SUNCOR ENERGY INC
Form 40-F
March 02, 2018

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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 40-F

(Check One)

o Registration statement pursuant to Section 12 of the Securities Exchange Act of 1934
or
ý Annual report pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934

For fiscal year ended:	December 31, 2017
Commission File Number:	No. 1-12384

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

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

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, 2017 there were 1,640,983,359 Common Shares issued and outstanding**

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 preceding 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 for 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 ý No o

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 12b-2 of the Exchange Act.

Emerging growth company o

If an emerging growth company that prepares its financial statements in accordance with U.S. GAAP, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. o

INCORPORATION BY REFERENCE

This annual report on Form 40-F is incorporated by reference into and as an exhibit to, as applicable, each of the following Registration Statements of the Registrant under the Securities Act of 1933: Form S-8 (File No. 333-87604), Form S-8 (File No. 333-112234), Form S-8 (File No. 333-118648), Form S-8 (File No. 333-124415), Form S-8 (File No. 333-149532), Form S-8 (File No. 333-161021) and Form S-8 (File No. 333-161029). The Registrant's Annual Information Form dated March 1, 2018, included in this annual report on Form 40-F, and Audited Consolidated Financial Statements and Management's Discussion and Analysis for the year ended December 31, 2017, included as Exhibit 99-1 and Exhibit 99-2, respectively, to this annual report on Form 40-F, are incorporated by reference into and as an exhibit to, as applicable, the Registrant's Registration Statement on Form F-10 (File No. 333- 212212).

ANNUAL INFORMATION FORM DATED MARCH 1, 2018

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Schedules

ADVISORIES

In this Annual Information Form (AIF), references to "Suncor" or "the company" mean Suncor Energy Inc., its subsidiaries, partnerships and joint arrangements, unless the context otherwise requires. References to the "Board of Directors" or the "Board" mean the Board of Directors of Suncor Energy Inc.

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.

References to the 2017 audited Consolidated Financial Statements mean Suncor's audited Consolidated Financial Statements prepared in accordance with Canadian generally accepted accounting principles (GAAP), which is within the framework of International Financial Reporting Standards (IFRS), the notes and the auditor's report, as at and for each year in the two-year period ended December 31, 2017. References to the MD&A mean Suncor's Management's Discussion and Analysis, dated March 1, 2018.

This AIF contains forward-looking statements based on Suncor's current plans, 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 and Non-GAAP Financial Measures section of this AIF for information regarding risk factors and material assumptions underlying the forward-looking statements.

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 this AIF by reference.

GLOSSARY OF TERMS AND ABBREVIATIONS

Common Industry Terms

Products

Conventional natural gas is natural gas that has been generated elsewhere and has migrated as a result of hydrodynamic forces and is trapped in discrete accumulations by seals that may be formed by localized structural, depositional or erosional geological features.

Crude oil is a mixture, consisting mainly 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** is a naturally occurring solid or semi-solid hydrocarbon, consisting mainly of heavier hydrocarbons that are too heavy or thick to flow or be pumped without being diluted or heated, and that is not primarily recoverable at economic rates through a well without the implementation of enhanced recovery methods. After it is extracted, bitumen may be upgraded into crude oil and other petroleum products.
>
> **Light Crude Oil** is crude oil with a relative density greater than 31.1 degrees American Petroleum Institute (API) gravity.
>
> **Medium Crude Oil** is crude oil with a relative density greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity.
>
> **Heavy Crude Oil** is crude oil with a relative density greater than 10.0 degrees API gravity and less than or equal to 22.3 degrees API gravity.
>
> **Synthetic Crude Oil (SCO)** is a mixture of liquid hydrocarbons derived by upgrading bitumen and may contain sulphur or other elements or compounds. 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**.

Natural gas is a naturally occurring mixture of hydrocarbon gases and other gases.

Natural gas liquids (NGLs) are hydrocarbon components that can be recovered from natural gas as a liquid, including, but not limited to, ethane, propane, butanes, pentanes, and condensates. **Liquefied petroleum gas (LPG)** consists predominantly of propane and/or butane and, in Canada, frequently includes ethane.

Oil and gas exploration and development terms

Development costs are costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing 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, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells.

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

Oil sands are naturally occurring stratified deposits of unconsolidated sand/sandstone and other sedimentary rocks saturated with varying amounts of water and bitumen.

Reservoir is a subsurface rock unit that contains an accumulation of petroleum.

Wells

> **Appraisal wells** are drilled into a discovered hydrocarbon accumulation to further understand the extent and size of the accumulation.
>
> **Cuttings reinjection wells** are drilled for the safe disposal of drilling waste, including drill cuttings, mud slurry, old drilling fluids and waste water, in order to minimize the environmental impact.

Delineation wells are drilled for the purpose of assessing the stratigraphy, structure and bitumen saturation of an oil sands lease. The wells are also used to define known accumulations for the assignment of reserves.

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.

Disposal wells are drilled in areas where excess fluids from operations can be safely injected for safe disposal. These wells are operated within limits approved by the appropriate regulatory bodies.

Dry holes 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 of discovering commercial reservoirs or deposits of crude oil and/or natural gas.

Infill wells are drilled between existing development wells to target regions of the reservoir containing bypassed hydrocarbons or to accelerate production.

Observation wells are used to monitor changes in a producing field. Parameters being monitored may include fluid saturations, temperature or reservoir pressure.

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

Stratigraphic test wells are usually drilled without the intention of being completed for production and are geologically directed to obtain information pertaining to a specific geologic condition, such as **core hole drilling** or **delineation wells** on oil sands leases, or to measure the commercial potential (i.e., size and quality) of a discovery, such as **appraisal wells** for offshore discoveries.

Production terms

Crude feedstock generally refers either to (i) the bitumen required in the production of SCO for the company's oil sands operations, or (ii) crude oil and/or other components required in the production of refined petroleum products for the company's downstream operations.

Diluent is a light hydrocarbon mixture used to blend with bitumen or heavy crude oil to reduce its viscosity so that it can be transported by pipeline.

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

Extraction refers to the process of separating bitumen from oil sands.

Froth treatment refers to the process of adding a light hydrocarbon to bitumen froth produced in the extraction process in order to separate the bitumen from the water and fine solids in the bitumen froth.

In situ refers to methods of extracting bitumen from deep deposits of oil sands by means other than surface mining.

Midstream refers to transportation, storage and wholesale marketing of crude or refined petroleum products.

Overburden is the material overlying oil sands that must be removed before mining. Overburden is removed on an ongoing basis to continually expose the ore.

Paraffinic froth treatment (PFT) refers to a froth treatment process whereby a lighter diluent or solvent that contains more paraffin is used, resulting in a higher quality bitumen that can be sold directly to market without further upgrading.

Production sharing contracts (PSC) are a common type of contract, outside North America, 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 of the resource and operation of associated facilities. The resource extraction company does not obtain title to the product; however, the company is subject to the upstream risks and rewards. An **exploration and production sharing agreement (EPSA)** is a form of PSC, which also states which parties are responsible for exploration activities.

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 water (converted to steam) required to produce one cubic metre of oil. A lower ratio indicates more efficient use of steam.

Upgrading is the two-stage process by which bitumen is converted into SCO.

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 periodically and later sold as a byproduct.

Secondary upgrading, a purification process also referred to as hydrotreating, adds hydrogen to, and reduces the sulphur and nitrogen of, primary upgrading output to create sweet SCO and diesel.

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

Reserves

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	thousands of barrels
mbbls/d	thousands of barrels per day
mmbbls	millions of barrels
mmbbls/d	millions of barrels per day
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
mmboe/d	millions of barrels of oil equivalent per day
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
bcfe	billions of cubic feet of natural gas equivalent
GJ	gigajoules
mmbtu	millions of British thermal units
API	American Petroleum Institute
CO_2	carbon dioxide
CO_{2e}	carbon dioxide equivalent
m^3	cubic metres
m^3/d	cubic metres per day
m^3/s	cubic metres per second
km	kilometres
MW	Megawatts
Mt	Megatonnes

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

Products, Markets and Processes

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

Suncor converts certain natural gas volumes to boe, boe/d, mboe, mboe/d and mmboe on the basis of six mcf to one boe. Any figure presented in boe, boe/d, mboe, mboe/d or mmboe may be misleading, particularly if used in isolation. A conversion ratio of six mcf of natural gas to one bbl of crude oil or NGLs 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 as a result of rounding.

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

CORPORATE STRUCTURE

Name, Address and Incorporation

Suncor Energy Inc. (formerly Suncor Inc.) was originally formed by the amalgamation under the *Canada Business Corporations Act* (the CBCA) 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, the company further amalgamated with a wholly owned subsidiary under the CBCA. The company amended its articles in 1995 to move its registered office from Toronto, Ontario, to Calgary, Alberta, and again in April 1997 to adopt the name, "Suncor Energy Inc." In April 1997, May 2000, May 2002, and May 2008, the company amended its articles to divide its issued and outstanding shares on a two-for-one basis.

Pursuant to an arrangement under the CBCA, which was completed effective August 1, 2009, Suncor amalgamated with Petro-Canada to form a single corporation continuing under the name "Suncor Energy Inc." On January 1, 2017, Suncor amalgamated with certain of its wholly owned subsidiaries under the CBCA.

Suncor's 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, 2017, are as follows:

Name	Jurisdiction Where Organized	Description
Canadian operations		
Suncor Energy Oil Sands Limited Partnership	Alberta	This partnership holds most of the company's Oil Sands operations assets.
Suncor Energy Products Partnership	Alberta	This partnership holds substantially all of the company's Canadian refining and marketing assets.
Suncor Energy Marketing Inc.	Alberta	Through this subsidiary, production from Suncor's upstream Canadian businesses is marketed. This subsidiary also administers Suncor's energy trading and power activities, markets certain third-party products, procures crude oil feedstock and natural gas for Suncor's downstream business, and procures and markets NGLs and LPG for Suncor's downstream business.
Suncor Energy Ventures Corporation	Alberta	A subsidiary which indirectly owns a 36.74% ownership in the Syncrude joint operation.
Suncor Energy Ventures Partnership	Alberta	This partnership owns a 22% ownership in the Syncrude joint operation.
U.S. operations		
Suncor Energy (U.S.A.) Marketing Inc.	Delaware	A subsidiary that procures and markets third-party crude oil, in addition to procuring crude oil feedstock for the company's refining operations.
Suncor Energy (U.S.A.) Inc.	Delaware	A subsidiary through which Suncor's U.S. refining and marketing operations are conducted.
International operations		

Suncor Energy UK Limited	U.K.	A subsidiary through which the majority of Suncor's operations in the U.K. are conducted.

The company's remaining subsidiaries each accounted for (i) less than 10% of the company's consolidated assets as at December 31, 2017, and (ii) less than 10% of the company's consolidated operating revenues for the fiscal year ended December 31, 2017. In aggregate, the remaining subsidiaries accounted for less than 20% of each of the company's consolidated assets as at December 31, 2017 and the company's consolidated operating revenues for the fiscal year ended December 31, 2017.

