IMPERIAL OIL LTD
Form 10-K
February 27, 2019
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE

SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2018	**Commission file number: 0-12014**

IMPERIAL OIL LIMITED

(Exact name of registrant as specified in its charter)

CANADA	**98-0017682**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
505 QUARRY PARK BOULEVARD S.E., CALGARY, AB, CANADA	**T2C 5N1**
(Address of principal executive offices)	**(Postal Code)**

Registrant s telephone number, including area code:

1-800-567-3776

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

Title of each class	Name of each exchange on which registered
None	None

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

Common Shares (without par value)
(Title of Class)

Indicate by check mark if the registrant is a well-known seasoned issuer (as defined in Rule 405 of the Securities Act).

Yes No......

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934. Yes...... No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 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 No......

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No......

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. Yes No......

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of large accelerated filer , accelerated filer , smaller reporting company and emerging growth company in Rule 12b-2 of the Securities Exchange Act of 1934).

Large accelerated filer	Smaller reporting company......
Accelerated filer......	Emerging growth company......
Non-accelerated filer......	

If an emerging growth company, 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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12 b-2 of the Securities Exchange Act of 1934). Yes..... No

As of the last business day of the 2018 second fiscal quarter, the aggregate market value of the voting stock held by non-affiliates of the registrant was Canadian $10,663,467,561 based upon the reported last sale price of such stock on the Toronto Stock Exchange on that date.

The number of common shares outstanding, as of February 13, 2019, was 777,576,359.

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All dollar amounts set forth in this report are in Canadian dollars, except where otherwise indicated. Note that numbers may not add due to rounding.

The following table sets forth (i) the rates of exchange for the Canadian dollar, expressed in United States (U.S.) dollars, in effect at the end of each of the periods indicated, (ii) the average of exchange rates in effect on the last day of each month during such periods, and (iii) the high and low exchange rates during such periods, in each case based on the noon buying rate in New York City for wire transfers in Canadian dollars as certified for customs purposes by the Federal Reserve Bank of New York.

dollars	**2018**	2017	2016	2015	2014
Rate at end of period	**0.7329**	0.7989	0.7448	0.7226	0.8620
Average rate during period	**0.7693**	0.7714	0.7559	0.7748	0.9023
High	**0.8143**	0.8243	0.7972	0.8529	0.9423
Low	**0.7326**	0.7275	0.6853	0.7148	0.8588

On February 13, 2019, the noon buying rate in New York City for wire transfers in Canadian dollars as certified for customs purposes by the Federal Reserve Bank of New York was $0.7563 U.S. = $1.00 Canadian.

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Forward-looking statements

Statements of future events or conditions in this report, including projections, targets, expectations, estimates, and business plans are forward-looking statements. Forward-looking statements can be identified by words such as believe, anticipate, intend, propose, plan, goal, seek, project, predict, target, estimate, expect, strategy, outlook, schedule, future, continue, likely, may, should, will and similar references to future periods. Disclosure related to estimates, development, timing and recovery of reserves; the improvement of recovery through experimental operations; the timing, cost, efficiency and production of the Aspen and Cold Lake expansion projects; activities with respect to Beaufort Sea licences; Kearl production outlook and growth activities; downstream feedstock mix and logistics; anticipated capital and operating expenditures, including with respect to environmental protection; participation in future investments; anticipated share purchases; the company s long-term business outlook including demand, supply and energy mix; segment growth, competitive strategies and benefits from integration; product sales growth through optimization and expansion; earnings sensitivities; and capital structure and financial strength as a competitive advantage and risk mitigation constitute forward-looking statements.

Forward-looking statements are based on the company s current expectations, estimates, projections and assumptions at the time the statements are made. Actual future financial and operating results, including expectations and assumptions concerning demand growth and energy source, supply and mix; commodity prices and foreign exchange rates; production rates, growth and mix; project plans, dates, costs, capacities and execution; production life and resource recoveries; cost savings; product sales; applicable laws and government policies, including taxation and climate change; financing sources; and capital and environmental expenditures could differ materially depending on a number of factors. These factors include changes in the supply of and demand for crude oil, natural gas, and petroleum and petrochemical products and resulting price and margin impacts; transportation for accessing markets; political or regulatory events, including changes in law or government policy, applicable royalty rates and tax laws; the receipt, in a timely manner, of regulatory and third-party approvals; third party opposition to operations and projects; environmental risks inherent in oil and gas exploration and production activities; environmental regulation, including climate change and greenhouse gas regulation and changes to such regulation; currency exchange rates; availability and allocation of capital; availability and performance of third party service providers; unanticipated operational disruptions; management effectiveness; commercial negotiations; project management and schedules; response to technological developments; operational hazards and risks; cybersecurity incidents; disaster response preparedness; the ability to develop or acquire additional reserves; and other factors discussed in Item 1A risk factors and Item 7 management s discussion and analysis of financial condition and results of operations of this annual report on Form 10-K.

Forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties, some that are similar to other oil and gas companies and some that are unique to Imperial Oil Limited. Imperial Oil Limited s actual results may differ materially from those expressed or implied by its forward-looking statements and readers are cautioned not to place undue reliance on them. Imperial Oil Limited undertakes no obligation to update any forward-looking statements contained herein, except as required by applicable law.

The term project as used in this report can refer to a variety of different activities and does not necessarily have the same meaning as in any government payment transparency reports.

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PART I

Item 1. Business

Imperial Oil Limited was incorporated under the laws of Canada in 1880 and was continued under the Canada Business Corporations Act (the CBCA) by certificate of continuance dated April 24, 1978. The head and principal office of the company is located at 505 Quarry Park Boulevard S.E., Calgary, Alberta, Canada T2C 5N1. Exxon Mobil Corporation (ExxonMobil) owns approximately 69.6 percent of the outstanding shares of the company. In this report, unless the context otherwise indicates, reference to the company or Imperial includes Imperial Oil Limited and its subsidiaries, and reference to ExxonMobil includes Exxon Mobil Corporation and its affiliates, as appropriate.

The company is one of Canada s largest integrated oil companies. It is active in all phases of the petroleum industry in Canada, including the exploration for, and production and sale of, crude oil and natural gas. In Canada, it is a major producer of crude oil, the largest petroleum refiner and a leading marketer of petroleum products. It is also a major producer of petrochemicals.

The company s operations are conducted in three main segments: Upstream, Downstream and Chemical. Upstream operations include the exploration for, and production of, crude oil, natural gas, synthetic oil and bitumen. Downstream operations consist of the transportation and refining of crude oil, blending of refined products and the distribution and marketing of those products. Chemical operations consist of the manufacturing and marketing of various petrochemicals.

Financial information about segments and geographic areas for the company is contained in the Financial section of this report under note 3 to the consolidated financial statements: Business segments .

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Upstream

Disclosure of reserves

Summary of oil and gas reserves at year-end

The table below summarizes the net proved reserves for the company, as at December 31, 2018, as detailed in the Supplemental information on oil and gas exploration and production activities part of the Financial section, starting on page 34 of this report.

All of the company s reported reserves are located in Canada. The company has reported proved reserves based on the average of the first-day-of-the-month price for each month during the last 12-month period ending December 31. Natural gas is converted to an oil-equivalent basis at six million cubic feet per one thousand barrels. No major discovery or other favourable or adverse event has occurred since December 31, 2018 that would cause a significant change in the estimated proved reserves as of that date.

	Liquids (a)	Natural gas	Synthetic oil	Bitumen	Total oil-equivalent basis
	millions of barrels	billions of cubic feet	millions of barrels	millions of barrels	millions of barrels
Net proved reserves:					
Developed	**24**	**273**	**466**	**2,861**	**3,396**
Undeveloped	**38**	**366**	**-**	**305**	**404**
Total net proved	**62**	**639**	**466**	**3,166**	**3,800**

(a) Liquids include crude oil, condensate and natural gas liquids (NGLs). NGL proved reserves are not material and are therefore included under liquids.

The estimation of proved reserves, which is based on the requirement of reasonable certainty, is an ongoing process based on rigorous technical evaluations, commercial and market assessments, and detailed analysis of well information such as flow rates and reservoir pressures. Furthermore, the company only records proved reserves for projects which have received significant funding commitments by management made toward the development of the reserves. Although the company is reasonably certain that proved reserves will be produced, the timing and amount recovered can be affected by a number of factors, including completion of development projects, reservoir performance, regulatory approvals, government policies, consumer preferences, changes in the amount and timing of capital investments, royalty framework and significant changes in long-term oil and gas price levels. In addition, proved reserves could be affected by an extended period of low prices which could reduce the level of the company s capital spending and also impact its partners capacity to fund their share of joint projects. The company s operating decisions and its outlook for future production volumes are not impacted by proved reserves as disclosed under the U.S. Securities and Exchange Commission (SEC) definition.

As a result of improved prices during 2018, under the SEC definition of proved reserves, an additional 2.3 billion barrels of bitumen at Kearl qualified as proved reserves at year-end 2018.

Technologies used in establishing proved reserves estimates

Imperial s proved reserves in 2018 were based on estimates generated through the integration of available and appropriate geological, engineering and production data, utilizing well established technologies that have been demonstrated in the field to yield repeatable and consistent results.

Data used in these integrated assessments included information obtained directly from the subsurface via wellbores, such as well logs, reservoir core samples, fluid samples, static and dynamic pressure information, production test data, and surveillance and performance information. The data utilized also included subsurface information obtained through indirect measurements, including seismic data, calibrated with available well control information. The tools used to interpret the data included proprietary seismic processing software, proprietary reservoir modeling and simulation software, and commercially available data analysis packages.

In some circumstances, where appropriate analog reservoirs were available, reservoir parameters from these analogs were used to increase the quality of and confidence in the reserves estimates.

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Preparation of reserves estimates

Imperial has a dedicated reserves management group that is separate from the base operating organization. Primary responsibilities of this group include oversight of the reserves estimation process for compliance with the U.S. Securities and Exchange Commission rules and regulations, review of annual changes in reserves estimates and the reporting of Imperial s proved reserves. This group also maintains the official reserves estimates for Imperial s proved reserves. In addition, this group provides training to personnel involved in the reserve estimation and reporting processes within Imperial.

The reserves management group maintains a central database containing the company s official reserves estimates. Appropriate controls, including limitations on database access and update capabilities, are in place to ensure data integrity within this central database. An annual review of the system s controls is performed by internal audit. Key components of the reserves estimation process include technical evaluations and analysis of well and field performance, and a rigorous peer review. No changes may be made to reserves estimates in the central database, including the addition of any new initial reserves estimates or subsequent revisions, unless those changes have been thoroughly reviewed and evaluated by duly authorized personnel within the base operating organization. In addition, changes to reserves estimates that exceed certain thresholds require further review and endorsement by the operating organization and the reserves management group, culminating in reviews with and approval by senior management and the company s board of directors.

The internal qualified reserves evaluator is a professional geoscientist registered in Alberta, Canada and has over 20 years of petroleum industry experience, including 14 years of reserves related experience. The position provides leadership to the internal reserves management group and is responsible for filing a reserves report with the Canadian securities regulatory authorities. The company s internal reserves evaluation staff consists of 40 persons with an average of 13 years of relevant technical experience in evaluating reserves, of whom 20 persons are qualified reserves evaluators for purposes of Canadian securities regulatory requirements. The company s internal reserves evaluation management team is made up of 17 persons with an average of 13 years of relevant experience in evaluating and managing the evaluation of reserves.

Proved undeveloped reserves

As at December 31, 2018, approximately 11 percent of the company s proved reserves were proved undeveloped reflecting volumes of 404 million oil-equivalent barrels. Proved undeveloped reserves are associated with Cold Lake and the Montney and Duvernay unconventional assets. This compared to 450 million oil-equivalent barrels of proved undeveloped reserves reported at the end of 2017. The decrease of 46 million oil-equivalent barrels of proved undeveloped reserves includes 63 million oil-equivalent barrels at Cold Lake and conventional assets, partially offset by an increase of 17 million oil-equivalent barrels at the Montney and Duvernay unconventional assets. Conversion of proved undeveloped reserves into proved developed was 22 million oil-equivalent barrels in 2018, associated with conventional, and Montney and Duvernay unconventional assets.

Proved undeveloped reserves that have remained undeveloped for five years or more represent about 71 percent (285 million oil-equivalent barrels) of proved undeveloped reserves and are associated with ongoing drilling programs at Montney and Duvernay unconventional assets and at Cold Lake. These undeveloped reserves are planned to be developed in a staged approach to align with operational capacity and efficient capital spending commitment over the life of the assets. The company is reasonably certain that these proved reserves will be produced; however the timing and amount recovered can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals, government policies, consumer preferences, changes in the amount and timing of capital investments, royalty framework and significant changes in long-term oil and gas price levels.

One of the company s requirements to report resources as proved reserves is that management has made significant funding commitments towards the development of the reserves. The company has a disciplined investment strategy and many major fields require a long lead-time in order to be developed. The company made investments of about $391 million during the year to progress the development of proved undeveloped reserves in its Montney and Duvernay unconventional assets and at Cold Lake. These investments represented about 40 percent of the $991 million in total reported Upstream capital and exploration expenditures.

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Oil and gas production, production prices and production costs

Reference is made to the portion of the Financial section entitled Management s discussion and analysis of financial condition and results of operations on page 38 of this report for a narrative discussion on the material changes.

Average daily production of oil

The company s average daily oil production by final products sold during the three years ended December 31, 2018 was as follows. All reported production volumes were from Canada.

thousands of barrels per day (a)		**2018**	2017	2016
Bitumen:				
Cold Lake:	- gross (b)	**147**	162	161
	- net (c)	**120**	132	138
Kearl:	- gross (b)	**146**	126	120
	- net (c)	**135**	123	118
Total bitumen:	- gross (b)	**293**	288	281
	- net (c)	**255**	255	256
Synthetic oil (d):	- gross (b)	**62**	62	68
	- net (c)	**60**	57	67
Liquids (e):	- gross (b)	**6**	5	15
	- net (c)	**7**	4	13
Total:	- gross (b)	**361**	355	364
	- net (c)	**322**	316	336

(a) Volume per day metrics are calculated by dividing the volume for the period by the number of calendar days in the period.
(b) Gross production is the company s share of production (excluding purchases) before deduction of the mineral owners or governments share or both.
(c) Net production is gross production less the mineral owners or governments share or both.
(d) The company s synthetic oil production volumes were from the company s share of production volumes in the Syncrude joint venture.
(e) Liquids include crude oil, condensate and NGLs.

Average daily production and production available for sale of natural gas

The company s average daily production and production available for sale of natural gas during the three years ended December 31, 2018 are set forth below. All reported production volumes were from Canada. All gas volumes in this report are calculated at a pressure base of 14.73 pounds per square inch absolute at 60 degrees Fahrenheit. Reference is made to the portion of the Financial section entitled Management s discussion and analysis of financial condition and results of operations on page 38 of this report for a narrative discussion on the material changes.

millions of cubic feet per day (a)	**2018**	2017	2016
Gross production (b) (c)	**129**	120	129
Net production (c) (d) (e)	**126**	114	122
Net production available for sale (f)	**94**	80	87

(a) Volume per day metrics are calculated by dividing the volume for the period by the number of calendar days in the period.
(b) Gross production is the company s share of production (excluding purchases) before deduction of the mineral owners or governments share or both.
(c) Production of natural gas includes amounts used for internal consumption with the exception of the amounts reinjected.
(d) Net production is gross production less the mineral owners or governments share or both.
(e) Net production reported in the above table is consistent with production quantities in the net proved reserves disclosure.
(f) Includes sales of the company s share of net production and excludes amounts used for internal consumption.

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Total average daily oil-equivalent basis production

The company s total average daily production expressed in an oil-equivalent basis is set forth below, with natural gas converted to an oil-equivalent basis at six million cubic feet per one thousand barrels.

thousands of barrels per day (a)	**2018**	2017	2016
Total production oil-equivalent basis:			
- gross (b)	**383**	375	386
- net (c)	**343**	335	356

(a) Volume per day metrics are calculated by dividing the volume for the period by the number of calendar days in the period.
(b) Gross production is the company s share of production (excluding purchases) before deduction of the mineral owners or governments share or both.
(c) Net production is gross production less the mineral owners or governments share or both.

Average unit sales price

The company s average unit sales price and average unit production costs by product type for the three years ended December 31, 2018 were as follows.

