IMPERIAL OIL LTD
Form 10-K
February 25, 2015
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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, 2014 **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.)**
237 FOURTH AVENUE S.W., CALGARY, AB, CANADA	**T2P 3M9**
(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 ü 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 ü

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 ü No......

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

Yesü 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 ü No......

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

Large accelerated filer ü Accelerated filer...... Non-accelerated filer....... Smaller reporting company........

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 ü

As of the last business day of the 2014 second fiscal quarter, the aggregate market value of the voting stock held by non-affiliates of the registrant was Canadian $11,729,170,628 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 11, 2015, was 847,599,011.

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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	**2014**	2013	2012	2011	2010
Rate at end of period	**0.8620**	0.9401	1.0042	0.9835	0.9991
Average rate during period	**0.9023**	0.9665	1.0006	1.0144	0.9659
High	**0.9423**	1.0164	1.0299	1.0584	1.0040
Low	**0.8588**	0.9348	0.9600	0.9430	0.9280

On February 11, 2015, 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 $0.7915 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. Actual future results, including demand growth and energy source mix; production growth and mix; project plans, dates, costs and capacities; production rates and resource recoveries; cost savings; product sales; financing sources; and capital and environmental expenditures could differ materially depending on a number of factors, such as changes in the price, and supply of and demand for crude oil, natural gas, and petroleum and petrochemical products; political or regulatory events; project schedules; commercial negotiations; the receipt, in a timely manner, of regulatory and third-party approvals; unanticipated operational disruptions; unexpected technological developments; and other factors discussed in Item 1A of this annual report on Form 10-K and in the management s discussion and analysis of financial condition and results of operations contained in Item 7. 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. Imperial 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.

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.

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 237 Fourth Avenue S.W. Calgary, Alberta, Canada T2P 3M9; telephone 1-800-567-3776. Exxon Mobil Corporation 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.

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 and natural gas and 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 2 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, 2014, as detailed in the Supplemental information on oil and gas exploration and production activities part of the Financial section, starting on page 28 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, 2014 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	**36**	**300**	**534**	**1,635**	**2,255**
Undeveloped	**10**	**327**	**-**	**1,639**	**1,704**
Total net proved	**46**	**627**	**534**	**3,274**	**3,959**

(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 pressure declines. 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 and significant changes in projections of long-term oil and gas price levels.

Technologies used in establishing proved reserves estimates

Additions to Imperial s proved reserves in 2014 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 high-quality 3-D and 4-D 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.

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 United States Securities and Exchange Commission (SEC) rules and regulations, review of annual changes in reserves estimates and the reporting of Imperial s proved reserves. This group also maintains the official company 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.

Key components of the reserves estimation process include technical evaluations and analysis of well and field performance and a rigorous peer review. The reserves management group maintains a central database

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containing the official company 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. 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 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 Operations Technical Subsurface Engineering Manager is a professional engineer registered in Alberta, Canada and has over 25 years of petroleum industry experience, including 21 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 50 persons with an average of 15 years of relevant technical experience in evaluating reserves, of whom 32 persons are qualified reserves evaluators for purposes of Canadian securities regulatory requirements. The company s internal reserves evaluation management team is made up of 15 persons with an average of 11 years of relevant experience in evaluating and managing the evaluation of reserves. No independent qualified reserves evaluator or auditor was involved in the preparation of the company s reserves data.

Proved undeveloped reserves

As at December 31, 2014, approximately 43 percent of the company s proved reserves were proved undeveloped reserves reflecting volumes of 1,704 million oil-equivalent barrels. Nearly all of those undeveloped reserves are associated with either the Kearl project or Cold Lake field. This compared to 1,509 million oil-equivalent barrels of proved undeveloped reserves reported at the end of 2013. Increased proved undeveloped reserves were primarily associated with the conclusion of technical studies supporting the lengthening of the expected useful life of the Kearl operating assets under routine maintenance and sustaining capital conditions.

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 significant lead-time in order to be developed. The company made investments of about $3.9 billion during the year to progress the development of reported proved undeveloped reserves. The largest project under development in 2014 was the Kearl expansion project. By 2014 year-end, the Kearl expansion project construction phase was essentially complete and the commissioning of facilities commenced in preparation for start-up.

Proved undeveloped reserves at Cold Lake are associated with the ongoing drilling program and the Nabiye project. Imperial moved eight million oil-equivalent barrels in 2014 from proved undeveloped to proved developed reserves at Cold Lake through ongoing drilling programs. Production at the Nabiye project is expected in the first quarter of 2015 at which time proved undeveloped reserves will be moved to proved developed reserves.

Proved undeveloped reserves that have remained undeveloped for five years or more are primarily associated with Cold Lake and were not material compared to the company s proved reserves and proved undeveloped reserves.

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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 32 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, 2014 was as follows. All reported production volumes were from Canada.

thousands of barrels per day (a)		**2014**	2013	2012
Bitumen:				
Cold Lake:	- gross (b)	**146**	153	154
	- net (c)	**114**	127	123
Kearl:	- gross (b)	**51**	16	-
	- net (c)	**47**	15	-
Total Bitumen:	- gross (b)	**197**	169	154
	- net (c)	**161**	142	123
Synthetic oil (d):	- gross (b)	**64**	67	72
	- net (c)	**60**	65	69
Liquids:	- gross (b)	**21**	25	24
	- net (c)	**16**	20	18
Total:	- gross (b)	**282**	261	250
	- net (c)	**237**	227	210

(a) Barrels per day metric is 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.

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, 2014 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 32 of this report for a narrative discussion on the material changes.

millions of cubic feet per day (a)	**2014**	2013	2012
Gross production (b) (c)	**168**	201	192
Net production (c) (d) (e)	**156**	189	195
Net production available for sale (f)	**124**	152	161

(a)

Cubic feet per day metric is 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. Net natural gas production in 2012 included favourable royalty cost adjustments.

(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 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)	**2014**	2013	2012
Total production oil-equivalent basis:			
- gross (b)	**310**	295	282
- net (c)	**263**	259	243

(a) Barrels per day metric is 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, 2014, were as follows.

dollars per barrel	**2014**	2013	2012
Liquids	**67.82**	75.61	71.52
Synthetic oil	**99.58**	99.69	92.48
Bitumen	**67.20**	60.57	59.76
dollars per thousand cubic feet			
Natural gas	**4.54**	3.27	2.33

Average unit production costs

dollars per barrel	**2014**	2013	2012
Synthetic oil	**62.14**	53.27	48.41
Bitumen	**34.87**	32.20	21.98
Total oil-equivalent basis (a)	**41.02**	35.93	29.10

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

Synthetic oil production costs increased in 2014 primarily due to higher maintenance activities at Syncrude.

Synthetic oil production costs increased in 2013 primarily due to higher planned maintenance activities at Syncrude. Increased bitumen production costs in 2013 were primarily driven by Kearl start-up and operating costs.

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, 2014.

wells	**2014**	2013	2012
Net productive exploratory	**-**	1	1
Net dry exploratory	**-**	1	-
Net productive development	**111**	157	39
Net dry development	**-**	-	-
Total	**111**	159	40

In 2014, the following wells were drilled to add productive capacity: 90 development wells at Cold Lake, of which 74 development wells relate to the Cold Lake Nabiye expansion project, eight net tight gas wells and 13 net other wells.

In 2013, the following wells were drilled to add productive capacity: 120 development wells at the Cold Lake Nabiye expansion project, 34 net tight oil development wells and three net other wells.

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In 2012, the following wells were drilled to add productive capacity: 28 development wells in undeveloped areas of existing phases at Cold Lake, three development evaluation wells at Cold Lake, four net Horn River pilot wells and four net tight oil development wells.

Wells drilling

At December 31, 2014, the company was participating in the drilling of the following exploratory and development wells. All wells were located in Canada.