GENERAL DEVELOPMENT OF THE BUSINESS

Overview

Suncor is an integrated energy company headquartered in Calgary, Alberta, Canada. The company is strategically focused on developing one of the world's largest petroleum resource basins Canada's Athabasca oil sands. In addition, Suncor explores for, acquires, develops, produces and markets crude oil and natural gas in Canada and internationally; the company transports and refines crude oil, and markets petroleum and petrochemical products primarily in Canada. The company also conducts energy trading activities focused principally on the marketing and trading of crude oil, natural gas, power and byproducts. Suncor also operates a renewable energy business as part of its overall portfolio of assets.

Suncor has classified its operations into the following segments:

OIL SANDS

Suncor's Oil Sands segment, with assets located in the Athabasca oil sands of northeast Alberta, recovers bitumen from mining and in situ operations and either upgrades this production into SCO for refinery feedstock and diesel fuel, or blends the bitumen with diluent for direct sale to market. The Oil Sands segment is comprised of:

Oil Sands operations refer to Suncor's wholly owned and operated mining, extraction, upgrading, in situ and related logistics and storage assets in the Athabasca oil sands region. Oil Sands operations consist of:

Oil Sands Base operations include the Millennium and North Steepbank mining and extraction operations, integrated upgrading facilities known as Upgrader 1 and Upgrader 2, and the associated infrastructure for these assets including utilities, cogeneration units, energy and reclamation facilities.

In Situ operations include oil sands bitumen production from Firebag and MacKay River and supporting infrastructure, such as central processing facilities; cogeneration units; hot bitumen infrastructure, including insulated pipelines, diluent import lines and a cooling and blending facility; and associated storage assets such as Suncor's East Tank Farm (ETF) operations specific to In Situ. Production is either upgraded by Oil Sands Base, or blended with diluent and marketed directly to customers.

Oil Sands ventures operations include Suncor's 53.55% interest in the Fort Hills mining project, where Suncor is the operator. The company's interest in Fort Hills increased from its previous 50.8% as a result of the resolution of the commercial dispute regarding project funding among the partners. On December 21, 2017, Suncor acquired an additional 2.26% interest, bringing Suncor's share in the project as at December 31, 2017, to 53.06%. On February 20, 2018, Suncor acquired an additional 0.49% interest in the project, in accordance with the terms of the same dispute settlement agreement. The Fort Hills project includes the mine, primary and secondary extraction facilities, and supporting infrastructure. The ETF facility was expanded in July 2017 to support Fort Hills production. The expanded facilities that blend Fort Hills bitumen for Suncor and the other Fort Hills project partners are described as the East Tank Farm Development (ETFD). On November 22, 2017, the company completed the disposition of a combined 49% ownership interest in the new ETFD to the Fort McKay First Nation and the Mikisew Cree First Nation through the creation of the Thebacha Limited Partnership. Oil Sands ventures operations also include Suncor's 58.74% working interest in the Syncrude oil sands mining, extraction and upgrading facilities, as well as undeveloped mining leases. As at December 31, 2017, Suncor's share in Syncrude was 53.74%. On February 23, 2018, Suncor acquired an additional 5% interest in Syncrude from Mocal Energy Limited (Mocal) for US$730 million, subject to closing adjustments.

EXPLORATION AND PRODUCTION

Suncor's Exploration and Production (E&P) segment consists of offshore operations off the east coast of Canada and in the North Sea, and onshore assets in North America, Libya and Syria.

E&P Canada operations include Suncor's 37.675% working interest in Terra Nova, which Suncor operates. Suncor also holds non-operated interests in Hibernia (20% in the base project and 19.190% in the Hibernia Southern Extension Unit (HSEU)), White Rose (27.5% in the base project and 26.125% in the extensions), and Hebron (21.034%). In addition, Suncor holds interests in several exploration licences offshore Newfoundland and Labrador. E&P Canada also includes Suncor's working interests in natural gas properties in northeast B.C. On February 7, 2018, Suncor reached an agreement with Canbriam Energy Inc. (Canbriam) to exchange all of Suncor's northeast B.C. mineral landholdings, including associated production, along with additional cash consideration of $52 million for a 37% equity interest in the private natural gas company. The transaction is subject to regulatory approval and is expected to close in March 2018.

E&P International operations include Suncor's non-operated interests in Buzzard (29.89%), Golden Eagle Area Development (GEAD) (26.69%), the Rosebank future development project (30%) and the Oda project (30%). On February 9, 2018, Suncor entered into an agreement with Faroe Petroleum to acquire a 17.5% non-operated interest in the Fenja development project. The transaction is subject to customary closing conditions and regulatory approval and is expected to close in the second quarter of 2018. The first three projects are located in the U.K. sector of the North Sea, while the Oda and Fenja projects are located in the Norwegian North Sea. Suncor also holds interests in several exploration licences offshore of the U.K. and Norway. Suncor owns, pursuant to EPSAs, working interests in the exploration and development of oilfields in the Sirte Basin in Libya; some of these oilfields remain shut in due to political unrest, with the timing of a return to normal operations uncertain. Suncor also owns, pursuant to a PSC, an interest in the Ebla gas development in Syria. Suncor's operations in Syria were suspended indefinitely in 2011 due to political unrest in the country, and the company believes the assets in both Libya and Syria have sustained various degrees of damage over the past several years, including certain assets that the company believes have sustained significant damage.

REFINING AND MARKETING

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

Refining and Supply operations refine crude oil and intermediate feedstock into a broad range of petroleum and petrochemical products. Refining and Supply consists of:

Eastern North America operations include a refinery located in Montreal, Quebec and a refinery located in Sarnia, Ontario. Suncor previously operated a lubricants business located in Mississauga, Ontario that manufactured and blended products which were marketed worldwide. Suncor sold the lubricants business in 2017. The sale closed on February 1, 2017.

Western North America operations include refineries located in Edmonton, Alberta and Commerce City, Colorado.

Other Refining and Supply assets include interests in a petrochemical plant and a sulphur recovery facility in Montreal, Quebec, product pipelines and terminals in Canada and the U.S., and the St. Clair ethanol plant in Ontario.

Marketing operations sell refined petroleum products to retail, commercial and industrial customers through a combination of Petro-Canada™ and Sunoco™ company-owned locations and branded-dealers, a nationwide commercial road transport network and a bulk sales channel in Canada, as well as through other retail stations and wholesale customers in Colorado.

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 marketing, supply and trading activities, and other activities not directly attributable to any other operating segment.

Renewable Energy investment activities include development, construction, and ownership of Suncor-operated and joint venture partner-operated renewable power facilities across Canada. This includes a portfolio of operating wind power facilities located in Alberta, Saskatchewan and Ontario, as well as a portfolio of optioned lands for future wind and solar power project development.

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

Corporate activities include 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 **Eliminations**. Intersegment activity includes the sale of product between the company's segments and insurance for a portion of the company's operations by the **Corporate** captive insurance entity.

Three-Year History

Over the last three years, several events have influenced the general development of Suncor's business.

2015

Demonstrated commitment to Suncor's core business through further investment in the oil sands. The company acquired an additional 10% of the Fort Hills mining project from Total E&P Canada Ltd. (Total E&P), bringing Suncor's interest in the project at that time to 50.8%.

Upgrader utilization exceeded 90%. Suncor's long-term commitment to operational excellence continued to drive operational efficiencies, including increased upgrader reliability in 2015.

Fort Hills construction ramped up with substantial completion of detailed engineering work. Construction continued to ramp up with more than 50% of construction completed at the end of 2015.

Firebag nameplate capacity increased from 180,000 bbls/d to 203,000 bbls/d. Cost-effective debottlenecking activities were completed at Firebag, with sustained production levels in excess of 180,000 bbls/d achieved in 2015. This resulted in a nameplate capacity increase effective January 1, 2016.

Completion of asset exchange and lease with TransAlta Corporation. Suncor assumed operating control of the Poplar Creek cogeneration facilities, which provide steam and power to the company's Oil Sands operations, in exchange for Suncor's Kent Breeze and its share of Wintering Hills wind power facilities. Bringing the Poplar Creek assets in-house has improved Suncor's overall Oil Sands operations reliability and profitability.

Enbridge's Line 9 reversal was commissioned during the fourth quarter of 2015. The reversal provides Suncor the flexibility to supply its Montreal refinery with a full slate of inland-priced crude, enhancing the long-term competitiveness of the refinery.

Government of Alberta announced a new climate plan. The new plan announced in late 2015 included a carbon pricing regime coupled with an overall emissions limit for the oil sands. The climate plan places some certainty on the future greenhouse gas (GHG) costs for Suncor, while the limit on oil sands emissions, with a focus on technology and innovation, sets the ambition for managing the trajectory of oil sands emissions.

Government of Alberta Royalty Review. The Government of Alberta conducted a review of the province's oil and gas royalties. Subsequent to year end, the new royalty system was announced, which maintained the existing oil sands rates, providing certainty and predictability for the industry.

2016

Acquisition of Canadian Oil Sands Limited (COS). In the first quarter of 2016, Suncor acquired COS, which owned 36.74% of Syncrude. This acquisition has provided Suncor with an incremental 128,600 bbls/d of SCO production capacity through its additional ownership interest in Syncrude.

Acquisition of additional 5% interest in Syncrude. In June 2016, Suncor acquired an additional 5% interest in Syncrude from Murphy Oil Company Limited (Murphy), which added a further 17,500 bbls/d of SCO capacity, bringing Suncor's ownership interest in Syncrude at that time to 53.74%.

Completed a turnaround of the Upgrader 2 facilities. The first full turnaround of the Upgrader 2 facilities was completed since the company moved to a five-year cycle.

Executed an equity offering for net proceeds of $2.8 billion. The net proceeds were used to fund the acquisition of the additional 5% interest in Syncrude from Murphy and to reduce debt to provide ongoing balance sheet flexibility.

Oil Sands operations production returned safely to normal operating rates. Suncor's Oil Sands production, including Syncrude, was completely shut in during the forest fires in the Fort McMurray region. Suncor leveraged its capability to safely evacuate community members and workers from the region. No assets were damaged during the forest fires and operations subsequently returned to normal production rates by mid-July.

Purchased 30% participating interest in the Rosebank project. The Rosebank project is considered one of the largest remaining undeveloped resources in the U.K. North Sea. The project is expected to be complementary to Suncor's existing U.K. portfolio.

2017

Sale of Suncor's interest in the Cedar Point wind facility. On January 24, 2017, the company closed the sale of Suncor's 50% share of Cedar Point for gross proceeds of $291 million.

Sale of Petro-Canada Lubricants Inc. (PCLI) business. On February 1, 2017, the company completed the sale of PCLI, including the production and manufacturing facilities in Mississauga, Ontario as well as the global marketing and distribution assets held by PCLI, for gross proceeds of $1.125 billion to a subsidiary of HollyFrontier Corporation (HollyFrontier). The sale of PCLI reinforces the company's commitment to continuously optimize its asset portfolio and focus on core assets.

Suncor commenced a normal course issuer bid (NCIB). Suncor filed its notice of intention to commence a new NCIB to purchase and cancel up to $2.0 billion of the company's shares, beginning on May 2, 2017 and ending on May 1, 2018, through the facilities of the Toronto Stock Exchange, New York Stock Exchange and/or alternative trading platforms. As at December 31, 2017, the company had repurchased 33.2 million common shares at an average price of $42.61 per share, for a total repurchase cost of $1.413 billion.