Canadian dollars per barrel	**2018**	2017	2016
Bitumen	**37.56**	39.13	26.52
Synthetic oil	**70.66**	67.58	57.12
Liquids (a)	**40.20**	38.49	28.01
Canadian dollars per thousand cubic feet			
Natural gas	**2.43**	2.58	2.41

(a) Liquids include crude oil, condensate and NGLs.

In 2018, Imperial s average Canadian dollar realizations for bitumen declined generally in line with Western Canada Select, adjusted for changes in the exchange rate and transportation costs. The company s average Canadian dollar realizations for synthetic crude increased, however the widening of the western Canadian light crude differential relative to West Texas Intermediate during the fourth quarter of 2018 negatively impacted synthetic crude realizations.

In 2017, Imperial s average Canadian dollar realizations for bitumen and synthetic crudes increased generally in line with the North American benchmarks, adjusted for changes in the exchange rate and transportation costs.

Average unit production costs

Canadian dollars per barrel	**2018**	2017	2016
Bitumen	**29.39**	26.81	24.24
Synthetic oil	**60.34**	58.96	46.24
Total oil-equivalent basis (a)	**35.28**	32.96	28.52

(a) Includes liquids, bitumen, synthetic oil and natural gas.

In 2018, bitumen unit production costs were higher, primarily driven by Kearl costs associated with improving reliability, partly offset by the impact of higher production.

In 2018, synthetic oil unit production costs were higher, primarily driven by higher maintenance costs, including impacts of the June 20 site-wide power disruption.

In 2017, synthetic oil unit production costs were higher, primarily driven by impacts of the fire at the Syncrude Mildred Lake upgrader.

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Drilling and other exploratory and development activities

The company has been involved in the exploration for and development of crude oil and natural gas in Canada only.

Wells drilled

The following table sets forth the net exploratory and development wells that were drilled or participated in by the company during the three years ended December 31, 2018.

wells	**2018**	2017	2016
Net productive exploratory	**-**	-	-
Net dry exploratory	**-**	-	-
Net productive development	**19**	5	6
Net dry development	**1**	-	-
Total	**20**	5	6

In 2018, wells drilled to add productive capacity include 10 development wells at Cold Lake and 9 wells associated with the Montney and Duvernay unconventional assets.

In 2017 and 2016, wells were drilled to add productive capacity, associated primarily with the Montney and Duvernay unconventional assets.

Wells drilling

At December 31, 2018, the company was participating in the drilling of the following exploratory and development wells, located primarily within the Montney and Duvernay unconventional assets. All wells were located in Canada.

	2018	
wells	Gross	Net
Total	**24**	**11**

Exploratory and development activities regarding oil and gas resources

Cold Lake

To maintain production at Cold Lake, capital expenditures for additional production wells and associated facilities are required periodically. Additional wells were drilled on existing phases in 2018.

The company also conducts experimental pilot operations to improve recovery of bitumen from wells by means of new drilling, production or recovery techniques.

Aspen, Cold Lake expansion and other oil sands activities

The company filed a regulatory application for a new in-situ oil sands project at Aspen in December 2013, using steam-assisted gravity drainage (SAGD) technology to develop the project in three phases producing about 45,000 barrels per day before royalties, per phase. In 2015, the company amended the regulatory application to develop the

Aspen project using solvent-assisted, steam-assisted gravity drainage (SA-SAGD) technology. The technology significantly improves capital efficiency and lowers greenhouse gas intensity versus the existing SAGD technologies. The project is proposed to be executed in two phases producing about 75,000 barrels per day before royalties, per phase.

In October 2018, regulatory approval for the Aspen in-situ project was received from the Alberta Energy Regulator. The first phase of the project was approved by the company s board and appropriated for $2.6 billion. Construction began late in the fourth quarter of 2018.

In March 2016, Imperial filed a regulatory application for the Cold Lake expansion project to develop the Grand Rapids interval using SA-SAGD technology. The project is proposed to produce 50,000 barrels per day, before royalties. In August 2018, regulatory approval for the Cold Lake expansion project was received from the Alberta Energy Regulator. The regulatory approval is currently being reviewed. No final investment decisions have been made at this time.

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Work continues on technical evaluations to support potential Corner, Clyden and Chard in-situ development regulatory applications.

The company also has interests in other oil sands leases in the Athabasca and Peace River areas of northern Alberta. Evaluation wells completed on these leased areas established the presence of bitumen. The company continues to evaluate these leases to determine their potential for future development.

Montney and Duvernay

The company is continuing to evaluate, develop and produce resources in its Montney and Duvernay unconventional assets in the western provinces.

Beaufort Sea

In 2007, the company acquired a 50 percent interest in an exploration licence in the Beaufort Sea. As part of the evaluation, a 3-D seismic survey was conducted in 2008 and the company has since carried out data collection programs to support environmental studies and safe exploration drilling operations.

In 2010, the company executed an agreement to cross-convey interests with another company to acquire a 25 percent interest in an additional Beaufort Sea exploration licence. As a result of that agreement, the company operates both licences and its interest in the original licence was reduced to 25 percent. The exploration licences are held through 2019 and 2020, respectively.

In 2013, the company and its joint venture partners filed a project description, initiating the formal regulatory review of the project.

In December 2016, the Federal Government of Canada declared Arctic waters off limits to new offshore oil and gas licences for five years subject to review at the end of that period. Existing licences will not be impacted. The Federal Government continues to consult with existing leaseholders. Current activities continue to focus on community consultation and progressing legislative changes to extend the life of existing licences. The company continues to evaluate the licences.

Liquefied natural gas (LNG) activity

WCC LNG Ltd., jointly owned by the company (20 percent) and ExxonMobil Canada Ltd. (80 percent), was granted an export licence in 2013 for up to 30 million tonnes of LNG per year for a period of 25 years. In 2016, the licence period was extended to 40 years. In December, 2018, after careful review, Imperial and ExxonMobil Canada Ltd. withdrew the WCC LNG project from the British Columbia environmental assessment process.

Exploratory and development activities regarding oil and gas resources extracted by mining methods

The company continues to evaluate other undeveloped, mineable oil sands acreage in the Athabasca region.

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Present activities

Review of principal ongoing activities

Cold Lake

Cold Lake is an in-situ heavy oil bitumen operation. The product, a blend of bitumen and diluent, is shipped to the company s refineries, Exxon Mobil Corporation refineries and to other third parties. Diluent is natural gas condensate or other light hydrocarbons added to the crude bitumen to facilitate transportation by pipeline and rail.

During 2018, net production at Cold Lake was about 120,000 barrels per day and gross production was about 147,000 barrels per day.

Kearl

Kearl is a joint venture established to recover shallow deposits of oil sands using open-pit mining methods to extract the crude bitumen, which is processed through extraction and froth treatment trains. The company holds a 70.96 percent participating interest in the joint venture and ExxonMobil Canada Properties holds the other 29.04 percent. The product, a blend of bitumen and diluent, is shipped to the company s refineries, Exxon Mobil Corporation refineries and to other third parties.

During 2018, the company s share of Kearl s net bitumen production was about 135,000 barrels per day and gross production was about 146,000 barrels per day. Increased 2018 production reflects improved operational reliability associated with ore preparation, enhanced piping durability and feed management.

Imperial continues to progress work to increase Kearl annual average production to 240,000 barrels of bitumen per day (Imperial s gross share would be about 170,000 barrels of bitumen per day), through planned investment including supplemental crushing capacity and flow distribution interconnects to enhance reliability, increase redundancy and reduce downtime. The work is expected to be complete by year-end 2019.

Syncrude

Syncrude is a joint venture established to recover shallow deposits of oil sands using open-pit mining methods to extract crude bitumen, and then upgrade it to produce a high-quality, light (32 degrees API), sweet, synthetic crude oil. The company holds a 25 percent participating interest in the joint venture. The produced synthetic crude oil is shipped to the company s refineries, Exxon Mobil Corporation refineries and to other third parties.

In 2018, the company s share of Syncrude s net production of synthetic crude oil was about 60,000 barrels per day and gross production was about 62,000 barrels per day.

The Province of Alberta, in its capacity as lessor of Cold Lake, Kearl and Syncrude oil sands leases, is entitled to a royalty on production. Royalties are subject to the oil sands royalty regulations which are based upon a sliding scale determined largely by the price of crude oil.

Delivery commitments

The company has no material commitments to provide a fixed and determinable quantity of oil or gas under existing contracts and agreements.

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Oil and gas properties, wells, operations and acreage

Production wells

The company s production of liquids, bitumen and natural gas is derived from wells located exclusively in Canada. The total number of wells capable of production, in which the company had interests at December 31, 2018 and December 31, 2017, is set forth in the following table. The statistics in the table are determined in part from information received from other operators.

	Year ended December 31, 2018				Year ended December 31, 2017			
	Crude oil		Natural gas		Crude oil		Natural gas	
wells	Gross (a)	Net (b)	Gross (a)	Net (b)	Gross (a)	Net (b)	Gross (a)	Net (b)
Total (c)	**4,760**	**4,655**	**3,459**	**1,164**	4,603	4,494	3,460	1,160

(a) Gross wells are wells in which the company owns a working interest.
(b) Net wells are the sum of the fractional working interest owned by the company in gross wells, rounded to the nearest whole number.
(c) Multiple completion wells are permanently equipped to produce separately from two or more distinctly different geological formations. At year-end 2018, the company had an interest in 16 gross wells with multiple completions (2017 - 17 gross wells).

Land holdings

At December 31, 2018 and December 31, 2017, the company held the following oil and gas rights, and bitumen and synthetic oil leases, all of which are located in Canada, specifically in the western provinces, in the Canada lands and in the Atlantic offshore.

		Developed		Undeveloped		Total	
thousands of acres		**2018**	2017	**2018**	2017	**2018**	2017
Western provinces (a):							
Liquids and gas	- gross (b)	**1,497**	1,492	**807**	825	**2,304**	2,317
	- net (c)	**721**	718	**446**	455	**1,167**	1,173
Bitumen	- gross (b)	**197**	197	**595**	674	**792**	871
	- net (c)	**182**	182	**292**	319	**474**	501
Synthetic oil	- gross (b)	**118**	118	**136**	136	**254**	254
	- net (c)	**29**	29	**34**	34	**63**	63
Canada lands (d):							
Liquids and gas	- gross (b)	**4**	4	**1,831**	1,831	**1,835**	1,835
	- net (c)	**2**	2	**498**	498	**500**	500
Atlantic offshore:							
Liquids and gas	- gross (b)	**65**	65	**286**	288	**351**	353
	- net (c)	**6**	6	**45**	46	**51**	52
Total (e):	- gross (b)	**1,881**	1,876	**3,655**	3,754	**5,536**	5,630
	- net (c)	**940**	937	**1,315**	1,352	**2,255**	2,289

(a) Western provinces include British Columbia, Alberta and Saskatchewan.

(b) Gross acres include the interests of others.

(c) Net acres exclude the interests of others.

(d) Canada lands include the Arctic Islands, Beaufort Sea / Mackenzie Delta, and other Northwest Territories, Nunavut and Yukon regions.

(e) Certain land holdings are subject to modification under agreements whereby others may earn interests in the company s holdings by performing certain exploratory work (farm-out) and whereby the company may earn interests in others holdings by performing certain exploratory work (farm-in).

Western provinces

The company s bitumen leases include about 194,000 net acres of oil sands leases near Cold Lake and an area of about 34,000 net acres at Kearl. The company also has about 69,000 net acres of undeveloped, mineable oil sands acreage in the Athabasca region. In addition, the company has interests in other bitumen oil sands leases in the Athabasca areas totaling about 177,000 net acres, which include about 62,000 net acres of oil sands leases in the Clyden area, about 34,000 net acres of oil sands leases in the Aspen area, about 30,000 net acres of oil sands leases in the Corner area and about 18,000 net acres in the Chard area. These 177,000 net acres are suitable for in-situ recovery techniques.

The company s share of Syncrude joint venture leases covering about 63,000 net acres accounts for the entire synthetic oil acreage.

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Oil sands leases have an exploration period of 15 years and are continued beyond that point by meeting the minimum level of evaluation, by payment of escalating rentals, or by production. The majority of the acreage in Cold Lake, Kearl and Syncrude is continued by production.

The company holds interests in an additional 1,167,000 net acres of developed and undeveloped land in the western provinces related to crude oil and natural gas.

Crude oil and natural gas leases and licences from the western provinces have exploration periods ranging from two to 15 years and are continued beyond that point by proven production capability.

Canada lands

Land holdings in Canada lands primarily include exploration licence (EL) acreage in the Beaufort Sea of about 252,000 net acres and significant discovery licence (SDL) acreage in the Mackenzie Delta and Beaufort Sea areas of about 183,000 net acres.

Exploration licences on Canada lands and Atlantic offshore have a finite term. If a significant discovery is made, a SDL may be granted that holds the acreage under the SDL indefinitely, subject to certain conditions.

The company s net acreage in Canada lands is either continued by production or held through ELs and SDLs.

Atlantic offshore

The Atlantic offshore acreage is continued by production or held by SDLs.

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Downstream

Supply

The company supplements its own production of crude oil, condensate and petroleum products with substantial purchases from a number of other sources at negotiated market prices. Purchases are made under both spot and term contracts from domestic and foreign sources, including ExxonMobil.

Transportation

Imperial currently transports the company s crude oil production and third party crude oil required to supply refineries by contracted pipelines, common carrier pipelines and rail. To mitigate uncertainty associated with the timing of industry pipeline projects and pipeline capacity constraints, the company has developed rail infrastructure. The Edmonton rail terminal has total capacity to ship up to 210,000 barrels per day of crude oil.

Refining

The company owns and operates three refineries, which process predominantly Canadian crude oil. In 2017, Imperial decided to discontinue manufacturing base stocks, associated waxes and finished lubricants at its Strathcona Refinery lube complex and lube oil blend plant. Operations continued at the blend plant until mid-2018. In addition to crude oil, the company purchases finished products to supplement its refinery production.

The approximate average daily volumes of refinery throughput during the three years ended December 31, 2018, and the daily rated capacities of the refineries as at December 31, 2018, were as follows.

	Refinery throughput (a) Year ended December 31			Rated capacities (b) at December 31
thousands of barrels per day	**2018**	2017	2016	**2018**
Strathcona, Alberta	**173**	185	168	**191**
Sarnia, Ontario	**109**	103	108	**119**
Nanticoke, Ontario	**110**	95	86	**113**
Total	**392**	383	362	**423**

(a) Refinery throughput is the volume of crude oil and feedstocks that is processed in the refinery atmospheric distillation units.

(b) Rated capacities are based on definite specifications as to types of crude oil and feedstocks that are processed in the refinery atmospheric distillation units, the products to be obtained and the refinery process, adjusted to include an estimated allowance for normal maintenance shutdowns. Accordingly, actual capacities may be higher or lower than rated capacities due to changes in refinery operation and the type of crude oil available for processing.

Refinery throughput averaged 392,000 barrels per day in 2018, up from 383,000 barrels per day in 2017. Capacity utilization increased to 93 percent from 91 percent in 2017.

Refinery throughput averaged 383,000 barrels per day in 2017, up from 362,000 barrels per day in 2016. Capacity utilization increased to 91 percent from 86 percent in 2016, reflecting reduced turnaround maintenance activity.

Distribution

The company maintains a nationwide distribution system, to move petroleum products to market by pipeline, tanker, rail and road transport. The company owns and operates natural gas liquids and products pipelines in Alberta, Manitoba and Ontario and has interests in the capital stock of one crude oil and two products pipeline companies.

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Marketing

The company markets petroleum products throughout Canada under well-known brand names, most notably Esso and Mobil, to all types of customers.

Imperial supplies petroleum products to the motoring public through Esso and Mobil-branded sites and independent marketers. At the end of 2018, there were about 2,200 sites operating under a branded wholesaler model whereby Imperial supplies fuel to independent third parties who own and operate sites in alignment with Esso and Mobil brand standards. The Mobil fuels brand was launched in Canada in 2017 with the conversion of more than 200 existing unbranded third party sites completed by the end of 2018.

Imperial also sells petroleum products, including fuel, asphalt and lubricants, to large industrial and transportation customers, independent marketers, resellers, as well as other refiners. The company serves agriculture, residential heating and commercial markets through branded fuel and lubricant resellers.