	2014	
wells	Gross	Net
Total	**27**	**23**

Exploratory and development activities regarding oil and gas resources

Cold Lake

In February 2012, the Nabiye expansion at Cold Lake was sanctioned. Facilities start-up occurred throughout December 2014 followed by initial steam injection into the reservoir in January 2015. Bitumen production is targeted in the first quarter of 2015, ultimately increasing to 40,000 barrels per day, before royalties.

To maintain production at Cold Lake, additional wells were drilled on existing phases in 2014. In 2015, a development drilling program is planned within the approved development area to add productive capacity.

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

Mackenzie Delta

In 1999, the company and three other companies entered into an agreement to study the feasibility of developing Mackenzie Delta gas, anchored by three large onshore natural gas fields. The company retains a 100 percent interest in the largest of these fields.

In late 2010, the National Energy Board (NEB) announced its approval of plans to build and operate the project subject to 264 conditions in areas such as engineering, safety and environmental protection. Federal cabinet approved the project in early 2011.

The commercial viability of these natural gas resources, and the pipeline required to transport this natural gas to markets, is dependent on a number of factors. These factors include natural gas markets, continued support from northern parties, fiscal framework and the cost of constructing, operating and abandoning the field production and pipeline facilities.

The company continues to maintain the right of way agreements and permits required to develop its Mackenzie Delta natural gas resource and in December 2013, updated cost estimates were filed as required under one of the conditions of the permits. No final investment decision has been made.

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. Current activities continue to focus on data gathering, regulatory groundwork, and community consultation. No final drilling investment decision has been made.

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Other oil sands activity

The company filed a regulatory application for a new in-situ oil sands project at Aspen in December 2013. Steam-assisted gravity drainage (SAGD) technology would be used to develop the project in three phases producing about 45,000 barrels per day before royalties, per phase. No final investment decision has been made.

Work continues on technical evaluations to support potential Cold Lake Midzaghe (formerly Grand Rapids), Corner and Clyden 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.

Liquefied natural gas (LNG) export application

In December 2013, WCC LNG Ltd., jointly owned by the company (50 percent) and ExxonMobil Canada Ltd. (50 percent), received approval from the NEB to export up to 30 million tonnes of LNG per year for a period of 25 years. The company filed a project description with the B.C. Environmental Assessment Office in December 2014. The filing, required to initiate an environmental assessment, outlines the proposed production, storage and marine transportation of LNG to global markets. No final investment decision has been made.

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

Kearl

The company holds a 70.96 percent participating interest in the Kearl oil sands project, a joint venture with ExxonMobil Canada Properties, a subsidiary of Exxon Mobil Corporation. The Kearl project recovers shallow deposits of oil sands using open-pit mining methods.

The Kearl project received project development approvals from the Province of Alberta in 2007 and the Government of Canada in 2008. The Province of Alberta issued an operating and construction licence in 2008, which permits the project to mine oil sands and produce bitumen from approved development areas on oil sands leases. Production from the initial development commenced in April 2013, as discussed in the Present activities section on page 10.

The Kearl expansion project construction phase was essentially complete at the end of 2014, and the commissioning of facilities commenced in preparation for start-up. The project is expected to ultimately produce 110,000 barrels of bitumen per day, before royalties, of which the company s share will be about 78,000 barrels per day.

Potential future debottlenecking of both the initial development and expansion would increase output to reach the regulatory capacity of 345,000 barrels of bitumen per day, of which the company s share would be about 245,000 barrels per day. Such debottlenecking remains under evaluation.

Other oil sands activity

The company is continuing 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 primarily sold to refineries in the United States. The remainder of Cold Lake production is shipped to certain of the company s refineries and to third-party Canadian refineries.

During 2014, average net production at Cold Lake was about 114,000 barrels per day and gross production was about 146,000 barrels per day.

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

Kearl

Bitumen from the Kearl project is extracted from oil sands produced from open-pit mining operations and is processed through bitumen extraction facilities and froth treatment trains. The product, a blend of bitumen and diluent, is shipped to certain of the company s refineries, ExxonMobil refineries and to other unrelated third parties.

Production of mined diluted bitumen began in April 2013 and continued to ramp-up in 2014. The company s share of Kearl s net production was about 47,000 barrels per day and gross production was about 51,000 barrels per day.

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

Syncrude

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

In 2014, 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 64,000 barrels per day.

Effective January 1, 2009, the Syncrude Crown Royalty Agreement was amended. Under the amended agreement, starting in 2010 and through 2015, Syncrude will pay the existing Crown royalty rates plus an incremental royalty, the amount of which will be subject to minimum production thresholds, before transitioning to the new generic royalty framework in 2016. Also, beginning January 1, 2009, Syncrude s royalty is based on bitumen value with upgrading costs and revenues excluded from the calculation.

Conventional oil and gas

The Norman Wells oil field in the Northwest Territories is the company s largest conventional oil producing asset, with gross production of about 11,000 barrels per day, currently accounting for about 70 percent of the company s gross production of conventional crude oil.

In the second quarter of 2014, the company divested three mature conventional properties; Boundary Lake, Pembina and Rocky Mountain House. Combined production from these properties totalled about 15,000 oil-equivalent barrels per day in 2013, split about evenly between oil and gas.

Delivery commitments

The company has no material commitments to provide a fixed and determinable quantity of oil or gas under existing contracts or 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, 2014 and December 31, 2013, 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, 2014				Year-ended December 31, 2013			
	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)	**4,678**	**4,488**	**3,614**	**1,205**	5,207	4,847	3,615	1,235

(a) Gross wells are wells in which the company owns a working interest.
(b) Net wells are the sum of the fractional working interests 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 2014, the company had an interest in 25 gross wells with multiple completions (2013 - 25 gross wells (restated)).

The total number of wells decreased in 2014 primarily due to the divestment of mature conventional properties.

Land holdings

At December 31, 2014 and 2013, 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		**2014**	2013	**2014**	2013	**2014**	2013
Western provinces:							
Liquids and gas (a) (b)	- gross (c)	**1,614**	1,460	**888**	1,310	**2,502**	2,770
	- net (d)	**779**	764	**467**	662	**1,246**	1,426
Bitumen (a) (b)	- gross (c)	**141**	141	**725**	725	**866**	866
	- net (d)	**130**	130	**370**	370	**500**	500
Synthetic oil	- gross (c)	**118**	118	**135**	135	**253**	253
	- net (d)	**29**	29	**34**	34	**63**	63
Canada lands (e):							
Liquids and gas	- gross (c)	**4**	4	**2,274**	2,272	**2,278**	2,276
	- net (d)	**2**	2	**720**	718	**722**	720
Atlantic offshore:							
Liquids and gas	- gross (c)	**65**	65	**288**	288	**353**	353
	- net (d)	**6**	6	**46**	46	**52**	52
Total (f):	- gross (c)	**1,942**	1,788	**4,310**	4,730	**6,252**	6,518
	- net (d)	**946**	931	**1,637**	1,830	**2,583**	2,761

(a) Gross developed and undeveloped liquids, gas and bitumen acreages in 2013 reflect revised numbers excluding overriding royalty interest.
(b) In 2014, the former Celtic land holdings were realigned to conform with Imperial s data classification standards.
(c) Gross acres include the interests of others.
(d) Net acres exclude the interests of others.
(e) Canada lands include the Arctic Islands, Beaufort Sea/Mackenzie Delta, and other Northwest Territories, Nunavut and Yukon regions.
(f) 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 193,000 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 80,000 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 totalling about 193,000 net acres, which include about 62,000 net acres of oil sands leases in the Clyden area. These 193,000 net acres are amenable to 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.

Oil sands leases have an exploration period of fifteen years and are continued beyond that point by meeting the minimum level of evaluation, 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 1,246,000 net acres of developed and undeveloped land in western Canada related to crude oil and natural gas. Included in this number is a total acreage position of about 170,000 net acres at Horn River, British Columbia. In 2014, the company divested mature conventional properties totalling 134,000 net acres.