West White Rose Project sanctioned. Suncor is a non-operating partner with a blended working interest of approximately 26%. The company's share of peak oil production is estimated to be 20,000 bbls/d. First oil is targeted for 2022.

Sale of Suncor's interest in the Ripley wind facility. On July 10, 2017, the company closed the sale of Suncor's 50% share of Ripley for gross proceeds of $48 million.

Sale of 49% equity interest in Suncor's ETFD. On November 22, 2017, the company closed the sale to Fort McKay First Nation and Mikisew Cree First Nation of a 49% equity interest in Suncor's ETFD for gross proceeds of $503 million. The deal represents the largest business investment to date by First Nations in Canada.

US$750 million notes offering. On November 15, 2017, the company issued US$750 million of 4.00% senior unsecured notes due in 2047.

First oil from Hebron. Hebron commenced production of oil on November 27, 2017. At peak, Hebron is expected to produce more than 30,000 bbls/d, net to Suncor.

Repayment of debt. The company repaid US$1.25 billion 6.10% notes, US$600 million 6.05% notes and $700 million 5.80% notes all originally scheduled to mature in the first half of 2018. The reduction in outstanding debt reduced financing costs and has provided ongoing balance sheet flexibility.

Fort Hills commercial dispute resolution. On December 21, 2017, the Fort Hills partners resolved their commercial dispute with respect to funding of project capital and reached an agreement pursuant to which Suncor acquired an additional 2.26% interest in the project for consideration of $308 million. Suncor's share in the project as at December 31, 2017, was 53.06%. On February 20, 2018, Suncor acquired an additional 0.49% interest in the Fort Hills project for consideration of $65 million. Suncor's share in the project is now 53.55%.

Fort Hills PFT bitumen now being produced and shipped to market. During the fourth quarter of 2017, the company continued to test the front end of the plant to mitigate the risk associated with the ramp up in 2018. The bitumen froth from testing was further processed to SCO by Oil Sands operations. The Fort Hills project began producing paraffinic froth-treated bitumen from secondary extraction on January 27, 2018, and the production ramp up to the project's nameplate capacity of 194 mbbls/d (104 mbbls/d, net to Suncor) is progressing on schedule.

2018 Developments

Asset exchange with Canbriam. On February 7, 2018, Suncor reached an agreement with Canbriam to exchange all of Suncor's northeast B.C. mineral landholdings, including associated production, along with additional cash consideration of $52 million for a 37% equity interest in Canbriam, a private natural gas company. The transaction is subject to regulatory approval and is expected to close in March 2018.

Purchased 17.5% participating interest in the Fenja development project. On February 9, 2018, Suncor entered into an agreement with Faroe Petroleum to acquire a 17.5% non-operated interest in the Fenja development project located in the Norwegian North Sea for US$54.5 million. The transaction is subject to customary closing conditions and regulatory approvals and is expected to close in the second quarter of 2018.

Acquisition of additional 5% interest in Syncrude. On February 23, 2018, Suncor acquired an additional 5% interest in Syncrude from Mocal for US$730 million, subject to closing adjustments, adding a further 17,500 bbls/d of SCO capacity and increasing the company's ownership interest to 58.74%.

NARRATIVE DESCRIPTION OF SUNCOR'S BUSINESSES

For a discussion of the environmental and other regulatory conditions, and competitive conditions and seasonal impacts affecting Suncor's segments, refer to the Industry Conditions and Risk Factors sections of this AIF.

Oil Sands

Oil Sands Operations   Assets and Operations

Oil Sands Base Operations

Suncor's integrated Oil Sands Base operations, located in the Athabasca oil sands region of northeast Alberta, involve numerous activities:

Mining and Extraction

After overburden is removed, open-pit mining operations use shovels to excavate oil sands bitumen ore, which is trucked to sizers and breaker units that reduce the size of the ore. Next, a slurry of hot water, sand and bitumen is created and delivered via a 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. Coarse tailings produced in this process are placed directly into sand placement areas.

Upgrading

After the diluted bitumen is transferred to upgrading facilities, the naphtha is removed and recycled to be used again as diluent in the extraction processes. Bitumen is upgraded through a coking and distillation process. The upgraded product, referred to as sour SCO, is either sold to market 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 ultra-low sulphur diesel fuel and other byproducts.

Power and Steam Generation and Process Water Use

To generate steam for the mining and extraction process, the company uses either a cogeneration unit or coke-fired boilers. Electricity is generated by turbine generators, most of which are part of the Oil Sands Base cogeneration unit, or provided by cogeneration units at Firebag. Process water is used in extraction processes and then recycled.

Maintenance

Suncor regularly conducts planned maintenance events at its facilities. Large planned maintenance events that 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. Production levels and product mix are typically impacted during these activities.

Reclamation

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

Oil sands tailings are the remaining sand, water, clay, silt and residual hydrocarbons left after the majority of hydrocarbons are extracted from the ore during the water-based bitumen extraction process. Suncor's updated and approved tailings management plan involves an increase in treatment capacity using Accelerated De-Watering and treatment of mature fine tailings at Oil Sands Base, including the construction of a Permanent Aquatic Storage Structure. This approach is supported by the construction, operation and ongoing monitoring of a Demonstration Pit Lake, and aligns with the Government of Alberta's Tailings Management Framework

(TMF) and the Alberta Energy Regulator's (AER) *Directive 085 Fluid Tailings Management for Oil Sands Mining Projects* (the Tailings Directive).

Oil Sands Base Assets

Millennium and North Steepbank

Suncor pioneered the commercial development of the Athabasca oil sands beginning in 1962, achieving first production in 1967; 2017 marked Suncor's 50th anniversary of producing oil from the Athabasca oil sands. Bitumen is currently mined from the Millennium area, which began production in 2001, and the North Steepbank area, which began production in 2011. During 2017, the company mined approximately 169 million tonnes of bitumen ore (2016 129 million tonnes) and processed an average of 307 mbbls/d of mined bitumen in its extraction facilities (2016 238 mbbls/d).

Production figures for the 2016 comparative period reflect the effect of the 2016 forest fires in the Fort McMurray region, which resulted in production being temporarily shut in at the Millennium and North Steepbank mines, Upgrader 1 and Upgrader 2. The forest fires also impacted production at the company's in situ Firebag and MacKay River assets, and the Syncrude joint operation.

Upgrading Facilities

Suncor's upgrading facilities consist of two upgraders: Upgrader 1, which has capacity of approximately 110 mbbls/d of SCO, and Upgrader 2, which has capacity of approximately 240 mbbls/d of SCO. Suncor's secondary upgrading facilities consist of three hydrogen plants, three naphtha hydrotreaters, two gas oil hydrotreaters, one diesel hydrotreater, and one kero hydrotreater.

During 2017, Suncor averaged 318 mbbls/d of upgraded (SCO and diesel) production net of the company's internal consumption (2016 259 mbbls/d), mainly sourced from bitumen provided by both Oil Sands Base and In Situ operations, as well as from bitumen froth production from Fort Hills as a result of testing the front end of the plant.

Other Mining Leases

Suncor, directly and indirectly, owns interests in several other mineable oil sands leases, including Voyageur South and Audet. Suncor undertakes exploratory drilling programs on such leases from time to time as part of its mine replacement projects. Suncor holds a 100% working interest in both Voyageur South and Audet.

In Situ Operations

Suncor's In Situ operations at Firebag and MacKay River use SAGD technology to produce bitumen from oil sands deposits that are too deep to be mined.

The SAGD Process

SAGD is an enhanced oil recovery technology for producing bitumen. It requires drilling pairs of horizontal wells with one located above the other. To help reduce land disturbance and improve cost efficiency, well pairs are drilled from multi-well pads. Low pressure steam is injected into the upper wellbore to create a high-temperature steam chamber underground. This process reduces the viscosity of the bitumen, allowing heated bitumen and condensed steam to drain into the lower wellbore and flow up to the surface aided by subsurface pumps or circulating gas.

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 shipment, In Situ operations blend diluent with the bitumen, or transport it through an insulated pipeline as hot bitumen.

Power and Steam Generation

To generate steam for operations, the company uses Once Through Steam Generators (OTSGs) or cogeneration units. OTSGs are fuelled by both purchased natural gas and produced natural gas recovered at central processing facilities. Cogeneration units are energy-efficient systems, which use natural gas combustion to power turbines that generate electricity and steam used in SAGD operations. Excess electricity generation from cogeneration units is used at Oil Sands Base facilities and sold to the Alberta power grid.

Maintenance and Bitumen 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 characteristics 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 experience natural production declines after several years. In an effort to maintain bitumen supply, Suncor drills new wells from existing well pads or constructs new well pads to facilitate future well drilling.

In Situ Assets

Firebag

Production from Suncor's Firebag operations commenced in 2004. The Firebag complex has central processing facilities with a total capacity of 203 mbbls/d. Actual production from Firebag varies based on steaming and ramp-up periods for new wells, planned and unplanned maintenance, reservoir conditions and other factors.

As at December 31, 2017, Firebag had 13 well pads in operation, with 173 SAGD well pairs and 38 infill wells either producing or on initial steam injection. Central processing facilities have been designed to be flexible as to which well pads supply bitumen. Steam generated at the various facilities can be used at multiple well pads. In addition, Firebag includes five cogeneration units that generate steam, which are capable of producing approximately 474 MW of electricity. The Firebag site power load requirements are approximately 103 MW and, in 2017, Firebag exported approximately 239 MW of electricity to the Alberta power grid and Oil Sands Base plant. There are also 13 OTSGs at the site for additional steam generation.

During 2017, Firebag production averaged 182 mbbls/d (2016 181 mbbls/d) with a SOR of 2.7 (2016 2.6). Production in the second quarter of 2017 was impacted by the first turnaround of the expanded Firebag central facilities to be completed since the company moved to a five-year turnaround cycle. Production was also impacted by planned upgrader maintenance which was completed in that period.

MacKay River

Production from Suncor's MacKay River operations commenced in 2002. As at December 31, 2017, MacKay River included seven well pads with 110 well pairs either producing or on initial steam injection. The MacKay River central processing facilities have debottlenecked bitumen processing capacity of 38 mbbls/d. TransCanada Energy Ltd. owns the on-site cogeneration unit, which Suncor operates under a commercial agreement, that generates steam and electricity. There are also four OTSGs at the site for additional steam generation.

During 2017, MacKay River production averaged 31 mbbls/d (2016 28 mbbls/d) with a SOR of 3.1 (2016 3.2).

Other In Situ Leases

Suncor owns and operates several other oil sands leases which may support future in situ production, including Lewis, Meadow Creek, OSLO and Chard. As well, Suncor owns a non-operated interest in Kirby on which it may undertake exploratory or delineation drilling. Suncor holds a 100% working interest in Lewis, a 75% working interest in Meadow Creek, a 77.78% working interest in OSLO, interests varying from 25% to 50% in Chard and a 10% working interest in Kirby. In February 2018, Suncor submitted an application for the Lewis project to the AER.