The approximate daily volumes of net petroleum products (excluding purchases / sales contracts with the same counterparty) sold during the three years ended December 31, 2018, are set out in the following table.

thousands of barrels per day	**2018**	2017	2016
Gasolines	**255**	257	261
Heating, diesel and jet fuels	**183**	177	170
Heavy fuel oils (a)	**26**	18	16
Lube oils and other products	**40**	40	37
Net petroleum product sales (a)	**504**	492	484

(a) In 2018 and 2017, carbon black product sales are reported under Net petroleum product sales Heavy fuel oils; in 2016, they were reported under Total petrochemical sales Polymers and basic chemicals.

In 2018, sales growth continued to be driven by optimization across the full downstream value chain, and the expansion of Imperial s logistic capabilities.

Chemical

The company s Chemical operations manufacture and market benzene, aromatic and aliphatic solvents, plasticizer intermediates and polyethylene resin. Its petrochemical and polyethylene manufacturing operations are located in Sarnia, Ontario, adjacent to the company s petroleum refinery.

The company s total petrochemical sales volumes during the three years ended December 31, 2018, were as follows.

thousands of tonnes	**2018**	2017	2016
Total petrochemical sales (a)	**807**	774	908

(a) In 2018 and 2017, carbon black product sales are reported under Net petroleum product sales Heavy fuel oils; in 2016, they were reported under Total petrochemical sales Polymers and basic chemicals.

In 2018, sales volumes were higher primarily due to higher production in polymers and basic chemicals, driven by stronger reliability.

Lower sales volumes in 2017 were primarily due to the reclassification of carbon black product sales.

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Environmental protection

The company regards protecting the environment in connection with its various operations as a priority. The company works in cooperation with government agencies, industry associations and communities to address existing, and to anticipate potential, environmental protection issues. In the past five years, the company has made capital and operating expenditures of about $4.8 billion on environmental protection and facilities. In 2018, the company s environmental capital and operating expenditures totalled approximately $0.6 billion, which was spent primarily on activities to protect the air, land and water, including remediation projects. Capital and operating expenditures relating to environmental protection are expected to be about $0.7 billion in 2019.

Human resources

career employees (a)	**2018**	2017	2016
Total	**5,700**	5,400	5,600

(a) Rounded. Career employees are defined as active executive, management, professional, technical, administrative and wage employees who work full time or part time for the company and are covered by the company s benefit plans.

About 6 percent of the company s employees are members of unions.

Competition

The Canadian energy and petrochemical industries are highly competitive. Competition exists in the search for and development of new sources of supply, the construction and operation of crude oil, natural gas and refined products pipelines and facilities and the refining, distribution and marketing of petroleum products and chemicals. The energy and petrochemical industries also compete with other industries in supplying the energy, fuel and chemical needs of both industrial and individual consumers.

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Government regulation

Petroleum and natural gas rights

Most of the company s petroleum and natural gas rights were acquired from governments, either federal or provincial. These rights, in the form of leases or licences, are generally acquired for cash or work commitments. A lease or licence entitles the holder to explore for petroleum and / or natural gas on the leased lands for a specified period.

In western provinces, the lease holder can produce the petroleum or natural gas discovered on the leased lands and retains the rights based on continued production. Oil sands leases are retained by meeting the minimum level of evaluation, payment of rentals, or by production.

The holder of a licence relating to Canada lands and the Atlantic offshore can apply for a SDL if a discovery is made. If granted, the SDL holds the lands indefinitely subject to certain conditions. The holder may then apply for a production licence in order to produce petroleum or natural gas from the licenced land.

Project approval

Approvals and licences from relevant provincial or federal governmental or regulatory bodies are required for the company to carry out, or make modifications to, its oil and gas activities. The project approval process for major projects can involve, among other things, environmental assessments (including relevant mitigation measures), stakeholder and Indigenous consultation and input regarding project concerns, and public hearings. Approval may be subject to various conditions and commitments arising through these processes.

Crude oil

Production

The maximum allowable gross production of crude oil from wells in Canada is subject to limitations by various regulatory authorities on the basis of engineering and conservation principles.

Additionally, in December 2018, the Government of Alberta introduced temporary mandatory production curtailment regulations, which took effect on January 1, 2019. These regulations impose production limits on large producers in Alberta. The duration and impact of these regulations is uncertain.

Exports

Export contracts of more than one year for light crude oil and petroleum products and two years for heavy crude oil (including bitumen) require the prior approval of the National Energy Board (NEB) and the Government of Canada. Export contracts of less than one year for light crude oil and petroleum products and two years for heavy crude oil (including bitumen) require an order from the NEB.

Natural gas

Production

The maximum allowable gross production of natural gas from wells in Canada is subject to limitations by various regulatory authorities. These limitations are to ensure oil recovery is not adversely impacted by accelerated gas production practices. These limitations do not impact gas reserves, only the timing of production of the reserves and did not have a significant impact on Imperial s 2018 gas production rates.

Exports

The Government of Canada has the authority to regulate the export price for natural gas and has a gas export pricing policy, which accommodates export prices for natural gas negotiated between Canadian exporters and U.S. importers.

Exports of natural gas from Canada require approval by the NEB and the Government of Canada. The Government of Canada allows the export of natural gas by NEB order without volume limitation for terms not exceeding 24 months.

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Royalties

The Government of Canada and the provinces in which the company produces crude oil and natural gas, impose royalties on production from lands where they own the mineral rights. Some producing provinces also receive revenue by imposing taxes on production from lands where they do not own the mineral rights.

Different royalties are imposed by the Government of Canada and each of the producing provinces. Royalties imposed on crude oil, natural gas and natural gas liquids vary depending on a number of parameters, including well production volumes, selling prices and recovery methods. For information with respect to royalties for Cold Lake, Syncrude and Kearl, see Upstream section entitled Present activities under Item 1 on page 11.

Investment Canada Act

The Investment Canada Act requires Government of Canada approval, in certain cases, of the acquisition of control of a Canadian business by an entity that is not controlled by Canadians. The acquisition of natural resource properties may, in certain circumstances, be considered a transaction that constitutes an acquisition of control of a Canadian business requiring Government of Canada approval.

The Act also requires notification of the establishment of new unrelated businesses in Canada by entities not controlled by Canadians, but does not require Government of Canada approval except when the new business is related to Canada s cultural heritage or national identity. The Government of Canada is also authorized to take any measures that it considers advisable to protect national security, including the outright prohibition of a foreign investment in Canada. By virtue of the majority stock ownership of the company by ExxonMobil, the company is considered to be an entity which is not controlled by Canadians.

Competition Act

The Competition Bureau ensures that Canadian businesses and consumers prosper in a competitive and innovative marketplace. The Competition Bureau is responsible for the administration and enforcement of the Competition Act (the Act). A merger transaction, whether or not notifiable, is subject to examination by the Commissioner of the Competition Bureau to determine whether the merger will have, or is likely to have, the effect of preventing or lessening substantially competition in a definable market. The assessment of the competitive effects of a merger is made with reference to the factors identified under the Act.

An Advance Ruling Certificate (ARC) may be issued by the Commissioner to a party or parties to a proposed merger transaction who want to be assured that the transaction will not give rise to proceedings under section 92 of the Act. Section 102 of the Act provides that an ARC may be issued when the Commissioner is satisfied that there would not be sufficient grounds on which to apply to the Competition Tribunal for an order against a proposed merger. The issuance of an ARC is discretionary. An ARC cannot be issued for a transaction that has been completed, nor does an ARC ensure approval of the transaction by any agency other than the Competition Bureau.

The company online

The company s website **www.imperialoil.ca** contains a variety of corporate and investor information which is available free of charge, including the company s annual report on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K and amendments to these reports, as well as required interactive data filings. These reports are made available as soon as reasonably practicable after they are filed or furnished to the SEC. The SEC s website, www.sec.gov, contains reports, proxy and information statements, interactive data files, and other information regarding issuers that are submitted and posted electronically with the SEC.

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Item 1A. Risk factors

Imperial s financial and operating results are subject to a variety of risks inherent in oil, gas and petrochemical businesses. Many of these risk factors are not within Imperial s control and could adversely affect Imperial s business, financial and operating results, or financial position. These risk factors include:

Volatility of commodity prices

The company s operations and earnings may be significantly affected by changes in oil, natural gas and petrochemical prices, and by changes in margins on refined products and petrochemicals. Crude oil, natural gas, petrochemical and petroleum product prices and margins depend on local, regional, and global events or conditions that affect supply and demand for the relevant commodity. Commodity prices have been volatile, and the company expects that volatility to continue. Any material decline in crude oil prices could have a material adverse effect on Imperial s Upstream operations, financial position, proved reserves and the amount spent to develop reserves. On the other hand, a material increase in crude oil prices could have a material adverse effect on Imperial s Downstream margins, depending on the market conditions for refined products.

Demand related factors which could impact Imperial s results include economic conditions, where periods of low or negative economic growth will typically have an adverse impact on results; technological improvements in energy efficiency; seasonal weather patterns, which affect the demand for our products, including lower demand for gasoline, impacting Downstream results in the winter; increased competitiveness of alternative energy sources; new product quality regulations; technological changes or consumer preferences that affect the market for petroleum products, such as technological advances in energy storage that make wind and solar more competitive for power generation or increased consumer demand for alternative fueled or electric vehicles; and broad-based changes in personal income levels.

Commodity prices and margins also vary depending on a number of factors affecting supply. For example, increased supply from the development of new oil and gas supply sources and technologies to enhance recovery from existing sources tend to reduce commodity prices to the extent such supply increases are not offset by commensurate growth in demand. Similarly, increases in industry refining or petrochemical manufacturing capacity relative to demand tend to reduce margins on affected products. World oil, gas and petrochemical supply levels can also be affected by factors that reduce available supplies, such as adherence by member countries or others to Organization of the Petroleum Exporting Countries (OPEC) production quotas and the occurrence of wars, hostile actions, natural disasters, disruptions in competitors operations, or unexpected pipeline or rail constraints that may disrupt supplies. Technological change can also alter the relative costs for competitors to find, produce, and refine oil and gas and to manufacture petrochemicals.

A significant portion of the company s production is bitumen, which is blended with diluent to create a marketable heavy crude oil. The market price for western Canadian heavy crude oil is typically lower than light and medium grades of oil, principally due to the higher transportation and refining costs. Western Canadian crude oil may also be subject to limits on transportation capacity to markets. In Alberta, increased differentials between western Canadian crude oil and WTI in the second half of 2018 led the Government of Alberta to introduce temporary mandatory production curtailment regulations, which took effect on January 1, 2019. Future crude price differentials are uncertain and changes in the heavy or light crude oil differentials could have a material adverse effect on the company s business. Increases to diluent prices, relative to heavy crude oil prices, could also have an adverse effect on the company s business.

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Government and political factors

Imperial s results can be adversely impacted by political, legal or regulatory developments affecting operations and markets. Changes in government policy or regulations, changes in law or interpretation of settled law, third party opposition to company or infrastructure projects, and duration of regulatory reviews could impact Imperial s existing operations and planned projects. For example, increases in taxes or government royalty rates (including retroactive claims), changes in trade policies and agreements, changes in environmental regulations, assessment processes or other laws that increase the cost of compliance or reduce or delay available business opportunities, increasing and expanding stakeholder consultation (including Indigenous stakeholders), the adoption of regulations mandating efficiency standards, and the use of alternative fuels or uncompetitive fuel components could affect the company s operations. Additionally, in December 2018 the Government of Alberta introduced temporary mandatory production curtailment regulations, which took effect on January 1, 2019. These regulations impose production limits on large producers in Alberta. The duration and impact of these regulations is uncertain, and could have an adverse effect on the company s business. Imperial is actively evaluating the impact on the company. Government intervention in free markets may introduce unintended consequences such as market volatility and uncertainty, misallocation of resources, free trade risk and erosion of investor confidence.

Environmental risks

All phases of the Upstream, Downstream and Chemical businesses are subject to environmental regulation pursuant to a variety of Canadian federal, provincial, territorial and municipal laws and regulations, as well as international conventions (collectively, environmental legislation).

Environmental legislation imposes, among other things, restrictions, liabilities and obligations in connection with the generation, handling, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances into the environment. As well, environmental regulations are imposed on the qualities and compositions of the products sold and imported. Environmental legislation also requires that wells, facility sites and other properties associated with the company s operations be operated, maintained, monitored, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, certain types of operations, including exploration and development projects and significant changes to certain existing projects, may require the submission and approval of environmental impact assessments. Compliance with environmental legislation can require significant expenditures and failure to comply with environmental legislation may result in the cessation of operations, imposition of fines and penalties and liability for clean-up costs and damages.

The costs of complying with environmental legislation in the future could have a material adverse effect on the company s financial condition or results of operations. The company anticipates that changes in environmental legislation may require, among other things, reductions in emissions from its operations to the air and water and may result in increased capital expenditures. Changes in environmental legislation (including, but not limited to, application of regulations related to air, water, land and biodiversity) may increase the cost of compliance or reduce or delay available business opportunities. Future changes in environmental legislation could occur and result in stricter standards and enforcement, larger fines and liability, and increased capital expenditures and operating costs, which could have a material adverse effect on the company s financial condition or results of operations.

There are operational risks inherent in oil and gas exploration and production activities, as well as the potential to incur substantial financial liabilities, if those risks are not effectively managed. The ability to insure such risks is limited by the capacity of the applicable insurance markets, which may not be sufficient to cover the likely cost of a major adverse operating event. Accordingly, the company s primary focus is on prevention, including through its rigorous operations integrity management system. The company s future results will depend on the continued effectiveness of these efforts.

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Climate change and greenhouse gas restrictions

Due to concern over the risks of climate change, a number of provinces and the Government of Canada have adopted, or are considering the adoption of, regulatory frameworks to reduce greenhouse gas emissions. These include adoption of carbon emissions pricing, cap and trade regimes, carbon taxes, emissions limits, increased efficiency standards, low carbon fuel standards and incentives or mandates for renewable energy. Such policies could make Imperial s products more expensive and less competitive, reduce or delay available business opportunities, reduce demand for hydrocarbons, and shift hydrocarbon demand toward lower greenhouse gas emission energy sources. Current and pending greenhouse gas regulations or policies may also increase compliance and abatement costs, lengthen project evaluation and implementation times, impact reserves evaluations and affect operations. Increased costs may not be recoverable in the market place and could reduce the global competitiveness of the company s crude oil, natural gas and refined products.

Currency

Prices for commodities produced by the company are commonly benchmarked in U.S. dollars. The majority of Imperial s sales and purchases are related to these industry U.S. dollar benchmarks. As the company records and reports its financial results in Canadian dollars, to the extent that the value of the Canadian dollar strengthens, the company s reported earnings will be negatively affected. The company does not currently make use of derivative instruments to offset exposures associated with foreign currency.

Other business risks

Imperial is reliant on a number of key chemicals, catalysts and third party service providers, including input and output commodity transportation (pipelines, rail, trucking, marine) and utilities providing services, including electricity and water, to various company operations. The lack of availability and capacity, and proximity of pipeline facilities and railcars could negatively impact Imperial s ability to produce at capacity levels. Transportation disruptions could adversely affect the company s price realizations, refining operations and sales volumes, as well as potentially limit the ability to deliver production to market. A third party utilities outage could have an adverse impact on the company s operations and ability to produce.

Management effectiveness

In addition to external economic and political factors, Imperial s future business results also depend on the company s ability to manage successfully those factors that are at least in part within its control. The extent to which Imperial manages these factors will impact its performance relative to competition. For projects in which the company is not the operator, Imperial depends on the management effectiveness of one or more co-venturers whom the company does not control.

Project management

The company s results are affected by its ability to develop and operate projects and facilities as planned. The company s results will, therefore, be affected by events or conditions that affect the advancement, operation, cost or results of such projects or facilities. These risks include the company s ability to obtain the necessary environmental and other regulatory approvals; changes in regulations; changes in resources and operating costs including the availability and cost of materials, equipment and qualified personnel; the impact of general economic, business and market conditions; and the occurrence of unforeseen technical difficulties.

Operational efficiency

An important component of Imperial s competitive performance, especially given the commodity based nature of Imperial s business, is the ability to operate efficiently, including the company s ability to manage expenses and improve production yields on an ongoing basis. This requires continuous management focus, including technological improvements, cost control, productivity enhancements and regular reappraisal of the company s asset portfolio. The company s operations and results also depend on key personnel and subject matter expertise, the recruitment, development and retention of high caliber employees, and the availability of skilled labour.

