bitumen or heavy crude oil is converted into synthetic crude oil.

> **Primary upgrading,** also referred to as coking or thermal cracking, heats the bitumen in coke drums to remove excess carbon. The superheated hydrocarbon vapours are sent to fractionators where they condense into naphtha, kerosene and gas oil. Carbon residue, or coke, is removed from the coke drums on short intervals and later sold as a byproduct.
>
> **Secondary upgrading,** a purification process also referred to as hydrotreating, adds hydrogen to, and reduces the sulphur of, primary upgrading output to create sweet synthetic crude oil and diesel.

Upstream refers to the exploration, development and production of conventional crude oil, bitumen or natural gas.

<u>Reserves and resources</u>

Please refer to the Definitions for Reserves Data Tables section of the Statement of Reserves Data and Other Oil and Gas Information in this AIF.

Common Abbreviations

The following is a list of abbreviations that may be used in this AIF:

Measurement	
bbl(s)	barrel(s)
bbls/d	barrels per day
mbbls/d	thousands of barrels per day
mmbbls	millions of barrels
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
mboe	thousands of barrels of oil equivalent
mboe/d	thousands of barrels of oil equivalent per day
mmboe	millions of barrels of oil equivalent
mcf	thousands of cubic feet of natural gas
mcf/d	thousands of cubic feet of natural gas per day
mcfe	thousands of cubic feet of natural gas equivalent
mmcf	millions of cubic feet of natural gas
mmcf/d	millions of cubic feet of natural gas per day
mmcfe	millions of cubic feet of natural gas equivalent
mmcfe/d	millions of cubic feet of natural gas equivalent per day
bcf	billions of cubic feet of natural gas
GJ	gigajoule
mmbtu	millions of British thermal units
m^3	cubic metres
m^3/d	cubic metres per day

Places and Currencies	
U.S.	United States
U.K.	United Kingdom
B.C.	British Columbia
$ or Cdn$	Canadian dollars
US$	United States dollars
£	Pounds sterling
€	Euros

<u>Products, Markets and Processes</u>

WTI	West Texas Intermediate
WCS	Western Canadian Select
NGL(s)	natural gas liquid(s)
LPG	liquefied petroleum gas
SCO	synthetic crude oil
NYMEX	New York Mercantile Exchange
TSX	Toronto Stock Exchange
NYSE	New York Stock Exchange
SAGD	steam-assisted gravity drainage
PSC	production sharing contract

km	kilometres	EPSA	exploration and production sharing agreement
MW	megawatts		

Suncor converts certain crude oil and NGL volumes to mmcfe or mmcfe/d on the basis of one bbl to six mcf, and certain natural gas volumes to boe, mboe, mmboe or mboe/d on the same basis. Any figure presented in mcfe, mmcfe, mmcfe/d, boe, boe/d, mboe, mmboe or mboe/d may be misleading, particularly if used in isolation. A conversion ratio of one bbl of crude oil or NGL to six mcf of natural gas is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Conversion Table (1)(2)

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

(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.

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 further 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 the issued and outstanding shares on a two-for-one basis.

Pursuant to an arrangement (the Arrangement), which was completed effective August 1, 2009, Suncor amalgamated with Petro-Canada 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 common shares of the continuing Suncor entity for each Petro-Canada common share held and Suncor shareholders received one common share of the continuing Suncor entity for each common share held.

Our registered and head office is located at 150 - 6th Avenue, S.W., Calgary, Alberta, T2P 3E3.

Intercorporate Relationships

Material subsidiaries, each of which was owned 100%, directly or indirectly, by the company as at December 31, 2011 are as follows:

Name	Jurisdiction where organized	Description
Canadian operations		
Suncor Energy Oil Sands Limited Partnership	Canada	This partnership holds most of the company's oil sands assets.
Suncor Energy Ventures Partnership	Canada	This partnership was created in 2011 and holds the company's interest in the Syncrude joint venture.
Suncor Energy Products Partnership	Canada	This partnership holds substantially all of the company's Canadian refining and marketing assets.
Suncor Energy Oil & Gas Partnership	Canada	This partnership holds certain upstream Canadian oil and gas assets.
Suncor Energy Joslyn Partnership	Canada	This partnership holds our working interest in the Joslyn joint venture.
Suncor Energy Products Inc.	Canada	A subsidiary of Suncor Energy Inc. that holds interests in the company's energy marketing and renewable energy businesses, and which is a partner of Suncor Energy Products Partnership.

Name	Jurisdiction where organized	Description
Suncor Energy Marketing Inc.	Canada	A subsidiary of Suncor Energy Products Inc. through which the products produced by our upstream North American businesses are marketed. Through this subsidiary, we also administer Suncor's energy trading activities, market certain third-party products, procure crude oil feedstocks and natural gas for our downstream business, and procure and market NGLs and LPG for our downstream business.

Name	Jurisdiction where organized	Description
U.S. operations		
Petro-Canada U.S. Holdings Ltd.	U.S.	A subsidiary of Suncor Energy Inc. that holds the majority of our U.S. interests.
Suncor Energy (U.S.A.) Inc.	U.S.	A subsidiary of Suncor Energy Inc. through which our U.S. refining and marketing operations are conducted.
International operations		
3908968 Canada Inc.	Canada	A subsidiary of Suncor Energy Inc. that holds certain of our international interests.
Suncor Energy UK Holdings Ltd.	U.K.	A subsidiary of 3908968 Canada Inc. that holds certain of our U.K. interests. Formerly Petro-Canada U.K. Holdings Limited.
Suncor Energy UK Limited	U.K.	A subsidiary of Suncor Energy UK Holdings Ltd. through which certain of our operations are conducted in the U.K. Formerly Petro-Canada U.K. Limited.
Petro-Canada Cooperative Holding U.A.	The Netherlands	A subsidiary of 3908968 Canada Inc. that holds certain of our international interests.
Petro-Canada (International) Holdings B.V.	The Netherlands	A subsidiary of Petro-Canada Cooperative Holding UA that holds certain of our international interests.
Petro-Canada Palmyra B.V.	The Netherlands	A subsidiary of Petro-Canada (International) Holdings BV that holds the majority of our interests in Syria.
Petro-Canada Germany GmbH (1)	Germany	A subsidiary of Petro-Canada (International) Holdings BV that holds the majority of our interests in Libya.
Petro-Canada Oil (North Africa) GmbH (2)	Germany	A subsidiary of Petro-Canada Germany GmbH through which the majority of our Libya operations are conducted.

(1) Subsequent to December 31, 2011, Petro-Canada Germany GmbH changed its name to Suncor Energy Germany GmbH.

(2) Subsequent to December 31, 2011, Petro-Canada Oil (North Africa) GmbH changed its name to Suncor Energy Oil (North Africa) GmbH.

Individually, the company's remaining subsidiaries accounted for (i) less than 10% of the company's consolidated assets as at December 31, 2011, and (ii) less than 10% of the company's consolidated sales and operating revenues for the fiscal year ended December 31, 2011. In 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 market third-party petroleum products. We also carry on energy trading activities focused principally on the marketing and trading of crude oil, natural gas, refined products and byproducts.

Suncor has classified its operations into the following segments:

OIL SANDS

Suncor's Oil Sands segment, with assets located in northeast Alberta, recovers bitumen from mining and in situ operations and upgrades the majority of this production into refinery feedstock, diesel fuel and byproducts. The Oil Sands segment includes:

- **Oil Sands** operations refers to Suncor's wholly owned and operated mining, extraction, upgrading and in situ assets in the Athabasca oil sands region. Oil Sands activities consist of:

  - **Oil Sands Base** operations include the Millennium and Steepbank (including the North Steepbank Extension) mining and extraction operations, two integrated upgrading facilities known as Upgrader 1 and Upgrader 2, and the associated infrastructure for these assets including utilities, energy and reclamation facilities, such as Tailings Reduction Operations (TRO$_{TM}$) assets.

  - **In Situ** operations include oil sands bitumen production from Firebag and MacKay River and supporting infrastructure, such as central processing facilities and cogeneration units. The majority of In Situ production is upgraded by Oil Sands Base; however, the company's marketing plan includes sales of bitumen when marketing conditions are favourable or as operating conditions at Oil Sands Base require.

- **Oil Sands Ventures** includes the company's interests in significant growth projects, including two where Suncor is the operator the Fort Hills mining (40.8%) and the Voyageur upgrader (51%) projects, and one where Total E&P Canada Ltd. (Total E&P) is the operator the Joslyn mining project (36.75%). Oil Sands Ventures also includes the company's 12% interest in the Syncrude oil sands mining and upgrading joint venture.

EXPLORATION AND PRODUCTION

In January 2011, Suncor combined its International and Offshore and Natural Gas segments into the Exploration and Production segment, which consists of offshore operations off the east coast of Canada and in the North Sea, and onshore operations in North America, Libya and Syria.

- **East Coast Canada** operations include Suncor's 37.675% working interest in Terra Nova, for which Suncor is the operator. Suncor also holds a 20% interest in the Hibernia base project and a 19.5% interest in the Hibernia Southern Extension Unit (HSEU), a 27.5% interest in the White Rose base project and a 26.125% interest in the White Rose Extensions, and a 22.729% interest in Hebron, all of which are operated by other companies.

- **International** operations include Suncor's 29.89% working interest in Buzzard and a 26.69% interest in the Golden Eagle Area Development (Golden Eagle) both of which are operated by another company in the U.K. portion of the North Sea. Suncor also holds interests in several North Sea licences offshore the U.K. and Norway. Suncor owns, pursuant to a Production Sharing Contract, an interest in the Ebla gas development in the Ash Shaer and Cherrife areas in Syria. Suncor also owns, pursuant to Exploration and Production Sharing Agreements, working interests in the exploration and development of oilfields in the Sirte Basin in Libya.

Due to recent unrest in both countries, the company has declared force majeure under its contractual obligations in Libya and Syria. Operations in Libya are in the process of restarting, while operations in Syria have been suspended indefinitely.

North America Onshore operations include Suncor's interests in a number of assets in Western Canada, which primarily produce natural gas.

REFINING AND MARKETING

Suncor's Refining and Marketing segment consists of two primary operations:

Refining and Product Supply operations refine crude oil into a broad range of petroleum and petrochemical products. Eastern North America operations include refineries located in Montreal, Quebec and Sarnia, Ontario, and a lubricants business located in Mississauga, Ontario that manufactures, blends and markets products worldwide. Western North America operations include refineries located in Edmonton, Alberta and Commerce City, Colorado. Other assets include interests in a petrochemical plant, pipelines and product terminals in Canada and the U.S.

Downstream **Marketing** operations sell refined petroleum products and lubricants to retail, commercial and industrial customers through a combination of company-owned, branded-dealer and other retail stations in Canada and Colorado, a nationwide commercial road transport network in Canada, and a bulk sales channel in Canada.

CORPORATE, ENERGY TRADING AND ELIMINATIONS

The grouping **Corporate, Energy Trading and Eliminations** includes the company's investments in renewable energy projects, results related to energy supply and trading activities, and other activities not directly attributable to any other operating segment.

Renewable Energy interests include six operating wind power projects and the St. Clair ethanol plant in Ontario.

Energy Trading activities primarily involve the marketing and trading of crude oil, natural gas, refined petroleum products and byproducts and the use of midstream infrastructure and financial derivatives to optimize related trading strategies.

Corporate includes stewardship of Suncor's debt and borrowing costs, expenses not allocated to the company's businesses, and the company's captive insurance activities that self-insure a portion of the company's asset base.

Intersegment revenues and expenses are removed from consolidated results in **Group Eliminations**. Intersegment activity includes the sale of feedstock by the Oil Sands and Exploration and Production segments to the Refining and Marketing segment, the sale of fuels and lubricants by the Refining and Marketing segment to the Oil Sands segment, the sale of ethanol by the Renewable Energy business to the Refining and Marketing segment, and the provision of insurance for a portion of the company's operations by the Corporate captive insurance entity.

Three-Year History

2009

Economic downturn leads to "safe mode" for key growth projects. In the first quarter of 2009, Suncor placed a number of oil sands projects into safe mode as a result of the downturn in the global economy. Safe mode is the deferral of projects and maintenance of equipment and facilities in a safe manner in order to expedite remobilization when appropriate. The placement and maintenance of projects in safe mode resulted in significant operating expenses in 2009 and 2010, and the ensuing changes to project scheduling resulted in increased capital expenditures when projects were eventually remobilized. As a result of the merger and an improvement in the economy, in 2010, Firebag Stage 3, Firebag Stage 4 and the Millennium Naphtha Unit (MNU) projects were all taken out of safe mode. The Voyageur upgrader project began remobilizing in 2011.