Meadow Creek is a SAGD project that is part of Suncor's planned in situ replication strategy. Suncor holds a 75% interest and is operator of the project which is located approximately 40 km south of Fort McMurray. Meadow Creek consists of two independent In Situ projects: Meadow Creek East and Meadow Creek West.

In early 2017, Suncor received AER approval for the Meadow Creek East project. This approval is Suncor's first in situ development approval since Firebag. The project will be developed in two stages with anticipated production of 40 mbbls/d up to 80 mbbls/d, provided economic conditions continue to support such a project. Construction could begin as early as 2020 with first oil expected as early as 2023.

In October 2017, Suncor submitted an application for the Meadow Creek West project to the AER. Meadow Creek West has an anticipated production capacity of 40 mbbls/d. Construction is anticipated to begin in 2022 with first oil expected in 2025.

Oil Sands Ventures Assets

Syncrude

As at December 31, 2017, Suncor held a 53.74% interest in the Syncrude joint operation, which has gross bitumen conversion to SCO capacity of 350 mbbls/d (188 mbbls/d net to Suncor). Subsequent to the end of 2017, the company acquired an additional 5% interest in Syncrude from Mocal, bringing Suncor's interest in Syncrude to 58.74% and adding an additional 17.5 mbbls/d of SCO capacity. Syncrude began producing in 1978 and is operated by Syncrude Canada Ltd. (SCL). In 2006, SCL entered into a management services agreement with Imperial Oil Resources (Imperial Oil) to provide business services and leadership. The project is located near Fort McMurray and includes mining operations at Mildred Lake North and Aurora North. In 2012, the Syncrude co-owners announced a plan to develop two mining areas adjacent to the current mine, Mildred Lake West Extension (MLX-W) and Mildred Lake East Extension (MLX-E), subject to final sanctioning and regulatory approvals, which would consequently extend the life of Mildred Lake by a minimum of 10 years. In 2015, a decision was made by the co-owners to progress with the MLX-W program. The MLX-E program is expected to follow MLX-W development if economic conditions prove suitable. The MLX-W program will sustain bitumen production levels at the Mildred Lake site after resource depletion at the North Mine. The plan proposes to use existing mining and extraction facilities. Regulatory applications for these areas were submitted in 2014 and are awaiting AER review. A response is expected from the AER in the second quarter of 2018 and, provided economic conditions support such a project, sanctioning of MLX-W is expected in late 2019 or early 2020.

The proximity of Syncrude to Oil Sands Base affords an opportunity for cost management and collaboration between the company and Syncrude, that involves exploring the option, subject to approval by Syncrude co-owners, for pipelines connecting Syncrude and Oil Sands Base in order to provide opportunities to optimize assets, including during periods of planned maintenance or interruption. During the second quarter of 2017, due to the facility incident at Syncrude, untreated product was transported by truck and sold by Syncrude to Suncor and subsequently sold to market. In addition, a successful bitumen trucking trial was completed, transporting hot bitumen from Suncor's MacKay River to Syncrude for further upgrading.

Syncrude mining operations use truck, shovel and pipeline systems, similar to those at Oil Sands Base. Extraction and upgrading technologies at Syncrude are similar to those used at Oil Sands Base, with the exception that Syncrude uses a fluid coking process that involves the continuous thermal cracking of the heaviest hydrocarbons. At Mildred Lake, electricity is provided by a utility plant fuelled by natural gas and rich fuel gas from upgrading operations. At Aurora North, Syncrude operates two 80 MW gas turbine power plants to provide electricity.

Syncrude produces a single sweet SCO product. Marketing of this product is the responsibility of the individual co-owners.

Land reclamation activities are similar to those at Oil Sands Base; however, certain aspects of the tailings management processes are different. Syncrude's tailings plan uses the following: freshwater capping, a composite tails mixture of fine tails and gypsum, and centrifuge technology that separates water from tailings. The updated tailings management plan for Syncrude is pending approval by the AER.

In 2017, Suncor's share of Syncrude production averaged 134 mbbls/d (2016 130 mbbls/d). Sustaining capital expenditures in 2018 for Syncrude are expected to focus on a planned turnaround and capacity maintenance. Production in the second quarter of 2017 was significantly impacted by a facility incident that occurred late in the first quarter of 2017. Syncrude completed the required facility repairs, coker maintenance and the planned upgrader turnaround and returned to normal operating rates by early August 2017.

Fort Hills

Fort Hills is an oil sands mining area comprising leases on the east side of the Athabasca River, north of Oil Sands Base operations. Fort Hills operations are substantially similar to those of Suncor's Oil Sands Base assets; however, Fort Hills uses a PFT process to produce a marketable bitumen product that is partially decarbonized, resulting in a higher quality bitumen and eliminating the need for upgrading facilities.

Suncor holds a 53.55% working interest in Fort Hills and is the operator of the project. The company's interest in Fort Hills increased from its previous 50.8% to 53.06% in December 2017, as a result of the resolution of the commercial dispute regarding project funding among the partners. Suncor's share in the project as at December 31, 2017, was 53.06%. On February 20, 2018, Suncor acquired an additional 0.49% interest in the project, in accordance with the terms of the same dispute settlement agreement, for consideration of $65 million. Suncor's share of the project costs from sanction to December 31, 2017 were $8.7 billion, including the impacts of changes in foreign exchange rates. During the second half of 2017, the mining and primary extraction assets were tested and first bitumen froth was successfully produced. The Fort Hills project began producing PFT bitumen from secondary extraction on January 27, 2018. This Fort Hills bitumen was received by ETFD and successfully transported to market. The second and third trains of secondary extraction are being insulated and expected to start up in the first half of 2018. Fort Hills remains on track to reach 90% capacity by the end of 2018. The Fort Hills project has a gross nameplate capacity of 194 mbbls/d of bitumen (104 mbbls/d net to Suncor).

Other Oil Sands Ventures Leases

Suncor indirectly owns interests in other mineable oil sands leases, including Mildred Lake West, Lease 29 and Aurora South, through the company's 58.74% working interest in the Syncrude joint operation. The company also owns a 36.75% working interest in Joslyn mining leases.

New Technology

Technology is a fundamental component of Suncor's business. Suncor pioneered commercial oil sands development and continues to advance technology through innovation and collaboration to improve efficiencies, lower costs and increase environmental performance. Development of new technology can take extended periods of time, first to demonstrate technical viability and then to demonstrate economic viability. The necessary validation typically occurs through a series of progressive tests which allow results to be reliably scaled and assessed for implementation.

Early in 2018, Suncor announced that, following a successful commercial-scale evaluation, the company will proceed with the phased implementation of autonomous haulage systems (AHS) at its operated mine sites, starting with the North Steepbank mine. Autonomous haul trucks, which operate using GPS, wireless communication and perceptive technologies, have demonstrated an ability to maneuver safely, effectively and efficiently in Suncor's operating environment and offer a number of advantages over existing truck and shovel operations, including enhanced safety performance, better operating efficiency and lower operating costs.

Suncor is also working on, or has completed, several new technology projects that are proceeding with the next phase of field testing. Examples of Suncor's new technology projects include:

- Oxy-Fuel Combustion The OTSG Oxy-Fuel Demonstration Carbon Capture Technology has the potential to result in the development of a reliable, lower cost solution to capture CO_2 from OTSGs that can be used on a commercial scale for in situ bitumen production. By replacing air with oxygen in the fuel mix on SAGD boilers, the CO_2 produced will be more concentrated, making it easier to capture, while at the same time greatly reducing emissions of nitrogen oxide.

- Zero Liquid Discharge Suncor uses a zero liquid discharge process at the company's MacKay River in situ facility and expects to achieve maximum water reuse by recovering waste water from produced bitumen.

Enhanced Solvent Extraction Incorporating Electromagnetic Heating (ESEIEH) This new method of in situ bitumen recovery uses radio frequency heating and solvents with the goal of reducing energy, GHG and water footprints. The second phase of the pilot project began operations in the third quarter of 2015 and is expected to continue through 2018.

N-SOLV The Nsolv process uses a waterless, warm vaporized solvent technology with the potential of reducing energy, GHG and water impacts during in situ bitumen recovery. An operating pilot of this new technology was completed in early 2017. Suncor and

Nsolv Corporation are evaluating the results and the potential to scale technology up for deployment in a demonstration facility.

Steam Assisted Gravity Drainage Less Intensive Technology Enhanced (SAGD LITE) Field trials are underway to evaluate new SAGD technologies such as solvent addition, surfactant addition, flow control devices and injection control devices that are expected to improve cost, SORs, ultimate recovery and productivity. Monitoring and evaluation will continue throughout 2018.

Sales of Principal Products

Primary markets for SCO and bitumen production from Suncor's Oil Sands segment, including PFT bitumen from Fort Hills, include refining operations in Alberta, Ontario, Quebec, the U.S. Midwest and the U.S. Rocky Mountain regions and markets on the U.S. Gulf Coast. Diesel production from upgrading operations is sold primarily in Western Canada and the United States, marketed by Suncor's Energy Trading business.

For bitumen production from In Situ operations, Suncor's marketing strategy allows it to take advantage of changes in market conditions by either upgrading the bitumen directly at the company's Oil Sands Base facilities, upgrading diluted bitumen at Suncor's Edmonton refinery, or selling diluted bitumen directly to third parties. Increased bitumen sales may also be required during upgrading facilities outages. In Situ bitumen production processed by Oil Sands Base upgrading facilities in 2017 increased to 101 mbbls/d or 47% (2016 93 mbbls/d or 44%) of total in situ bitumen production.

	2017		2016	
Sales Volumes and Operating Revenues Principal Products	**mbbls/d**	**% operating revenues**	mbbls/d	% operating revenues
SCO and diesel (including Syncrude)	**453.4**	**87**	392.0	88
Bitumen	**110.6**	**12**	117.4	11
Byproducts and other operating revenues[(1)]	**n/a**	**1**	n/a	1
	564.0		509.4	

(1) Operating revenues include revenues associated with excess power from cogeneration units.

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

Distribution of Products

Production from Oil Sands operations, including Fort Hills, is gathered into Suncor's Fort McMurray facilities at the Athabasca Terminal, which is operated by Enbridge Inc. (Enbridge), or the East Tank Farm, which is operated by Suncor, and connected to the Athabasca Terminal. Suncor has arrangements with Enbridge to store SCO, diluted bitumen and diesel at this facility. Product moves from the Athabasca Terminal in the following ways:

To Edmonton via the Oil Sands pipeline, which is owned and operated by Suncor. At Edmonton, the product is sold to local refiners, including Suncor, or transferred onto the Enbridge mainline or the TransMountain Pipeline system. Production from Syncrude is shipped via the Pembina Syncrude Pipeline.

To Cheecham, Alberta on the Enbridge Athabasca Pipeline or the Enbridge Wood Buffalo Pipeline. From Cheecham, on the Enbridge Athabasca Pipeline or the Enbridge Wood Buffalo Pipeline Extension to Hardisty, Alberta.

To Edmonton via the Enbridge Waupisoo Pipeline, originating at Cheecham.