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Research and development and technical change

Imperial relies upon the research and development organizations of the company and ExxonMobil, with whom the company conducts shared research. To maintain the company s competitive position, especially in light of the technological nature of Imperial s business and the need for continuous efficiency improvement, research and development organizations must be successful and able to adapt to a changing market and policy environment, including developing technologies to help reduce greenhouse gas emissions. To remain competitive, the company must also continuously adapt and capture the benefits of new technologies including growing the company s capabilities to utilize digital data technologies to gain new business insights.

Safety, business controls and environmental risk management

The scope and nature of the company s operations present a variety of significant hazards and risks, including operational hazards and risks such as explosions, fires, pipeline ruptures and crude oil spills. Imperial s operations are also subject to the additional hazards of pollution, releases of toxic gas and environmental hazards and risks, such as severe weather, and geological events. The company s results depend on management s ability to minimize these inherent risks, to effectively control business activities and to minimize the potential for human error. Imperial applies rigorous management systems, including a combined program of effective operations integrity management, ongoing upgrades, key equipment replacements, and comprehensive inspection and surveillance. The company also maintains a disciplined framework of internal controls and applies a controls management system for monitoring compliance with this framework. Substantial liabilities and other adverse impacts could result if the company s management systems and controls do not function as intended.

Cybersecurity

Imperial is regularly subject to attempted cybersecurity disruptions from a variety of threat actors, including state-sponsored actors. Imperial s defensive preparedness includes multi-layered technological capabilities for prevention and detection of cybersecurity disruptions; non-technological measures such as threat information sharing with governmental and industry groups; internal training and awareness campaigns including testing of employee awareness via mock threats; and an emphasis on resiliency including business response and recovery evaluated through ongoing workshops and exercises directed to mitigating the effects of potential cybersecurity disruptions. If the measures we are taking to protect against cybersecurity disruptions prove to be insufficient, the company, customers, employees or third parties could be adversely affected. Cybersecurity disruptions could cause physical harm to people or the environment; damage or destroy assets; compromise business systems; result in proprietary information being altered, lost or stolen; result in employee, customer or third party information being compromised; or otherwise disrupt business operations. Imperial could incur significant costs to remedy the effects of such a cybersecurity disruption, in addition to costs in connection with resulting regulatory actions, litigation or reputational harm.

Preparedness

The company s operations may be disrupted by severe weather events, natural disasters, human error, and similar events. Imperial s ability to mitigate the adverse impacts of these events depends in part upon the effectiveness of its rigorous disaster preparedness and response planning, as well as business continuity planning.

Reputation

Imperial s reputation is an important corporate asset. An operating incident, significant cybersecurity disruption or other adverse events, such as those described in Item 1A, may have a negative impact on Imperial s reputation, which in turn could make it more difficult for Imperial to compete successfully for new opportunities, obtain necessary regulatory approvals, or could reduce consumer demand for the company s branded products. Imperial s reputation may also be harmed by events which negatively affect the image of the industry as a whole.

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Reserves

The company s future production and cash flows from bitumen, synthetic oil, liquids and natural gas reserves are highly dependent upon the company s success in exploiting its current reserve base. To maintain production and cash flows, the company must continue to replace produced reserves as they are depleted, which can be accomplished through exploration discovery of new resources, appraisal and investments in developing discovered resources, or acquisition of reserves. To the extent cash flows from operations are insufficient to fund capital expenditures and external sources of capital become limited or unavailable, the company s ability to make the necessary capital investments to maintain and expand oil and natural gas reserves will be adversely impacted. In addition, the company may be unable to find and develop or acquire additional reserves to replace oil and natural gas production at acceptable costs.

Estimates of economically recoverable oil and natural gas reserves and future net cash flows involve many uncertainties, including factors beyond the company s control. Key factors with uncertainty include: geological and engineering estimates; the assumed effects of regulation or changes to regulation by government agencies including royalty frameworks and environmental regulations; future commodity prices; and operating costs. Actual production, revenues, taxes, development costs, abandonment costs, and operating expenditures with respect to reserves will likely vary from such estimates, and such variances could be material.

Item 1B. Unresolved staff comments

None.

Item 2. Properties

Reference is made to Item 1 above.

Item 3. Legal proceedings

On December 18, 2018, Imperial entered a guilty plea in the Ontario Court of Justice for committing the offence of discharging or causing or permitting the discharge of wastewater with a low pH from Imperial s refinery in Sarnia, Ontario into the St. Clair River on April 19, 2016, which may impair the quality of the water contrary to section 30(1) of the Ontario Water Resources Act, R.S.O. 1990, c. O.40. Imperial is required to pay a fine of $325,000 plus a 25 percent victim fine surcharge, for a total of $406,250.

Item 4. Mine safety disclosures

Not applicable.

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PART II

Item 5. Market for registrant s common equity, related stockholder matters and issuer purchases of equity securities

Market information

The company s common shares are listed and trade on the Toronto Stock Exchange in Canada, and have unlisted trading privileges and trade on the NYSE American LLC in the United States. The symbol for the company s common shares on these exchanges is IMO.

As of February 13, 2019 there were 10,559 holders of record of common shares of the company.

Information for security holders outside Canada

Cash dividends paid to shareholders resident in countries with which Canada has an income tax convention are usually subject to a Canadian non-resident withholding tax of 15 percent, but may vary from one tax convention to another.

The withholding tax is reduced to 5 percent on dividends paid to a corporation resident in the U.S. that owns at least 10 percent of the voting shares of the company.

The company is a qualified foreign corporation for purposes of the reduced U.S. capital gains tax rates, which are applicable to dividends paid by U.S. domestic corporations and qualified foreign corporations.

There is no Canadian tax on gains from selling shares or debt instruments owned by non-residents not carrying on business in Canada, as long as the shareholder does not, in any given 60 month period, own 25 percent or more of the shares of the company.

Between October 1, 2018 and December 31, 2018, pursuant to the company s restricted stock unit plan, 2,125 shares were issued to employees or former employees outside the U.S. in reliance on Regulation S under the Securities Act.

Securities authorized for issuance under equity compensation plans

Sections of the company s management proxy circular are contained in the Proxy information section , starting on page 97. The company s management proxy circular is prepared in accordance with Canadian securities regulations.

Reference is made to the section under the Company executives and executive compensation :

- Entitled Performance graph within the Compensation discussion and analysis section on page 150 of this report; and

- Entitled Equity compensation plan information , within the Compensation discussion and analysis , on page 156 of this report.

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Issuer purchases of equity securities

	Total number of shares purchased	Average price paid per share (Canadian dollars)	Total number of shares purchased as part of publicly announced plans or programs	Maximum number of shares that may yet be purchased under the plans or programs (a)
October 2018				
(October 1 - October 31)	**3,540,254**	**42.82**	**3,540,254**	**26,391,088**
November 2018				
(November 1 - November 30)	**3,862,113**	**41.01**	**3,862,113**	**22,528,975**
December 2018				
(December 1 - December 31)	**2,737,760**	**36.36**	**2,737,760**	**19,791,215** (b)

(a) On June 22, 2018, the company announced by news release that it had received final approval from the Toronto Stock Exchange for a new normal course issuer bid and will continue its existing share purchase program. The program enables the company to purchase up to a maximum of 40,391,196 common shares during the period June 27, 2018 to June 26, 2019. This maximum includes shares purchased under the normal course issuer bid and from Exxon Mobil Corporation concurrent with, but outside of the normal course issuer bid. As in the past, Exxon Mobil Corporation has advised the company that it intends to participate to maintain its ownership percentage at approximately 69.6 percent. The program will end should the company purchase the maximum allowable number of shares, or on June 26, 2019.

(b) In its most recent quarterly earnings release, the company stated that it currently anticipates exercising its share purchases uniformly over the duration of the program. Purchase plans may be modified at any time without prior notice.

The company will continue to evaluate its share purchase program in the context of its overall capital activities.

Item 6. Selected financial data

millions of Canadian dollars	**2018**	2017	2016	2015	2014
Revenues	**34,964**	29,125	25,049	26,756	36,231
Net income (loss)	**2,314**	490	2,165	1,122	3,785
Total assets at year-end	**41,456**	41,601	41,654	43,170	40,830
Long-term debt at year-end	**4,978**	5,005	5,032	6,564	4,913
Total debt at year-end	**5,180**	5,207	5,234	8,516	6,891
Other long-term obligations at year-end	**2,943**	3,780	3,656	3,597	3,565
Canadian dollars					
Net income (loss) per common share - basic	**2.87**	0.58	2.55	1.32	4.47
Net income (loss) per common share - diluted	**2.86**	0.58	2.55	1.32	4.45
Dividends per common share - declared	**0.73**	0.63	0.59	0.54	0.52

Reference is made to the table setting forth exchange rates for the Canadian dollar, expressed in U.S. dollars, on page 2 of this report.

Item 7. Management s discussion and analysis of financial condition and results of operations

Reference is made to the section entitled Management s discussion and analysis of financial condition and results of operations in the Financial section , starting on page 38 of this report.

Item 7A. Quantitative and qualitative disclosures about market risk

Reference is made to the section entitled Market risks and other uncertainties in the Financial section , starting on page 51 of this report. All statements other than historical information incorporated in this Item 7A are forward-looking statements. The actual impact of future market changes could differ materially due to, among other things, factors discussed in this report.

Item 8. Financial statements and supplementary data

Reference is made to the table of contents in the Financial section on page 34 of this report:

Consolidated financial statements, together with the report thereon of PricewaterhouseCoopers LLP (PwC) dated February 27, 2019 beginning with the section entitled Report of independent registered public accounting firm on page 59 and continuing through note 18, Other comprehensive income (loss) information on page 91;

Supplemental information on oil and gas exploration and production activities (unaudited) starting on page 92; and

Quarterly financial data on page 96.

Item 9. Changes in and disagreements with accountants on accounting and financial disclosure

None.

Item 9A. Controls and procedures

As indicated in the certifications in Exhibit 31 of this report, the company s principal executive officer and principal financial officer have evaluated the company s disclosure controls and procedures as of December 31, 2018. Based on that evaluation, these officers have concluded that the company s disclosure controls and procedures are effective in ensuring that information required to be disclosed by the company in the reports that it files or submits under the Securities Exchange Act of 1934, as amended, is accumulated and communicated to them in a manner that allows for timely decisions regarding required disclosures and are effective in ensuring that such information is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms.

Reference is made to page 58 of this report for Management s report on internal control over financial reporting and page 59 for the Report of independent registered public accounting firm on the company s internal control over financial reporting as of December 31, 2018.

There has not been any change in the company s internal control over financial reporting during the last fiscal quarter that has materially affected, or is reasonably likely to materially affect, the company s internal control over financial reporting.

Item 9B. Other information

None.

PART III

Item 10. Directors, executive officers and corporate governance

Sections of the company s management proxy circular are contained in the Proxy information section , starting on page 97. The company s management proxy circular is prepared in accordance with Canadian securities regulations.

The company currently has eight directors. The articles of the company require that the board have between five and fifteen directors. Each director is elected to hold office until the close of the next annual meeting. Each of the seven individuals listed in the section entitled Nominees for director on pages 98 to 101 of this report have been nominated for election at the annual meeting of shareholders to be held April 26, 2019. All of the nominees are directors and have been since the dates indicated. S.D. Whittaker is currently a director and is not standing for re-election in 2019 as she will reach the company s mandatory retirement age for directors in 2019.

Reference is made to the section under Nominees for director :

Director nominee tables , on pages 98 to 101 of this report;

Reference is made to the sections under Corporate governance disclosure :

Other public company directorships of our board members , on page 109 of this report.

The table entitled Audit committee under Board and committee structure , on page 115 of this report;

Ethical business conduct , starting on page 127 of this report; and

Largest shareholder , on page 129 of this report.

Reference is made to the sections under Company executives and executive compensation :

Named executive officers of the company and Other executive officers of the company , on pages 131 to 133 of this report.

Item 11. Executive compensation

Sections of the company s management proxy circular are contained in the Proxy information section , starting on page 97. The company s management proxy circular is prepared in accordance with Canadian securities regulations.

Reference is made to the sections under Corporate governance disclosure :

Director compensation , on pages 119 to 125 of this report; and

Share ownership guidelines of independent directors and chairman, president and chief executive officer , on page 126 of this report.

Reference is made to the following sections under Company executives and executive compensation :

Letter to shareholders from the executive resources committee on executive compensation , starting on page 134 of this report; and

Compensation discussion and analysis , on pages 136 to 158 of this report.

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Item 12. Security ownership of certain beneficial owners and management and related stockholder matters

Sections of the company s management proxy circular are contained in the Proxy information section , starting on page 97. The company s management proxy circular is prepared in accordance with Canadian securities regulations.

Reference is made to the section under Company executives and executive compensation entitled Equity compensation plan information , within the Compensation discussion and analysis section, on page 156 of this report.

Reference is made to the section under Corporate governance disclosure entitled Largest shareholder , on page 129 of this report.

Reference is also made to the security ownership information for directors and executive officers of the company under the preceding Items 10 and 11. The compensation of the directors and executive officers of the company for the year-ended December 31, 2018 is described in the sections under Nominees for director starting on page 98, Director compensation starting on page 119 and Company executives and executive compensation starting on page 131. The following table shows the number of Imperial Oil Limited and Exxon Mobil Corporation common shares owned and restricted stock units held by each named executive officer, as of February 13, 2019.

	Imperial Oil Limited		**Exxon Mobil Corporation**	
Named executive officer	Common shares (a)	Restricted stock units (b)	Common shares (a)	Restricted stock units (b)
R.M. Kruger	-	545,800	1,741	118,500
D.E. Lyons	-	19,200	8,372	40,150
J.R. Whelan	-	44,000	28,065	23,200
T.B. Redburn	3,328	90,950	-	-
P.M. Dinnick	-	20,800	1,761	10,000
B.A. Babcock (c)	-	88,750	366	-

(a) No common shares are beneficially owned by reason of exercisable options. None of these individuals owns more than 0.01 percent of the outstanding shares of Imperial Oil Limited or Exxon Mobil Corporation.
(b) Restricted stock units do not carry voting rights prior to the issuance of shares on settlement of the awards.
(c) B.A. Babcock served as the company s senior vice-president, finance and administration, and controller until her retirement on April 30, 2018.

As of February 13, 2019, the current directors and the executive officers of the company consist of 18 persons who, as a group, beneficially own 130,138 common shares of the company, being approximately 0.02 percent of the total outstanding shares of the company, and 48,510 common shares of Exxon Mobil Corporation, being less than 0.01 percent of the total outstanding shares of Exxon Mobil Corporation. None of these common shares are beneficially owned by reason of exercisable options. This information not being within the knowledge of the company has been provided by the directors and the executive officers individually. As a group as of February 13, 2019, the current directors and executive officers of the company held 954,575 restricted stock units of the company and 247,850 restricted stock units of Exxon Mobil Corporation.

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Item 13. Certain relationships and related transactions, and director independence

Sections of the company s management proxy circular are contained in the Proxy information section , starting on page 97. The company s management proxy circular is prepared in accordance with Canadian securities regulations.

Reference is made to the section under Corporate governance disclosure entitled Independence of our board members , on page 106 of this report.

Reference is made to the section under Corporate governance disclosure entitled Transactions with Exxon Mobil Corporation , on page 129 of this report.

D.C. Brownell is deemed a non-independent member of the board of directors and the executive resources committee, public policy and corporate responsibility committee, nominations and corporate governance committee and community collaboration and engagement committee under the relevant standards. As an employee of Exxon Mobil Corporation, D.C. Brownell is independent of the company s management and is able to assist these committees by reflecting the perspective of the company s shareholders.

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Item 14. Principal accountant fees and services

Auditor information

The audit committee of the board of directors recommends that PwC be reappointed as the auditor of the company until the close of the next annual meeting. PwC has been the auditor of the company for more than five years and are located in Calgary, Alberta. PwC is a participating audit firm with the Canadian Public Accountability Board.

Auditor fees

The aggregate fees of PwC for professional services rendered for the audit of the company s financial statements and other services for the fiscal years ended December 31, 2018 and December 31, 2017 were as follows:

thousands of Canadian dollars	**2018**	2017
Audit fees	**1,808**	1,756
Audit-related fees	**94**	94
Tax fees	**-**	-
All other fees	**-**	-
Total fees	**1,902**	1,850

Audit fees included the audit of the company s annual financial statements, internal control over financial reporting, and a review of the first three quarterly financial statements in 2018. Audit-related fees consisted of other assurance services including the audit of the company s retirement plan and royalty statement audits for oil and gas producing entities. The company did not engage the auditor for any other services.