Merger with Petro-Canada. On August 1, 2009, Suncor merged with Petro-Canada, adding approximately 375 mboe/d of upstream production at that time, which included the MacKay River in situ bitumen project, a 12% ownership interest in the Syncrude joint venture, interests in all of the major producing fields offshore Newfoundland and Labrador, interests in several offshore fields in the U.K. and the Netherlands portions of the North Sea, including Buzzard, interests in foreign operations pursuant to PSCs in Syria and Libya, and significant natural gas assets in Western Canada and the U.S. Rockies. Growth assets acquired included the Fort Hills oil sands mining project, other extensive oil sands acreage considered prospective for in situ development of bitumen resources, and interests in other North Sea fields that would eventually become known as Golden Eagle. Downstream assets acquired included the Edmonton and Montreal refineries, a lubricants plant, and the Petro-Canada$_{TM}$ branded network of retail service stations and wholesale cardlock sites. In addition, responsibilities for crude marketing and procurement activities related to Petro-Canada assets were assumed by Suncor's existing Energy Trading business.

Steepbank extraction plant completed. To reduce the distance to the mine face, a new bitumen extraction plant on the east side of the Athabasca River was completed, resulting in improved reliability and bitumen recovery.

Fires at Suncor's upgrading facilities. In December 2009, there was a fire at the company's Upgrader 2 facilities, which were repaired and returned to normal operations in February 2010. In February 2010, there was a fire at our Upgrader 1 facilities, which were repaired and returned to full operations by April 2010.

2010

Disposition of non-core assets. Subsequent to the merger, the company undertook a strategic initiative to sell non-core assets. Throughout 2010, the company completed or entered into agreements for the disposition of non-core assets representing approximately 60 mboe/d of production. This included assets in the U.S. Rockies, the Netherlands portion of the

North Sea, Trinidad and Tobago, the Scott, Telford and Guillemot areas in the U.K. portion of the North Sea, and numerous natural gas packages in Western Canada. Some of these disposals closed in 2011. Additional disposals of non-core North America Onshore assets representing approximately 5.9 mboe/d of 2010 production occurred in 2011.

Reclamation of tailings pond. Suncor became the first oil sands company to complete surface reclamation of a tailings pond. The 220-hectare site was the company's first storage pond for oil sands tailings when commercial production began in 1967. Suncor renamed the area Wapisiw Lookout.

Tailings Reduction Operations (TRO$_{TM}$). Suncor received approval from Alberta regulators to convert from the Consolidated Tailings (CT) management process to TRO$_{TM}$, a process in which mature fine tailings are dried, rather than mixed with sand and other materials to form CT. Suncor expects that TRO$_{TM}$ will allow the company to significantly reduce the area required for tailings management, increase the speed at which it is able to reclaim its tailings ponds and meet the requirements of the Tailings Directive approved by Alberta's Energy Resources Conservation Board (ERCB) in 2009.

Production commences in Syria. Suncor achieved commercial production of natural gas from the Ebla project in April. First oil was later achieved from Ebla in December.

First oil from the White Rose Extensions. In the second quarter, first oil was achieved from the North Amethyst portion of the White Rose Extensions.

Terra Nova redetermination. In December, the joint venture owners of the Terra Nova oilfield finalized the redetermination of working interests required under the Terra Nova Development and Operating Agreement following field payout on February 1, 2005. Suncor's working interest increased to 37.675% from 33.990%.

Transformation of downstream Marketing operations. Suncor rebranded 158 Sunoco$_{TM}$ retail sites to consolidate its post-merger Canadian downstream marketing operations under the Petro-Canada$_{TM}$ brand. Suncor divested 104 retail sites in Ontario to comply with Canadian Competition Bureau requirements relating to the merger.

Suncor announced plans to grow production to one million barrels of oil equivalent per day. In December, Suncor announced that it had entered into agreements with Total E&P. Concurrent with this announcement, Suncor introduced its long-term growth strategy to increase production to over one million boe/d by 2020. Key components of the plan included arrangements with Total E&P for the restart of construction of the Voyager upgrader, and the joint development of the Fort Hills and Joslyn mining projects with the respective joint venture owners of these projects. Other key components of the ten-year growth strategy included continued development of the company's Firebag and MacKay River in situ projects, and investments in, and ongoing production from, international and offshore operations.

2011

Exploration and Production segment created. In January, Suncor announced organizational changes that included the International and Offshore and Natural Gas business divisions merging into a single organization primarily focused on conventional production, which includes both onshore and offshore operations.

Ethanol plant expansion completed. In January, Suncor completed the expansion of its ethanol plant in Ontario that doubled production capacity to 400 million litres per year, making it Canada's largest biofuels production facility.

Operations in Libya temporarily suspended. In response to political unrest and sanctions in Libya in the first quarter, the joint venture operator shut in production, while Suncor suspended all exploration activities and declared force majeure under its EPSAs. The uncertainty about the company's future in Libya caused by these events at that time resulted in the company recording an impairment charge against the company's assets. Sanctions in Libya were eventually lifted upon the transition to a new government, and the joint venture operator was able to restart production from all major producing fields by early January 2012.

Transactions with Total E&P close. After receiving the necessary regulatory approvals, Suncor and Total E&P completed their previously announced transactions. In exchange for net proceeds of $1.820 billion (after closing adjustments) and a 36.75% interest in the Joslyn project, Suncor sold to Total E&P a 49% interest in the Voyageur upgrader and a 19.2% interest in the Fort Hills project.

Largest turnaround in Suncor history. During the second quarter, the company completed safely and on time a turnaround at its Upgrader 2 facilities.

New wind farms commissioned. In May, the eight-turbine, 20-MW Kent Breeze wind power project in southwest Ontario commenced operations. In November, Suncor completed construction of, and initiated full production from, the 55-turbine, 88-MW Wintering Hills project in southern Alberta.

First oil at Firebag Stage 3. In July, Suncor achieved first oil from the first of three well pads at the Firebag Stage 3 expansion. With the ramp up of production from the Stage 3 expansion and the addition of infill wells at Firebag, Suncor's In Situ production surpassed 100,000 bbls/d of bitumen for the first time in the fourth quarter.

Development of Golden Eagle approved. In the third quarter, the field development plan for Golden Eagle was approved. The company anticipates first production late in 2014 or early 2015.

North Steepbank Extension. In December, the company started mining ore from the North Steepbank Extension (NSE) at its Oil Sands Base operations. The opening of this new mine extension enables Suncor to access additional oil sands ore, decrease overall haul distances and decrease mine congestion.

Operations in Syria suspended. In December, sanctions were introduced that resulted in Suncor declaring force majeure under its contractual obligations and suspending its operations in Syria. Consequently, the company has ceased recording all production and revenue associated with its Syrian assets.

Systems integration project completed. During the year, the company integrated Exploration and Production and Refining and Marketing assets acquired in the merger onto a common information systems platform. Oil Sands and Corporate assets were integrated during 2010.

2012

Chief Executive Officer Rick George to retire. Suncor's long-standing chief executive officer (CEO) announced his plan to retire after more than 20 years leading the company. Steve Williams, Suncor's chief operating officer (COO), was appointed president and a member of the company's Board of Directors, and will assume the role of CEO upon Mr. George's retirement in May 2012.

NARRATIVE DESCRIPTION OF SUNCOR'S BUSINESSES

Oil Sands

For a discussion of environmental and other regulatory conditions, and competitive conditions and seasonal impacts affecting our Oil Sands segment, refer to the Industry Conditions and Risk Factors sections of this AIF.

Oil Sands Base Operations

Our integrated Oil Sands Base operations, located near Fort McMurray, Alberta, involve numerous activities:

Mining and Extraction

After overburden is removed, open-pit mining operations use shovels to excavate the oil sands bitumen ore, which is trucked to sizers and breaker units that reduce the size of the ore, then create a slurry of hot water, rock, sand and bitumen. The slurry is delivered via a hydrotransport pipeline to extraction plants. The raw bitumen is separated from the slurry using a hot water process that creates a bitumen froth. Naphtha is added to the bitumen froth to form a diluted bitumen, which is subsequently sent to a centrifuge plant that removes most of the remaining impurities and minerals.

Upgrading

After the diluted bitumen is transferred to upgrading facilities, the naphtha is removed and recycled to be used again as diluent. Bitumen is upgraded through a coking and distillation process. The upgraded product, referred to as sour SCO, is either sold directly to customers or upgraded further into sweet SCO by removing sulphur and nitrogen using a hydrotreating process. In addition to sweet and sour SCO, upgrading processes also produce diesel, naphtha, kerosene and gas oil.

Utilities

Process water is used in extraction processes and then recycled. Steam and electricity are generated through facilities on site. Steam required for operations is generated by a cogeneration unit or coke-fired boilers. Electricity is generated by turbine generators, some of which are part of the cogeneration unit. Excess energy produced is sold back to the power grid; however, during peak periods, Suncor purchases additional electricity from the grid.

Maintenance

In the normal course of our operations, we regularly conduct planned maintenance events at our facilities. Large planned maintenance events, which require units to be taken offline to be completed, are often referred to as turnarounds. Turnaround maintenance provides opportunities for both preventive maintenance and capital replacement, which are expected to improve reliability and operational efficiency. Planned maintenance events generally occur on routine cycles, determined by historical operating performance, recommended usage factors or regulatory requirements. A turnaround typically involves shutting down the unit, inspecting it for wear or other damage, repairing or replacing components, and then restarting the unit.

Reclamation

Mining processes disturb areas of land that must be reclaimed. Land reclamation activities involve monitoring soil salvage and replacement, wetlands research, fish, waterfowl and other wildlife protection, and re-vegetation.

The extraction process produces tailings that are a mixture of water, clay, sand and residual bitumen. Suncor has developed a new tailings management approach, known as TRO_{TM}, which involves converting tailings more rapidly into a solid landscape suitable for reclamation. In this process, mature fine tailings are mixed with a polymer flocculent and then deposited in thin layers on shallow slopes. The resulting product is a dry material that is capable of being reclaimed in place or moved to another location for final reclamation. The new process is expected to eliminate the need for new tailings ponds at existing mining operations, improve tailings management going forward and, in the years ahead, reduce the number of tailings ponds presently in operation.

Oil Sands Base Assets

Mining and Extraction

Suncor pioneered the commercial development of the Athabasca oil sands beginning in 1962. The original mining area is essentially depleted, and, for several years, bitumen has been mined almost exclusively from the Millennium area, which began production in 2001. During 2011, the company mined approximately 160 million tonnes from Millennium, and started mining ore from the NSE.

Suncor currently operates two extraction plants, the second of which was brought into service during 2009. The original extraction plant on the west side of the Athabasca River is operated only as required to support reclamation activities. During 2011, Suncor averaged processing 289,000 bbls/d of mined bitumen ore in its extraction facilities.

Upgrading

Suncor's upgrading facilities consist of two upgraders Upgrader 1, which has a primary upgrading capacity of 110,000 bbls/d of SCO, and Upgrader 2, which has a primary upgrading capacity of 240,000 bbls/d of SCO. When the MNU is fully commissioned, Suncor's secondary upgrading facilities will consist of three hydrogen plants, three naphtha hydrotreaters, two gas oil hydrotreaters and two diesel hydrotreaters.

During 2011, Suncor averaged 279,700 bbls/d of upgraded bitumen (SCO) production and an additional 25,000 bbls/d of non-upgraded bitumen production (2010 251,400 bbls/d upgraded, 31,600 bbls/d non-upgraded).

Other Mining Leases

Suncor owns several other oil sands leases, including those known as Voyageur South and Audet, which it believes can be developed using mining techniques and on which it undertakes modest exploratory drilling programs on a year-to-year basis.

In Situ Operations

Suncor's In Situ operations, Firebag and MacKay River, use SAGD technology to separate bitumen from oil sands deposits that are too deep to be mined economically and primarily provide additional bitumen to Oil Sands Base upgrading facilities.