From Edmonton and Hardisty, where Suncor has both owned storage capacity and additional capacity under contract, the company has various options for delivering product to customers:

- To 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.
- To Suncor's Sarnia refinery on the Enbridge mainline.
- To most major refining hubs via the Enbridge mainline, Express/Platte and Keystone pipeline systems.
- To Suncor's Montreal refinery on Enbridge's Line 9.

Royalties

Oil sands projects are subject to the royalty framework issued by the Government of Alberta (the Royalty Framework), and regulated by the *Oil Sands Royalty Regulation 2009* (OSRR 2009) and supporting regulations, which were approved in 2008. Under the Royalty Framework, royalties for oil sands projects are based on a sliding-scale rate of 25% to 40% of net revenue, subject to a minimum royalty within a range of 1% to 9% of gross revenue. Revenues used in royalty formulas are driven primarily by benchmark prices for WCS, while sliding-scale percentages in royalty formulas depend on prices for WTI from Cdn$55/bbl for the minimum rate 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).

Oil Sands Base, Fort Hills and Syncrude

Since January 1, 2016, Suncor's Oil Sands Base and Syncrude operations have been subject to the generic royalty regime as set out in the Royalty Framework.

In 2017, Suncor incurred royalties at an average rate of 1% of gross revenue for Oil Sands Base (2016 recovery of 1% due to the impact of prior year audit settlements recorded in 2016) and at an average rate of 6% of gross revenue for Syncrude operations (2016 3%). Oil Sands Base and Syncrude are both in the post-payout phase.

Fort Hills is subject to the same Royalty Framework as Oil Sands Base and Syncrude; however, Fort Hills is in the pre-payout phase.

In Situ

Royalty rates for Suncor's MacKay River and Firebag operations are based on the Royalty Framework.

In 2017, Suncor incurred royalties at an average rate of 2% of gross revenue for MacKay River (2016 recovery of 1% due to the impact of prior year audit settlements recorded in 2016), which is in the post-payout phase, and royalties at an average rate of 2% of gross revenue for Firebag (2016 1%), which continues in the pre-payout phase.

Exploration and Production

E&P Canada Assets and Operations

East Coast Canada

Based in St. John's, Newfoundland and Labrador, this business includes interests in four producing fields and future developments and extensions. Suncor is also involved in exploration drilling for new opportunities. Suncor is the only company in this region with interests in every field currently in production.

Terra Nova

The Terra Nova oilfield is approximately 350 km southeast of St. John's. Terra Nova was discovered 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 mbbls/d (68 mbbls/d net to Suncor) and oil storage capacity of 960 mbbls. Terra Nova was the first harsh environment development in North America to use a FPSO vessel. Actual annual production levels are lower than production capacity, reflecting current reservoir capability, including natural declines, gas and water injection and production limits, and asset and facility reliability. The Terra Nova oilfield is divided into three distinct areas, known as the Graben, the East Flank and the Far East. Production from Terra Nova began in January 2002. Drilling activities took place at Terra Nova in the second half of 2017 and drilling will continue in 2018. As at December 31, 2017, there were 28 wells: 17 oil production wells, nine water injection wells and two gas injection wells.

In 2017, Suncor's share of Terra Nova production averaged 12 mbbls/d (2016 12 mbbls/d). Annual turnaround maintenance was completed at the Terra Nova facility in September 2017, which lasted approximately five weeks.

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 Based Structure (GBS) that sits on the ocean floor, and has gross production capacity of 230 mbbls/d (46 mbbls/d net to Suncor) and oil storage capacity of 1,300 mbbls. Actual production levels are lower, reflecting current reservoir capability, including natural declines, gas and water injection and production limits, and asset and facility reliability. Hibernia commenced production in November 1997. As at December 31, 2017, there were 72 wells: 41 oil production wells, 25 water injection wells, five gas injection wells, and one water-alternating-gas injection well.

In 2010, final agreements were signed between the Hibernia co-venturers and the Government of Newfoundland and Labrador that established the fiscal, equity and operational principles for the development of the HSEU. At the end of 2017, there were five oil production wells and seven water injection wells in the HSEU. The production wells were drilled from the GBS platform and are included in the Hibernia well count above. Of the seven water injection wells, six were drilled using a mobile offshore drill rig at a single drill centre. Water for injection purposes is supplied from the GBS platform via a subsea flowline.

In 2017, Suncor's share of Hibernia production averaged 29 mbbls/d (2016   27 mbbls/d).

White Rose and the White Rose Extensions

White Rose is approximately 350 km southeast of St. John's. Operated by Husky Oil Operations Limited (Husky), White Rose uses a FPSO vessel and has gross production capacity of 140 mbbls/d (39 mbbls/d net to Suncor) and oil storage capacity of 940 mbbls. Actual annual production levels are lower than production capacity, reflecting current reservoir capability, including natural declines, gas and water injection and production limits, and asset and facility reliability. Production from White Rose began in November 2005. As at December 31, 2017, there were 36 wells: 19 oil production wells, 13 water injection wells, three gas storage wells, and one gas injection well.

In 2007, the White Rose co-venturers signed an agreement with the Government of Newfoundland and Labrador for the development of the White Rose Extensions, which include the North Amethyst, South White Rose Extension, and West White Rose satellite fields. First oil was achieved at North Amethyst in May 2010. Development of the South White Rose Extension began in 2013, with first oil being achieved in June 2015.

Development of the West White Rose field has been divided into two stages. The first stage was approved in 2010 and first oil was achieved in September 2011. The second stage, West White Rose Project (WWRP), was sanctioned during the second quarter of 2017 with first oil targeted for 2022. The project is expected to extend the life of the existing White Rose assets, with Suncor's share of peak oil production estimated to be 20 mbbls/d. Major development activity is expected to begin in 2018.

In 2017, Suncor's share of White Rose production averaged 11 mbbls/d (2016 11 mbbls/d). Turnaround maintenance was completed at White Rose in September 2017, which lasted approximately two weeks.

Hebron

The Hebron oilfield is located 340 km southeast of St. John's and is operated by ExxonMobil Canada Properties (ExxonMobil Canada). The development includes a concrete GBS that sits on the ocean floor and supports an integrated topsides deck used for production, drilling and accommodations. At peak, the Hebron project is expected to produce more than 30 mbbls/d, net to Suncor, ramping up over the next several years. Hebron has an oil storage capacity of 1,200 mbbls and 52 well slots. Suncor's share of the post-sanction project cost to first oil was approximately $2.4 billion.

In 2017, activities included sailing the platform to its final offshore location and successfully positioning on the seafloor. Drilling activities commenced in the third quarter of 2017 and will continue throughout 2018. First oil was achieved on November 27, 2017, with Suncor's share of production averaging 0.4 mbbls/d in 2017. As at December 31, 2017, there was one oil production well and one cuttings reinjection well.

Other Assets

Suncor continues to pursue opportunities offshore Newfoundland and Labrador. During 2014, Suncor was a successful joint bidder with ExxonMobil Canada for exploration licences in the Flemish Pass and Carson Basin, located approximately 500 km off the east coast of Newfoundland. These licences carry a work commitment from 2018 to 2021. The company also holds interests in 48 significant discovery licences and three exploration licences offshore in this area.

North America Onshore

The North America Onshore business develops and produces natural gas and NGLs in Western Canada. These assets produce approximately 2 mboe/d, primarily natural gas, from the Kobes/Montney assets in northeast B.C., in which Suncor has a 100% working interest.

Subsequent to the end of 2017, Suncor reached an agreement with Canbriam to exchange all of Suncor's northeast B.C. mineral landholdings, including associated production, along with additional cash consideration of $52 million for a 37% equity interest in Canbriam, a private natural gas company. The transaction is subject to regulatory approval and is expected to close in March 2018.

E&P International Assets and Operations

North Sea

Buzzard

The Buzzard oilfield is located in the Outer Moray Firth, 95 km northeast of Aberdeen, Scotland. Operated by Nexen Petroleum U.K. Limited (Nexen U.K.), a subsidiary of China National Offshore Oil Corporation Limited, the Buzzard facilities have gross installed production capacity of approximately 220 mbbls/d (66 mbbls/d net to Suncor) of oil and 80 mmcf/d (24 mmcf/d net to Suncor) of natural gas. Actual annual production levels are lower than production capacity, reflecting current reservoir capability, including natural declines, water injection limits, gas and water production limits, and asset and infrastructure reliability. Buzzard commenced production in January 2007 and consists of four bridge-linked platforms supporting wellhead facilities, production facilities, living quarters and utilities, as well as sulphur handling. As at December 31, 2017, there were 48 wells: 35 oil and gas production wells and 13 water injection wells. In 2017, Suncor's share of Buzzard production averaged 44 mboe/d (2016 46 mboe/d).

Golden Eagle Area Development (GEAD)

GEAD, which is operated by Nexen U.K., is approximately 20 km north of the Buzzard oilfield and consists of the unitization of the Peregrine, Hobby, Golden Eagle and Solitaire discoveries. The development incorporates a production, utilities and accommodation platform, linked to a separate wellhead platform, with first oil achieved in October 2014. The GEAD co-owners also hold adjacent exploration licences and continue to explore the region. The facilities have gross production capacity of approximately 76 mboe/d (20 mboe/d net to Suncor). As at December 31, 2017, there were 19 wells: 14 oil and gas production wells and five water injection wells. In 2017, Suncor's share of GEAD production averaged 20 mboe/d (2016 19 mboe/d).

Rosebank

In 2016, Suncor acquired a 30% participating interest in the Rosebank project. This project, which was discovered in December 2004 and is operated by Chevron North Sea Limited, is located approximately 130 km northwest of the Shetland Islands, in the U.K. North Sea, in water depths of approximately 1,100 metres. The project is currently in the Front End Engineering and Design phase and has an anticipated gross design capacity of 100 mbbls/d (30 mbbls/d net to Suncor) of crude oil and 80 mmcf/d (24 mmcf/d net to Suncor) of natural gas.

Oda (Norway)

The Oda field (PL405 licence) was discovered in 2011 and is located 13 km east of the producing Ula field in the southern part of the Norwegian North Sea. Spirit Energy is the operator and Suncor has a 30% working interest. The project was sanctioned in November 2016 and the field will be developed with a subsea template that will be tied back to the Ula field. First oil is planned for 2019, with peak production expected to reach 35 mbbls/d (11 mbbls/d net to Suncor) in the second half of 2019. Suncor's share of the post-sanction project cost estimate is approximately $270 million.

Fenja (Norway)

In February 2018, Suncor signed an agreement to acquire a 17.5% participating interest in the Fenja development project (PL586 licence). The transaction is subject to regulatory approval and is expected to close in the second quarter of 2018. The Fenja field, which was discovered in 2014 and is operated by VNG Norge, is located approximately 30 km southwest of the Statoil-operated Njord field in the Norwegian Sea. The plan for development and operation has been submitted to the Ministry of Petroleum and Energy for approval which is expected in the first half of 2018. The field will be developed with two subsea templates with six wells tied back to the Statoil-operated Njord platform. First oil is planned for 2021, with peak production expected to reach 34 mbbls/d (6 mbbls/d net to Suncor) between 2021 and 2022. Suncor's share of the post-sanction project cost estimate is approximately $280 million.