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

Canada lands

Land holdings in Canada lands primarily include exploration licence (EL) acreage in the Beaufort Sea of about 252,000 net acres and in the Summit Creek area of central Mackenzie Valley totalling about 222,000 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 exploration licences 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 freely negotiated prices. Purchases are made under both spot and term contracts from domestic and foreign sources, including Exxon Mobil Corporation.

Transportation

Imperial currently transports about 530,000 barrels per day of crude oil by both contracted pipelines and common carrier pipelines. The company has secured an additional 305,000 barrels per day capacity on crude oil pipeline projects set to be in service over the next several years. To mitigate uncertainty associated with the timing of pipeline projects, the company is developing rail infrastructure with potential incremental capacity up to 210,000 barrels per day. These transportation capacities are primarily to ship crude oil.

Refining

The company owns and operates three refineries, which process predominantly Canadian crude oil. The Strathcona refinery operates lubricating oil production facilities. In addition to crude oil, the company purchases finished products to supplement its refinery production.

In 2014, capital expenditures of about $93 million were made at the company s refineries. Capital expenditures focused mainly on refinery projects to improve reliability, feedstock flexibility, energy efficiency and environmental performance.

The approximate average daily volumes of refinery throughput during the three years ended December 31, 2014, and the daily rated capacities of the refineries as at December 31, 2014 were as follows.

	Refinery throughput (a) Year-ended December 31			Rated capacities (b) at December 31
thousands of barrels per day	**2014**	2013	2012	**2014**
Strathcona, Alberta	**182**	172	163	**189**
Sarnia, Ontario	**109**	105	103	**119**
Nanticoke, Ontario	**103**	99	99	**113**
Dartmouth, Nova Scotia (c) (d)	**n/a**	50	70	**n/a**
Total	**394**	426	435	**421**

(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.

(c) Refinery operations at the Dartmouth refinery were discontinued on September 16, 2013.

(d) Dartmouth refinery rated capacity as at December 31, 2012 was 85,000 barrels per day.

In 2014, refinery throughput was 94 percent of capacity, six percent higher than the previous year. The higher rate was primarily a result of improved reliability and increased product sales. Capacity utilization in 2013 was calculated based on the number of days the refineries were operated as a refinery.

Distribution

The company maintains a nationwide distribution system, including 22 primary terminals, to handle bulk and packaged petroleum products moving from refineries 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.

Marketing

The company markets more than 550 petroleum products throughout Canada under well-known brand names, most notably Esso and Mobil, to all types of customers.

The company sells to the motoring public through Esso retail service stations. On average during the year, there were more than 1,700 retail service stations, of which about 470 were company-owned or leased, but none of which were company operated. The remaining approximately 1,200 Esso branded service stations operate under a branded wholesaler model. The company continues to improve its Esso retail service station network, providing customer services such as car washes and convenience stores, primarily at high volume sites in urban centres.

In January 2015, the company announced that it will evaluate its operating model for the company-owned retail stations. The assessment will evaluate the potential opportunity to extend the branded wholesaler operating model to the remaining company-owned retail stations as part of Imperial s Esso branded growth strategy. Operating model changes, if any, should have no impact on the end user consumer.

The Canadian agriculture, residential heating and commercial markets are served by 27 branded resellers. The company also sells petroleum products to large industrial and transportation customers, independent marketers, resellers as well as other refiners.

The approximate daily volumes of net petroleum products (excluding purchases/sales contracts with the same counterparty) sold during the three years ended December 31, 2014, are set out in the following table.

thousands of barrels per day	**2014**	2013	2012
Gasolines	**244**	223	221
Heating, diesel and jet fuels	**179**	160	151
Heavy fuel oils	**22**	29	30
Lube oils and other products	**40**	42	43
Net petroleum product sales	**485**	454	445

Total Downstream capital expenditures were $572 million in 2014.

Chemical

The company s Chemical operations manufacture and market ethylene, 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.

Infrastructure required to implement a long-term supply agreement for ethane from the nearby Marcellus shale gas development was completed and first deliveries of this feedstock to the Sarnia chemical plant were received in the second quarter of 2014.

The company s total sales volumes of petrochemicals during the three years ended December 31, 2014, were as follows.

thousands of tonnes	**2014**	2013	2012
Total sales of petrochemicals	**953**	940	1,044

Higher sales volumes in 2014 were primarily due to strong demand in polymers and basic chemicals.

Capital expenditures in 2014 were $26 million.

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Research

In 2014, the company s total gross research expenditures, before credits, were about $175 million, as compared with $199 million in 2013, and $201 million in 2012. Research expenditures are mainly for developing technologies to improve bitumen recovery, reduce costs, reduce the environmental impact of Upstream operations, supporting environmental and process improvements in the refineries, as well as accessing ExxonMobil s research worldwide.

The company has scientific research agreements with affiliates of Exxon Mobil Corporation, which provide for technical and engineering work to be performed by all parties, the exchange of technical information and the assignment and licensing of patents and patent rights. These agreements provide mutual access to scientific and operating data related to nearly every phase of the petroleum and petrochemical operations of the parties.

Environmental protection

The company regards protecting the environment in connection with its various operations a priority. The company works in cooperation with government agencies, industry associations and communities to deal with existing, and to anticipate potential, environmental protection issues. In the past five years, the company has made capital and operating expenditures of about $5.6 billion on environmental protection and facilities. In 2014, the company s environmental capital and operating expenditures totalled approximately $1.7 billion, which was spent primarily on water and tailings treatment and emission reductions at both company owned facilities and Syncrude and remediation of idled facilities and operations. Capital and operating expenditures relating to environmental protection are expected to be about $1.7 billion in 2015.

Human resources

Career employees (a)	**2014**	2013	2012
Total	**5,500**	5,300	5,100

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

The increase in career employees in 2014 is primarily associated with the company s preparation for the 2015 start-up of the Kearl expansion project. About seven percent of the company s employees are members of unions.

Competition

The Canadian petroleum, natural gas and chemical 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 petroleum industry also competes with other industries in supplying energy, fuel and other needs of consumers.

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.

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Crude oil

Production

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

Exports

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

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 2014 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.

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 under Item 1.

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 Exxon Mobil Corporation, the company is considered to be an entity which is not controlled by Canadians.

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 public may read and copy any materials the company files with the SEC at the SEC s Public Reference Room at 100 F Street, NE., Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC s website, www.sec.gov, contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

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Item 1A. Risk factors
Volatility of oil and natural gas prices

The company s results of operations and financial condition are dependent on the prices it receives for its oil and natural gas production. Crude oil and natural gas prices are determined by global and North American markets and are subject to changing supply and demand conditions. These can be influenced by a wide range of factors including economic conditions, international political developments and weather. Disruptions to pipelines linking production to markets may reduce the price for that production or lead to curtailment of production. In the past, crude oil and natural gas prices have been volatile, and the company expects that volatility to continue. Any material decline in oil or natural gas prices could have a material adverse effect on the company s operations, financial condition, proved reserves and the amount spent to develop oil and natural gas reserves.

A significant portion of the company s production is bitumen. The market prices for bitumen differ from the established market indices for light and medium grades of oil principally due to the higher transportation and refining costs associated with bitumen and limited refining capacity capable of processing bitumen. Bitumen may also be subject to limits on transportation capacity to markets to a larger extent than light crude oil. As a result, the price received for bitumen is generally lower than the price for medium and light oil. Future differentials are uncertain and increases in the bitumen differentials could have a material adverse effect on the company s business.

The company does not use derivative instruments to offset exposures associated with hydrocarbon prices, currency exchange rates and interest rates that arise from existing assets, liabilities and transactions. The company does not engage in speculative derivative activities nor does it use derivatives with leveraged features.

Environmental risks

All phases of the Upstream, Downstream and Chemical businesses are subject to environmental regulation pursuant to a variety of Canadian federal, provincial 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 to 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 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 to the air from its operations and result in increased capital expenditures. Changes in environmental regulations or other laws (including changes in laws related to hydraulic fracturing) may increase our 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

Due to concern over the risk 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 cap and trade regimes, carbon taxes, increased efficiency standards, and incentives or mandates for renewable energy. These requirements could make our products more expensive, lengthen project implementation times, and reduce demand for hydrocarbons, as well as shift hydrocarbon demand toward lower-carbon sources such as natural gas. Current and pending greenhouse regulations may also increase our compliance costs, such as for monitoring or sequestering emissions.