The SAGD process

The SAGD process drills pairs of horizontal wells with one located above the other. To help reduce land disturbance and improve cost efficiency, well pairs are drilled from central multi-well pads. Steam is injected into the upper well to create a high-temperature steam chamber underground. This process reduces the viscosity of the thick bitumen, allowing heated bitumen and condensed steam to drain into the bottom well and flow up to the surface aided by subsurface pumps or circulating gas. Typically, it takes 18 to 24 months for the steam chamber to reach conditions that support peak production levels.

Central processing facilities

The bitumen and water mixture is pumped to separation units at central processing facilities, where the water is removed from the bitumen, treated and recycled for use in steam generation. To facilitate transportation of viscous bitumen, In Situ operations add diluent (naphtha) or use an insulated (referred to as "hot") bitumen pipeline.

Steam generation

Gas vapours recovered at central processing facilities are treated and used as fuel to power Once Through Steam Generators. Cogeneration units are energy efficient systems, which use natural gas combustion to power turbines that generate electricity and steam.

Maintenance and feedstock supply

Central processing facilities, steam generation units and well pads are all subject to routine inspection and maintenance cycles.

SAGD production volumes are impacted by reservoir quality and the capacity of central processing facilities and steam generation units to process liquids and generate steam. As with conventional oil and gas properties, SAGD wells will experience natural production declines after several years. Suncor strives to maintain bitumen supply by drilling new wells from existing well pads or by developing new well pads.

New technologies

Suncor is involved in numerous pilot projects, both operated and non-operated. These pilot projects evaluate potential enhancements to existing SAGD operations or potential new technologies targeted at improving capital efficiency and lowering SORs.

<u>In Situ Assets</u>

Firebag

Initial development of Suncor's Firebag operations included two well pads, each with ten well pairs, and central processing facilities for each of Firebag Stage 1 and Stage 2, with production commencing in 2004 and 2006, respectively. A cogeneration unit was added in 2007. The combined processing capacity of these initial Firebag operations was approximately 95,000 bbls/d of bitumen at design SORs of 2.0 to 2.5; however, actual SORs for Firebag have been higher than the design specifications, largely due to geological heterogeneity (inconsistent quality throughout the reservoir). Prior to first oil from the Stage 3 expansion, production averaged between 50,000 to 60,000 bbls/d for 2010 and 2011. As at December 31, 2011, the cumulative SOR at Firebag was 3.3. As production from the Stage 3 expansion increases, the Firebag SOR is expected to decrease.

During 2011, the company completed its Firebag Stage 3 expansion, which added three well pads, two cogeneration units and a central processing facility. Commissioning of the cogeneration units is expected to be completed in the first quarter of 2012. The Firebag Stage 4 expansion, scheduled for completion during 2013, includes two well pads, an additional central processing facility and two more cogeneration units. The design capacity for both of the Stage 3 and Stage 4 expansions is 62,500 bbls/d of bitumen. Actual production may vary from this capacity based on steaming and ramp-up periods, scheduled and unscheduled maintenance, reservoir conditions and other factors. Suncor designed the Stage 3 and Stage 4 expansions with the goal of integrating the entire Firebag operation. Steam and electricity generated at one facility or unit can be used at any well pad. Central processing facilities have been designed to be flexible as to which well pads supply bitumen.

Suncor has received regulatory approval for further expansion of Firebag beyond Stage 4 for an aggregate of 368,000 bbls/d of bitumen.

During 2011, Firebag operations averaged production of 59,500 bbls/d of bitumen (2010 53,600 bbls/d), approximately 90% of which was upgraded by Oil Sands Base operations.

MacKay River

Production from MacKay River commenced in 2002 from two well pads with 25 well pairs, and subsequent expansion phases added four more well pads with 31 producing well pairs. Starting in June 2011, a new phase of 22 well pairs was initiated, with production coming on-stream in the fourth quarter of 2011 and continuing to build throughout 2012. Central processing facilities have a nameplate capacity of approximately 30,000 bbls/d of bitumen. A third party owns and operates the on-site cogeneration unit in return for a fee and natural gas fuel being purchased by Suncor. As at December 31, 2011, the cumulative SOR at MacKay River was 2.5.

Suncor has regulatory approval for 73,000 bbls/d of bitumen production from MacKay River and is currently evaluating an expansion to add a second central processing facility. Suncor has approval to include its Dover properties in the MacKay River project area, and has submitted an application to develop a portion of these lands.

During 2011, MacKay River operations averaged production of 30,000 bbls/d of bitumen (2010 31,500 bbls/d), approximately 30% of which was upgraded by Oil Sands Base operations.

Other In Situ Leases

Suncor owns several other oil sands leases, including those known as Meadow Creek, Lewis, Chard and Kirby, which it believes can be developed using in situ techniques, and on which it may undertake modest exploratory drilling programs on a year-to-year basis.

Oil Sands Ventures Assets and Operations

Syncrude

Suncor holds a 12% interest in the Syncrude joint venture, also located near Fort McMurray, which includes operations at the Mildred Lake North and Aurora North oil sands mines. Syncrude also has regulatory approval to develop the Aurora South oil sands mining leases.

Syncrude began producing in 1978 and is operated by Syncrude Canada Ltd. (SCL). In 2006, SCL entered into a comprehensive management services agreement with Imperial Oil Resources (Imperial Oil) to provide operational, technical and business management services. This agreement has an initial term of ten years and includes renewal provisions.

Syncrude mining operations use truck, shovel and hydrotransport systems, similar to those at Oil Sands Base. Extraction and upgrading technologies at Syncrude are also similar to those used at Oil Sands Base, except that Syncrude uses a fluid coking process that involves the continuous thermal cracking of the heaviest hydrocarbons, as opposed to a delayed coking process. At Mildred Lake, electricity is provided by a utility plant fuelled by off-gas from upgrading operations and natural gas. At Aurora North, Syncrude operates two 80-MW gas turbine power plants. The gross design capacity for Syncrude facilities is approximately 375,000 bbls/d, but when allowances are made for scheduled and unscheduled downtime the gross productive capacity of the facilities is approximately 350,000 bbls/d.

Syncrude primarily produces a single sweet synthetic light crude product. Marketing of this product is the responsibility of the individual joint venture owners.

Land reclamation activities are similar to those at Oil Sands Base; however, tailings management processes are different. Syncrude's ERCB-approved tailings plan uses the following: freshwater capping, a composite tails mixture of fine tails and gypsum, and plans for centrifuge technology that separates water from tailings.

In 2011, Suncor's share of Syncrude production averaged 34,600 bbls/d (2010 35,200 bbls/d).

Voyageur Upgrader, Fort Hills and Joslyn

Oil Sands Ventures also includes assets important to Suncor's long-term growth strategy. During the first quarter of 2011, Suncor completed transactions with Total E&P, which brought Total E&P into the Voyageur upgrader project, increased their working interest in the Fort Hills oil sands mining project and brought Suncor into the Joslyn oil sands mining project.

Fort Hills is the oil sands mining project comprising leases on the east side of the Athabasca River, north of Oil Sands Base operations. Preliminary designs for Fort Hills plan for 164,000 bbls/d of bitumen production (gross). Suncor originally acquired a 60% working interest in Fort Hills as a result of the merger, and then agreed to a partial disposition of 19.2% as part of transactions with Total E&P. Suncor now holds a 40.8% working interest in the Fort Hills project. Suncor Energy Operating Inc., a wholly owned subsidiary of Suncor, is the contract operator for the Fort Hills project. Prior to the merger, the joint venture owners of Fort Hills had completed design basis memorandum engineering in 2008, but deferred a final investment decision as a result of the economic downturn. Subsequent to completing the transactions with Total E&P, the Fort Hills project has restarted design basis memorandum engineering. Total E&P holds a 39.2% working interest in the Fort Hills project and Teck Resources Limited holds the remaining 20%.

Joslyn is the oil sands mining project comprising leases southwest of the Fort Hills project and on the west side of the Athabasca River. Preliminary designs for the Joslyn North mine project plan for 100,000 bbls/d of bitumen production (gross). Suncor acquired a 36.75% working interest in this asset as a result of transactions with Total E&P. Under this joint venture agreement, Total E&P is scheduled to act as operator, holding a 38.25% interest, while Occidental Oil and Gas Corporation (15%) and Inpex Canada Ltd. (10%) hold the remaining interests.

Suncor anticipates that the majority of bitumen production from the Fort Hills and Joslyn projects will be upgraded into SCO and other products by the Voyageur upgrader. Suncor began design work for the Voyageur upgrader in 2004. The original Voyageur program received approval from the Board of Directors in January 2008. The Voyageur upgrader project was placed into safe mode in January 2009 as a result of the economic downturn, at which time construction was approximately 15% complete. Subsequent to the transactions with Total E&P in December 2010, the Voyageur upgrader project team has engaged in activities such as remobilizing personnel and assessing the condition of assets. Preliminary design plans are for 200,000 bbls/d (gross) of upgrading capacity.

The development of each of these projects is still subject to approval by Suncor's Board of Directors and the joint venture owners for each respective project.

Sales of Principal Products

Primary markets for SCO and bitumen production from Suncor's Oil Sands segment, which is sold to and subsequently marketed by Suncor's Energy Trading business, include refining operations in Alberta, Ontario, the U.S. Midwest and the U.S. Rocky Mountain regions. Diesel production from upgrading operations is sold primarily in Western Canada, marketed by Suncor's Refining and Marketing business.

For bitumen production from In Situ operations, Suncor's marketing strategy allows it to take advantage of changes in market conditions by either: a) upgrading the bitumen directly at our Oil Sands Base facilities; b) upgrading the bitumen at Suncor's refineries; or c) selling diluted bitumen directly to third parties. Direct bitumen sales may also be required during outages of upgrading facilities or interruptions in pipeline systems. During 2011, 73% (2010 63%) of In Situ bitumen production was processed by Oil Sands Base upgrading facilities.

In 2011, sales of light sweet SCO and diesel represented 44% and sales of light sour SCO and bitumen represented 45% of total Oil Sands segment operating revenues. There were no individual customers that represented 10% or more of Suncor's consolidated revenues in 2011 or 2010.

Operating revenues include sales of non-proprietary volumes purchased from third parties. These volumes are typically transacted when Oil Sands Base or third-party refinery capacities are constrained, in conjunction with a corresponding sales agreement, which allow Suncor and the third party to optimize their logistics. These volumes may also include purchases of third-party diluent to support sales of bitumen, required when the company is unable to meet diluent demands internally.

Information on average daily sales volumes and the corresponding percentage of Oil Sands segment operating revenues by product for each of the last two years are as follows:

Sales Volumes and Operating Revenues Principal Products	2011		2010	
	mbbls/d	% operating revenues	mbbls/d	% operating revenues
Light sweet SCO and diesel (including Syncrude)	144.4	44	137.9	43
Light sour SCO and bitumen	194.6	45	176.6	46
Non-proprietary, byproducts and other operating revenues	n/a	11	n/a	11
	339.0		314.5	

In the normal course of business, Suncor enters into long-term strategic supply agreements for its proprietary sour SCO, which contain varying terms with respect to pricing, volume, expiry and terminations.

Distribution of Products

Production from Oil Sands Base operations is gathered from our Fort McMurray facilities at the Athabasca Terminal, which is operated by Enbridge Inc. (Enbridge). Suncor has various arrangements with Enbridge at this facility to store SCO, diluted bitumen and diesel. Production from Firebag is transported to the Athabasca Terminal via a pipeline that is operated by Suncor, while production from MacKay River is transported to the Athabasca Terminal via an insulated pipeline.

Product moves from the Athabasca Terminal in the following ways:

SCO is sent to Edmonton via the Oil Sands pipeline, which is owned by Suncor and operated by the Refining and Marketing segment. At Edmonton, the product is sold to local refiners or transferred onto the Enbridge Mainline system.

- SCO and diluted bitumen is transported to Hardisty, Alberta via Cheecham, Alberta on the Enbridge Athabasca Pipeline.
- SCO also reaches Edmonton via the Waupisoo pipeline, which is owned and operated by Enbridge. This pipeline begins from the Enbridge Athabasca Pipeline at Cheecham.

From Hardisty, where Suncor has storage capacity under contract, Suncor has various options for delivering product to customers:

- SCO reaches Suncor's Commerce City refinery via the Express and Platte pipelines. Suncor owns and operates a pipeline that is connected to the Commerce City refinery, which originates from the Guernsey, Wyoming station that is part of the Platte pipeline.
- SCO reaches Suncor's Sarnia refinery on the Enbridge Mainline and Lakehead systems.