Other Assets

Suncor continues to pursue other opportunities in the North Sea and Norwegian Sea. The company holds interests in 20 exploration licences in the U.K. and Norwegian sectors of these areas.

Other International

Libya

In Libya, Suncor is a signatory to seven EPSAs with the National Oil Company (NOC). Five of the seven EPSAs relate to fields with developed production and exploration prospects; the remaining two are exploration EPSAs related to properties that do not contain reserves, one of which is to be relinquished following an unsuccessful exploration program. Under the EPSAs, Suncor pays 100% of the exploration costs, 50% of the development costs and 12% of the operating costs. The development, operating and eligible exploration costs are recovered through a 12% share of production (Cost Recovery oil). Any Cost Recovery oil remaining after Suncor's costs have been recovered is referred to as excess petroleum, and is shared between Suncor and the NOC based on several factors. The total oil Suncor receives for cost recovery and its share of excess petroleum is referred to as entitlement volumes. The EPSAs expire on December 31, 2032, but include an initial five-year extension through the end of 2037. 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.

Since 2013, production and liftings in Libya have been intermittent due to political unrest, and the remaining value of Suncor's assets in Libya was impaired in 2015. Suncor had production and liftings from some of its oilfields in 2017, but others remain shut in due to political unrest. The timing of a return to normal operations in Libya remains uncertain.

The estimated cost of Suncor's remaining exploration work program commitment at December 31, 2017 is US$359 million. Suncor declared force majeure for all exploration commitments in Libya effective December 14, 2014, and this declaration remains in effect.

In 2016, Suncor changed its method of recording production in Libya to reflect entitlement volumes. In previous periods, Suncor reported volumes on a 50% working interest share of total production. Suncor's share of production in Libya on an entitlement basis averaged 4.5 mbbls/d in 2017 (2016 0.4 mbbls/d).

Syria

In December 2011, amid continuing unrest in Syria, sanctions were imposed and Suncor declared force majeure under its contractual obligations, suspending its operations in the country. Consequently, the company has ceased recording all production and revenue associated with its Syrian assets. Since 2011, Suncor has not been able to monitor the status of any of its assets in the country, including whether certain facilities have suffered damage, although the company believes some assets have sustained significant damage. As a result of continued uncertainty about Suncor's future in the country, the remaining value of the Suncor assets was impaired in 2013.

Sales of Principal Products

Oil and gas production from East Coast Canada, the North Sea and North America Onshore is either marketed by Suncor's Energy Trading business acting as a marketing agent, or sold to the company's Energy Trading business, which then markets the products to customers under direct sales 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 all made on a spot basis, and incorporate pricing that is generally determined on a daily or monthly basis in relation to a specified market reference price.

In Libya, crude oil is marketed by the NOC on behalf of Suncor.

Exploration and Production Sales Summary:

	2017		2016	
Sales Volumes	**mboe/d**	**% operating revenues**	mboe/d	% operating revenues
E&P Canada				
Crude oil and NGLs	**51.1**	**43**	51.6	46
Natural gas	**1.8**	**0**	2.7	0
E&P International				
Crude oil and NGLs[1]	**66.5**	**56**	63.5	53
Natural gas	**1.4**	**1**	1.5	1
Total Exploration and Production				
Crude oil and NGLs	**117.6**	**99**	115.1	99

Natural gas	**3.2**	**1**	4.2	1

(1) E&P International crude oil and NGLs includes production volumes for Libya on an entitlement basis.

Distribution of Products

East Coast Canada field production is transported by shuttle tanker from offshore installations 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, the U.S., Europe, Latin America and Asia. 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.

North America Onshore gas production is typically sold at Station 2, part of the Spectra B.C. transmission system. Suncor also holds firm capacity on the TransCanada PipeLines Gas Transmission Northwest Pipeline, which enables Suncor to deliver natural gas to the Pacific Northwest and California markets.

Buzzard crude oil is transported via the third-party operated Forties Pipeline System to the Hound Point terminal in Scotland and sold as part of the Forties Blend crude stream. Natural gas is transported via the third-party operated Frigg Pipeline System to the St. Fergus Gas Terminal in Scotland.

Golden Eagle crude oil is transported to the third-party operated Flotta Terminal in the Orkney Islands in Scotland, where it is shipped to market as part of the Flotta Gold blend. Natural gas is transported via the third-party operated SAGE Pipeline System to the St. Fergus Gas Terminal in Scotland.

Royalties

East Coast Canada

Terra Nova has reached the net royalty stage, consisting of a two tier profit-sensitive royalty. Tier one is the greater of 10% of gross revenue or 30% of net revenue (gross revenue adjusted for eligible costs). Tier two is an additional 12.5% of net revenue. During 2017, Terra Nova royalties averaged 16% of gross revenue (2016 23% of gross revenue) due to higher eligible capital expenditures in 2017.

Hibernia production from the original oilfields and the AA Block has reached the net royalty stage, consisting of a two tier profit-sensitive royalty and an additional net profits interest (NPI) of 10% of net revenue. Tier one is the greater of 5% of gross revenue or 30% of net revenue. Tier two is an additional 12.5% of net revenue; however, this has not yet been triggered. For the portion of the HSEU that is contained within the original Hibernia licence area, a tier three royalty ranges between 7.5% and 12.5% of net revenue, depending on the price of WTI.

The HSEU royalty structure is similar to the Hibernia arrangement, but is subject to an additional tier three royalty that ranges between 2.5% and 7.5% of net revenue, depending on the price of WTI. The HSEU tier three royalty will coincide with the triggering of the tier one royalty; however, the HSEU is currently still in the basic royalty stage and subject to a royalty of 5% of gross revenue.

During 2017, Hibernia (including the HSEU) royalties and NPI combined to average 26% of gross revenue (2016 19% of gross revenue).

The White Rose base project has reached the net royalty stage, consisting of a two tier profit-sensitive royalty. Tier one is the greater of 7.5% of gross revenue or 20% of net revenue. Tier two is an additional 10% of net revenue. The White Rose Extension tier one and two royalty structures are the same as the base project, and there is an additional tier three royalty of 6.5% of net revenue, payable if WTI is greater than US$50/bbl. The White Rose Extension is currently paying tier one and tier three royalties, but has not yet triggered tier two. During 2017, total White Rose royalties averaged 9% of gross revenue (2016 10% of gross revenue).

The Hebron royalty consists of an initial sliding-scale basic royalty, followed by a three-tiered royalty which will become payable upon the achievement of specified levels of profitability. The basic royalty will start at 1% and increase to 7.5% of gross revenue depending on certain milestones. The tier one royalty is equal to 20% of net revenue. The tier two royalty is equal to an additional 10% of net revenue. The tier three royalty is equal to 6.5% of net revenue, payable if WTI is greater than US$50/bbl. During 2017, Hebron royalties averaged 1% of gross revenue.

E&P International

There are no royalties on oil and gas production from the North Sea; however, in the U.K., oil and gas profits in the North Sea are subject to a 40% income tax rate. In addition, oil and gas profits in Norway are subject to a 78% income tax rate. For operations in Libya, all government interests, except for income taxes, are presented as royalties.

Refining and Marketing

Refining and Supply Assets and Operations

Eastern North America

Montreal Refinery

The Montreal refinery has a crude oil capacity of 137 mbbls/d, processing primarily conventional crude oil, with a flexible configuration that allows processing of light, sour and heavy grades of crude oil, as well as intermediate feedstock. Crude oil is procured at market prices on a spot basis or under contracts that can be terminated on short notice. Crude oil for the refinery can be supplied through several channels, including via Enbridge's Line 9, the Portland-Montreal Pipeline, by marine transportation, and by rail for inland crudes. The Montreal refinery received inland-sourced crude volumes averaging 113.7 mbbls/d in 2017.

Production from the Montreal refinery includes gasoline, distillate, heavy fuel oil, solvents, asphalt and petrochemicals, which are distributed primarily across Quebec and Ontario. The Montreal refinery also continues to produce feedstock sold under a long-term supply contract with HollyFrontier, following the completion of the sale of Suncor's Mississauga lubricants facility in early 2017. Refined products are delivered to distribution terminals and customers via the Trans-Northern Pipeline, truck, rail and marine vessel.

Sarnia Refinery

The Sarnia refinery has a crude oil capacity of 85 mbbls/d, processing both SCO from 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 mainline and Lakehead pipeline systems. Suncor procures conventional crude oil feedstock primarily from Western Canada and has the ability to supplement supply with purchases from the U.S.

Production yield from the Sarnia refinery includes gasoline, kerosene, and jet and diesel fuels, 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 products into the U.S.

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

Other Facilities

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 paraxylene, which is used by customers to manufacture polyester textiles and plastic bottles. Paraxylene production was approximately 368,000 metric tonnes in 2017 (2016 351,000 metric tonnes). 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 operates Canada's largest ethanol facility, the St. Clair Ethanol plant in the Sarnia-Lambton region of Ontario, with a nameplate capacity of 396 million litres per year. In 2017, the plant produced 408 million litres of ethanol (2016 414 million litres).

Suncor closed the sale of PCLI, including the production and manufacturing facilities in Mississauga, Ontario as well as the global marketing and distribution assets held by PCLI, to HollyFrontier on February 1, 2017, for gross proceeds of $1.125 billion. HollyFrontier will continue to operate PCLI under the Petro-Canada™ brand.

Western North America

Edmonton Refinery

The Edmonton refinery has a crude oil capacity of 142 mbbls/d and has the capability to run a full slate of feedstock sourced from Suncor's Oil Sands operations. Crude oil is supplied to the refinery via company-owned and third-party pipelines.

Feedstock is supplied from Suncor's Oil Sands operations, Syncrude operations (including volumes purchased by Suncor from other co-owners' share of production) and other producers from the Wood Buffalo and Cold Lake regions of Alberta. The refinery can process approximately 41 mbbls/d of blended feedstock (comprised of 29 mbbls/d of bitumen and 12 mbbls/d of diluent) and process approximately 44 mbbls/d of sour SCO. The refinery can also process approximately 57 mbbls/d of sweet SCO through its synthetic train.

Production yield from the Edmonton refinery includes primarily gasoline, distillate and other light oils, 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.

Commerce City Refinery

The Commerce City refinery has a crude throughput capacity of 98 mbbls/d. The refinery processes primarily conventional crude oil, and has processed up to 16 mbbls/d of sour SCO and diluted bitumen from Suncor's Oil Sands operations. A majority of crude feedstock is supplied from sources in the U.S., including 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. Crude oil is supplied to the Commerce City refinery primarily by pipeline, with the remainder transported via truck.

Production yield from the Commerce City refinery includes primarily gasoline, distillate and paving-grade asphalt. The majority of the refined products 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.

Other Facilities

To support the supply and demand balance in the Vancouver area, Suncor imports and exports finished products through its Burrard distribution terminal located on the west coast of B.C. 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 tables summarize the crude feedstock, utilizations and production yield mix for Suncor's refineries for the years ended December 31, 2017 and 2016.