The audit committee formally and annually evaluates the performance of the external auditor, recommends the external auditor to be appointed by the shareholders, recommends their remuneration and oversees their work. The audit committee also approves the proposed current year audit program of the external auditor, assesses the results of the program after the end of the program period and approves in advance any non-audit services to be performed by the external auditor after considering the effect of such services on their independence.

All of the services rendered by the auditor to the company were approved by the audit committee.

Auditor independence

The audit committee continually discusses with PwC their independence from the company and from management. PwC have confirmed that they are independent with respect to the company within the meaning of the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta, the Public Company Accounting Oversight Board (United States) (PCAOB) and the rules of the U.S. Securities and Exchange Commission. The company has concluded that the auditor s independence has been maintained.

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PART IV

Item 15. Exhibits, financial statement schedules

Reference is made to the table of contents in the Financial section on page 34 of this report.

The following exhibits, numbered in accordance with Item 601 of Regulation S-K, are filed as part of this report:

(3) (i) Restated certificate and articles of incorporation of the company (Incorporated herein by reference to Exhibit (3.1) to the company s Form 8-K filed on May 3, 2006 (File No. 0-12014)).

(ii) By-laws of the company (Incorporated herein by reference to Exhibit (3)(ii) to the company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2003 (File No. 0-12014)).

(10) (ii) (1) Syncrude Ownership and Management Agreement, dated February 4, 1975 (Incorporated herein by reference to Exhibit 13(b) of the company s Registration Statement on Form S-1, as filed with the Securities and Exchange Commission on August 21, 1979 (File No. 2-65290)).

(2) Letter Agreement, dated February 8, 1982, between the Government of Canada and Esso Resources Canada Limited, amending Schedule C to the Syncrude Ownership and Management Agreement filed as Exhibit (10)(ii)(2) (Incorporated herein by reference to Exhibit (20) of the company s Annual Report on Form 10-K for the year ended December 31, 1981 (File No. 2-9259)).

(3) Alberta Cold Lake Crown Agreement, dated June 25, 1984, relating to the royalties payable and the assurances given in respect of the Cold Lake production project (Incorporated herein by reference to Exhibit (10)(ii)(11) of the company s Annual Report on Form 10-K for the year ended December 31, 1986 (File No. 0-12014)).

(4) Amendment to Syncrude Ownership and Management Agreement, dated March 10, 1982 (Incorporated herein by reference to Exhibit (10)(ii)(14) of the company s Annual Report on Form 10-K for the year ended December 31, 1989 (File No. 0-12014)).

(5) Alberta Cold Lake Transition Agreement, effective January 1, 2000, relating to the royalties payable in respect of the Cold Lake production project and terminating the Alberta Cold Lake Crown Agreement. (Incorporated herein by reference to Exhibit (10)(ii)(20) of the company s Annual Report on Form 10-K for the year ended December 31, 2001 (File No. 0-12014)).

(6) Amendment to Syncrude Ownership and Management Agreement effective January 1, 2001 (Incorporated herein by reference to Exhibit (10)(ii)(22) of the company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2002 (File No. 0-12014)).

(7) Amendment to Syncrude Ownership and Management Agreement effective September 16, 1994 (Incorporated herein by reference to Exhibit (10)(ii)(23) of the company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2002 (File No. 0-12014)).

(8) Syncrude Bitumen Royalty Option Agreement, dated November 18, 2008, setting out the terms of the exercise by the Syncrude Joint Venture owners of the option contained in the existing Crown Agreement to convert to a royalty payable on the value of bitumen, effective January 1, 2009 (Incorporated herein by reference to Exhibit 1.01(10)(ii)(2) of the company s Form 8-K filed on November 19, 2008 (File No. 0-12014)).

(iii) (A) (1) Form of Letter relating to Supplemental Retirement Income (Incorporated herein by reference to Exhibit (10)(c)(3) of the company s Annual Report on Form 10-K for the year ended December 31, 1980 (File No. 2-9259)).

(2) Deferred Share Unit Plan for Nonemployee Directors. (Incorporated herein by reference to Exhibit (10)(iii)(A)(6) of the company s Annual Report on Form 10-K for the year ended December 31, 1998 (File No. 0-12014)).

(3) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2008 and subsequent years, as amended effective November 20, 2008 (Incorporated herein by reference to Exhibit 9.01(c)[10(iii)(A)(5)] of the company s Form 8-K filed on November 25, 2008 (File No. 0-12014)).

(4) Short Term Incentive Program for selected executives effective February 2, 2012 (Incorporated herein by reference to Exhibit 9.01(c)[10(iii)(A)(1)] of the company s Form 8-K filed on February 7, 2012 (File No. 0-12014)).

(5) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2011 and subsequent years, as amended effective November 14, 2011 (Incorporated herein by reference to Exhibit 9.01(c)[10(iii)(A)(1)] of the company s Form 8-K filed on February 23, 2012 (File No. 0-12014)).

(6) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2016 and subsequent years, as amended effective October 26, 2016 (Incorporated herein by reference to Exhibit 9.01(c)[10(iii)(A)(1)] of the company s Form 8-K filed on October 31, 2016 (File No. 0-12014)).

(7) Amended Short Term Incentive Program with respect to awards granted in 2016 and subsequent years, as amended effective October 26, 2016 (Incorporated herein by reference to Exhibit 9.01(c)[10(iii)(A)(1)] of the company s Form 8-K filed on October 31, 2016 (File No. 0-12014)).

(21) Imperial Oil Resources Limited is incorporated in Canada, and is a wholly-owned subsidiary of the company. The names of all other subsidiaries of the company are omitted because, considered in the aggregate as a single subsidiary, they would not constitute a significant subsidiary as of December 31, 2018.

(31.1) Certification by principal executive officer of Periodic Financial Report pursuant to Rule 13a-14(a).

(31.2) Certification by principal financial officer of Periodic Financial Report pursuant to Rule 13a-14(a).

(32.1) Certification by chief executive officer of Periodic Financial Report pursuant to Rule 13a-14(b) and 18 U.S.C. Section 1350.

(32.2) Certification by chief financial officer of Periodic Financial Report pursuant to Rule 13a-14(b) and 18 U.S.C. Section 1350.

Copies of Exhibits may be acquired upon written request of any shareholder to the investor relations manager, Imperial Oil Limited, 505 Quarry Park Boulevard S.E., Calgary, Alberta T2C 5N1, and payment of processing and mailing costs.

Item 16. Form 10-K summary

Not applicable.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf on February 27, 2019 by the undersigned, thereunto duly authorized.

Imperial Oil Limited

by */s/ Richard M. Kruger*
(Richard M. Kruger)
Chairman, president and chief executive officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 27, 2019 by the following persons on behalf of the registrant and in the capacities indicated.

Signature	Title
/s/ Richard M. Kruger (Richard M. Kruger)	Chairman, president and chief executive officer and director (Principal executive officer)
/s/ Daniel E. Lyons (Daniel E. Lyons)	Senior vice-president, finance and administration, and controller (Principal financial officer and principal accounting officer)
/s/ Dave C. Brownell (Dave C. Brownell)	Director
/s/ David W. Cornhill (David W. Cornhill)	Director
/s/ Krystyna T. Hoeg (Krystyna T. Hoeg)	Director
/s/ Miranda C. Hubbs (Miranda C. Hubbs)	Director
/s/ Jack M. Mintz (Jack M. Mintz)	Director

/s/ David S. Sutherland (David S. Sutherland)	Director
/s/ Sheelagh D. Whittaker (Sheelagh D. Whittaker)	Director

Financial section

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Financial information (U.S. GAAP)

millions of Canadian dollars	**2018**	2017	2016	2015	2014
Revenues	**34,964**	29,125	25,049	26,756	36,231
Net income (loss):					
Upstream	**(138)**	(706)	(661)	(704)	2,059
Downstream	**2,366**	1,040	2,754	1,586	1,594
Chemical	**275**	235	187	287	229
Corporate and other	**(189)**	(79)	(115)	(47)	(97)
Net income (loss)	**2,314**	490	2,165	1,122	3,785
Cash and cash equivalents at year-end	**988**	1,195	391	203	215
Total assets at year-end	**41,456**	41,601	41,654	43,170	40,830
Long-term debt at year-end	**4,978**	5,005	5,032	6,564	4,913
Total debt at year-end	**5,180**	5,207	5,234	8,516	6,891
Other long-term obligations at year-end	**2,943**	3,780	3,656	3,597	3,565
Shareholders equity at year-end	**24,489**	24,435	25,021	23,425	22,530
Cash flow from operating activities	**3,922**	2,763	2,015	2,167	4,405
Per share information (Canadian dollars)					
Net income (loss) per common share - basic	**2.87**	0.58	2.55	1.32	4.47
Net income (loss) per common share - diluted	**2.86**	0.58	2.55	1.32	4.45
Dividends per common share - declared	**0.73**	0.63	0.59	0.54	0.52

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Frequently used terms

Listed below are definitions of several of Imperial s key business and financial performance measures. The definitions are provided to facilitate understanding of the terms and how they are calculated.

Capital employed

Capital employed is a measure of net investment. When viewed from the perspective of how capital is used by the business, it includes the company s property, plant and equipment, and other assets, less liabilities, excluding both short-term and long-term debt. When viewed from the perspective of the sources of capital employed in total for the company, it includes total debt and equity. Both of these views include the company s share of amounts applicable to equity companies, which the company believes should be included to provide a more comprehensive measurement of capital employed.

millions of Canadian dollars	**2018**	2017	2016
Business uses: asset and liability perspective			
Total assets	**41,456**	41,601	41,654
Less: Total current liabilities excluding notes and loans payable	**(3,753)**	(3,934)	(3,681)
Total long-term liabilities excluding long-term debt	**(8,034)**	(8,025)	(7,718)
Add: Imperial s share of equity company debt	**23**	19	17
Total capital employed	**29,692**	29,661	30,272
Total company sources: Debt and equity perspective			
Notes and loans payable	**202**	202	202
Long-term debt	**4,978**	5,005	5,032
Shareholders equity	**24,489**	24,435	25,021
Add: Imperial s share of equity company debt	**23**	19	17
Total capital employed	**29,692**	29,661	30,272

Return on average capital employed (ROCE)

ROCE is a financial performance ratio. From the perspective of the business segments, ROCE is annual business-segment net income divided by average business-segment capital employed (an average of the beginning and end-of-year amounts). Segment net income includes Imperial s share of segment net income of equity companies, consistent with the definition used for capital employed, and excludes the cost of financing. The company s total ROCE is net income excluding the after-tax cost of financing divided by total average capital employed. The company has consistently applied its ROCE definition for many years and views it as the best measure of historical capital productivity in a capital-intensive, long-term industry to demonstrate to shareholders that capital has been used wisely over the long term. Additional measures, which are more cash flow based, are used to make investment decisions.

millions of Canadian dollars	**2018**	2017	2016
Net income	**2,314**	490	2,165
Financing (after tax), including Imperial s share of equity companies	**77**	48	53
Net income excluding financing	**2,391**	538	2,218

Average capital employed		**29,677**	29,967	31,116
Return on average capital employed (percent)	corporate total	**8.1**	1.8	7.1

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Cash flow from operating activities and asset sales

Cash flow from operating activities and asset sales is the sum of the net cash provided by operating activities and proceeds from asset sales reported in the Consolidated statement of cash flows. This cash flow reflects the total sources of cash both from operating the company s assets and from the divesting of assets. The company employs a long-standing and regular disciplined review process to ensure that all assets are contributing to the company s strategic objectives. Assets are divested when they no longer meet these objectives or are worth considerably more to others. Because of the regular nature of this activity, the company believes it is useful for investors to consider sales proceeds together with cash provided by operating activities when evaluating cash available for investment in the business and financing activities, including shareholder distributions.

millions of Canadian dollars	**2018**	2017	2016
Cash from operating activities	**3,922**	2,763	2,015
Proceeds from asset sales	**59**	232	3,021
Total cash flow from operating activities and asset sales	**3,981**	2,995	5,036

Operating costs

Operating costs are the costs during the period to produce, manufacture, and otherwise prepare the company s products for sale including energy costs, staffing and maintenance costs. They exclude the cost of raw materials, taxes and interest expense and are on a before-tax basis. While the company is responsible for all revenue and expense elements of net income, operating costs represent the expenses most directly under the company s control and therefore, are useful in evaluating the company s performance.

Reconciliation of operating costs

millions of Canadian dollars	**2018**	2017	2016
From Imperial s Consolidated statement of income			
Total expenses	**32,026**	28,842	24,910
Less:			
Purchases of crude oil and products	**21,541**	18,145	15,120
Federal excise tax	**1,667**	1,673	1,650
Financing	**108**	78	65
Subtotal	**23,316**	19,896	16,835
Imperial s share of equity company expenses	**74**	62	63
Total operating costs	**8,784**	9,008	8,138

Components of operating costs

millions of Canadian dollars	**2018**	2017	2016
From Imperial s Consolidated statement of income			
Production and manufacturing (a)	**6,121**	5,586	5,105
Selling and general (a)	**908**	883	1,118
Depreciation and depletion	**1,555**	2,172	1,628
Non-service pension and postretirement benefit (a)	**107**	122	130

Exploration	**19**	183	94
Subtotal	**8,710**	8,946	8,075
Imperial s share of equity company expenses	**74**	62	63
Total operating costs	**8,784**	9,008	8,138

(a) Prior year amounts have been reclassified (note 2).

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Management s discussion and analysis of financial condition and results of operations

Overview

The following discussion and analysis of Imperial s financial results, as well as the accompanying financial statements and related notes to consolidated financial statements to which they refer, are the responsibility of the management of Imperial Oil Limited.

The company s accounting and financial reporting fairly reflect its business model involving exploration for, and production of, crude oil and natural gas and manufacture, trade, transport and sale of crude oil, natural gas, petroleum products, petrochemicals and a variety of specialty products.

Imperial, with its resource base, financial strength, disciplined investment approach and technology portfolio, is well positioned to participate in substantial investments to develop new Canadian energy supplies. The company s integrated business model, with significant investments in Upstream, Downstream and Chemical segments, reduces the company s risk from changes in commodity prices. While commodity prices depend on supply and demand and may be volatile on a short-term basis, Imperial s investment decisions are grounded on fundamentals reflected in its long-term business outlook, and use a disciplined approach in selecting and pursuing the most attractive investment opportunities. The corporate plan is a fundamental annual management process that is the basis for setting near-term operating and capital objectives, in addition to providing the longer-term economic assumptions used for investment evaluation purposes. Volumes are based on individual field production profiles, which are also updated annually. Price ranges for crude oil, natural gas, refined products and chemical products are based on corporate plan assumptions developed annually and are utilized for investment evaluation purposes. Major investment opportunities are evaluated over a range of potential market conditions. Once major investments are made, a reappraisal process is completed to ensure relevant lessons are learned and improvements are incorporated into future projects.

The term project as used in this report can refer to a variety of different activities and does not necessarily have the same meaning as in any government payment transparency reports.

Business environment and risk assessment

Long-term business outlook

The Long-term business outlook is based on Exxon Mobil Corporation s 2018 *Outlook for Energy*, which is used to help inform the company s long-term business strategies and investment plans. By 2040, the world s population is projected at around 9.2 billion people, or about 1.7 billion more people than in 2016. Coincident with this population increase, the company expects worldwide economic growth to average close to 3 percent per year, with economic output nearly doubling by 2040. As economies and populations grow, and as living standards improve for billions of people, the need for energy is expected to continue to rise. Even with significant efficiency gains, global energy demand is projected to rise by about 25 percent from 2016 to 2040. This increase in energy demand is expected to be driven by developing countries (i.e., those that are not member nations of the Organization for Economic Co-operation and Development (OECD)). Canada is expected to see flat to modest local energy demand growth through to 2040 and will continue to be a large supplier of energy exports to help meet rising global energy needs.

As expanding prosperity helps drive global energy demand higher, increasing use of energy efficient technologies and practices, as well as lower emission fuels will continue to help significantly reduce energy consumption and emissions per unit of economic output over time. Substantial efficiency gains are likely in all key aspects of the world s economy through 2040, affecting energy requirements for power generation, transportation, industrial applications, and residential and commercial needs.