Currency

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.

Reserves replacement

The company s future liquids, bitumen, synthetic oil and natural gas reserves and production, and therefore cash flows, are highly dependent upon the company s success in exploiting its current reserve base and acquiring or discovering additional reserves. Without additions to the company s reserves through exploration, acquisition or development activities, reserves and production will decline over time as reserves are depleted. 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 impaired. 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.

Research and development

In light of the technological nature of our business and the need for continuous efficiency improvement, the company relies upon the research and development organizations of the company and ExxonMobil, with whom the company conducts shared research.

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, crude oil spills, severe weather, and geological events. Our operations are also subject to the additional hazards of pollution, releases of toxic gas and other environmental hazards and risks. Our results depend on management s ability to minimize these inherent risks, to control effectively our business activities and to minimize the potential for human error. We apply rigorous management systems including a combined program of effective operations integrity management, ongoing upgrades, key equipment replacements, and comprehensive inspection and surveillance. We also maintain a disciplined framework of internal controls and apply a controls management system for monitoring compliance with this framework. Substantial liabilities and other adverse impacts could result if our management systems and controls do not function as intended.

Emergency preparedness

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

Other business risks

The marketability of the company s production is subject in part to the risks associated with transporting, processing and storing crude oil, natural gas and other related products. The availability, proximity, and capacity of pipeline facilities and railcars could negatively impact our ability to produce at capacity levels. Transportation disruptions could adversely affect commodity prices, the company s price realizations, refining operations and sales volumes, or limit our ability to deliver production to market.

Other factors that may affect the demand for oil, gas and petrochemicals, and therefore impact the company s results, include technological improvements in energy efficiency; seasonal weather patterns, which affect the demand for energy associated with heating and cooling; increased competitiveness of alternative energy

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sources; and changes in technology or consumer preferences that alter fuels choices, such as toward alternative fueled vehicles.

Business risks also include the risk of cyber security breaches. If management s systems for protecting against cyber security risk prove not to be sufficient, the company could be adversely affected such as by having its business systems compromised, its proprietary information altered, lost or stolen, or its business operations disrupted.

Reserve estimates

There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond the company s control. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flow are based upon a number of factors and assumptions made as of the date on which the reserve estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the assumed effects of regulation by governmental agencies and future commodity prices and operating costs, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable oil and natural gas reserves, the classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different reserves evaluators or by the same evaluators at different times, may vary substantially. Actual production, revenues, taxes, and development, abandonment and operating expenditures with respect to reserves will likely vary from such estimates, and such variances could be material.

Estimates with respect to reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be material, in the estimated reserves.

Project factors

The company s results depend on its ability to develop and operate major 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 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.

Item 1B. Unresolved staff comments

None.

Item 2. Properties

Reference is made to Item 1 above.

Item 3. Legal proceedings

Not applicable.

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 trade on the Toronto Stock Exchange and the NYSE MKT LLC, a subsidiary of NYSE Euronext. Reference is made to the Quarterly financial and stock trading data portion of the Financial section on page 82 of this report. The closing price for Imperial Oil Limited common shares on the Toronto Stock Exchange was $49.74 as at February 11, 2015.

Dividends

The following table sets forth the frequency and amount of all cash dividends declared by the company on its outstanding common shares for the two most recent fiscal years.

	2014				2013			
dollars	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Declared dividend per share:	**0.13**	**0.13**	**0.13**	**0.13**	0.13	0.12	0.12	0.12

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 five percent on dividends paid to a corporation resident in the U.S. that owns at least ten 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.

As of February 11, 2015 there were 11,867 holders of record of common shares of the company.

Between October 1, 2014 and December 31, 2014, pursuant to the company s restricted stock unit plan, 1,375 shares were issued to employees outside the U.S. in reliance on Regulation S under the *Securities Act*, and 1,100 shares were issued to a seconded employee in reliance on the section 4(a)(2) exemption under the *Securities Act*.

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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 83. The company s management proxy circular is prepared in accordance with Canadian securities regulations.

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

Entitled Performance graph within the Compensation discussion and analysis section on page 130 of this report; and

Entitled Equity compensation plan information , within the Compensation discussion and analysis section , on page 135 of this report.

Issuer purchases of equity securities

	Total number of shares purchased	Average price paid per share (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 2014 (October 1 October 31)	**-**	**-**	**-**	**1,000,000**
November 2014 (November 1 - November 30)	**-**	**-**	**-**	**1,000,000**
December 2014 (December 1 - December 31)	**2,475**	**51.05**	**2,475**	**997,525**

(a) On June 23, 2014, 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 share repurchase program. The new program enables the company to repurchase up to a maximum of 1,000,000 common shares during the period June 25, 2014 to June 24, 2015. The program will end when the company has purchased the maximum allowable number of shares, or on June 24, 2015.

Item 6. Selected financial data

millions of dollars	**2014**	2013	2012	2011	2010
Operating revenues	**36,231**	32,722	31,053	30,474	24,946

Net income	**3,785**	2,828	3,766	3,371	2,210
Total assets at year-end	**40,830**	37,218	29,364	25,429	20,580
Long-term debt at year-end	**4,913**	4,444	1,175	843	527
Total debt at year-end	**6,891**	6,287	1,647	1,207	756
Other long-term obligations at year-end	**3,565**	3,091	3,983	3,876	2,753
dollars					
Net income per share basic	**4.47**	3.34	4.44	3.98	2.61
Net income per share diluted	**4.45**	3.32	4.42	3.95	2.59
Dividends declared	**0.52**	0.49	0.48	0.44	0.43

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 32 of this report.

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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 44 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 28 of this report:

Consolidated financial statements, together with the report thereon of PricewaterhouseCoopers LLP (PwC) dated February 24, 2015 beginning with the section entitled Report of independent registered public accounting firm on page 50 and continuing through note 18, Acquisition on page 77;

Supplemental information on oil and gas exploration and production activities (unaudited) starting on page 78; and

Quarterly financial and stock trading data (unaudited) on page 82.

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, 2014. 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 49 of this report for Management s report on internal control over financial reporting and page 50 for the Report of independent registered public accounting firm on the company s internal control over financial reporting as of December 31, 2014.

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.

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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 83. The company s management proxy circular is prepared in accordance with Canadian securities regulations.

The company currently has seven 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 Director information on pages 84 to 92 of this report have been nominated for election at the annual meeting of shareholders to be held April 30, 2015. All of the nominees are directors and have been since the dates indicated.

Reference is made to the sections under III. Board of directors :

Director information , on pages 84 to 92 of this report;

The table entitled Audit committee under Board and committee structure , on page 99 of this report; and

Other public company directorships , on page 107 of this report.

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

Named executive officers of the company and Other executive officers of the company , on page 113 and page 114 of this report.

Reference is made to the sections under V. Other important information :

Largest shareholder , on page 137 of this report; and

Ethical business conduct , starting on page 139 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 83. The company s management proxy circular is prepared in accordance with Canadian securities regulations.

Reference is made to the sections under III. Board of directors :

Share ownership guidelines of independent directors and chairman, president and chief executive officer , on page 106 of this report; and

Directors compensation , on pages 108 to 112 of this report.

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

Letter to Shareholders from the executive resources committee on executive compensation , starting on page 115 of this report; and

Compensation discussion and analysis , on pages 117 to 136 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 83. The company s management proxy circular is prepared in accordance with Canadian securities regulations.

Reference is made to the section under IV. Company executives and executive compensation entitled Equity compensation plan information , within the Compensation discussion and analysis section, on page 135 of this report.