Average Daily Crude Throughput (mbbls/d, except as noted)	Montreal		Sarnia		Edmonton		Commerce City	
	2017	2016	**2017**	2016	**2017**	2016	**2017**	2016
Sweet synthetic	**7.9**	5.8	**23.0**	25.0	**52.1**	45.1		
Sour synthetic			**35.7**	26.5	**41.7**	44.6	**11.2**	9.2
Diluted bitumen	**24.3**	25.0			**42.1**	40.1	**7.9**	9.1
Sweet conventional	**86.7**	89.1	**1.4**	0.3		0.5	**66.3**	64.9
Sour conventional	**6.8**	7.7	**20.7**	23.5	**0.7**	1.3	**12.8**	10.4
Heavy conventional								
Total	**125.7**	127.6	**80.8**	75.3	**136.6**	131.6	**98.2**	93.6
Utilization (%)	**92**	93	**95**	89	**96**	93	**100**	95
Equity Crude Processed[1]	**7.6**	10.5	**48.9**	36.4	**103.8**	108.2	**11.2**	9.2

(1) Includes Suncor's upstream operations, including its working interest in Syncrude.

Refined petroleum production yield mix (%)	Montreal		Sarnia		Edmonton		Commerce City	
	2017	2016	**2017**	2016	**2017**	2016	**2017**	2016
Gasoline	**42**	39	**49**	51	**45**	46	**48**	50
Distillates	**34**	34	**39**	37	**50**	50	**35**	34
Other	**24**	27	**12**	12	**5**	4	**17**	17

Distribution Terminals and Pipelines

Suncor owns and operates 13 major refined product terminals across Canada (including terminals adjacent to refineries) 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 the Refining and Marketing segment's current storage and distribution needs.

Suncor has ownership interests in certain pipelines, including the following:

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, Wyoming

Marketing Assets and Operations

Suncor's retail service station network operates nationally in Canada primarily under the Petro-Canada™ brand. As at December 31, 2017, this network consisted of 1,517 outlets across Canada. In addition, refined products are marketed through independent dealers and joint operations. Suncor's Canadian retail network had sales of gasoline motor fuels averaging approximately 4.8 million litres per site in 2017 (2016 4.9 million litres) and attracted an estimated 17.5% share (2016 17.2%) of the national retail market.

Suncor's Colorado retail network consists of 44 owned outlets branded Shell®, Exxon® and Mobil®. Suncor also has product supply agreements with 161 Shell®-branded sites in both Colorado and Wyoming, and with 27 Exxon® and Mobil®-branded sites in Colorado. Marketing activities from the retail network also generate non-petroleum revenues from convenience store sales and car washes.

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

Retail Summary

Locations	As at December 31 2017	2016
Retail Service Stations Canada		
Petro-Canada™-branded	**1 516**	1 492
Sunoco™-branded	**1**	1
	1 517	1 493
Retail Service Stations[(1)] U.S.		
Shell®-branded retail service stations Colorado/Wyoming	**196**	218
Exxon®-branded retail service stations Colorado	**26**	15
Mobil®-branded retail service stations Colorado	**10**	5
	232	238
Wholesale Cardlock Sites Canada		
Petro-Canada™-branded cardlock sites (PETRO-PASS™)	**305**	282

(1) The comparative period has been revised to reflect current period presentation, which includes Shell®, Exxon® and Mobil®-branded sites for which Suncor has exclusive product supply agreements.

	2017		2016	
Sales Volumes	**mbbls/d**	**% operating revenues**	mbbls/d	% operating revenues
Gasoline (includes motor and aviation gasoline)				
Eastern North America	**117.5**		115.2	
Western North America	**125.4**		129.1	
	242.9	**46**	244.3	47
Distillates (includes diesel and heating oils, and aviation jet fuels)				
Eastern North America	**86.8**		76.3	

Western North America	**112.5**		109.8	
	199.3	**37**	186.1	36
Other (includes heavy fuel oil, asphalts, lubricants, petrochemicals, other)				
Eastern North America	**62.4**		61.8	
Western North America	**25.9**		29.2	
	88.3	**17**	91.0	17
	530.5		521.4	

Sales volumes for specific products are moderately affected 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; 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 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, and the Sarnia and Montreal refineries. In addition, Suncor may purchase refined products from third-party suppliers.

Other Suncor Businesses

Energy Trading

Suncor's Energy Trading business is organized around five main commodity groups crude oil, natural gas, sulphur, petroleum coke and electricity and has trading offices in Canada, the U.K. and the U.S.. Energy Trading provides commodity supply, transportation and storage and optimizes price realizations for Suncor's products. The company's customers include mid- to large-sized commercial and industrial consumers, utility companies and energy producers.

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

The Energy Trading business supports the company's Refining and Marketing business by optimizing the supply of crude and NGLs feedstock to the four refineries, managing crude inventory levels during refinery turnarounds and periods of unplanned maintenance, as well as managing external impacts from pipeline disruptions. The business provides reliable natural gas supply to Suncor's upstream and downstream operations and generates incremental revenue through trading and asset optimization.

Renewable Energy

Suncor's renewable energy investment activities include development, construction and ownership of Suncor-operated and joint venture partner-operated renewable power assets across Canada. This currently includes a portfolio of four operating wind power facilities located in Alberta, Saskatchewan and Ontario with a gross installed capacity of 111 MW. In addition, Suncor holds a number of sites for potential future wind and solar power projects that are in various stages of development.

In 2016, the company commenced a sale process for certain assets within the Renewable Energy business. Total gross installed capacity decreased by 176 MW due to the sale of Suncor's interest in the Cedar Point Wind Power Project, which closed on January 24, 2017, and Suncor's interest in the Ripley Wind Power Project, which closed on July 10, 2017.

Suncor's wind power projects as at December 31, 2017:

Wind Power Projects		Ownership Interest (%)	Gross (MW)	Turbines	Completed
Operated by Suncor					
Adelaide	Strathroy, Ontario	75.0	40	18	2014
Non-operated					
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

SUNCOR EMPLOYEES

The following table shows the distribution of employees among Suncor's business units and corporate office.

As of December 31	2017	2016
Oil Sands[(1)]	**6 196**	6 006
Exploration and Production	**332**	339
Refining and Marketing[(2)]	**2 737**	3 401
Corporate, Energy Trading and Renewable Energy[(3)]	**3 116**	3 091
Total	**12 381**	12 837

(1) Includes employees related to the Fort Hills operations.

(2) The decline in Refining and Marketing primarily relates to the sale of PCLI.

(3) Includes employees from the company's Projects group, which supports the business units.

In addition to Suncor's employees, the company also uses independent contractors to supply a range of services.

Approximately 38% of the company's employees were covered by collective agreements at the end of 2017. The majority of the collective agreements, covering 3,774 employees represented by Unifor at various locations, were renewed in 2016. Negotiations are in progress with Teamsters Canada at the Burrard terminal and with Unifor for the ETFD. None of the company's collective agreements are scheduled to expire in 2018.

ETHICS, SOCIAL AND ENVIRONMENTAL POLICIES

Suncor has adopted several policies focused on ethics, social and environmental matters.

Suncor's standards for the ethical conduct of the company's business are set forth in a Standards of Business Conduct Code (the Code), which applies to Suncor's directors, officers, employees and independent contractors, and requires strict compliance with legal requirements. 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, harassment, 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 independent contractor is required to annually complete a Code training course, read a summary of the Code, affirm that he or she understands the requirements of the Code, and provide confirmation of compliance with the Code since his or her last affirmation or confirmation that any instance of non-compliance has been discussed and resolved with the individual's supervisor. Compliance is then reported to Suncor's Governance Committee of the Board of Directors. A copy of the Code is available on Suncor's website at www.suncor.com.

Suncor has a Supplier Code of Conduct which highlights the values that are important to Suncor and is a guide to the standard of behaviour required of all suppliers, contractors, consultants and other third parties with whom Suncor does business. The Supplier Code of Conduct addresses topics such as safety, human rights, harassment, bribery and corruption and confidential information, among others. Compliance with the Supplier Code of Conduct is a standard requirement for all Suncor supply chain contracts.

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 international human rights principles, such as those described in the Universal Declaration of Human Rights. The policy contains guiding principles such as human rights due diligence, respecting the cultures, customs and values of Suncor's employees and the communities where the company operates, security policies that are consistent with international human rights standards and access to dispute resolution mechanisms. The policy makes clear that the scope of Suncor's human rights due diligence includes its own operations and, where it can influence its third-party business relationships, the operations of others.

Suncor has a Stakeholder Relations Policy, which reflects Suncor's values. 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 states that successful stakeholder engagement guides informed decision-making, resolving issues with timely, cost-effective and mutually beneficial solutions, building stronger communities and supporting shared learning.

Suncor has a Canadian Aboriginal Relations Policy, which affirms Suncor's desire to work in collaboration with Aboriginal Peoples to create shared value. The policy sets the foundation for a consistent approach to the company's relationships with Aboriginal Peoples 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 working closely with Aboriginal Peoples 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 interests regarding the opportunities and impacts of energy development on communities and on their traditional and current uses of lands and resources.

Suncor has an Environment, Health and Safety (EH&S) policy, which affirms Suncor's commitment to be a sustainable energy company by working to achieve or exceed levels of performance governed by legislation and by the evolving environmental, social and economic expectations of the company's stakeholders. The policy reflects Suncor's belief that the company's EH&S efforts are complementary and interdependent with the company's economic and social performance. The policy states that Suncor management is responsible for ensuring that employees and contractors under their direction are competent to manage their EH&S responsibilities and are 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.

The Environment, Health, Safety and Sustainable Development Committee of the Board of Directors meets quarterly to review Suncor's effectiveness in meeting its EH&S obligations. The committee also reviews the effectiveness with which Suncor establishes appropriate EH&S policies, including environmental performance, given legal, industry and community standards. Management systems are overseen by this committee to implement such policies and ensure compliance.

Suncor's annual President's Operational Excellence Awards support and highlight the goals of the EH&S policy by honouring employees and contractors who demonstrate an exceptional commitment to environment, health and safety performance. The awards ceremony highlights progress on safety initiatives and provides educational opportunities for all employees.

The aforementioned policies are reviewed regularly, and are accessible to employees and contractors on the company's intranet. Additional workshops and targeted training sessions on various matters under the policies are also conducted as warranted throughout the year. Information regarding the policies is provided for employees primarily though feature articles on the company's intranet. The Aboriginal Relations Policy also has Cree and Dene audio translations. Training on that policy is also provided for employees and independent contractors whose roles require interaction with Aboriginal communities.

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, 2018, with an effective date of December 31, 2017. Reserves evaluations have not been updated since the effective date and, thus, do not reflect changes in the company's reserves since that date. The preparation date of the information is February 23, 2018.

Disclosure of Reserves Data

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

The reserves data included in this section of the AIF for Suncor's Mining and In Situ operations is based upon evaluations conducted by GLJ Petroleum Consultants Ltd. (GLJ), 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 assets offshore Newfoundland and Labrador, its natural gas assets located in Western Canada (collectively, E&P Canada), and conventional assets offshore the U.K. and Norway (North Sea), is based upon evaluations conducted by Sproule Associates Limited or Sproule International Limited (collectively, Sproule), 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.