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Global electricity demand is expected to increase approximately 60 percent from 2016 to 2040, with developing countries likely to account for about 85 percent of the increase. Consistent with this projection, power generation is expected to remain the largest and fastest growing major segment of global primary energy demand, supported by a wide variety of energy sources. The share of coal fired generation is likely to decline substantially and approach 25 percent of the world s electricity by 2040, versus nearly 40 percent in 2016, in part as a result of policies to improve air quality, as well as reduce greenhouse gas emissions to address the risks of climate change. From 2016 to 2040, the amount of electricity supplied using natural gas, nuclear power, and renewables is likely to approximately double, and account for about 95 percent of the growth in electricity supplies. Electricity from wind and solar is likely to increase about 400 percent, helping total renewables (including other sources, i.e., hydropower) to account for about half of the increase in electricity supplies worldwide through 2040. Total renewables will likely reach nearly 35 percent of global electricity supplies by 2040. Natural gas and nuclear are also expected to increase shares over the period to 2040, reaching about 25 percent and 12 percent respectively of global electricity supplies by 2040. Supplies of electricity by energy type will reflect significant differences across regions, reflecting a wide range of factors including the cost and availability of various energy types.

Energy for global transportation including cars, trucks, ships, trains and airplanes is expected to increase by about 30 percent from 2016 to 2040. Transportation energy demand is likely to account for approximately 60 percent of the growth in liquid fuels demand worldwide over this period. Liquid fuels demand for light duty vehicles is expected to remain relatively flat to 2040 as the impact of better fuel economy and significant growth in electric cars, led by China, Europe, and the United States, work to offset growth in the worldwide car fleet of about 75 percent. By 2040, light-duty vehicles are expected to account for about 20 percent of global liquid fuels demand. Nearly all the world s transportation fleets are likely to continue to run on liquid fuels, which are widely available and offer practical advantages in providing a large quantity of energy in small volumes.

Liquid fuels provide the largest share of global energy supplies today due to their broad based availability, affordability, ease of transportation, storage and fitness as a practical solution to meet a wide variety of needs. By 2040, global demand for liquid fuels is projected to grow to approximately 118 million barrels per day, an increase of about 20 percent from 2016. The non-OECD share of global liquid fuels demand is expected to increase to about 65 percent by 2040, as liquid fuels demand in the OECD is likely to decline by close to 10 percent. Much of the global liquid fuels demand today is met by crude production from traditional conventional sources; these supplies will remain important and significant development activity is expected to offset much of the natural declines from these fields. At the same time, a variety of emerging supply sources including tight oil, deep water oil, oil sands, natural gas liquids and biofuels are expected to grow to help meet rising demand. The world s resource base is sufficient to meet projected demand through 2040 as technological advances continue to expand the availability of economic supply options. However, timely investments will remain critical to meeting global needs with reliable and affordable supplies.

Natural gas is a versatile and practical fuel for a wide variety of applications and it is expected to grow the most of any primary energy type from 2016 to 2040, meeting more than 35 percent of global energy demand growth. Global natural gas demand is expected to rise nearly 40 percent from 2016 to 2040, with about 45 percent of that increase in the Asia Pacific region. Significant growth in supplies of unconventional gas the natural gas found in shale and other tight rock formations will help meet these needs. In total, about 55 percent of the growth in natural gas supplies is expected to be from unconventional sources. However, it is expected conventionally produced natural gas is likely to remain the cornerstone of global supply, meeting about two-thirds of worldwide demand in 2040. Liquefied natural gas (LNG) trade will expand significantly, meeting about one-third of the increase in demand growth, with much of this supply expected to help meet rising demand in Asia Pacific.

The world s energy mix is highly diverse and will remain so through 2040. Oil is expected to remain the largest source of energy with its share remaining close to one-third in 2040. Coal is currently the second largest source of energy, but it is likely to lose that position to natural gas in the 2020 to 2025 timeframe. The share of natural gas is expected to reach 25 percent by 2040, while the share of coal falls to about 20 percent. Nuclear power is projected to grow significantly, as many nations are likely to expand nuclear capacity to address rising electricity needs, as well as energy security and environmental issues. Total renewable energy is likely to exceed 15 percent of total global energy by 2040, with biomass, hydro and geothermal contributing a combined share of more than 10 percent. Total energy supplied from wind, solar and biofuels is expected to increase rapidly, growing nearly 250 percent from 2016 to 2040, when they will approach about 5 percent of the world s energy.

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The company anticipates that the world s available oil and gas resource base will grow not only from new discoveries, but also from reserve increases in previously discovered fields. Technology will underpin these increases. The investments to develop and supply resources to meet global demand through 2040 will be significant - even if demand remains flat. This reflects a fundamental aspect of the oil and natural gas business, in that, as the International Energy Agency (IEA) notes in its *World Energy Outlook in 2018,* a key understanding driver for new investment is declining output from existing fields . According to the IEA s New Policies Scenario, the investment required to meet oil and natural gas supply requirements worldwide over the period 2018 to 2040 will be about US$21 trillion (measured in 2017 dollars) or approximately US$900 billion per year on average.

International accords and underlying regional and national regulations covering greenhouse gas emissions continue to evolve with uncertain timing and outcome, making it difficult to predict their business impact. Imperial s estimates of potential costs related to greenhouse gas emissions align with applicable provincial and federal regulations. Additionally, Imperial uses ExxonMobil s *Outlook for Energy* as a foundation for estimating energy supply and demand requirements from various energy sources and uses, and the *Outlook for Energy* takes in account policies established to reduce energy related greenhouse gas emissions. The climate accord reached at the Conference of the Parties (COP 21) in Paris set many new goals, and many related policies are still emerging. The *Outlook for Energy* reflects an environment with increasingly stringent climate policies and is consistent with the aggregation of Nationally Determined Contributions which were submitted by signatories to the United Nations Framework Convention on Climate Change (UNFCCC) 2015 Paris Agreement. The *Outlook for Energy* seeks to identify potential impacts of climate related policies, which often target specific sectors. It estimates potential impacts of these climate related policies on consumer energy demand by using various assumptions and tools including, depending on the sector, application of a proxy cost of carbon or assessment of targeted policies (i.e., automotive fuel economy standards). As people and nations look for ways to reduce risks of global climate change, they will continue to need practical solutions that do not jeopardize the affordability or reliability of the energy they need.

Practical solutions to the world s energy and climate challenges will benefit from market competition, well informed, well designed and transparent policy approaches that carefully weigh costs and benefits. Such policies are likely to help manage the risks of climate change while also enabling societies to pursue other high priority goals around the world including clean air and water, access to reliable, affordable energy, and economic progress for all people. All practical and economically viable energy sources, both conventional and unconventional, will need to be pursued to continue meeting global energy demand, recognizing the scale and variety of worldwide energy needs, as well as the importance of expanding access to modern energy to promote better standards of living for billions of people.

The information provided in the Long-term business outlook includes internal estimates and forecasts based upon ExxonMobil s internal data and analyses, as well as publicly available information from external sources including the International Energy Agency.

Upstream

Imperial produces crude oil and natural gas for sale predominantly into North American markets. Imperial s Upstream business strategies guide the company s exploration, development, production, research and gas marketing activities. These strategies include maximizing asset reliability, accelerating development and application of high impact technologies, maximizing value by capturing new business opportunities and managing the existing portfolio, as well as pursuing sustainable improvements in organizational efficiency and effectiveness. These strategies are underpinned by a relentless focus on operations integrity, commitment to innovative technologies, disciplined approach to investing and cost management, development of employees and investment in the communities within which the company operates.

Imperial has a significant oil and gas resource base and a large inventory of potential projects. The company continues to evaluate opportunities to support long-term growth. As future development projects bring new production online, Imperial expects growth from oil sands in-situ and mining, as well as unconventional resources, with the largest growth potential related to in-situ. Actual volumes will vary from year to year due to the factors described in Item 1A. Risk factors.

The industry experienced challenges throughout 2018 with the volatility in crude differentials in the western Canadian market. Prices for most of the company s crude oil sold are referenced to Western Canada Select (WCS) and West Texas Intermediate (WTI) oil markets. While WTI crude oil prices improved in 2018, abundant crude oil supply and limited pipeline takeaway capacity caused the average price of WCS to decrease slightly versus 2017. The WTI / WCS differential widened significantly during the fourth quarter of 2018 to average approximately US$40 per barrel, compared to around US$12 per barrel in the same period of 2017. In December 2018 the Government of Alberta introduced temporary mandatory production curtailment regulations, which took effect on January 1, 2019. Following the announcement to impose production limits on large producers in Alberta, the WTI / WCS differential narrowed. The duration and impact of these regulations is uncertain. Imperial believes prices over the long-term will be driven by market supply and demand, with the demand side largely being a function of general economic activities, levels of prosperity, technology advances, consumer preference and government policies. On the supply side, prices may be significantly impacted by political events, logistics constraints, the actions of OPEC, governments and other factors. To manage the risks associated with price, Imperial evaluates annual plans and all major investments across a range of price scenarios.

Downstream

Imperial s Downstream serves predominantly Canadian markets with refining, logistics and marketing assets. Imperial s Downstream business strategies competitively position the company across a range of market conditions. These strategies include targeting industry leading performance in reliability, safety and operations integrity, as well as maximizing value from advanced technologies, capitalizing on integration across Imperial s businesses, selectively investing for resilient and advantaged returns, operating efficiently and effectively, and providing quality, valued and differentiated products and services to customers.

Imperial owns and operates three refineries in Canada, with aggregate distillation capacity of 423,000 barrels per day. Refining margins are largely driven by differences in commodity prices and are a function of the difference between what a refinery pays for its raw materials (primarily crude oil) and the market prices for the range of products produced (primarily gasoline, heating oil, diesel oil, jet fuel, fuel oil and asphalt). Crude oil and many products are widely traded with published prices, including those quoted on the New York Mercantile Exchange. Prices for these commodities are determined by the global and regional marketplaces and are influenced by many factors, including global and regional supply / demand balances, inventory levels, industry refinery operations, import / export balances, currency fluctuations, seasonal demand, weather and political climate.

In 2018, Imperial s margins strengthened, benefitting from widening crude differentials and strong product prices.

As described in more detail in Item 1A. Risk factors , proposed carbon policy and other climate related regulations, as well as continued biofuels mandates, could have negative impacts on the downstream business. Imperial s integration across the value chain, from refining to marketing, enhances overall value across the fuels business.

Imperial supplies petroleum products to the motoring public through Esso and Mobil-branded sites and independent marketers. At the end of 2018, there were about 2,200 sites operating under a branded wholesaler model whereby Imperial supplies fuel to independent third parties who own and operate sites in alignment with Esso and Mobil brand standards. The Mobil fuels brand was launched in Canada in 2017 with the conversion of more than 200 existing unbranded third party sites completed by the end of 2018.

Chemical

North America continued to benefit from abundant supplies of natural gas and gas liquids, providing both low cost energy and feedstock for steam crackers, and a favourable margin environment for integrated chemical producers. Imperial sustained a competitive advantage through continued operational excellence, investment and cost discipline. In 2018, the company continued to capture value from the integration of its chemical plant in Sarnia with the refinery. The company also benefits from its integration within ExxonMobil s North American chemical businesses, enabling Imperial to maintain a leadership position in its key market segments.

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Results of operations

Consolidated

millions of Canadian dollars	**2018**	2017	2016
Net income (loss)	**2,314**	490	2,165

2018

Net income in 2018 was $2,314 million, or $2.86 per share on a diluted basis, an increase of $1,824 million compared to net income of $490 million or $0.58 per share in 2017. The prior year results included upstream non-cash impairment charges of $566 million.

2017

Net income in 2017 was $490 million, or $0.58 per share on a diluted basis, reflecting impairment charges of $289 million ($0.35 per share) associated with the Horn River development and $277 million ($0.33 per share) associated with the Mackenzie gas project. This compares with net income of $2,165 million or $2.55 per share in 2016, which included a gain of $1.7 billion ($2.01 per share) from the sale of retail sites.

Upstream

millions of Canadian dollars	**2018**	2017	2016
Net income (loss)	**(138)**	(706)	(661)

2018

Upstream recorded a net loss of $138 million in 2018, compared to a net loss of $706 million in 2017. Improved results reflect the absence of impairment charges of $566 million, higher Kearl volumes of about $210 million, lower royalties of about $80 million and favourable foreign exchange effects of about $50 million. These items were partially offset by higher operating costs of about $200 million, lower Cold Lake volumes of about $170 million and lower Canadian crude oil realizations of about $60 million.

2017

Upstream recorded a net loss of $706 million in 2017, reflecting impairment charges of $289 million associated with the Horn River development and $277 million associated with the Mackenzie gas project. Excluding these impairment charges, the net loss of $140 million compares to a net loss of $661 million in 2016. Results benefitted from higher Canadian crude oil realizations of about $1,190 million and higher Kearl volumes of about $60 million. Results were negatively impacted by higher royalties of about $250 million, lower Syncrude and Norman Wells volumes of about $190 million, higher operating expenses mainly associated with Syncrude and Kearl of about $150 million, higher energy costs of about $80 million and the impact of a stronger Canadian currency of about $60 million.

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Average realizations

Canadian dollars	**2018**	2017	2016
Bitumen (per barrel)	**37.56**	39.13	26.52
Synthetic oil (per barrel)	**70.66**	67.58	57.12
Conventional crude oil (per barrel)	**41.84**	53.51	32.93
Natural gas liquids (per barrel)	**38.66**	31.46	15.58
Natural gas (per thousand cubic feet)	**2.43**	2.58	2.41

2018

WTI averaged US$65.03 per barrel in 2018, up from US$50.85 per barrel in 2017. WCS averaged US$38.71 per barrel and US$38.95 per barrel for the same periods. The WTI / WCS differential widened to average approximately US$26 per barrel in 2018, from around US$12 per barrel in 2017. The Canadian dollar averaged US$0.77 in 2018, unchanged from 2017.

Imperial s average Canadian dollar realizations for bitumen declined generally in line with WCS, adjusted for changes in the exchange rate and transportation costs. Bitumen realizations averaged $37.56 per barrel in 2018, a decrease of $1.57 per barrel from 2017. The company s average Canadian dollar realizations for synthetic crude increased by $3.08 per barrel to average $70.66 per barrel in 2018, however the widening of the western Canadian light crude differential relative to WTI during the fourth quarter of 2018 negatively impacted synthetic crude realizations.

2017

WTI averaged US$50.85 per barrel in 2017, up from US$43.44 per barrel in the prior year. WCS averaged US$38.95 per barrel and US$29.49 per barrel respectively for the same periods. The WTI / WCS differential narrowed to approximately US$12 per barrel in 2017, from around US$14 per barrel in 2016. The Canadian dollar averaged US$0.77 in 2017, an increase of about US$0.02 from 2016.

Imperial s average Canadian dollar realizations for bitumen and synthetic crudes increased generally in line with the North American benchmarks, adjusted for changes in the exchange rate and transportation costs. Bitumen realizations averaged $39.13 per barrel for 2017, an increase of $12.61 per barrel versus 2016. Synthetic crude realizations averaged $67.58 per barrel, an increase of $10.46 per barrel from 2016.

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Crude oil and NGLs - production and sales (a)

thousands of barrels per day	**2018**		2017		2016	
	gross	**net**	gross	net	gross	net
Bitumen	**293**	**255**	288	255	281	256
Synthetic oil (b)	**62**	**60**	62	57	68	67
Conventional crude oil	**5**	**5**	4	3	14	12
Total crude oil production	**360**	**320**	354	315	363	335
NGLs available for sale	**1**	**2**	1	1	1	1
Total crude oil and NGL production	**361**	**322**	355	316	364	336
Bitumen sales, including diluent (c)	**406**		381		374	
NGL sales	**6**		6		5	

Natural gas - production and production available for sale (a)

millions of cubic feet per day	**2018**		2017		2016	
	gross	**net**	gross	net	gross	net
Production (d) (e)	**129**	**126**	120	114	129	122
Production available for sale (f)		**94**		80		87

(a) Volume per day metrics are calculated by dividing the volume for the period by the number of calendar days in the period. Gross production is the company s share of production (excluding purchases) before deduction of the mineral owners or governments share or both. Net production excludes those shares.