Reference is made to the section under V. Other important information entitled Largest shareholder , on page 137 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. As of February 11, 2015, P.J. Masschelin was the owner of 3,000 common shares of the company and held 89,050 restricted stock units of the company. T.G. Scott held 88,525 restricted stock units of the company. W.J. Harnett was the owner of 12,858 common shares of the company and held 80,825 restricted stock units of the company. B.G. Merkel was the owner of 6,978 common shares of the company and held 75,950 restricted stock units of the company.

The directors and the executive officers of the company, whose compensation for the year-ended December 31, 2014 is described in the sections under III. Board of directors starting on page 84 and IV. Company executives and executive compensation starting on page 113, consist of 15 persons, who, as a group, own beneficially 102,081 common shares of the company, being approximately 0.01 percent of the total number of outstanding shares of the company, and 557,875 shares of Exxon Mobil Corporation (including 426,800 restricted shares). This information not being within the knowledge of the company has been provided by the directors and the executive officers individually. As a group, the directors and executive officers of the company held restricted stock units to acquire 443,275 common shares of the company, as of February 11, 2015.

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 83. The company s management proxy circular is prepared in accordance with Canadian securities regulations.

Reference is made to the section under V. Other important information entitled Transactions with Exxon Mobil Corporation , on page 137 of this report.

Reference is made to the section under III. Board of directors entitled Independence of the directors , on page 96 of this report.

D.G. (Jerry) Wascom is deemed a non-independent member of the executive resources committee, environmental, health and safety committee, nominations and corporate governance committee and contributions committee under the relevant standards. As an employee of ExxonMobil Refining & Supply Company, D.G. (Jerry) Wascom is independent of the company s management and is able to assist these committees by reflecting the perspective of the company s shareholders.

Item 14. Principal accountant fees and services

Sections of the company s management proxy circular are contained in the Proxy information section, starting on page 83. The company s management proxy circular is prepared in accordance with Canadian securities regulations.

Reference is made to the section under V. Other important information entitled Auditor information , on page 138 of this report.

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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 28 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-Q 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)).

(21)		Imperial Oil Resources Limited, McColl-Frontenac Petroleum Inc., Imperial Oil Resources N.W.T. Limited and Imperial Oil Resources Ventures Limited, all incorporated in Canada, are wholly-owned subsidiaries 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, 2014.
(23) (ii)	(A)	Consent of Independent Registered Public Accounting Firm (PricewaterhouseCoopers LLP).
(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, 237 Fourth Avenue S.W., Calgary, Alberta, Canada T2P 3M9, and payment of processing and mailing costs.

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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 24, 2015 by the undersigned, thereunto duly authorized.

Imperial Oil Limited

By */s/ Richard M. Kruger*
(Richard M. Kruger, Chairman of the Board,
President and Chief Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 24, 2015 by the following persons on behalf of the registrant and in the capacities indicated.

Signature	Title
/s/ Richard M. Kruger (Richard M. Kruger)	Chairman of the Board, President and Chief Executive Officer and Director (Principal Executive Officer)
/s/ Paul J. Masschelin (Paul J. Masschelin)	Senior Vice-President, Finance and Administration, and Controller (Principal Financial Officer and Principal Accounting Officer)
/s/ Krystyna T. Hoeg (Krystyna T. Hoeg)	Director
/s/ Jack M. Mintz	Director

(Jack M. Mintz)	
/s/ David S. Sutherland	Director
(David S. Sutherland)	
/s/ D.G. (Jerry) Wascom	Director
(D.G. (Jerry) Wascom)	
/s/ Sheelagh D. Whittaker	Director
(Sheelagh D. Whittaker)	
/s/ Victor L. Young	Director
(Victor L. Young)	

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Financial section

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Financial summary (U.S. GAAP)

millions of dollars	**2014**	2013	2012	2011	2010
Operating revenues	**36,231**	32,722	31,053	30,474	24,946
Net income by segment:					
Upstream	**2,059**	1,712	1,888	2,457	1,764
Downstream	**1,594**	1,052	1,772	884	442
Chemical	**229**	162	165	122	69
Corporate and Other	**(97)**	(98)	(59)	(92)	(65)
Net income	**3,785**	2,828	3,766	3,371	2,210
Cash and cash equivalents at year-end	**215**	272	482	1,202	267
Total assets at year-end	**40,830**	37,218	29,364	25,429	20,580
Long-term debt at year-end	**4,913**	4,444	1,175	843	527
Total debt at year-end	**6,891**	6,287	1,647	1,207	756
Other long-term obligations at year-end	**3,565**	3,091	3,983	3,876	2,753
Shareholders equity at year-end	**22,530**	19,524	16,377	13,321	11,177
Cash flow from operating activities	**4,405**	3,292	4,680	4,489	3,207
Per-share information (dollars)					
Net income per share - basic	**4.47**	3.34	4.44	3.98	2.61
Net income per share - diluted	**4.45**	3.32	4.42	3.95	2.59
Dividends declared	**0.52**	0.49	0.48	0.44	0.43

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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 dollars	**2014**	2013	2012
Business uses: asset and liability perspective			
Total assets	**40,830**	37,218	29,364
Less: total current liabilities excluding notes and loans payable	**(4,003)**	(5,245)	(5,433)
total long-term liabilities excluding long-term debt	**(7,406)**	(6,162)	(5,907)
Add: Imperial s share of equity company debt	**19**	23	24
Total capital employed	**29,440**	25,834	18,048
Total company sources: debt and equity perspective			
Notes and loans payable	**1,978**	1,843	472
Long-term debt	**4,913**	4,444	1,175
Shareholders equity	**22,530**	19,524	16,377
Add: Imperial s share of equity company debt	**19**	23	24
Total capital employed	**29,440**	25,834	18,048

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 both evaluate management s performance and 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 dollars	**2014**	2013	2012
Net income	**3,785**	2,828	3,766
Financing costs (after tax), including Imperial s share of equity companies	**1**	1	1

Net income excluding financing costs		**3,786**	2,829	3,767
Average capital employed		**27,637**	21,941	16,302
Return on average capital employed (percent)	corporate total	**13.7**	12.9	23.1

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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 dollars	**2014**	2013	2012
Cash from operating activities	**4,405**	3,292	4,680
Proceeds from asset sales	**851**	160	226
Total cash flow from operating activities and asset sales	**5,256**	3,452	4,906

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, as defined below, 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 dollars	**2014**	2013	2012
From Imperial s Consolidated Statement of Income			
Total expenses	**31,945**	29,192	26,195
Less:			
Purchases of crude oil and products	**22,479**	20,155	18,476
Federal excise tax	**1,562**	1,423	1,338
Financing costs	**4**	11	(1)
Subtotal	**24,045**	21,589	19,813
Imperial s share of equity company expenses	**39**	37	34
Total operating costs	**7,939**	7,640	6,416

Components of Operating Costs

millions of dollars	**2014**	2013	2012
From Imperial s Consolidated Statement of Income			
Production and manufacturing	**5,662**	5,288	4,457
Selling and general	**1,075**	1,082	1,081
Depreciation and depletion	**1,096**	1,110	761

Exploration	**67**	123	83
Subtotal	**7,900**	7,603	6,382
Imperial s share of equity company expenses	**39**	37	34
Total operating costs	**7,939**	7,640	6,416

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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 straightforward business model involving the extracting, refining and marketing of hydrocarbons and hydrocarbon-based products. The company s business involves the production (or purchase), manufacture and sale of physical products, and all commercial activities are directly in support of the underlying physical movement of goods.

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. While commodity prices remain volatile on a short-term basis depending upon supply and demand, Imperial s investment decisions are based on its long-term business outlook, using 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. Potential investment opportunities are tested over a wide range of economic scenarios to establish the resiliency of each opportunity. Once 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

By 2040, the world s population is projected to grow to approximately nine billion people, or about two billion more than in 2010. Coincident with this population increase, the company expects worldwide economic growth to average close to three percent per year. As economies and population grow, and as living standards improve for billions of people, the need for energy will continue to rise. Even with significant efficiency gains, global energy demand is projected to rise by about 35 percent from 2010 to 2040. This demand increase is expected to be concentrated in developing countries (i.e., those that are not member nations of the Organization for Economic Cooperation and Development).