The reserves data summarizes Suncor's SCO, bitumen, light crude oil and medium crude oil (combined, including immaterial amounts of heavy crude oil) and conventional natural gas (including immaterial amounts of NGLs) reserves and the net present values of future net revenues for these reserves using forecast prices and costs prior to provision for interest and general and administrative expense.

Advisories Reserves Data

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 cost assumptions will be attained and variances could be material. There is no guarantee that the estimates for SCO, bitumen, light crude oil and medium crude oil, heavy crude oil, conventional natural gas and NGLs reserves provided herein will be recovered. Actual SCO, bitumen, light crude oil and medium crude oil, heavy crude oil, conventional natural gas and NGLs volumes recovered may be greater than or less than the estimates provided herein. Readers should review the Glossary of Terms and Abbreviations and the definitions and information contained in the Notes to Reserves Data Tables, Definitions for Reserves Data Tables and Notes to Future Net Revenues Tables in conjunction with the following notes and tables.

Significant Risk Factors and Uncertainties Affecting Reserves

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, or regulatory requirements. Additional technical information regarding geology, hydro geology, reservoir properties and reservoir fluid properties is obtained through seismic programs, drilling programs, updated reservoir performance studies and analysis, and production history, and may result in revisions to reserves. Pricing, market availability and economic conditions affect the profitability of reserves development. Royalty regimes and environmental regulations and other regulatory changes 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 may result in an increase to reserves. Political unrest, such as is occurring in Syria and Libya, has resulted in volumes that would otherwise be classified as reserves being classified as contingent resources.

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

The reserves included in this AIF represent estimates only. There are numerous uncertainties inherent in estimating quantities and quality of these reserves, including many factors beyond the company's control. In general, estimates of reserves and the future net cash flows from these reserves are based upon a number of variable factors and assumptions, such as production forecasts, regulations, pricing, the timing and amount of capital expenditures, future royalties, future operating costs, future abandonment and reclamation costs, and yield rates for upgraded production of SCO from bitumen all of which may vary considerably from actual results and may be affected by many of the factors identified under Industry Conditions and Risk Factors herein. The accuracy of any reserves estimate is a matter of interpretation and judgment and is a function of the quality and quantity of available data, which may have been gathered over time. For these reasons, estimates of the reserves and categorization of such reserves based on the certainty of recovery, prepared by different engineers or by the same engineers at different times, may vary.

Reserves estimates are based upon geological assessment, including drilling and laboratory tests. Mining reserves estimates also consider production capacity and upgrading yields, mine plans, operating life and regulatory constraints. In Situ reserves estimates are also based upon the testing of core samples and seismic operations and demonstrated commercial success of in situ processes. Suncor's actual production, revenues, royalties, taxes, and development and operating expenditures with respect to the company's reserves will vary from such estimates, and such variances could be material. Production performance subsequent to the date of the estimate may justify future revision, either upward or downward, if material.

The reserves evaluations are based in part on the assumed success of activities the company intends to undertake in future years. The reserves and estimated cash flow to be derived from the reserves contained in the reserves evaluations may be increased or reduced to the extent that such activities do or do not achieve the level of success assumed in the reserves evaluations.

Specific significant risk factors and uncertainties affecting Suncor's reserves include, amongst others:

Volatility of Commodity Prices

Commodity pricing affects the profitability of reserves development. For example, higher commodity prices may result in higher reserves by making more projects economically viable or extending their economic life; conversely, lower commodity prices may result in lower reserves. Low commodity prices could have a material adverse effect on Suncor's reserves. Refer to the Risk Factors Volatility of Commodity Prices section of this AIF.

Carbon Risk

Suncor operates in jurisdictions that have regulated, or have proposed to regulate, industrial GHG emissions, including the laws enacted by the Government of Alberta impacting Suncor's current and future Oil Sands assets, a summary of which is set forth in the Industry Conditions Environmental Regulation Climate Change section of this AIF. Such laws could impose significant compliance costs on Suncor, which could potentially impact the economic viability of certain projects recorded as reserves, or could require that new technologies be developed. Future development could be adversely impacted if compliance costs result in projects not being economically viable or if required technologies are not developed. Refer to the Risk Factors Carbon Risk section of this AIF.

Political Unrest

As a result of political unrest in Syria, Suncor reclassified all Syria reserves to contingent resources, effective December 31, 2012. Suncor also reclassified all Libya reserves to contingent resources, effective December 31, 2016, due to political unrest in Libya. All Syria and Libya volumes remain classified as contingent resources as at December 31, 2017. The criteria for the reclassification of the aforementioned volumes back to reserves include sustained periods of political stability, operational and production stability, and normalization of business relations including financial transactions. Refer to the Risk Factors Foreign Operations section of this AIF.

Abandonment and Reclamation costs

Refer to the Additional Information Relating to Reserves Data Abandonment and Reclamation Costs section below.

Refer to the Risk Factors section of this AIF for additional information on significant risk factors and uncertainties affecting Suncor's reserves.

Oil and Gas Reserves Tables and Notes

Summary of Oil and Gas Reserves[1]
as at December 31, 2017
(forecast prices and costs)[2]

	SCO[3] (mmbbls)		Bitumen (mmbbls)		Light Crude & Medium Crude Oil[4] (mmbbls)		Conventional Natural Gas[5] (bcfe)		Total (mmboe)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved Developed Producing										
Mining	2 134	1 923							2 134	1 923
In Situ	160	151	108	100					268	251
E&P Canada					51	40	20	17	54	43
Total Canada	2 294	2 074	108	100	51	40	20	17	2 456	2 217
North Sea					57	57	2	2	57	57
Total Proved Developed Producing	**2 294**	**2 074**	**108**	**100**	**108**	**97**	**22**	**20**	**2 513**	**2 274**
Proved Developed Non-Producing										
Mining										
In Situ	16	12	22	21					39	33
E&P Canada							2	2		
Total Canada	16	12	22	21			2	2	39	33
North Sea										
Total Proved Developed Non-Producing	**16**	**12**	**22**	**21**			**2**	**2**	**39**	**33**
Proved Undeveloped										
Mining			929	863					929	863
In Situ	575	487	675	572					1 250	1 059
E&P Canada					47	46			47	46
Total Canada	575	487	1 603	1 435	47	46			2 226	1 968
North Sea										
Total Proved Undeveloped	**575**	**487**	**1 603**	**1 435**	**47**	**46**			**2 226**	**1 968**
Proved										
Mining	2 134	1 923	929	863					3 062	2 786
In Situ	751	650	805	692					1 557	1 343
E&P Canada					98	86	21	19	102	90
Total Canada	2 885	2 573	1 734	1 555	98	86	21	19	4 721	4 218

North Sea					57	57	2	2	57	57
Total Proved	**2 885**	**2 573**	**1 734**	**1 555**	**155**	**143**	**24**	**22**	**4 778**	**4 275**
Probable										
Mining	608	544	581	492					1 189	1 036
In Situ	1 216	979	342	262					1 558	1 240
E&P Canada					227	191	6	6	228	192
Total Canada	1 823	1 523	923	754	227	191	6	6	2 975	2 469
North Sea					34	34	4	4	35	35
Total Probable	**1 823**	**1 523**	**923**	**754**	**261**	**225**	**10**	**10**	**3 009**	**2 504**
Proved Plus Probable										
Mining	2 741	2 467	1 510	1 356					4 251	3 823
In Situ	1 967	1 629	1 147	954					3 114	2 583
E&P Canada					326	278	28	25	330	282
Total Canada	4 708	4 096	2 657	2 310	326	278	28	25	7 696	6 687
North Sea					91	91	6	6	92	92
Total Proved Plus Probable	**4 708**	**4 096**	**2 657**	**2 310**	**417**	**369**	**34**	**31**	**7 788**	**6 779**

Please see Notes (1) through (5) at the end of the reserves data section for important information about volumes in this table.

Reconciliation of Gross Reserves[1]
as at December 31, 2017
(forecast prices and costs)[2]

	SCO[3]			Bitumen			Light Crude & Medium Crude Oil[4][5]			Conventional Natural Gas[6]			Total	
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probabl
	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	bcfe	bcfe	bcfe	mmboe	mmbo
Mining														
December 31, 2016	2 317	617	2 934	879	577	1 455							3 196	1 19
Extensions & Improved Recovery[7]														
Technical Revisions[8]	(47)	(10)	(57)	10	(20)	(10)							(37)	(30
Discoveries[9]														
Acquisitions[10]				40	25	64							40	25
Dispositions[11]														
Economic Factors[12]														
Production[13]	(136)		(136)										(136)	
December 31, 2017	**2 134**	**608**	**2 741**	**929**	**581**	**1 510**							**3 062**	**1 18**
In Situ														
December 31, 2016	746	1 169	1 915	825	410	1 235							1 571	1 57
Extensions & Improved Recovery[7]	4	(4)		2	(2)								6	(6
Technical Revisions[8]	30	50	80	19	(66)	(47)							49	(16
Discoveries[9]														
Acquisitions[10]														

Dispositions(11)														
Economic Factors(12)														
Production(13)	(28)		(28)	(41)		(41)							(69)	
December 31, 2017	**751**	**1 216**	**1 967**	**805**	**342**	**1 147**							**1 557**	**1 558**
E&P Canada														
December 31, 2016							104	206	310	27	8	35	108	208
Extensions & Improved Recovery(7)							2	33	35				2	33
Technical Revisions(6)(8)							12	(12)		3	(1)	2	13	(12
Discoveries(9)														
Acquisitions(10)														
Dispositions(11)														
Economic Factors(12)										(3)	(1)	(4)	(1)	
Production(13)							(19)		(19)	(5)		(5)	(20)	
December 31, 2017							**98**	**227**	**326**	**21**	**6**	**28**	**102**	**228**
Total Canada														
December 31, 2016	3 063	1 786	4 849	1 704	987	2 691	104	206	310	27	8	35	4 875	2 981
Extensions & Improved Recovery(7)	4	(4)		2	(2)		2	33	35				8	27
Technical Revisions(8)	(17)	41	23	29	(86)	(57)	12	(12)		3	(1)	2	25	(58
Discoveries(9)														
Acquisitions(10)				40	25	64							40	25

Dispositions[11]														
Economic Factors[12]										(3)	(1)	(4)	(1)	
Production[13]	(164)		(164)	(41)		(41)	(19)		(19)	(5)		(5)	(225)	
December 31, 2017	**2 885**	**1 823**	**4 708**	**1 734**	**923**	**2 657**	**98**	**227**	**326**	**21**	**6**	**28**	**4 721**	**2 975**

Please see Notes (1) through (13) at the end of the reserves data section for important information about volumes in this table.

Reconciliation of Gross Reserves[1] *(continued)*
as at December 31, 2017
(forecast prices and costs)[2]

	SCO[3]			Bitumen			Light Crude & Medium Crude Oil[4][5]			Conventional Natural Gas[6]			Total		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	P Pr
	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	bcfe	bcfe	bcfe	mmboe	mmboe	m
North Sea															
December 31, 2016							69	32	101	4	4	8	69	33	
Extensions & Improved Recovery[7]								2	2					2	
Technical Revisions[8]							11		12	3		3	12		