(b) The company s synthetic oil production volumes were from the company s share of production volumes in the Syncrude joint venture.

(c) Diluent is natural gas condensate or other light hydrocarbons added to crude bitumen to facilitate transportation to market by pipeline and rail.

(d) Gross production of natural gas includes amounts used for internal consumption with the exception of the amounts re-injected.

(e) Net production is gross production less the mineral owners or governments share or both. Net production reported in the above table is consistent with production quantities in the net proved reserves disclosure.

(f) Includes sales of the company s share of net production and excludes amounts used for internal consumption.

2018

Gross production of Cold Lake bitumen averaged 147,000 barrels per day in 2018, compared to 162,000 barrels per day in 2017. Lower volumes were primarily due to production timing associated with steam management and planned maintenance.

Gross production of Kearl bitumen averaged 206,000 barrels per day in 2018 (146,000 barrels Imperial s share) up from 178,000 barrels per day (126,000 barrels Imperial s share) in 2017. Increased 2018 production reflects improved operational reliability associated with ore preparation, enhanced piping durability and feed management.

During 2018, the company s share of gross production from Syncrude averaged 62,000 barrels per day, unchanged from 2017.

2017

Gross production of Cold Lake bitumen averaged 162,000 barrels per day in 2017, up from 161,000 barrels per day in 2016.

Gross production of Kearl bitumen averaged 178,000 barrels per day in 2017 (126,000 barrels Imperial s share) up from 169,000 barrels per day (120,000 barrels Imperial s share) in 2016. Increased 2017 production reflects improved reliability associated with the mining and ore preparation operations.

During 2017, the company s share of gross production from Syncrude averaged 62,000 barrels per day, compared to 68,000 barrels per day in 2016. Syncrude 2017 production was impacted by the March 2017 fire at the Syncrude Mildred Lake upgrader and planned maintenance. In 2016, production was impacted by the Alberta wildfires and planned maintenance.

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Downstream

millions of Canadian dollars	**2018**	2017	2016
Net income (loss)	**2,366**	1,040	2,754

2018

Downstream net income was $2,366 million, an increase of $1,326 million versus the prior year. Higher earnings primarily reflect stronger margins of about $1,530 million, partially offset by the absence of a $151 million gain on the sale of a surplus property in 2017.

2017

Downstream net income was $1,040 million, compared to $2,754 million in 2016, which included a $1,841 million gain from the sale of company-owned retail sites and the general aviation business. Excluding the impact of the 2016 asset sales, earnings increased by $127 million reflecting higher refining margins of about $340 million, lower marketing expenses of about $160 million, mainly associated with the retail divestment, and a gain of $151 million from the sale of a surplus property. These factors were partially offset by lower marketing margins of about $330 million, mainly associated with the impact of the retail divestment, and higher maintenance activity of about $130 million.

Refinery utilization

thousands of barrels per day (a)	**2018**	2017	2016
Total refinery throughput (b)	**392**	383	362
Refinery capacity at December 31	**423**	423	423
Utilization of total refinery capacity (percent)	**93**	91	86

Sales

thousands of barrels per day (a)	**2018**	2017	2016
Gasolines	**255**	257	261
Heating, diesel and jet fuels	**183**	177	170
Heavy fuel oils (c)	**26**	18	16
Lube oils and other products	**40**	40	37
Net petroleum product sales (c)	**504**	492	484

(a) Volume per day metrics are calculated by dividing the volume for the period by the number of calendar days in the period.
(b) Crude oil and feedstocks sent directly to atmospheric distillation units.
(c) In 2018 and 2017, carbon black product sales are reported under Net petroleum product sales Heavy fuel oils; in 2016, they were reported under Total petrochemical sales Polymers and basic chemicals.

2018

Refinery throughput averaged 392,000 barrels per day in 2018, up from 383,000 barrels per day in 2017. Capacity utilization increased to 93 percent from 91 percent in 2017. Petroleum product sales were 504,000 barrels per day in 2018, up from 492,000 barrels per day in 2017. Sales growth continues to be driven by optimization across the full downstream value chain, and the expansion of Imperial s logistics capabilities.

2017

Refinery throughput averaged 383,000 barrels per day in 2017, up from 362,000 barrels per day in 2016. Capacity utilization increased to 91 percent from 86 percent in 2016, reflecting reduced turnaround maintenance activity. Petroleum product sales were 492,000 barrels per day in 2017, up from 484,000 barrels per day in 2016. Sales growth continues to be driven by optimization across the full downstream value chain.

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Chemical

millions of Canadian dollars	**2018**	2017	2016
Net income (loss)	**275**	235	187

Sales

thousands of tonnes	**2018**	2017	2016
Polymers and basic chemicals (a)	**602**	564	697
Intermediate and others	**205**	210	211
Total petrochemical sales (a)	**807**	774	908

(a) In 2018 and 2017, carbon black product sales are reported under Net petroleum product sales Heavy fuel oils; in 2016, they were reported under Total petrochemical sales Polymers and basic chemicals.

2018

Chemical net income was $275 million, an increase of $40 million versus the prior year, reflecting higher margins and volumes.

2017

Chemical net income was $235 million, up from $187 million in 2016, mainly due to stronger margins.

Corporate and other

millions of Canadian dollars	**2018**	2017	2016
Net income (loss)	**(189)**	(79)	(115)

2018

For 2018, Corporate and other expenses were $189 million, compared to $79 million in 2017. As part of the implementation of the Financial Accounting Standards Board s update, Compensation Retirement Benefits (Topic 715): *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*, beginning January 1, 2018, Corporate and other includes all non-service pension and postretirement benefit expenses. Prior to 2018, the majority of these costs were allocated to the operating segments.

2017

For 2017, Corporate and other costs were $79 million, versus $115 million in 2016, mainly due to lower share-based compensation charges.

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Liquidity and capital resources

Sources and uses of cash

millions of Canadian dollars	**2018**	2017	2016
Cash provided by (used in)			
Operating activities	**3,922**	2,763	2,015
Investing activities	**(1,559)**	(781)	1,947
Financing activities	**(2,570)**	(1,178)	(3,774)
Increase (decrease) in cash and cash equivalents	**(207)**	804	188
Cash and cash equivalents at end of year	**988**	1,195	391

The company issues long-term debt from time to time and maintains a commercial paper program. However, internally generated funds cover the majority of its financial requirements. Cash that may be temporarily surplus to the company s immediate needs is carefully managed through counterparty quality and investment guidelines to ensure that it is secure and readily available to meet the company s cash requirements and to optimize returns.

Cash flows from operating activities are highly dependent on crude oil and natural gas prices, as well as petroleum and chemical product margins. In addition, to provide for cash flow in future periods, the company needs to continually find and develop new resources, and continue to develop and apply new technologies to existing fields in order to maintain or increase production.

The company s financial strength enables it to make large, long-term capital expenditures. Imperial s portfolio of development opportunities and the complementary nature of its business segments help mitigate the overall risks for the company and its cash flows. Further, due to its financial strength, debt capacity and portfolio of opportunities, the risk associated with delay of any single project would not have a significant impact on the company s liquidity or ability to generate sufficient cash flows for its operations and fixed commitments.

Funding of registered retirement plans complies with federal and provincial pension regulations, and the company makes contributions to the plans based on an independent actuarial valuation completed at least once every three years depending on funding status. The most recent valuation of the company s registered retirement plans was completed as at December 31, 2016. The company contributed $203 million to the registered retirement plans in 2018. Future funding requirements are not expected to affect the company s existing capital investment plans or its ability to pursue new investment opportunities.

Cash flow from operating activities

2018

Cash flow generated from operating activities was $3,922 million in 2018, up from $2,763 million in 2017, primarily reflecting higher earnings, partially offset by unfavourable working capital effects.

2017

Cash flow generated from operating activities was $2,763 million in 2017, compared with $2,015 million in 2016, reflecting higher earnings, excluding the impact of asset sales and impairment charges, partially offset by the absence of favourable working capital effects.

Cash flow from investing activities

2018

Investing activities used net cash of $1,559 million in 2018, compared with $781 million used in 2017, reflecting higher additions to property, plant and equipment, and lower proceeds from asset sales.

2017

Investing activities used net cash of $781 million in 2017, compared with cash generated from investing activities of $1,947 million in 2016, reflecting lower proceeds from asset sales.

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Cash flow from financing activities

2018

Cash used in financing activities was $2,570 million in 2018, compared with $1,178 million used in 2017.

At the end of 2018, total debt outstanding was $5,180 million, compared with $5,207 million at the end of 2017.

In November 2018, the company extended the maturity date of its existing $250 million committed long-term line of credit to November 2020. The company has not drawn on the facility.

In December 2018, the company extended the maturity date of its existing $250 million committed short-term line of credit to December 2019. The company has not drawn on the facility.

During 2018, the company, under its share purchase program, purchased about 48.7 million shares for $1,971 million, including shares purchased from Exxon Mobil Corporation.

Dividends paid in 2018 were $572 million. The per share dividend paid in 2018 was $0.70, up from $0.62 in 2017.

2017

Cash used in financing activities was $1,178 million in 2017, compared with $3,774 million in 2016, mainly reflecting the absence of debt repayments, partially offset by share purchases under the company s share purchase program.

At the end of 2017, total debt outstanding was $5,207 million, compared with $5,234 million at the end of 2016.

In November 2017, the company extended the maturity date of its existing $250 million committed long-term line of credit to November 2019. The company has not drawn on the facility.

In December 2017, the company extended the maturity date of its existing $250 million committed short-term line of credit to December 2018. The company has not drawn on the facility.

During 2017 the company purchased about 16.4 million shares for $627 million, including shares purchased from Exxon Mobil Corporation.

Dividends paid in 2017 were $524 million. The per share dividend paid in 2017 was $0.62, up from $0.58 in 2016.

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Financial strength

	2018	2017	2016
Total debt as a percentage of capital (a)	**18**	18	17

(a) Current and long-term debt (page 63) and the company s share of equity company debt, divided by debt and shareholders equity (page 63).

Debt represented 18 percent of the company s capital structure at the end of 2018.

Debt-related interest incurred in 2018, before capitalization of interest, was $133 million, compared with $103 million in 2017. The average effective interest rate on the company s debt was 2.5 percent in 2018, compared with 2.0 percent in 2017.

The company s financial strength represents a competitive advantage of strategic importance providing it the opportunity to readily access capital markets under the full range of market conditions and enables the company to take on large, long-term capital commitments in the pursuit of maximizing shareholder value.

Commitments

The following table shows the company s commitments outstanding at December 31, 2018. It combines data from the Consolidated balance sheet and from individual notes to the consolidated financial statements, where appropriate.

		Payment due by period				
			2020	2022	2024 and	
millions of Canadian dollars	Note reference	2019	to 2021	to 2023	beyond	Total
Long-term debt (a)	15	**-**	**4,478**	**26**	**474**	**4,978**
- Due in one year		**27**				**27**
Operating leases (b)	14	**130**	**125**	**24**	**12**	**291**
Firm capital commitments (c)		**645**	**91**	**-**	**-**	**736**
Pension and other postretirement obligations (d)	5	**267**	**114**	**115**	**754**	**1,250**
Asset retirement obligations (e)	6	**71**	**81**	**57**	**1,208**	**1,417**
Other long-term purchase agreements (f)		**814**	**1,575**	**1,695**	**8,637**	**12,721**

(a) Long-term debt includes a loan from an affiliated company of ExxonMobil of $4,447 million and capital lease obligations of $558 million, $27 million of which is due in one year. The payment by period for the related party long-term loan is estimated based on the right of the related party to cancel the loan on at least 370 days advance written notice.

(b) Minimum commitments for operating leases, shown on an undiscounted basis, covers primarily storage tanks, rail cars and marine vessels.

(c) Firm capital commitments represent legally-binding payment obligations to third parties where agreements specifying all significant terms have been executed for the construction and purchase of fixed assets and other permanent investments. In certain cases where the company executes contracts requiring commitments to a work scope, those commitments have been included to the extent that the amounts and timing of payments can be reliably estimated. Firm capital commitments related to capital projects are shown on an undiscounted basis. In 2018 the company entered into approximately $300 million in firm capital commitments mainly associated with the Aspen in-situ project.

(d) The amount by which the benefit obligations exceeded the fair value of fund assets for pension and other postretirement plans at year end. The payments by period include expected contributions to funded pension plans in 2019 and estimated benefit payments for unfunded plans in all years.

(e) Asset retirement obligations represent the fair value of legal obligations associated with site restoration on the retirement of assets with determinable useful lives.

(f) Other long-term purchase agreements are non-cancelable, or cancelable only under certain conditions and long-term commitments other than unconditional purchase obligations. They include primarily transportation services agreements, raw material supply and community benefits agreements.

Unrecognized tax benefits totaling $36 million have not been included in the company s commitments table because the company does not expect there will be any cash impact from the final settlements as sufficient funds have been deposited with the Canada Revenue Agency. Further details on the unrecognized tax benefits can be found in note 4 to the financial statements on page 75.

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Litigation and other contingencies

As discussed in note 10 to the consolidated financial statements on page 85, a variety of claims have been made against Imperial and its subsidiaries. Based on a consideration of all relevant facts and circumstances, the company does not believe the ultimate outcome of any currently pending lawsuits against the company will have a material adverse effect on the company s operations, financial condition, or financial statements taken as a whole.

Additionally, as discussed in note 10, Imperial was contingently liable at December 31, 2018, for guarantees relating to performance under contracts. These guarantees do not have a material effect on the company s operations, financial condition, or financial statements taken as a whole.

There are no events or uncertainties beyond those already included in reported financial information that would indicate a material change in future operating results or financial condition.

Capital and exploration expenditures

millions of Canadian dollars	**2018**	2017
Upstream (a)	**991**	416
Downstream	**383**	200
Chemical	**25**	17
Other	**28**	38
Total	**1,427**	671

(a) Exploration expenses included.

Total capital and exploration expenditures were $1,427 million in 2018, an increase of $756 million from 2017.

For the Upstream segment, capital and exploration expenditures were $991 million in 2018, compared with $416 million in 2017. Investments were primarily related to growth activities including further development of unconventional assets, investment in supplemental crushing capacity at Kearl, and progressing the Aspen in-situ project.

For the Downstream segment, capital expenditures were $383 million in 2018, compared with $200 million in 2017. In 2018, investments were primarily in support of enhancing the company s distribution network as well as refinery projects to improve reliability, feedstock flexibility, energy efficiency and environmental performance.

Total capital and exploration expenditures are expected to range between $2.3 billion to $2.4 billion in 2019. Planned increases in spending versus 2018 are largely driven by the Aspen in-situ project, drilling and other Upstream projects. Actual spending could vary depending on the progress of individual projects.

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Market risks and other uncertainties

Crude oil, natural gas, petroleum product and chemical prices have fluctuated in response to changing market forces. The impacts of these price fluctuations on earnings from Upstream, Downstream and Chemical operations have varied.

Imperial s earnings are influenced by North American crude oil benchmark prices as well as changes in the differentials between these benchmarks and western Canadian prices for light and heavy crude oil. Imperial s integrated business model reduces the company s risk from changes in commodity prices. For instance, when light and heavy differentials between North American crude benchmarks and western Canadian prices widen together, Imperial is able to mitigate the impact of these widening differentials through integration with Downstream investments in refineries, pipeline commitments and the Edmonton rail terminal. As a result, the negative exposure to these widening differentials in the Upstream is more than offset by the benefit of lower feedstock costs in the Downstream.

At this time, Imperial is a net consumer of natural gas, used in Imperial s Upstream operation and refineries. A decrease in the value of natural gas reduces Imperial s operating expenses, thereby increasing Imperial s earnings.

In the competitive downstream and chemical environments, earnings are primarily determined by margin capture rather than absolute price levels on products sold. Refining margins are a function of the difference between what a refiner pays for its raw materials (primarily crude oil) and the market prices for the range of products produced. These prices in turn depend on global and regional supply / demand balances, inventory levels, refinery operations, import / export balances and weather.

Industry crude oil and natural gas commodity prices and petroleum and chemical product prices are commonly benchmarked in U.S. dollars. The majority of Imperial s sales and purchases are related to these industry U.S. dollar benchmarks. As the company records and reports its financial results in Canadian dollars, to the extent that the Canadian / U.S. dollar exchange rate fluctuates, the company s earnings will be affected.