As expanding prosperity drives global energy demand higher, increasing use of energy-efficient and lower-emission fuels, technologies and practices 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 economy through 2040, affecting energy requirements for transportation, power generation, industrial applications, and residential and commercial needs.

Energy for transportation - including cars, trucks, ships, trains and airplanes - is expected to increase by about 40 percent from 2010 to 2040. The growth in transportation energy demand is likely to account for approximately 60 percent of the growth in liquid fuels demand worldwide over this period. Nearly all the world s transportation fleets will continue to run on liquid fuels which are abundant, widely available, easy to transport, and provide a large quantity of energy in small volumes.

Demand for electricity around the world is likely to increase approximately 85 percent by 2040, led by growth in developing countries. Consistent with this projection, power generation is expected to remain the largest and fastest-growing major segment of global energy demand. Meeting the expected growth in power demand will require a diverse set of energy sources. Natural gas demand is likely to grow most significantly and become the leading source of generated electricity by 2040, reflecting the efficiency of gas-fired power plants. Today, coal has the largest fuel share in the power sector, but its share is likely to decline significantly by 2040 as policies are gradually adopted to reduce environmental impacts including those related to local air quality and greenhouse gas emissions. Nuclear power and renewables, led by hydropower and wind, are expected to grow significantly over the period.

Liquid fuels provide the largest share of global energy supplies today due to their broad-based availability, affordability and ease of transportation, distribution and storage to meet consumer needs. By 2040, global demand for liquid fuels is expected to grow to approximately 115 million barrels of oil-equivalent per day, an increase of almost 30 percent from 2010. Globally, crude production from traditional conventional sources will likely decline slightly through 2040, with significant development activity mostly offsetting natural declines from these fields. However, this decline is expected to be more than offset by rising production from a wide variety of emerging supply sources including tight oil, deepwater, oil sands, natural gas liquids, and biofuels. The world s resource base is sufficient to meet projected demand through 2040 as technology advances continue to expand the availability of economic supply options. However, access to resources and timely investments will remain critical to meeting global needs with reliable, affordable supplies.

Natural gas is a versatile fuel, suitable for a wide variety of applications, and is expected to be the fastest growing major fuel source through 2040. Global demand is expected to rise about 65 percent from 2010 to 2040, with about half of that increase in the Asia Pacific region. Helping meet these needs will be significant growth in supplies of unconventional gas - the natural gas found in shale and other rock formations that was once considered uneconomic to produce. About two-thirds of the growth in natural gas supplies is expected to be from unconventional sources, which will account for close to 35 percent of global gas supplies by 2040. The worldwide liquefied natural gas market is expected to more than triple by 2040, stimulated by growing natural gas demand.

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 by approximately 2025 to 2030 timeframe. The share of natural gas is expected to exceed 25 percent by 2040, while the share of coal falls to less than 20 percent. Nuclear power is projected to grow significantly, as many nations expand nuclear capacity to address rising electricity needs as well as energy security and environmental issues. Total renewable energy is likely to reach close to 15 percent of total energy by 2040, with biomass, hydro and geothermal contributing combined share of more than ten percent. Total energy supplied from wind, solar and biofuels is expected to increase close to 450 percent from 2010 to 2040, when they will be approaching four percent of world energy.

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 cost to develop and supply these resources will be significant. According to the International Energy Agency, the investment required to meet total oil and gas energy needs worldwide over the period 2014 to 2040 will be about $28 trillion (measured in 2013 dollars), or more than one trillion per year on average.

International accords and underlying regional and national regulations for greenhouse gas reduction are evolving with uncertain timing and outcome, making it difficult to predict their business impact. Imperial s estimates of potential costs related to possible public policies covering energy-related greenhouse gas emissions are consistent with those outlined in Exxon Mobil Corporation s (ExxonMobil) long-term *Outlook for Energy*, which is used as a foundation for assessing the business environment and Imperial s investment evaluations.

The information provided in the Long-term business outlook includes internal estimates and forecasts based upon 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 predominately into the North American markets. Imperial s Upstream business strategies guide the company s exploration, development, production, research and gas marketing activities. These strategies include capturing material and accretive opportunities to continually high-grade the resource portfolio, exercising a disciplined approach to investing and cost management, developing and applying high-impact technologies, pursuing productivity and efficiency gains, and growing profitable oil and gas production. These strategies are underpinned by a relentless focus on operational excellence, commitment

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Management s discussion and analysis of financial condition and results of operations (continued)

to innovative technologies, development of employees and investment in the communities within which the company operates.

The company s current Upstream activities support plans to significantly increase production this decade. The Kearl initial development, the largest capital investment in the company s history, started up in 2013. The Kearl expansion project and the Nabiye expansion project at Cold Lake were also advanced in 2014 and are expected to commence production in 2015. To support the company s long-term growth a variety of existing and new logistics outlets have been secured or are being developed.

Imperial has a large portfolio of oil and gas resources in Canada, both developed and undeveloped. With the relative maturity of conventional production in established producing areas, Imperial s production is expected to come increasingly from oil sands and unconventional sources.

Prices for most of the company s crude oil sold are referenced to West Texas Intermediate (WTI) oil markets, a common benchmark for mid-continent North American markets. In 2014, the average WTI crude oil price, in U.S. dollars, was lower versus 2013. This negative impact, however, was more than offset by the effect of the weaker Canadian dollar. The markets for crude oil and natural gas have a history of significant price volatility. After some years of relatively stable prices, the end of 2014 saw prices drop to levels not seen since 2009. Imperial believes prices over the long term will continue to be driven by market supply and demand, with the demand side largely being a function of global economic growth. To manage the risks associated with price, Imperial evaluates annual plans and all investments across a wide range of price scenarios. The company s assessment is that its operations will continue to be successful in a variety of market conditions. This is the outcome of disciplined investment, cost management, and asset enhancement programs.

Downstream

Imperial s Downstream serves predominately Canadian markets with refining, logistics and marketing assets. Imperial s Downstream business strategies guide the company s activities. These strategies include targeting best-in-class operations in all aspects of the business, 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 valued products and services to customers.

Imperial owns and operates three refineries in Canada, with aggregate distillation capacity of 421,000 barrels per day. Imperial s fuels marketing business includes retail operations across Canada serving customers through more than 1,700 Esso-branded retail service stations, as well as wholesale and industrial operations through a network of 22 primary distribution terminals.

Globally, the downstream industry environment remains challenging. Slowing demand growth and overcapacity in the refining sector will continue to increase competitive pressure. In Canada, in recent years, access to price-advantaged feedstock, as a result of North American crude logistics constraints and increasing North American crude oil production, along with lower natural gas prices have strengthened refining margins.

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 market prices for the range of products produced (primarily gasoline, heating oil, diesel oil, jet fuel and fuel oil). 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 global and regional marketplaces and are influenced by many factors, including supply/demand balances, inventory levels, industry refinery operations, import/export balances, currency fluctuations, seasonal demand, weather and political climate.

Imperial s long-term outlook is that industry refining margins will be relatively weak as competition remains intense in the mature North American market. Additionally, as described in more detail in Item 1A Risk Factors, potential carbon policy and other climate-related regulations, as well as the continued growth in biofuels mandates, could have negative impacts on the refining business. Imperial s integration across the value chain, from refining to marketing, enhances overall value in both fuels and lubricants businesses.

In the retail fuels marketing business, about 470 of the 1,700 Esso-branded retail site network are company-owned. The remainder operates under a branded wholesaler model whereby Imperial supplies fuels to

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Management s discussion and analysis of financial condition and results of operations (continued)

independent third parties who own and operate retail sites in alignment with Esso brand standards. In January 2015, the company announced that it will evaluate its operating model for the company-owned retail service stations. The assessment will evaluate the potential opportunity to extend the branded wholesaler model to the remaining 470 sites as part of Imperial s Esso brand growth strategy.