From Hardisty, which is also connected to the Enbridge Mainline pipeline from Edmonton, crude can reach most major refining hubs via the Enbridge Mainline, Express/Platte and Keystone pipeline systems.

Natural gas is used in the production of SCO, particularly in our SAGD operations. Natural gas is delivered to Oil Sands Base and In Situ facilities via the Nova Gas Transmission Limited (NGTL) regulated pipeline system. Suncor also transports natural gas to our Oil Sands Base facilities on the company-owned and operated Albersun Pipeline, which has a capacity of 46 mmcf/d and extends approximately 300 km south of the Oil Sands Base facilities and is connected to the NGTL.

Oil Sands Base facilities are readily accessible by public road. MacKay River facilities are accessible by a combination of public and private roads. Firebag facilities are currently accessible by air and private road. In 2010, the East Athabasca Highway was constructed to provide access to the Firebag site. This highway is owned by Suncor, Husky Energy Inc. and Imperial Oil Ltd., and was constructed to provide each company with access to its oil sands operations in the area.

Royalty Agreements

New oil sands projects are subject to the New Royalty Framework issued by the Government of Alberta, and regulated by the *Oil Sands Royalty Regulation 2009* (OSRR 2009), and supporting regulations, which were approved on December 10, 2008.

In 2011, Oil Sands royalties (excluding Syncrude) were approximately 7% (2010 7%) of Oil Sands operating revenues before royalties, and excluding non-proprietary sales and sales of byproducts. In 2011, Suncor incurred royalties on Syncrude operations averaging approximately 8% of Syncrude gross revenue (2010 9%).

Oil Sands Base and Syncrude

As part of the New Royalty Framework, Suncor negotiated and entered into the Suncor Royalty Amending Agreement (Suncor RAA) with the Government of Alberta in January 2008 for royalties pertaining to its Oil Sands Base operations. Prior to the New Royalty Framework, Suncor exercised its option to transition to a bitumen-based royalty from an SCO-based royalty, which became effective January 1, 2009. Royalty rates for 2009 remained at 25% of net revenue. For the period from January 1, 2010 to December 31, 2015, royalty rates are based on a sliding scale (depending on the Canadian dollar equivalent for WTI) from 25% to 30% of R-C (Revenue-Cost), where R is gross revenues, net of bitumen quality adjustments and transportation costs, and C is allowable costs including allowable capital expenditures, which excludes substantially all operating and capital expenditures associated with upgrading facilities. The minimum royalty rate is 1.0% to 1.2% of R. In 2011 and 2010, Suncor incurred royalties on Oil Sands Base mining operations at a rate of 30% of R-C because of high prices for WTI.

In November 2008, the Alberta government and the joint owners of the Syncrude joint venture reached an agreement for the implementation of the New Royalty Framework for the Syncrude project (similar to the Suncor RAA). Under the new terms, Syncrude would continue paying the greater of 1% gross revenue, or 25% of net revenue, until the end of 2015. For 2011, the royalty rate was 25% of net revenue. As part of its agreement, Syncrude also exercised its option to transition to a bitumen-based royalty from an SCO-based royalty. As such, the upgrader facility at the Syncrude project is no longer considered a part of the royalty project. The Syncrude joint venture owners agreed to pay an additional royalty of $975 million over a six-year period starting in 2010, which is contingent on achieving certain production levels.

As part of the implementation of the New Royalty Framework, the Alberta government enacted new Bitumen Valuation Methodology (BVM) regulations effective January 1, 2009. These interim BVM regulations determine the valuation of bitumen for 2009 to 2011. Final regulations to establish the BVM calculation for future years are still to be developed by the Crown. For the year 2009, Suncor filed a non-compliance notice with the Crown, citing that reasonable adjustments were not considered by the Crown in the determination of bitumen value as permitted by the Suncor RAA. In December 2010, the Minister of Energy notified Suncor of a modification to the Suncor BVM, permitting adjustments for bitumen quality and transportation. Suncor filed its second non-compliance notice with the Crown, for the years 2009 and 2010, related to the quality adjustment made by the Minister, which Suncor believes is not reasonable. Pursuant to the OSRR 2009, Suncor provided replacement royalty reports for 2009 and 2010 and remitted, under protest, the balance of royalty payable at the end of January 2011. For 2011, Suncor continued to remit royalty payments based on its view of reasonable quality adjustments; however, royalty expense was calculated based on the Minister's quality adjustment. The Suncor RAA provides for an arbitration procedure failing settlement of these issues. Suncor filed a Notice of Commencement of Arbitration with the Crown on January 29, 2011.

The joint venture owners of Syncrude have 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 the Suncor RAA.

Beginning on January 1, 2016, Suncor's Oil Sands Base and Syncrude operations will be subject to the generic royalty regime under OSRR 2009 that is currently in place for all other oil sands royalty projects in Alberta, including Suncor's In Situ operations, as described below.

In Situ

Under the New Royalty Framework, royalties on Suncor's Firebag and MacKay River projects are based on a sliding-scale rate of 25% to 40% of R-C, subject to a minimum royalty of 1% to 9% of R, depending on oil prices for WTI from Cdn$55/bbl to the maximum rate at a WTI price of Cdn$120/bbl. A project remains subject to the minimum royalty (the pre-payout phase) until the project's cumulative gross revenue exceeds its cumulative costs, including an annual investment allowance (the post-payout phase). In 2011, Suncor incurred royalties at a rate of 34% of R-C for MacKay River, which reached the post-payout phase in November 2010, and royalties averaging 6% of R for Firebag, which continues in the pre-payout phase.

Exploration and Production

For a discussion of the environmental and other regulatory conditions, competitive conditions, foreign operations and seasonal impacts affecting our Exploration and Production segment, refer to the Industry Conditions and Risk Factors sections of this AIF.

East Coast Canada Assets and Operations

Based in St. John's, Newfoundland and Labrador, this business focuses on high-volume production from three existing fields, interests in future developments and expansions, and exploration drilling for new opportunities. Suncor holds a unique position as the only company with interests in all current producing fields.

Terra Nova

The Terra Nova oilfield is approximately 350 km southeast of St. John's, Newfoundland. Terra Nova was discovered by Petro-Canada in 1984, and was the second oilfield to be developed offshore Newfoundland and Labrador. Operated by Suncor, the production system uses a Floating Production, Storage and Offloading (FPSO) vessel that is moored on location, and has gross production capacity of 180,000 bbls/d and oil storage capacity of 960,000 bbls. Terra Nova was the first harsh environment development in North America to use a FPSO vessel. Actual production levels are lower than production capacity, reflecting current reservoir capability. Production from Terra Nova began in January 2002. At December 31, 2011, there were 28 wells in operation: 16 oil wells, nine water injection wells and three gas injection wells. Two of the oil wells have been shut in due to hydrogen sulphide (H_2S) flow line restrictions. In 2011, Suncor's share of Terra Nova production averaged 16,200 bbls/d (2010 23,200 bbls/d).

H_2S was detected in several oil wells in the fourth quarter of 2010. Wells and facilities directly and indirectly impacted by H_2S have been shut in while the company implements its mitigation plan to safely address the situation. In the fourth quarter of 2011, the company replaced a flow line that has remediated some of the H_2S issues. Remaining H_2S remediation is anticipated to be completed as part of the dockside maintenance program scheduled to commence in the third quarter of 2012. The dockside maintenance program also includes replacement of the FPSO swivel.

In December 2010, the joint venture owners of the Terra Nova oilfield finalized the redetermination of working interests required under the Terra Nova Development and Operating Agreement following field payout on February 1, 2005. As a result, Suncor's working interest increased to 37.675% from 33.990% effective January 1, 2011.

Field production is transported by shuttle tanker from the FPSO and either delivered directly to customers (if tanker schedules permit) or to the Newfoundland transshipment terminal in Placentia Bay, where it is subsequently loaded onto tankers for transport to markets in Eastern Canada or the U.S. Suncor has a 14% ownership interest in the transshipment facility and is part of a group of companies that share the operation of marine transportation assets for East Coast Canada.

Hibernia and the Hibernia Southern Extension Unit (HSEU)

The Hibernia oilfield, encompassing the Hibernia and Ben Nevis Avalon reservoirs, is approximately 315 km southeast of St. John's and was the first field to be developed in the Jeanne d'Arc Basin. Operated by Hibernia Management and Development Company Ltd., the production system is a fixed gravity base structure (GBS) that sits on the ocean floor, and has gross production capacity of 230,000 bbls/d and oil storage capacity of 1.3 mmbbls. Actual production levels are lower, reflecting current reservoir capability and natural declines. Hibernia commenced production in November 1997. At December 31, 2011, there were 64 wells in operation: 35 oil wells, 23 water injection wells and six gas injection. In 2011, Suncor's share of Hibernia production averaged 30,900 bbls/d (2010 30,900 bbls/d). Hibernia uses the same transshipment terminal and system of shuttle tankers that are used for Terra Nova.

Final fiscal agreements were signed between the Hibernia joint venture owners and the Government of Newfoundland and Labrador in 2010 that established the fiscal, equity and operational principles for the development of the HSEU. During 2011, the first two development wells were completed and are producing oil. Current development plans include drilling up to two additional producing wells and five water injection wells in a subsea, excavated drill centre, known as a glory hole. The number of producing and injection wells required may be revised as the development proceeds and uncertainties about reservoir capability are resolved.

White Rose and the White Rose Extensions

White Rose, the third oilfield development offshore Newfoundland, is about 350 km southeast of St. John's. Operated by Husky Oil Operations Limited, White Rose uses a FPSO vessel and has gross production capacity of 140,000 bbls/d and oil storage capacity of 940,000 bbls. Production from White Rose began in November 2005. At December 31, 2011, there were 25 wells in operation: twelve oil wells and 13 water injection wells. In 2011, Suncor's share of White Rose production averaged 18,500 bbls/d (2010 14,500 bbls/d). White Rose uses the same transshipment terminal and the same system of shuttle tankers that are used for Hibernia and Terra Nova.

In 2007, the White Rose joint venture owners signed a formal agreement with the Province of Newfoundland and Labrador for the development of the White Rose Extensions, which include the South White Rose Extension, North Amethyst and West White Rose satellite fields. In May 2010, first oil was achieved in North Amethyst, and development drilling is ongoing. Development of the West White Rose Extension will be divided into two stages. The first stage was approved in 2009 and first oil was achieved during the third quarter of 2011 with the completion of the first production well. A water injection well to support this initial production is expected to be completed in the second quarter of 2012. Results of the first stage, combined with other ongoing evaluation, will help define the scope of the second stage.

An extended, 18-week off-station maintenance program is scheduled to commence in the second quarter of 2012 for the White Rose FPSO, primarily to address issues with the FPSO propulsion system.

Hebron

Discovered in 1980, the Hebron oilfield is located 340 km southeast of St. John's. In 2008, the Hebron joint venture owners reached an agreement with the Government of Newfoundland and Labrador on commercial terms allowing development activities to proceed. The project is operated by ExxonMobil Canada Properties.

Development of the Hebron project anticipates the construction of a concrete GBS that supports an integrated topsides deck to be used for production, drilling and accommodations. Development plans include 1.2 mmbbls of oil storage capacity and 52 well slots with a gross oil production capacity of 150,000 bbls/d.

The contract for the front-end engineering and design of topsides, procurement and construction was awarded in September 2010. Initial construction on the GBS began in September 2011 in Newfoundland and Labrador. The decision from the joint venture owners of Hebron to sanction the development of Hebron is anticipated in late 2012, with initial production anticipated in late 2017.

Other Assets

The Ballicatters discovery well, located 22 km northeast of Hibernia, was completed earlier in 2011 and is comprised of gas and oil. Suncor and its partner are currently evaluating potential options to commercialize the discovery.

Suncor continues to pursue opportunities offshore Newfoundland and Labrador. The company holds interests in 48 other significant discovery licences and six other exploration licences offshore Newfoundland and Labrador.