Imperial is exposed to changes in interest rates, primarily on its debt which carries floating interest rates. The impact of a quarter percent change in interest rates affecting Imperial s debt would not be material to earnings, cash flow or fair value. Imperial has access to significant sources of long-term and short-term liquidity. Internally generated funds are expected to cover the majority of financial requirements, supplemented by long-term and short-term debt as needed.

The company s potential exposure to commodity price and margin, and Canadian / U.S. dollar exchange rate fluctuations is summarized in the earnings sensitivities table, which shows the estimated annual effect, under current conditions, on the company s after-tax net income. For any given period, the extent of actual benefit or detriment will be dependent on the price movements of individual types of crude oil and products, production and sales volumes, transportation capacity, costs and egress methods, and other factors. Accordingly, changes in benchmark prices for crude oil and crude oil differentials, and other factors listed in the table following, only provide broad indicators of changes in the earnings experienced in any particular period.

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Earnings sensitivities (a)

millions of Canadian dollars, after tax		
One dollar (U.S.) per barrel change in crude oil prices	+ (-)	**100**
One dollar (U.S.) per barrel change in light and heavy crude price differentials (b)	+ (-)	**40**
Ten cents per thousand cubic feet decrease (increase) in natural gas prices	+ (-)	**5**
One dollar (U.S.) per barrel change in refining 2-1-1 margins (c)	+ (-)	**140**
One cent (U.S.) per pound change in sales margins for polyethylene	+ (-)	**7**
One cent decrease (increase) in the value of the Canadian dollar versus the U.S. dollar	+ (-)	**100**

(a) Each sensitivity calculation shows the impact on net income resulting from a change in one factor, after tax and royalties and holding all other factors constant. These sensitivities have been updated to reflect current market conditions. They may not apply proportionately to larger fluctuations.
(b) Light and heavy crude differentials represent the difference between WTI benchmark prices and western Canadian prices for light and heavy crudes.
(c) The 2-1-1 crack spread is an indicator of the refining margin generated by converting two barrels of crude oil into one barrel of gasoline and one barrel of diesel.

The demand for crude oil, natural gas, petroleum products and petrochemical products are generally linked closely with economic growth. The occurrence of recessions or other periods of low or negative economic growth will typically have a direct adverse impact on the company s financial results. Although price levels of crude oil and natural gas may rise and fall significantly over the short to medium term due to global economic conditions, political events, decisions by OPEC, governments and other factors, industry economics over the long term will continue to be driven by market supply and demand. Accordingly, the company evaluates the viability of its major investments over a range of prices.

The global energy markets can give rise to extended periods in which market conditions are adverse to one or more of the company s businesses. Such conditions, along with the capital-intensive nature of the industry and very long lead times associated with many of the company s projects, underscore the importance of maintaining a strong financial position. Management views the company s financial strength as a competitive advantage.

In general, segment results are not dependent on the ability to sell and / or purchase products to / from other segments. Where such intersegment sales take place, they are the result of efficiencies and competitive advantages from integrated business segments and refinery and chemical complexes. About 59 percent of the company s intersegment sales are crude oil produced by the Upstream and sold to the Downstream. Other intersegment sales include those between refineries and the chemical plant related to raw materials, feedstocks and finished products. All intersegment sales are at market based prices.

The company has an active asset management program in which underperforming assets are either improved to acceptable levels or considered for divestment. The asset management program includes a disciplined, regular review to ensure that all assets are contributing to the company s strategic objectives.

Risk management

The company s size, strong capital structure and the complementary nature of the Upstream, Downstream and Chemical businesses reduce the company s enterprise-wide risk from changes in commodity prices and currency exchange rates. Imperial uses derivative instruments to offset exposures associated with hydrocarbon prices that arise from existing assets, liabilities and forecasted transactions. The company s derivatives are not accounted for under hedge accounting. Credit risk associated with the company s derivative position is mitigated by several factors, including the use of derivative clearing exchanges and the quality of and financial limits placed on derivative counterparties. The company believes there are no material market or credit risks to the company s financial position, results of operations or liquidity as a result of the derivatives described in note 7 on page 83. The company maintains a system of controls that includes the authorization, reporting and monitoring of derivative activity.

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Critical accounting estimates

The company s financial statements have been prepared in accordance with United States Generally Accepted Accounting Principles (U.S. GAAP). U.S. GAAP requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. The company s accounting and financial reporting fairly reflect its business model involving exploration for, and production of, crude oil and natural gas and manufacture, trade, transport and sale of crude oil, natural gas, petroleum products, petrochemicals and a variety of specialty products. Imperial does not use financing structures for the purpose of altering accounting outcomes or removing debt from the balance sheet. The company s significant accounting policies are summarized in note 1 to the consolidated financial statements on page 66.

Oil and gas reserves

Evaluations of oil and natural gas reserves are important to the effective management of upstream assets. They are an integral part of investment decisions about oil and gas properties such as whether development should proceed.

The estimation of proved reserves, which is based on the requirement of reasonable certainty, is an ongoing process based on rigorous technical evaluations, commercial and market assessments and detailed analysis of well information such as flow rates and reservoir pressure declines. The estimation of proved reserves is controlled by the company through long-standing approval guidelines. Reserve changes are made within a well-established, disciplined process driven by qualified geoscience and engineering professionals, assisted by the reserves management group which has significant technical experience, culminating in reviews with and approval by senior management and the company s board of directors. Notably, the company does not use specific quantitative reserve targets to determine compensation. Key features of the reserve estimation process are covered in Disclosure of reserves in Item 1.

Oil and natural gas reserves include both proved and unproved reserves.

> Proved oil and natural gas reserves are determined in accordance with U.S. Securities and Exchange Commission (SEC) requirements. Proved reserves are those quantities of oil and natural gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible under existing economic and operating conditions and government regulations. Proved reserves are determined using the average of first-of-month oil and natural gas prices during the reporting year.

Proved reserves can be further subdivided into developed and undeveloped reserves. Proved developed reserves include amounts which are expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves include amounts expected to be recovered from new wells on undrilled proved acreage or from existing wells where a relatively major expenditure is required for completion. Proved undeveloped reserves are recognized only if a development plan has been adopted indicating that the reserves are scheduled to be drilled within five years, unless specific circumstances support a longer period of time.

The percentage of proved developed reserves was 89 percent of total proved reserves at year-end 2018, an increase from 71 percent in 2017. Although the company is reasonably certain that proved reserves will be produced, the timing and amount recovered can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals and significant changes in long-term oil and natural gas prices.

Unproved reserves are quantities of oil and natural gas with less than reasonable certainty of recoverability and include probable reserves. Probable reserves are reserves that, together with proved reserves, are as likely as not to be recovered.

Revisions can include upward or downward changes in previously estimated volumes of proved reserves for existing fields due to the evaluation or re-evaluation of already available geologic, reservoir or production data; new geologic, reservoir or production data; or changes in the average of first-of-the-month prices and year-end costs that are used in the estimation of reserves. Revisions can also result from significant changes in either development strategy or production equipment / facility capacity.

At year-end 2016, downward revisions of proved developed and undeveloped bitumen reserves were a result of low prices. The entire 2.5 billion barrels of bitumen at Kearl and approximately 0.2 billion barrels of bitumen at Cold Lake no longer qualified as proved reserves under the U.S. Securities and Exchange Commission definition of proved reserves.

At year-end 2017, an additional 0.3 billion barrels of bitumen at Kearl and Cold Lake qualified as proved reserves resulting from improved prices in the year.

As a result of improved prices in 2018, an additional 2.3 billion barrels of bitumen at Kearl qualified as proved reserves at year-end 2018.

Under the terms of certain contractual arrangements or government royalty regimes, lower prices can also increase proved reserves attributable to Imperial. The company s operating decisions and its outlook for future production volumes are not impacted by proved reserves as disclosed under the U.S. Securities and Exchange Commission (SEC) definition.

Unit-of-production depreciation

The calculation of unit-of-production depreciation is a critical accounting estimate that measures the depreciation of upstream assets. Oil and natural gas reserve quantities are used as the basis to calculate unit-of-production depreciation rates for most upstream assets. Depreciation is calculated by taking the ratio of asset cost to total proved reserves or proved developed reserves applied to the actual cost of production. The volumes produced and asset cost are known, while proved reserves are based on estimates that are subject to some variability.

In the event that the unit-of-production method does not result in an equitable allocation of cost over the economic life of an upstream asset, an alternative method is used. The straight-line method is used in limited situations where the expected life of the asset does not reasonably correlate with that of the underlying reserves. For example, certain assets used in the production of oil and natural gas have a shorter life than the reserves, and as such, the company uses straight-line depreciation to ensure the asset is fully depreciated by the end of its useful life.

To the extent that proved reserves for a property are substantially de-booked and that property continues to produce such that the resulting depreciation charge does not result in an equitable allocation of cost over the expected life, assets will be depreciated using a unit-of-production method based on reserves determined at the most recent SEC price which results in a more meaningful quantity of proved reserves, appropriately adjusted for production and technical changes. This approach was applied in 2017 and 2018, with the corresponding effect on depreciation expense immaterial when compared to prior periods. In 2019, all properties have sufficient reserves at current SEC prices which will enable equitable allocation of cost over the economic lives of the Upstream assets. The effect of this approach compared to prior periods is anticipated to be immaterial.

Impact of oil and gas reserves and prices and margins on testing for impairment

The company tests assets or groups of assets for recoverability on an ongoing basis whenever events or changes in circumstances indicate the carrying amounts may not be recoverable. Among the events or changes in circumstances which could indicate that the carrying value of an asset or asset group may not be recoverable are the following:

- A significant decrease in the market price of a long-lived asset;
- A significant adverse change in the extent or manner in which an asset is being used or in its physical condition including a significant decrease in the company s current and projected reserve volumes;

- A significant adverse change in legal factors or in the business climate that could affect the value, including a significant adverse action or assessment by a regulator;
- An accumulation of project costs significantly in excess of the amount originally expected;
- A current-period operating loss combined with a history and forecast of operating or cash flow losses; and
- A current expectation that, more likely than not, a long-lived asset will be sold or otherwise disposed of significantly before the end of its previously estimated useful life.

Asset valuation analyses performed as part of the company s asset management program and other profitability reviews assist Imperial in assessing whether events or changes in circumstances indicate the carrying amounts of any of its assets may not be recoverable.

In general, Imperial does not view temporarily low prices or margins as an indication of impairment. Management believes prices over the long-term must be sufficient to generate investments in energy supply to meet global demand. Although prices will occasionally drop significantly, industry prices over the long-term will continue to be driven by market supply and demand fundamentals. On the supply side, industry production from mature fields is declining. This is being offset by investments to generate production from new discoveries, field developments and technological and efficiency advancements. OPEC investment activities and production policies also have an impact on world oil supplies. The demand side is largely a function of general economic activities and levels of prosperity. Because the lifespans of the company s major assets are measured in decades, the value of these assets is predominantly based on long-term views of future commodity prices and production costs. During the lifespan of these major assets, the company expects that oil and gas prices will experience significant volatility, and consequently these assets will experience periods of higher earnings and periods of lower earnings, or even losses. In assessing whether the events or changes in circumstances indicate the carrying value of an asset may not be recoverable, the company considers recent periods of operating losses in the context of its longer-term view of prices. While near-term prices are subject to wide fluctuations, longer term price views are more stable and meaningful for purposes of assessing future cash flows.

When the industry experiences a prolonged and deep reduction in commodity prices, the market supply and demand conditions may result in changes to the company s long-term price or margin assumptions it uses for its capital investment decisions. To the extent those changes result in a significant reduction to its long-term oil prices or natural gas prices or margin ranges, the company may consider that situation, in conjunction with other events or changes in circumstances such as a history of operating losses, as an indicator of potential impairment for certain assets.

In the upstream, the standardized measure of discounted cash flows included in the Supplemental information on oil and gas exploration and production activities is required to use prices based on the yearly average of first-of-month prices. These prices represent discrete points in time and could be higher or lower than the company s long-term price assumptions which are used for impairment assessments. The company believes the standardized measure does not provide a reliable estimate of the expected future cash flows to be obtained from the development and production of its oil and gas properties or of the value of its oil and gas reserves and therefore does not consider it relevant in determining whether events or changes in circumstances indicate the need for an impairment assessment.

If events or changes in circumstances indicate that the carrying value of an asset may not be recoverable, the company estimates the future undiscounted cash flows of the affected properties to judge the recoverability of carrying amounts. In performing this assessment, assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. Cash flows used in recoverability assessments are based on the company s assumptions which are developed in the annual planning and budgeting process, and are consistent with the criteria management uses to evaluate investment opportunities. These evaluations make use of the company s assumptions of future capital allocations, crude oil and natural gas commodity prices, refining and chemical margins, volumes, costs, foreign currency exchange rates and inflation rates. Volumes are based on projected field and facility production profiles, throughput, or sales. Where unproved reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the evaluation. Cash flow estimates for impairment testing exclude the effects of derivative instruments.

An asset group is impaired if its estimated future undiscounted cash flows are less than the asset group s carrying value. Impairments are measured by the amount by which the carrying value exceeds fair value. Fair value is based on market prices if an active market exists for the asset group or discounted cash flows using a discount rate commensurate with the risk. Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs would be recorded based on the estimated economic chance of success and the length of time that the company expects to hold the properties. Properties that are not individually significant are aggregated by groups and amortized based on development risk and average holding period.

Supplemental information regarding oil and gas results of operations, capitalized costs and reserves is provided following the notes to consolidated financial statements.

Pension benefits

The company s pension plan is managed in compliance with the requirements of governmental authorities and meets funding levels as determined by independent third-party actuaries. Pension accounting requires explicit assumptions regarding, among others, the discount rate for the benefit obligations, the expected rate of return on plan assets and the long-term rate of future compensation increases. All pension assumptions are reviewed annually by senior management. These assumptions are adjusted only as appropriate to reflect long-term changes in market rates and outlook. The long-term expected rate of return on plan assets of 5.0 percent used in 2018, compares to actual returns of 8.2 percent and 6.6 percent achieved over the last 10- and 20-year periods respectively, ending December 31, 2018. If different assumptions are used, the expense and obligations could increase or decrease as a result. The company s potential exposure to changes in assumptions is summarized in note 5 to the consolidated financial statements starting on page 76. At Imperial, differences between actual returns on plan assets and the long-term expected returns are not recorded in pension expense in the year the differences occur. Such differences are deferred, along with other actuarial gains and losses, and are amortized into pension expense over the expected average remaining service life of employees. Employee benefit expense represented about 1 percent of total expenses in 2018.

Asset retirement obligations and other environmental liabilities

Legal obligations associated with site restoration on the retirement of assets with determinable useful lives are recognized when they are incurred, which is typically at the time the assets are installed. The obligations are initially measured at fair value and discounted to present value. Over time, the discounted asset retirement obligation amount will be accreted for the change in its present value, with this effect included in production and manufacturing expenses. As payments to settle the obligations occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed 25 years, the discount rate will be adjusted only as appropriate to reflect long-term changes in market rates and outlook. For 2018, the obligations were discounted at 6 percent and the accretion expense was $85 million, before tax, which was significantly less than 1 percent of total expenses in the year. There would be no material impact on the company s reported financial results if a different discount rate had been used.

Asset retirement obligations are not recognized for assets with an indeterminate useful life. Asset retirement obligations for these facilities generally become firm at the time the facilities are permanently shut down and dismantled. These obligations may include the costs of asset disposal and additional soil remediation. However, these sites have indeterminate lives based on plans for continued operations, and as such, the fair value of the conditional legal obligations cannot be measured, since it is impossible to estimate the future settlement dates of such obligations. For these and non-operating assets, the company accrues provisions for environmental liabilities when it is probable that obligations have been incurred and the amount can be reasonably estimated.

Asset retirement obligations and other environmental liabilities are based on engineering estimated costs, taking into account the anticipated method and extent of remediation consistent with legal requirements, current technology and the possible use of the location. Since these estimates are specific to the locations involved, there are many individual assumptions underlying the company s total asset retirement obligations and provision for other environmental liabilities. While these individual assumptions can be subject to change, none of them is individually significant to the company s reported financial results.

Suspended exploratory well costs

The company continues capitalization of exploratory well costs when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project. Exploratory well costs not meeting these criteria are charged to expense. The facts and circumstances that support continued capitalization of suspended wells at year-end are disclosed in note 16 to the consolidated fina