Chemical

In North America, unconventional natural gas continued to provide advantaged ethane feedstock for steam crackers and a favourable margin environment for integrated chemical producers. The company s Sarnia chemical plant achieved a further feedstock cost advantage with access to Marcellus ethane beginning in the second quarter of 2014. The company s strategy for its Chemical business is to reduce costs and maximize value by continuing 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.

Results of operations

Consolidated

millions of dollars	**2014**	2013	2012
Net income	**3,785**	2,828	3,766

2014

Net income in 2014 was $3,785 million or $4.45 per share on a diluted basis, versus $2,828 million or $3.32 per share in 2013. Earnings improved in all operating segments in 2014 with Downstream earnings higher by $542 million, Upstream earnings by $347 million and Chemical earnings by $67 million.

2013

Net income in 2013 was $2,828 million or $3.32 per share on a diluted basis, versus $3,766 million or $4.42 per share in 2012. Earnings decreased primarily due to significantly lower industry refining margins of about $700 million, higher Kearl costs of about $180 million as production contribution was more than offset by start-up and operating costs, lower volumes at Syncrude of about $120 million and lower contribution from Cold Lake of about $120 million. 2013 earnings also included an after-tax charge of $280 million associated with the conversion of the Dartmouth refinery to a terminal. These factors were partially offset by the impacts of higher liquids realizations of about $125 million, a weaker Canadian dollar versus the U.S. dollar of about $125 million, higher marketing margins of about $120 million and lower refinery maintenance costs of about $90 million.

In 2013, the average price of benchmark West Texas Intermediate (WTI) crude oil was higher when compared to 2012 and led to higher western Canadian crude oil prices and higher liquids realization in the company s Upstream segment in 2013. Refining margins in the company s Downstream segment, however, were negatively impacted as the overall cost of crude oil processed largely followed the upward trend of western Canadian crude oil pricing.

Upstream

millions of dollars	**2014**	2013	2012
Net income	**2,059**	1,712	1,888

2014

Upstream net income in 2014 was $2,059 million, $347 million higher than 2013. Earnings in 2014 included a gain of $478 million from the divestment of conventional upstream producing assets, whereas 2013 included a $73 million gain for the sale of non-operating assets. Earnings also increased due to the impacts of a weaker Canadian dollar of about $280 million and higher liquids volumes of about $100 million, reflecting the incremental contribution from Kearl production. These factors were partially offset by higher royalty costs of about $220 million mainly associated with higher Canadian bitumen realizations, reduced allowable costs and the ramp up of Kearl production, as well as higher energy and other operating costs of about $130 million, and the impact of lower crude oil realizations of about $50 million.

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Management s discussion and analysis of financial condition and results of operations (continued)

2013

Net income for the year was $1,712 million, versus $1,888 million in 2012. Earnings decreased primarily due to higher Kearl costs of about $180 million as production contribution since start-up in late April was more than offset by year-to-date start-up and operating costs, lower volumes at Syncrude of about $120 million, and higher diluent and energy costs at Cold Lake totalling about $120 million. These factors were partially offset by higher liquids realizations of about $125 million and the impact of a weaker Canadian dollar of about $125 million.

Average realizations

Canadian dollars	**2014**	2013	2012
Conventional crude oil realizations (per barrel)	**76.03**	82.41	77.19
Natural gas liquids realizations (per barrel)	**49.11**	39.26	42.06
Natural gas realizations (per thousand cubic feet)	**4.54**	3.27	2.33
Synthetic oil realizations (per barrel)	**99.58**	99.69	92.48
Bitumen realizations (per barrel)	**67.20**	60.57	59.76

2014

Prices for most of the company s liquids production are based on WTI crude oil, a common benchmark for mid-continent North American oil markets. WTI was down about $5.14 per barrel in U.S. dollars, or about five percent in 2014, versus 2013. The company s average bitumen realizations in Canadian dollars in 2014 were $67.20 per barrel versus $60.57 per barrel in 2013, with the lower WTI benchmark price more than offset by the effect of the weaker Canadian dollar and the narrower price spread between light crude oil and bitumen. The company s average realizations from the sale of synthetic crude oil were largely unchanged from 2013, as the decrease in WTI crude oil benchmark price was essentially offset by the impact of a weaker Canadian dollar. The company s average realizations on natural gas sales of $4.54 per thousand cubic feet in 2014 were higher by $1.27 per thousand cubic feet versus 2013.

2013

Prices for most of the company s liquids production are based on WTI crude oil, a common benchmark for mid-continent North American oil markets. WTI crude oil price was up $3.90 per barrel in U.S. dollars, or about four percent in 2013, versus 2012. The company s average realizations also increased in Canadian dollars on sales of conventional, synthetic crude oil and bitumen. The company s average realizations on natural gas sales of $3.27 per thousand cubic feet in 2013 were higher by $0.94 per thousand cubic feet versus 2012.

Crude oil and NGLs - production and sales (a)

thousands of barrels per day	**2014**		2013		2012	
	gross	**net**	gross	net	gross	net

Bitumen (b)	**197**	**161**	169	142	154	123
Synthetic oil (c)	**64**	**60**	67	65	72	69
Conventional crude oil	**18**	**14**	21	17	20	15
Total crude oil production	**279**	**235**	257	224	246	207
NGLs available for sale	**3**	**2**	4	3	4	3
Total crude oil and NGL production	**282**	**237**	261	227	250	210
Bitumen sales, including diluent (d)	**259**		219		201	
NGL sales	**8**		9		8	

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Management s discussion and analysis of financial condition and results of operations (continued)

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

millions of cubic feet per day	**2014**		2013		2012	
	gross	**net**	gross	net	gross	net
Production (f)(g)	**168**	**156**	201	189	192	195
Production available for sale (h)		**124**		152		161

(a) Barrels per day metric is 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 bitumen production volumes included production volumes from the Cold Lake operation for all years presented in the table above and, beginning in 2013, also included production volumes from the Kearl initial development (2014 - 51,000 barrels per day gross, 47,000 barrels net; 2013 - 16,000 barrels gross, 15,000 barrels net).

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

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

(e) Cubic feet per day metric is calculated by dividing the volume for the period by the number of calendar days in the period.

(f) Production of natural gas includes amounts used for internal consumption with the exception of the amounts reinjected.

(g) Net production is gross production less the mineral owners or governments share or both. Net natural gas production in 2012 included favourable royalty cost adjustments. Net production reported in the above table is consistent with production quantities in the net proved reserves disclosure.

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

2014

Gross production of Cold Lake bitumen averaged 146,000 barrels per day in 2014, down from 153,000 barrels in 2013. Lower volumes were primarily due to the cyclic nature of steaming and associated production and the impact of several unplanned third-party power outages in the first quarter.

During the year, the company s share of gross production from Syncrude averaged 64,000 barrels per day, down from 67,000 barrels in 2013, primarily due to higher scheduled and unscheduled maintenance activities.

The company s share of gross production from the Kearl initial development in 2014 was 51,000 barrels per day versus 16,000 barrels in 2013. Production at the Kearl initial development continued to ramp-up in 2014.

Gross production of conventional crude oil averaged 18,000 barrels per day in the year, versus 21,000 barrels in 2013. The lower production volume was primarily due to the impact of properties divested during the first half of 2014.

Gross production of natural gas in 2014 was 168 million cubic feet per day, down from 201 million cubic feet in 2013. The lower production volume was primarily the result of the impact of divested properties.

2013

Gross production of Cold Lake bitumen was 153,000 barrels per day, compared to 154,000 barrels in 2012.

During the year, the company s share of gross production from Syncrude averaged 67,000 barrels per day, down from 72,000 barrels in 2012. Higher planned maintenance activities were the main contributor to the lower volumes.

The company s share of gross production of Kearl initial development was 16,000 barrels per day for the full year. Production of mined diluted bitumen began in April 2013 and continued to ramp-up in 2014. Since start-up, improvements have been made to equipment reliability. Although gross production rates of 100,000 barrels per day (71,000 Imperial s share) were reached in the fourth quarter, ongoing activities to stabilize performance at these higher levels are progressing. In the fourth quarter, sales to unrelated third parties commenced as planned.