International Assets and Operations

Buzzard North Sea

The Buzzard oilfield is located in the Outer Moray Firth, 95 km northeast of Aberdeen, Scotland. Operated by Nexen Petroleum U.K. Limited, the Buzzard facilities have gross installed production capacity of approximately 220,000 bbls/d of oil and 80 mmcf/d of natural gas. Oil production rates at Buzzard are currently limited to a maximum of approximately 215,000 bbls/d due to restrictions on third-party pipeline systems. Work is ongoing with the pipeline operator to increase the maximum production rate closer to the gross oil production capacity. Buzzard commenced production in January 2007. Buzzard consists of four bridge-linked platforms supporting wellhead facilities, production facilities, living quarters and utilities, and sulphur handling. In 2011, commissioning was completed for the fourth platform, which was installed to remove H_2S from oil production from some segments of the field. At December 31, 2011, there were 40 wells in operation: 29 oil and gas wells and 11 water injection wells. In 2011, Suncor's share of Buzzard production averaged 42,900 boe/d (2010 55,500 boe/d).

Crude oil is transported via the third-party operated Forties Pipeline System to the Kinneil terminal in Scotland. Natural gas is transported via the third-party operated Frigg pipeline to the St. Fergus gas terminal in Scotland.

Golden Eagle North Sea

During 2011, the Golden Eagle Area Development received regulatory approval from the U.K. Department of Energy and Climate Change. This development is approximately 70 km from the Aberdeen shore and consists of the unitization of the Pink, Hobby and Golden Eagle discoveries completed from 2007 to 2009. The development plan incorporates a combined production, utilities and accommodation platform, linked to a separate wellhead platform, with an initial gross production rate of 70,000 boe/d (gross) from 20 development wells. The operator, Nexen Petroleum U.K. Limited, estimates that the gross development cost will be £2 billion (Cdn$3.3 billion). First production is expected late in 2014 or early 2015. The joint venture owners of Golden Eagle also hold adjacent exploration licences and continue to explore the region.

Beta North Sea

In the Norway portion of the North Sea, Suncor is the operator of the Beta discovery. Suncor has a 65% working interest in this field, which is currently under evaluation. The company completed the first exploration well in early 2010, encountering hydrocarbons. An appraisal well was drilled and tested later in 2010 with positive results. Suncor has secured a rig to drill a third appraisal well, which is scheduled to commence in the second quarter of 2012.

Other Assets North Sea

During 2011, the operator for the PL405 licence (in the Norway portion of the North Sea) in which Suncor has a 30% interest, drilled an exploration well resulting in a discovery, referred to as the Butch prospect. A sidetrack well subsequently drilled at this prospect was abandoned early in 2012, due to well instability, before reaching its intended depth. In the U.K. portion of the North Sea, Suncor, as operator, has secured a rig and expects to drill a joint exploration well for the Romeo joint venture prospect (Block 30/11c). The joint well is to be drilled to comply with work commitments for two adjacent licences, one held by Suncor and its co-venturers, and the other by Total E&P U.K. Limited.

In late 2010 and early 2011, the company disposed of non-core assets in the U.K portion of the North Sea, including its working interests in production from the Guillemot and Scott/Telford areas. Also, in August 2010, the company disposed of non-core assets in the Netherlands portion of the North Sea.

Syria

Located in the Central Syrian Gas Basin, the Ebla project includes all hydrocarbons in the Ash Shaer and Cherrife development areas, which cover more than 300,000 acres. Suncor conducts its Syrian operations pursuant to a PSC, under which the company is a joint owner of the Ebla project with the General Petroleum Corporation (GPC). Under the PSC, the company pays 100% of the development costs and recovers these costs from a 40% share of production after deduction for royalties of 12.5%. This petroleum revenue is referred to as Cost Recovery petroleum. The amount by which Cost Recovery petroleum exceeds recoverable cost is referred to as Excess Cost Recovery petroleum; 50% of this amount is due to the GPC and the remaining 50% is shared between Suncor and the GPC according to a profit-sharing schedule. The Ebla PSC expires in April 2035, but includes a five-year extension subject to GPC approval. First commercial gas production from Ebla was achieved in April 2010 and first oil was achieved in December 2010. In 2011, Suncor's share of production in Syria averaged 17,600 boe/d (2010 11,600 boe/d).

The Ebla development comprises six natural gas producing wells in the Ash Shaer field, a gas gathering and compression station, approximately 80 km of pipeline, and a gas treatment plant. The facility is designed to produce 97 mmcf/d of natural gas, along with related LPG and condensate volumes. Natural gas is delivered into the Syrian national gas grid for domestic consumption. The Ebla development also includes three wells producing crude oil, which is sold to the GPC.

In December 2011, amid continuing unrest in Syria, sanctions were introduced and Suncor declared force majeure under its contractual obligations and suspended its operations in the country. Suncor withdrew its expatriate staff and undertook measures to maintain support for its Syrian employees. Consequently, the company has ceased recording all production and revenue associated with its Syrian assets.

Libya

In Libya, Suncor acts pursuant to several EPSAs that enable Suncor and the Libya National Oil Corporation (NOC) to jointly design and implement the redevelopment of existing fields in the Sirte Basin. Existing reserves are associated with five separate agreements (EPSAs I through V), which contain five primary production fields. Under the EPSAs, the company pays 100% of the exploration costs, 50% of the development and 12% of the operating costs, and recovers these costs from a 12% share of production, also referred to as Cost Recovery. Any petroleum remaining after Cost Recovery is referred to as Excess Petroleum, and is shared between Suncor and the NOC based on a profit-sharing schedule affected by several factors, with Suncor's share of profit ranging from 4% to 12%. The EPSAs expire on December 31, 2032, but include an initial five-year extension through the end of 2037. In 2011, Suncor's share of production in Libya averaged 12,100 bbls/d (2010 35,200 bbls/d). Libya is a member of the Organization of Petroleum Exporting Countries (OPEC) and is subject to quotas that can affect the company's production in Libya.

For most of the period from March to September 2011, the operator for the joint venture, Harouge Oil Operations BV (Harouge) shut in production as a result of political unrest that began earlier in the year. Sanctions prohibiting the purchase of oil from Libya, among other things, were also introduced by many governments. In March 2011, Suncor declared force majeure under its EPSAs. Beginning late in the third quarter of 2011, a new governing authority was formed in Libya and sanctions were lifted. By January 2012, Harouge had successfully restarted production from all major producing fields and work continues to stabilize production levels. Net production exiting December 2011 was approximately 30,000 bbls/d. Suncor remains optimistic about a gradual return to full operations in Libya and is working to remove its ESPAs from force majeure, where possible.

As a result of the merger, the company assumed the remaining US$500 million obligation for a signature bonus relating to Petro-Canada's ratification of the EPSAs in 2008. As at December 31, 2011, the undiscounted value of Suncor's remaining obligation is US$347 million, payable in several instalments through 2013. In addition, as part of its contractual obligations under the EPSAs, Suncor is the exploration operator and has committed to fully fund an exploration program, at an estimated remaining cost of US$360 million. As at December 31, 2011, Suncor is still under condition of force majeure with respect to its EPSAs and has re-engaged Harouge to discuss current operations and future plans, including contractual obligations.

North America Onshore Assets and Operations

The North America Onshore business includes the assets and operations previously reported under Suncor's Natural Gas segment, which is now part of the Exploration and Production segment. This business explores for, develops and produces natural gas, NGLs, crude oil and byproducts in Western Canada. After the merger with Petro-Canada, this business implemented a strategy with greater emphasis on liquids-rich and unconventional sources, and, as a result, disposed of a number of non-core assets throughout 2010 and 2011.

Given the vast amount of natural gas brought on-stream in North America by recent advances in shale gas technology, coupled with the economic downturn in 2008 and 2009, natural gas producers in North America continue to face relatively low gas prices. In light of this environment, Suncor has implemented a strategy to make its operations in this region more profitable. One component of that strategy involved selling assets that were no longer deemed core to Suncor's business strategy. As market conditions for such divestitures worsened, Suncor has started to focus more on another component of its strategy becoming more profitable in this region, primarily by increasing activity in tight oil projects. The company is also assessing and pursuing activities to grow the unconventional side of its North America Onshore operations.

In 2011, Suncor's share of production from its North America Onshore properties was 388 mmcfe/d (2010 575 mmcfe/d) with approximately 21 mmcfe/d of production in 2011 coming from assets that were disposed throughout the year (2010 143 mmcfe/d). Natural gas represented 92% of production in 2011 (2010 91%), with crude oil and NGL production representing the remainder. North America Onshore also sells sulphur, a byproduct of processing operations.

Operations are primarily focused on multiple geological zones throughout Western Canada. The business is structured with the following asset areas:

Zone / Area	Primary Focus	2011 mmcfe/d
Northeast B.C.	Montney, Triassic and Slave Point	113
Southeast Alberta	Sweet, dry gas	70
Foothills western Alberta, portions of northeast B.C.	Mississippian sour gas	161
Plains western Alberta	Cardium oil, Cretaceous gas	44
		388

In addition, Suncor holds assets that could allow the company to eventually explore long-term supply opportunities in northern frontier areas.

Natural gas extracted from the wellhead requires further processing. In Western Canada, Suncor operates several natural gas processing plants, with total licensed capacity of 772 mmcf/d, of which the company's share is 470 mmcf/d. Capacity not utilized by the company's own production is optimized through processing agreements with third-party producers. 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 91.5 mmcf/d of licensed capacity. The following table shows Suncor's working interest ownership and the licensed capacity of operated processing plants as at December 31, 2011.

Suncor Operated Natural Gas Processing Plants	Zone / Area	Working Interest Ownership %	Gross Licensed Capacity mmcf/d	Net Licensed Capacity mmcf/d
Hanlan Sour	Foothills	49.86	382.0	190.5
Hanlan Sweet	Foothills	40.73	44.2	18.0
Ferrier	Plains	100.00	120.0	120.0
Gilby East	Plains	100.00	52.4	52.4

Wilson Creek	Plains	52.17	34.6	18.1
Progress	Northeast B.C.	38.01	42.6	16.2
Boundary Lake Sour	Northeast B.C.	50.00	46.0	23.0
Boundary Lake Sweet	Northeast B.C.	100.00	20.0	20.0
Parkland 1	Northeast B.C.	43.98	18.1	8.0
Parkland 2	Northeast B.C.	34.75	11.7	4.1
Total			771.6	470.3

Natural gas production from Alberta is typically sold at the Nova Inventory Transfer point (NIT), which is one of the largest natural gas trading hubs in North America. Natural gas at NIT generally receives a daily or monthly average AECO (Alberta) spot price. Natural gas production from B.C. is typically sold at Station 2, part of the Spectra B.C. transmission system, and receives the Station 2 Gas Daily Index price, but can also be moved on the Alliance Pipeline system to its terminus in Illinois. To provide diversity in access to markets, Suncor holds firm capacity on the Alliance Pipeline system and the TransCanada PipeLines Gas Transmission Northwest Pipeline (GTN). The GTN firm capacity enables Suncor to deliver natural gas to the Pacific Northwest and California markets.

Conventional crude oil production from North America Onshore assets is shipped on pipelines operated by independent pipeline companies. We currently have no pipeline commitments related to the shipment of conventional crude oil. In most sale arrangements, Suncor is responsible for transportation to the point of sale.

Sales of Principal Products

Oil and gas production from East Coast Canada and the North Sea, and substantially all production from North America Onshore, are sold to our Energy Trading business, which then markets the products to customers under direct sale arrangements. Suncor does not typically enter into long-term supply arrangements to sell its production from its Exploration and Production segment. Contracts for these direct sales arrangements are of varied terms, with a majority having terms of one year or less, and incorporate pricing that is generally determined on a daily or monthly basis in relation to a specified market reference price.

In Syria, the company entered into purchase and sale agreements with the Syrian government for all hydrocarbon production from the Ebla project. In Libya, hydrocarbon production is marketed by the Libyan government on behalf of Suncor.

For each of Exploration and Production's operations, and for Exploration and Production in total, the following table provides information on average sales volumes for principal products and the corresponding percentage of operating revenues for 2011 and 2010:

Sales Volumes	2011		2010	
	mboe/d	% operating revenues	mboe/d	% operating revenues
East Coast Canada [1]				
Crude oil	52.3	42	54.2	29
International				
Crude oil and NGLs	62.4	34	111.1	46
Natural gas	14.0	4	21.5	4
North America Onshore				
Crude oil and NGLs	5.1	3	8.8	4
Natural gas	59.6	8	87.0	13
Total Exploration and Production				
Crude oil and NGLs	119.8	79	174.2	79
Natural gas	73.6	12	108.5	17

(1) Operating revenues for East Coast Canada include crude oil marketed on behalf of our partner in White Rose.

Royalty Agreements

East Coast Canada

The Terra Nova royalty consists of a sliding-scale, basic royalty payable throughout the project's life, with two tiers of incremental royalties, which became payable upon the achievement of specified levels of profitability that included an additional return allowance. The basic royalty is now capped at 10% of gross field revenue, based on the project reaching a specified cumulative production level. The tier one royalty is the greater of the basic royalty or 30% of net revenue, and became payable in 2005. Net revenue is gross revenue adjusted for eligible operating and capital costs. The tier two royalty, equal to 12.5% of net revenue, became payable in 2008. During 2011, Terra Nova royalty expense averaged

32% of gross revenue (2010   35%).

The Hibernia royalty agreement for production from the original oilfields and the AA Block consists of a sliding-scale gross royalty, two tiers of incremental royalty, and an additional net profits interest (NPI). The basic royalty is now capped at 5% of gross revenue, as the project has reached a specified cumulative production level. The tier one royalty, which became payable in 2009, is the greater of the gross royalty or 30% of net revenue. The tier two royalty is 12.5% of net revenue, but has not yet been triggered. Production from the AA Block, which commenced in late 2009, attracts an additional super royalty of 12.5% of net revenue. The NPI, which also became payable in 2009, is an additional 10% of net revenue.

Limited production from the HSEU began in 2011. The HSEU has a similar royalty structure (gross, tier one and tier two) to that described above for Hibernia. Currently, Suncor is only subject to a 5% gross royalty. HSEU production will be subject to an additional super royalty that ranges between 2.5% and 7.5% of net revenue, depending on the price for WTI. The HSEU super royalty will coincide with the triggering of the tier one net royalty. During 2011, Hibernia (including the HSEU) royalty expense and net profits interest combined to average 37% of gross revenue (2010 38%).

The White Rose royalty for the base project consists of a sliding-scale basic royalty payable throughout the project's life, with two tiers of incremental royalties, which became payable upon the achievement of specified levels of profitability that included an additional return allowance. The basic royalty is now capped at 7.5% of gross field revenue, based on the base project reaching a specified cumulative production level. The tier one royalty is the greater of the basic royalty or 20% of net revenue, and became payable in 2007. Net revenue adjusts gross revenue for eligible operating and capital costs. The tier two royalty, equal to 10% of net revenue, became payable in 2008. The White Rose Extensions royalty is similar to the base project, except that there is a tier three royalty, equal to 6.5% of net revenue, which is payable if WTI is greater than Cdn$50/bbl. None of the tier royalties have been triggered for the White Rose Extensions. During 2011, total White Rose royalty expense averaged 14% of gross revenue (2010 25%).

International

There are no royalties on oil and gas production from the North Sea; however, in the U.K., oil and gas profits are subject to a 62% income tax rate. For operations in Libya and Syria, all government interests, except for income taxes, are presented as royalties.

North America Onshore

Royalties for Suncor's North America Onshore production in Alberta are regulated by the *Natural Gas Royalty Regulation 2009*, introduced as part of the New Royalty Framework, which came into effect on January 1, 2009, but was later modified by changes that came into effect on January 1, 2011. Royalties for natural gas and conventional oil production are set by a sliding-scale formula ranging from 5% to 36% for natural gas and 0% to 40% for conventional crude oil that is dependent on factors such as well depth, production rate, and the price and quality of natural gas and crude oil. The maximum rates of 36% and 40% for the sliding-scales became effective on January 1, 2011 and were both reduced from 50%. NGLs have royalty rates of 30% for propane and butane and 40% for pentanes.

In response to the drop in commodity prices experienced during the second half of 2008, the provincial government introduced the New Well Royalty Reduction Program with the intent of promoting new drilling. New wells drilled after April 1, 2009 are subject to an initial 5% royalty for the first twelve months of production, subject to a 500 mmcfe or 50 mboe volume cap. After May 1, 2010, new wells that started producing exclusively from shale formations qualify for a maximum 5% royalty on all production for the first 36 months of production, and are not subject to volume caps.

The Alberta government's Natural Gas Deep Drilling Program also provides royalty relief for wells drilled beyond 2000 metres (true vertical depth). The maximum royalty rate for these wells is 5%, which applies for five years after the finished drilling date, and is subject to dollar caps that are determined based on total depth and whether the well is exploratory or developmental.

Operating and capital costs for gathering, compressing and processing facilities, and processing costs on a fee-for-service basis are allowable costs for deduction from gas and natural gas liquids gross royalties payable.

Royalties for Suncor's North America Onshore production in British Columbia are regulated primarily by the Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation. Royalty rates for natural gas production are subject to different formulas based on the date the well was drilled. Wells drilled before June 1998 attract a rate starting at 15%. Wells drilled after June 1998 attract a royalty starting at 9% or 12%, depending on whether wells were completed within five years of the date drilling rights were issued, and are subject to a sliding scale with a maximum royalty rate of 27% as prices increase. Similar to Alberta, royalty programs exist in British Columbia to provide relief for deep drilling, lower production rates, and unique production methods. Royalties on NGLs are assessed at a flat rate of 20% of sales.

Expenses for field gathering, compression and field processing are allowed as cost of services deductions from gross royalties, and royalty clients who use producer-owned processing facilities or distribution systems are also entitled to operating and capital cost deduction for these facilities.

During 2011, royalty expense for North America Onshore production averaged 11% of gross revenue (2010 14%).

Refining and Marketing

For a discussion of the environmental and other regulatory conditions, and competitive conditions and seasonal impacts affecting our Refining and Marketing segment, refer to the Industry Conditions and Risk Factors sections of this AIF.

Operations   Refining and Product Supply

Eastern North America

Effective January 1, 2012, the Montreal refinery had a crude oil capacity of 137,000 bbls/d. The observed performance of the refinery, after improvements in reliability and operations, enabled the nameplate capacity to be upwardly revised from the previously reported capacity of 130,000 bbls/d.

The refinery processes primarily foreign conventional crude oil, with a flexible configuration that allows processing of light, sour and heavy grades of crude oil, as well as intermediate feedstocks. Crude oil is procured from the market on a spot basis or under contracts that can be terminated on short notice. Crude oil for the refinery is largely supplied by the Portland-Montreal Pipeline.

Production yield from the Montreal refinery includes gasoline, distillates, asphalts, heavy fuel oil, petrochemicals and solvents, which are distributed primarily across Quebec and Ontario. The Montreal refinery also produces feedstock for our lubricants plant. Refined products are delivered to distribution terminals in Ontario via the Trans-Northern Pipeline and delivered to customers directly by truck, rail and marine vessel.

The Sarnia refinery has a crude oil capacity of 85,000 bbls/d, processing both SCO supplied by the company's Oil Sands operations and conventional crude oil purchased from third parties on a spot basis or under contracts that can be terminated on short notice. Crude oil is supplied to the Sarnia refinery primarily via the Enbridge pipelines system. Suncor procures conventional crude oil feedstock primarily from Western Canada, but periodically supplements supply with purchases from the U.S. and other countries. Foreign crude oil is delivered to Sarnia via the Enbridge pipeline system from Montreal.

Production yield from the Sarnia refinery includes gasoline, distillates and petrochemicals, which are primarily distributed in Ontario. Refined products are delivered to distribution terminals in Ontario via the Sun-Canadian Pipeline, or delivered to customers directly via marine vessel and rail. The Sarnia refinery also has limited access to pipelines delivering refined product into the U.S.

To meet the demands of Suncor's marketing network in Eastern North America, the company also imports gasoline and distillates from refiners in Europe. Suncor enters into reciprocal exchange arrangements with other refiners in Eastern North America, primarily for gasoline and distillates, as a means of minimizing transportation costs and balancing product availability. Specialty products, such as asphalts and petrochemicals, are also exported to customers in the U.S.

Suncor holds a 51% interest in ParaChem Chemicals L.P. (ParaChem), which owns and operates a petrochemicals plant located adjacent to the Montreal refinery. Feedstock for the plant includes xylene and toluene produced by the Montreal and Sarnia refineries. The plant primarily produces up to 350,000 metric tons per year of paraxylene, which is used by customers to manufacture polyester textiles and plastic bottles. ParaChem also produces benzene, hydrogen and heavy aromatics. Benzene production is delivered back to the Montreal refinery to be marketed with production from that facility.

Suncor's lubricants plant produces specialty lubricants and waxes that are marketed in Canada and internationally. The facility is the largest producer of lubricant base stocks in Canada, with annual base oil production capacity in excess of 900 million litres. Feedstock for the lubricants facility comes from Suncor's Montreal refinery and other purchase contracts.

Western North America

The Edmonton refinery has a crude oil capacity of 135,000 bbls/d and has the potential to run entirely on feedstocks sourced from oil sands and heavy crude oil from Alberta. Feedstock is supplied from Suncor's Oil Sands Base operations, Syncrude operations (including volumes purchased by Suncor from other joint venture owners' share of production) and other producers from the Athabasca and Cold Lake regions of Alberta. The refinery can process directly 35,000 bbls/d of blended feedstock (comprised of 25,000 bbls/d of bitumen and 10,000 bbls/d of diluent) and process 45,000 bbls/d of sour SCO. The refinery can also process 55,000 bbls/d of sweet SCO through its synthetic train. Crude oil is supplied to the refinery via third-party pipelines.

Production yield from the Edmonton refinery includes primarily gasoline and distillates, which are delivered to distribution terminals across Western Canada via the Alberta Products Pipeline, the TransMountain Pipeline and the Enbridge pipeline system, as well as via truck and rail.

Effective January 1, 2012, the Commerce City refinery had a crude oil capacity of 98,000 bbls/d. The observed performance of the refinery, after improvements in reliability and operations, enabled the nameplate capacity to be upwardly revised from the previously reported capacity of 93,000 bbls/d.

The refinery processes primarily conventional crude oil, but also has the capability of processing up to 15,000 bbls/d of sour SCO from Suncor's Oil Sands Base operations. A majority of crude feedstock is supplied from sources in the U.S., primarily the Rocky Mountain region, while the remainder is purchased from Canadian sources. Crude oil purchase contracts have terms ranging from month-to-month to multi-year. Approximately 60% of crude oil supplied to the refinery is transported via pipeline, with the remainder transported via truck.

Production yield from the Commerce City refinery includes primarily gasoline, diesel and asphalt. The majority of the refined products from the refinery are sold to commercial and wholesale customers in Colorado and Wyoming, and a retail network in Colorado. Refined products are distributed by truck, rail, and pipeline.

To support supply and demand balance in the Vancouver area, Suncor imports and exports finished products through its Burrard distribution terminal on the west coast of Canada. Suncor also enters into reciprocal exchange arrangements with other refiners in Western North America as a means of minimizing transportation costs and balancing product availability.

Refinery Throughputs, Utilizations and Yields

The following table summarizes the crude feedstock and utilizations for Suncor's refineries for the years ended December 31, 2011 and 2010. Refinery utilizations for 2011 include the impacts of planned maintenance events at the Sarnia, Edmonton and Commerce City refineries, and the impacts of a month-long disruption to third-party hydrogen supply at Edmonton.

Average Daily Crude Throughput	Montreal		Sarnia		Edmonton		Commerce City	
(mbbls/d, except as noted)	2011	2010	2011	2010	2011	2010	2011	2010
Oil Sands Base sweet synthetic			11.4	14.1	12.3	11.4		0.1
Oil Sands Base sour synthetic			25.2	17.4	41.2	42.5	7.7	9.4
Other synthetic			12.6	17.0	41.9	39.6		
East Coast Canada light conventional [1]	23.0	41.5						
Other light conventional	82.3	54.7	3.2	3.0		2.4	67.0	72.0
Sour conventional	10.2	6.4	18.6	19.3				
Heavy conventional	15.3	19.2			20.4	22.7	16.0	17.5
Total	130.8	121.8	71.0	70.8	115.8	118.6	90.7	99.0
Utilization [2] (%)	101	94	83	83	86	88	98	106

(1) Includes purchases of Suncor and third-party shares of production from East Coast Canada oilfields.

(2) Utilization rates for Montreal and Commerce City are determined based on refinery capacities in effect prior to January 1, 2012.

Refined petroleum production yield mix	Montreal		Sarnia		Edmonton		Commerce City	
(%)	2011	2010	2011	2010	2011	2010	2011	2010
Gasoline	40	42	44	53	46	42	51	51
Distillates	34	32	42	35	50	54	36	36
Other	26	26	14	12	4	4	13	13

Distribution Terminals and Pipelines

Suncor owns and operates 13 major refined products terminals across Canada and two product terminals in Colorado. Combined with access to facilities under long-term contractual arrangements with other parties, Suncor's North American assets are sufficient to meet Refining and Marketing's current storage and distribution needs.

Suncor has ownership interests in the following pipelines:

Pipeline	Ownership	Type	Origin	Destinations
Portland-Montreal Pipeline	23.8%	Crude oil	Portland, Maine	Montreal, Quebec
Trans-Northern Pipeline	33.3%	Refined product	Montreal, Quebec	Ontario Ottawa, Toronto, Oakville
Sun-Canadian Pipeline	55.0%	Refined product	Sarnia, Ontario	Ontario Toronto, London, Hamilton
Alberta Products Pipeline	35.0%	Refined product	Edmonton, Alberta	Calgary, Alberta
Rocky Mountain Crude Pipeline	100.0%	Crude oil	Guernsey, Wyoming	Denver, Colorado
Centennial Pipeline	100.0%	Crude oil	Guernsey, Wyoming	Cheyenne, Colorado

Operations   Marketing

Suncor's retail service station network operates nationally in Canada under the Petro-Canada$_{TM}$ brand. As at December 31, 2011, Suncor's branded retail service station network consisted of 1,465 outlets across Canada. Most of Suncor's owned and operated Sunoco$_{TM}$-branded retail sites were re-branded to the Petro-Canada$_{TM}$ brand in 2010. In addition to marketing through proprietary retail outlets, petroleum product is marketed through independent dealers and joint arrangements. Suncor's network had annual sales of gasoline motor fuels averaging approximately 4.9 million litres per site in 2011 (2010   5.1 million litres per site) and attracted an estimated 18% share (2010   19% share) of the national retail market (based on data available from Statistics Canada for the period from January to August 2011). The decline in market share in 2011 primarily reflects the loss of volume associated with the disposal of numerous retail sites in 2010 as mandated by the Canadian Competition Bureau as a result of the merger.

Suncor's Colorado retail network consists of 44 owned outlets. Suncor has product supply agreements with an additional 195 Shell®-branded sites and 62 Phillips 66®-branded sites in Colorado.

Marketing activities also generate non-petroleum revenues from convenience stores and car washes.

Suncor's wholesale operations sell petroleum products into farm, home heating, paving, small industrial, commercial and truck markets. Through its PETRO-PASS network, Suncor is the leading national marketer to the commercial road transport segment in Canada. Suncor also sells large volumes of petroleum products directly to large industrial and commercial customers and independent marketers.

The following tables summarize the locations comprising Suncor's retail and wholesale network and the daily sales volumes and corresponding percentages of Refining and Marketing's operating revenues for the years ended December 31, 2011 and 2010.

Locations	As at December 31 2011	2010
Retail Service Stations Canada		
Petro-Canada$_{TM}$-branded	1 456	1 447
Sunoco$_{TM}$-branded	9	10
	1 465	1 457
Retail Service Stations Colorado		
Shell®-branded retail service stations	38	37
Phillips 66®-branded retail service stations	6	7
	44	44
Wholesale Cardlock Sites Canada		
Petro-Canada$_{TM}$-branded cardlock sites (PETRO-PASS)	245	249

Sales Volumes	2011		2010	
	thousands of m^3/d	% operating revenues	thousands of m^3/d	% operating revenues
Gasoline (includes motor and aviation gasoline)				
Eastern North America	20.9		22.2	
Western North America	18.8		18.9	
	39.7	45	41.1	48
Distillates (includes diesel and heating oils, and aviation jet fuels)				
Eastern North America	12.8		12.4	
Western North America	17.6		18.0	
	30.4	41	30.4	37
Other (includes heavy fuel oil, asphalts, lubricants, petrochemicals, other)				
Eastern North America	9.8		10.7	
Western North America	3.2		5.1	
	13.0	14	15.8	15
	83.1		87.3	

Sales volumes for specific products are somewhat impacted by seasonal cycles: gasoline sales are typically higher during the summer driving season; heating oil sales are typically higher during the winter season; diesel sales are typically higher during the drilling season at the beginning of the year in Western Canada, and during agricultural planting and harvest seasons in early spring and late summer, respectively; and asphalt sales are typically higher during the summer construction paving period. Suncor has the flexibility to modify refinery inputs and outputs to match production yields with anticipated product demands.

Sales volumes can also be impacted when refineries undergo planned maintenance events, which reduce production. Suncor is able to partially mitigate this impact through its integrated facilities: the Edmonton refinery and Oil Sands Base upgrading facilities in Western North America, and the Sarnia and Montreal refineries in Eastern North America. In addition, Suncor may purchase refined products from third-party suppliers.

Other Suncor Businesses

Energy Trading

Suncor's Energy Trading business is organized around four main commodity groups crude oil, natural gas, sulphur and petroleum coke. Each commodity group provides value to customers through innovative commodity supply, transportation and pricing solutions. Our customers include mid- to large-sized commercial and industrial consumers, utility companies and energy producers, all of which demand specialized solutions to meet unique energy requirements.

The Energy Trading business supports the company's Oil Sands production by optimizing price realizations, managing inventory levels during unplanned outages at Suncor's facilities and managing the impacts of external market factors, like pipeline disruptions or outages at refining customers. The Energy Trading business has entered into arrangements for other midstream infrastructure, such as pipeline and storage capacity, to optimize delivery of existing and future growth production, while generating trading earnings on select strategies and opportunities.

The Energy Trading business continues to evaluate additional pipeline agreements to support planned increases in production capacity. Until the company completes its Oil Sands growth projects, Suncor's Energy Trading business expects to optimize the capacities associated with existing arrangements.

Renewable Energy

Suncor's renewable energy interests include a corn-based ethanol facility in southwest Ontario and six wind power projects in operation. Suncor is a Canadian pioneer in wind power with its investments in wind farms, which have a gross generating capacity of 255 MW and reduce carbon dioxide (CO_2) emissions by approximately 470,000 tonnes each year, compared with traditional power generation sources. We continue to evaluate new opportunities to build our renewable energy portfolio, and have a number of potential wind power project sites in various stages of evaluation.

Wind Farm		Ownership Interest (%)	Size (MW)	Turbines	Commissioned
Operated by Suncor					
Wintering Hills	Drumheller, Alberta	70.0	88	55	2011
Kent Breeze	Thamesville, Ontario	100.0	20	8	2011
Non-operated					
Ripley	Ripley, Ontario	50.0	76	38	2007
Chin Chute	Taber, Alberta	33.3	30	20	2006
Magrath	Magrath, Alberta	33.3	30	20	2004
SunBridge	Gull Lake, Saskatchewan	50 .0	11	17	2002

Since 2006, Suncor has invested in Canada's emerging biofuels industry. Suncor operates Canada's largest ethanol facility, the St. Clair Ethanol Plant in the Sarnia-Lambton region of Ontario. Our ethanol plant had an original production capacity of 200 million litres per year, which has since doubled with the completion of the plant expansion in January 2011. In 2011, the plant produced 381.5 million litres of ethanol (2010 206.0 million litres).

SUNCOR EMPLOYEES

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

As of December 31	2011	2010
Oil Sands	5 464	4 753
Exploration and Production	768	898
Refining and Marketing	3 161	3 151
Corporate, Energy Trading and Renewable Energy	3 633	3 274
Total	13 026	12 076

Corporate includes employees from our Major Projects group, which supports the business units. In addition to our employees, the company also uses independent contractors to supply a range of services.

Approximately 36% of the company's employees were covered by collective bargaining agreements at the end of 2011. The Communications, Energy and Paperworkers Union (CEP) represented the majority of the company's unionized employees. A collective agreement with CEP Local 707 representing approximately 3,200 Oil Sands employees is in force and expires in May 2013. Collective agreements that will expire in January 2013 are also in place with the CEP for approximately 1,000 employees in the company's refinery, lubricants, natural gas, and terminal operations. A collective agreement with the CEP representing approximately 65 employees for the Terra Nova facility was renewed in 2011 and will expire in September 2013.

A collective agreement with the United Steel Workers Union representing approximately 260 employees at the Commerce City refinery was recently renewed and will expire in January 2015. An independent union, the Suncor Employee Bargaining Association, represents approximately 200 employees at the Sarnia refinery under an agreement that will expire in May 2012.

SIGNIFICANT POLICIES

Suncor has a Standards of Business Conduct Code (the Code), which applies to Suncor's directors, officers, employees and contractors. The Code requires strict compliance with legal requirements and sets Suncor's standards for the ethical conduct of our business. Topics addressed in the Code include competition, conflict of interest, the protection and proper use of corporate assets and opportunities, confidentiality, disclosure of material information, trading in shares and securities, communications to the public, improper payments, fair dealing in trade relations, and accounting, reporting and business controls. The Code is supported by detailed policy guidance and standards and a Code compliance program, under which every Suncor director, officer, employee and contract worker is required to annually read a summary of the Code and affirm that he or she has reviewed the summary, affirm that he or she understands the requirements of the Code, and provide confirmation of his or her compliance with the Code during the preceding year. Compliance is then reported to the Audit Committee.

Suncor has a Human Rights Policy, which affirms Suncor's responsibility to respect human rights and ensures that Suncor is not complicit in human rights abuses. Suncor is subject to the laws of the countries in which it operates and is committed to complying with all such laws while honouring the spirit of international human rights principles, such as those described in the Universal Declaration of Human Rights and the Voluntary Principles on Security and Human Rights. The policy includes principles committed to a harassment-free and violence-free working environment, which respects the cultures, customs and values of the communities in which we operate. The policy makes it clear that the scope of Suncor's human rights due diligence includes its own operations and, where we can influence our third-party business relationships, the operations of others.

Suncor has a Stakeholder Relations Policy, which reflects Suncor's values and beliefs. The policy provides that Suncor is committed to developing and maintaining positive, meaningful relationships with stakeholders in all of its operating areas and provides Suncor's principles for guiding the development of stakeholder relations (respect, responsibility, transparency, timeliness and mutual benefit). The policy makes it clear that successful stakeholder engagement fosters informed decision-making, resolving issues with timely, cost-effective and mutually beneficial solutions and supporting shared learning.

Suncor has an Aboriginal Affairs Policy, which affirms Suncor's desire to work in collaboration with Canada's Aboriginal People to develop a thriving energy industry that allows Aboriginal communities to be vibrant, diversified and sustainable. The policy provides a consistent approach to the company's relationships with Canada's Aboriginal People and outlines Suncor's responsibilities and commitments, and is intended to guide Suncor's business decisions on a day-to-day basis. Suncor is committed to work closely with Canada's Aboriginal People and communities to build and maintain effective, long-term and mutually beneficial relationships. The policy makes it clear that responsible development takes into account Aboriginal issues and concerns about the effects, positive and negative, of energy development on communities and their traditional and current uses of lands and resources.

Suncor has an Environment, Health and Safety (EH&S) policy, which affirms Suncor's aspirations to be a sustainable energy company by meeting or exceeding the environmental, social and economic expectations of our current and future stakeholders. The policy reflect Suncor's beliefs that our EH&S efforts are complementary and interdependent with our economic and social performance. The policy makes it clear that Suncor management is responsible for ensuring that employees under their direction are competent to manage their EH&S responsibilities and knowledgeable of the hazards and risks associated with their jobs, and that all Suncor employees and contractors are accountable for compliance with relevant acts, codes, regulations, standards and procedures, and for their own personal safety and the safety of their co-workers.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Date of Statement

The statement of reserves data and other oil and gas information outlined below is dated March 1, 2012, with an effective date of December 31, 2011. The preparation date of the information is as of February 16, 2012.

Disclosure of Reserves Data

As a Canadian issuer, Suncor is subject to the reporting requirements of Canadian securities regulatory authorities, including the reporting of our reserves in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* (NI 51-101).

The reserves data set forth in this section of the AIF for Suncor's Mining (includes Oil Sands Base and Syncrude, unless otherwise noted) and In Situ operations is based upon evaluations conducted by GLJ Petroleum Consultants Ltd. (GLJ) with an effective date of December 31, 2011, contained in their reports (the GLJ Reports). The reserves data set forth below for all other reserves, which includes Suncor's interests in its conventional natural gas assets primarily located in Western Canada (North America Onshore), conventional assets offshore Newfoundland and Labrador (East Coast Canada), conventional assets offshore the U.K. (North Sea), and conventional assets in Syria and Libya (collectively, Other International), is based upon evaluations conducted by Sproule Associates Limited or Sproule International Limited (collectively, Sproule) with an effective date of

December 31, 2011 contained in their reports (the Sproule Reports). Each of GLJ and Sproule (collectively, the Evaluators) are independent qualified reserves evaluators as defined in NI 51-101. All factual data supplied to the Evaluators was accepted as presented. For general interest purposes, GLJ conducted field tours of Suncor's Millennium mine and the Syncrude Aurora North mine. No other field inspections were deemed necessary by the Evaluators.

The reserves data summarizes Suncor's SCO, bitumen, light and medium oil, NGL and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs (unless otherwise indicated) prior to provision for interest, and general and administrative expenses. Net present values of future revenues include the impact of certain abandonment costs. For more information on abandonment costs, see the Future Net Revenues Tables and Notes Abandonment and Reclamation Costs section of this AIF.

Future net revenues are presented on before-tax and after-tax bases. The reserves data conforms to the requirements of NI 51-101. See also the Notes to Reserves Data Tables and the Definitions for Reserves Data Tables discussions presented subsequently in this section of the AIF.

Advisories Future Net Revenues

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. There is no guarantee that the estimates for SCO, bitumen, light and medium oil, NGL and natural gas reserves provided herein will be recovered. Actual SCO, bitumen, light and medium oil, NGL and natural gas reserves may be greater than or less than the estimates provided herein. Readers should review the definitions and information contained in the Notes to Reserves Data Tables, Definitions for Reserves Data Tables and Notes to Future Net Revenues Tables discussions in conjunction with the following notes and tables.

Significant Factors or Uncertainties Affecting Reserves Data

The evaluation of reserves is a continuous process, one that can be significantly impacted by a variety of internal and external influences. Revisions are often required as a result of newly acquired technical data, technology improvements, or changes in historical performance, pricing, economic conditions, market availability, and regulatory requirements. Additional technical information regarding geology, reservoir properties, reservoir fluid properties and well performance are obtained through seismic programs, drilling programs, updated reservoir performance studies and analysis, and production history, and may result in upward or downward revisions to reserves. Pricing, market availability and economic conditions affect the profitability of reserves exploitation. Depending on the current business environment, higher commodity prices may result in higher reserves by making more projects economically viable and extending their economic life, while lower commodity prices may result in lower reserves, although this generally does not result for assets under Production Sharing Contracts. Regulatory changes, including royalty regimes and environmental regulations, cannot be predicted but may have positive or negative effects on reserves. Future technology improvements would be expected to have a favourable impact on the economics of reserves development and exploitation, and therefore result in an increase to reserves.

While the above factors, and many others, can be considered, certain judgments and assumptions are always required. As new information becomes available, these areas are reviewed and revised accordingly.

In 2011, the company's assets in Syria were impacted by political unrest. As a result of the current situation in Syria, reserves previously reported as proved developed producing and probable developed producing have been reclassified to the respective non-producing categories. In addition, estimated 2012 production from Syria has not been included as reserves, but has been reflected as contingent resources, as current sanctions prohibit Suncor from receiving payment for any production that may occur during the force majeure period.

For more information as to the risks involved when estimating reserves and resources, see the Risk Factors Uncertainty of Reserves and Resources Estimates section in this AIF.

Disclosure of Resources Data

GLJ conducted an independent evaluation of Best Estimate contingent resources volumes for all of Suncor's Mining properties and for Suncor's In Situ properties for which they also evaluated reserves. For Suncor's In Situ properties without attributed reserves, GLJ audited Suncor's internal evaluation of Best Estimate contingent resources volumes. Best Estimate contingent resources for conventional properties were prepared by Suncor's qualified reserves evaluators in accordance with the Canadian Oil and Gas Evaluation (COGE) Handbook. For more information on contingent resources, see the discussion in the Additional Information Relating to Reserves Data Contingent Resources section of this AIF.

Oil and Gas Reserves Tables and Notes

Summary of Oil and Gas Reserves (1)(2)(3)
as at December 31, 2011
(forecast prices and costs)

	SCO		Bitumen		Light & Medium Oil		Natural Gas		NGLs		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	bcf	bcf	mmbbls	mmbbls	mmboe	mmboe
Proved Developed Producing												
Mining	2 022.5	1 722.1									2 022.5	1 722.1
In Situ	203.0	191.0	47.7	39.4							250.7	230.4
East Coast Canada					48.1	38.2					48.1	38.2
North America Onshore					11.2	9.2	805.7	688.8	6.3	4.6	151.7	128.6
Total Canada	2 225.5	1 913.1	47.7	39.4	59.3	47.4	805.7	688.8	6.3	4.6	2 473.0	2 119.3
North Sea					71.5	71.5	3.3	3.3	0.3	0.3	72.3	72.3
Other International					96.0	35.7					96.0	35.7
Total Proved Developed Producing	**2 225.5**	**1 913.1**	**47.7**	**39.4**	**226.8**	**154.6**	**809.0**	**692.1**	**6.6**	**4.9**	**2 641.3**	**2 227.3**
Proved Developed Non-Producing												
Mining												
In Situ												
East Coast Canada												
North America Onshore					0.1	0.1	40.5	31.3	0.2	0.1	7.0	5.4
Total Canada					0.1	0.1	40.5	31.3	0.2	0.1	7.0	5.4
North Sea					21.4	21.4	1.1	1.1	0.1	0.1	21.6	21.6
Other International					36.6	14.3	334.5	206.9	11.9	7.0	104.2	55.8
Total Proved Developed Non-Producing					**58.1**	**35.8**	**376.1**	**239.3**	**12.2**	**7.2**	**132.8**	**82.8**
Proved Undeveloped												
Mining												
In Situ	502.0	430.0	661.1	572.4							1 163.1	1 002.4
East Coast Canada					26.6	20.7					26.6	20.7
North America Onshore					0.3	0.3	78.7	72.8	0.1		13.5	12.4
Total Canada	502.0	430.0	661.1	572.4	26.9	21.0	78.7	72.8	0.1		1 203.2	1 035.5
North Sea					43.3	43.3	2.7	2.7	0.1	0.1	43.8	43.8
Other International					5.8	2.4					5.8	2.4
Total Proved Undeveloped	**502.0**	**430.0**	**661.1**	**572.4**	**76.0**	**66.7**	**81.4**	**75.5**	**0.2**	**0.1**	**1 252.8**	**1 081.7**
Proved												
Mining	2 022.5	1 722.1									2 022.5	1 722.1
In Situ	705.0	621.0	708.8	611.8							1 413.8	1 232.8
East Coast Canada					74.7	58.9					74.7	58.9

North America Onshore					11.5	9.6	924.9	792.9	6.6	4.7	172.3	146.4
Total Canada	2 727.5	2 343.1	708.8	611.8	86.2	68.5	924.9	792.9	6.6	4.7	3 683.3	3 160.2
North Sea					136.2	136.2	7.1	7.1	0.5	0.5	137.9	137.9
Other International					138.4	52.4	334.5	207.1	11.9	7.0	206.1	93.9
Total Proved	**2 727.5**	**2 343.1**	**708.8**	**611.8**	**360.8**	**257.1**	**1 266.5**	**1 007.1**	**19.0**	**12.2**	**4 027.3**	**3 392.0**
Probable												
Mining	552.7	478.4									552.7	478.4
In Situ	1 271.9	1 061.2	693.9	552.0							1 965.8	1 613.2
East Coast Canada					275.3	201.0					275.3	201.0
North America Onshore					5.0	4.1	320.4	262.8	2.9	2.1	61.3	50.0
Total Canada	1 824.6	1 539.6	693.9	552.0	280.3	205.1	320.4	262.8	2.9	2.1	2 855.1	2 342.6
North Sea					36.1	36.1	2.9	2.9	0.1	0.1	36.7	36.7
Other International					104.9	40.3	405.5	168.8	14.5	7.0	187.0	75.4
Total Probable	**1 824.6**	**1 539.6**	**693.9**	**552.0**	**421.3**	**281.5**	**728.8**	**434.5**	**17.5**	**9.2**	**3 078.8**	**2 454.7**
Proved Plus Probable												
Mining	2 575.2	2 200.5									2 575.2	2 200.5
In Situ	1 976.9	1 682.2	1 402.7	1 163.8							3 379.6	2 846.0
East Coast Canada					350.0	259.9					350.0	259.9
North America Onshore					16.5	13.7	1 245.3	1 055.7	9.5	6.8	233.6	196.5
Total Canada	4 552.1	3 882.7	1 402.7	1 163.8	366.5	273.6	1 245.3	1 055.7	9.5	6.8	6 538.4	5 502.9
North Sea					172.3	172.3	10.0	10.0	0.6	0.6	174.5	174.5
Other International					243.3	92.7	740.0	375.9	26.4	14.0	393.0	169.3
Total Proved Plus Probable	**4 552.1**	**3 882.7**	**1 402.7**	**1 163.8**	**782.1**	**538.6**	**1 995.3**	**1 441.6**	**36.5**	**21.4**	**7 105.9**	**5 846.7**

Please see Notes (1) through (3) at the end of the reserves data section for important information about volumes in this table.

Summary of Oil and Gas Reserves [1][2][3]
as at December 31, 2011
(constant prices and costs)

	SCO		Bitumen		Light & Medium Oil		Natural Gas		NGLs		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	bcf	bcf	mmbbls	mmbbls	mmboe	mmboe
Proved Developed Producing												
Mining	2 022.5	1 718.2									2 022.5	1 718.2
In Situ	202.9	194.0	47.7	40.2							250.6	234.2
East Coast Canada					48.1	37.2					48.1	37.2
North America Onshore					11.2	9.6	731.8	640.1	6.1	4.4	139.2	120.7
Total Canada	2 225.4	1 912.2	47.7	40.2	59.3	46.8	731.8	640.1	6.1	4.4	2 460.4	2 110.3
North Sea					71.7	71.7	3.3	3.3	0.3	0.3	72.5	72.5
Other International					96.3	36.4					96.3	36.4
Total Proved Developed Producing	**2 225.4**	**1 912.2**	**47.7**	**40.2**	**227.3**	**154.9**	**735.1**	**643.4**	**6.4**	**4.7**	**2 629.2**	**2 219.2**
Proved Developed Non-Producing												
Mining												
In Situ												
East Coast Canada												
North America Onshore					0.1	0.1	18.3	14.7	0.2	0.1	3.3	2.6
Total Canada					0.1	0.1	18.3	14.7	0.2	0.1	3.3	2.6
North Sea					21.7	21.7	1.1	1.1	0.1	0.1	22.0	22.0
Other International					36.7	14.3	338.6	199.0	12.0	6.7	105.1	54.2
Total Proved Developed Non-Producing					**58.5**	**36.1**	**358.0**	**214.8**	**12.3**	**6.9**	**130.4**	**78.8**
Proved Undeveloped												
Mining												
In Situ	502.0	446.5	661.1	584.0							1 163.1	1 030.5
East Coast Canada					26.6	20.2					26.6	20.2
North America Onshore					0.3	0.3	11.5	10.5			2.2	2.1
Total Canada	502.0	446.5	661.1	584.0	26.9	20.5	11.5	10.5			1 191.9	1 052.8
North Sea					43.9	43.9	2.7	2.7	0.1	0.1	44.4	44.4
Other International					5.8	2.4					5.8	2.4
Total Proved Undeveloped	**502.0**	**446.5**	**661.1**	**584.0**	**76.6**	**66.8**	**14.2**	**13.2**	**0.1**	**0.1**	**1 242.1**	**1 099.6**
Proved												
Mining	2 022.5	1 718.2									2 022.5	1 718.2
In Situ	704.9	640.5	708.8	624.2							1 413.7	1 264.7
East Coast Canada					74.7	57.4					74.7	57.4
North America Onshore					11.5	10.0	761.6	665.3	6.3	4.5	144.7	125.4

Total Canada	2 727.4	2 358.7	708.8	624.2	86.2	67.4	761.6	665.3	6.3	4.5	3 655.6	3 165.7
North Sea					137.3	137.3	7.1	7.1	0.5	0.5	138.9	138.9
Other International												