Gross production of conventional crude oil averaged 21,000 barrels per day in the year, versus 20,000 barrels in 2012.

Gross production of natural gas in 2013 was 201 million cubic feet per day, up from 192 million cubic feet in 2012. The higher production volumes reflected contributions from the Celtic acquisition and the Horn River pilot, which more than offset normal field decline.

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Management s discussion and analysis of financial condition and results of operations (continued)

Downstream

millions of dollars	**2014**	2013	2012
Net income	**1,594**	1,052	1,772

2014

Downstream net income was $1,594 million, up $542 million from 2013. Earnings in 2013 included a charge of $280 million associated with the conversion of the Dartmouth refinery to a fuels terminal. Earnings also increased due to the impacts of improved refinery reliability and accessing advantaged crudes of about $330 million, a weaker Canadian dollar of about $130 million and higher marketing margins and sales volumes totalling about $105 million. These factors were partially offset by lower refining margins of about $230 million.

2013

Downstream net income was $1,052 million, versus $1,772 million in 2012. Earnings were negatively impacted by significantly lower industry refining margins of about $700 million. Earnings in 2013 also included an after-tax charge of $280 million associated with the conversion of the Dartmouth refinery to a fuels terminal. These factors were partially offset by higher marketing margins of about $120 million and lower refinery maintenance costs of about $90 million.

The overall cost of crude oil processed at the company s refineries largely followed the trend of western Canadian crude oils. Canadian wholesale prices of refined products are largely determined by wholesale prices in adjacent U.S. regions, where wholesale prices are predominately tied to international product markets. Lower Downstream earnings in 2013 when compared to 2012 were mainly the result of lower industry refining margins, partially offset by higher marketing margins.

Refinery utilization

thousands of barrels per day (a)	**2014**	2013	2012
Total refinery throughput (b)	**394**	426	435
Refinery capacity at December 31	**421**	421	506
Utilization of total refinery capacity (percent) (c)	**94**	88	86

Sales

thousands of barrels per day (a)	**2014**	2013	2012
Gasolines	**244**	223	221
Heating, diesel and jet fuels	**179**	160	151
Heavy fuel oils	**22**	29	30

Lube oils and other products	**40**	42	43
Net petroleum product sales	**485**	454	445

(a) Volumes per day are calculated by dividing total volumes for the year by the number of calendar days in the year.
(b) Crude oil and feedstocks sent directly to atmospheric distillation units.
(c) Refinery operations at the Dartmouth refinery were discontinued on September 16, 2013. Capacity utilization is calculated based on the number of days the refineries were operated as a refinery in 2013.

2014

Total refinery throughput was 394,000 barrels per day. Refinery throughput was 94 percent of capacity in 2014, six percent higher than the previous year. The higher rate was primarily a result of improved refinery reliability and increased product sales. Total net petroleum sales increased to 485,000 barrels per day, 31,000 barrels higher than 2013.

2013

In the second quarter of 2013, the company announced its decision to convert the Dartmouth refinery to a fuels terminal. In the third quarter, refinery operations at the Dartmouth refinery were discontinued. The company continues to supply east coast Canadian markets with petroleum products.

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Management s discussion and analysis of financial condition and results of operations (continued)

Total refinery throughput was 426,000 barrels per day. Refinery throughput was 88 percent of capacity in 2013, two percent higher than the previous year. The higher rate was primarily a result of increased product sales and optimized maintenance activities. Capacity utilization in 2013 is calculated based on the number of days the refineries were operated as a refinery. Total net petroleum sales increased to 454,000 barrels per day, 9,000 barrels higher than 2012.

Chemical

millions of dollars	**2014**	2013	2012
Net income	**229**	162	165

Sales

thousands of tonnes	**2014**	2013	2012
Polymers and basic chemicals	**741**	712	767
Intermediate and others	**212**	228	277
Total petrochemical sales	**953**	940	1,044

2014

Chemical net income was a record $229 million in 2014, up $67 million over 2013. Strong margins across all major product lines and the processing of cost-advantaged ethane feedstock from Marcellus shale gas beginning in the second quarter of 2014 contributed to these best-ever results.

2013

Chemical net income was $162 million, versus 2012 s record high of $165 million.

Corporate and Other

millions of dollars	**2014**	2013	2012
Net income	**(97)**	(98)	(59)

2014

For 2014, net income effects from Corporate and Other were negative $97 million, versus negative $98 million in 2013 primarily due to changes in share-based compensation charges.

2013

For 2013, net income effects from Corporate and Other were negative $98 million, versus negative $59 million in 2012 primarily due to changes in share-based compensation charges.

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Management s discussion and analysis of financial condition and results of operations (continued)

Liquidity and capital resources

Sources and uses of cash

millions of dollars	**2014**	2013	2012
Cash provided by/(used in)			
Operating activities	**4,405**	3,292	4,680
Investing activities	**(4,562)**	(7,735)	(5,238)
Financing activities	**100**	4,233	(162)
Increase/(decrease) in cash and cash equivalents	**(57)**	(210)	(720)
Cash and cash equivalents at end of year	**215**	272	482

Investments in 2014 were primarily funded by internally generated cash flow and proceeds from asset sales, supplemented by the issuance of long-term debt and commercial paper. Cash that may be temporarily available as 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. Projects are planned or underway to increase production capacity. However, these volume increases are subject to a variety of risks, including project execution, operational outages, reservoir performance, crude oil and natural gas prices, weather events and regulatory changes.

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.

An independent actuarial valuation of the company s registered retirement benefit plans was completed as at December 31, 2013. As a result of the valuation, the company contributed $362 million to the registered retirement benefit plans in 2014. The next required independent actuarial valuation will be as at December 31, 2016 and the company will continue to contribute within the requirements of pension regulations. 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

2014

Cash flow generated from operating activities was $4,405 million, compared with $3,292 million in 2013. Higher cash flow was primarily due to higher net income.

2013

Cash flow generated from operating activities was $3,292 million, compared with $4,680 million in 2012. Lower cash flow was primarily due to lower net income and working capital effects.

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Management s discussion and analysis of financial condition and results of operations (continued)

Cash flow used in investing activities

2014

Investing activities used net cash of $4,562 million in 2014, compared to $7,735 million in 2013. Additions to property, plant and equipment and additional investments totalled $5,413 million, compared with $7,899 million last year, which included acquisitions of $1,602 million. Proceeds from asset sales were $851 million compared with $160 million in 2013.

2013

Investing activities used net cash of $7,735 million in 2013, compared to $5,238 million in 2012. Additions to property, plant and equipment and acquisitions totalled $7,899 million, compared with $5,478 million last year. Proceeds from asset sales were $160 million compared with $226 million in 2012.

Cash flow from financing activities

2014

Cash provided by financing activities was $100 million, compared with cash provided by financing activities of $4,233 million in 2013.

The company raised new debt of $550 million; $430 million was drawn on existing facilities.

At the end of 2014, total debt outstanding was $6,891 million, compared with $6,287 million at the end of 2013.

In January 2014, the company increased the capacity of its existing floating rate loan facility with an affiliated company of ExxonMobil from $5 billion to $6.25 billion. All other terms and conditions of the agreement remained unchanged.

In March 2014, the company extended the maturity date of its existing $500 million 364-day short-term unsecured committed bank credit facility to March 2015. The company has not drawn on the facility.

In August 2014, the company extended the maturity date of its existing $500 million stand-by long-term bank credit facility to August 2016. The company has not drawn on the facility.

Cash dividends of $441 million were paid in 2014 compared with $407 million in 2013. Per-share dividends paid in 2014 totalled $0.52, up from $0.48 in 2013.

Subsequent to December 31, 2014 and up to February 11, 2015, the company increased its long-term debt by $490 million by drawing on an existing facility. The increased debt was used to finance normal operations and capital projects.

2013

Cash provided by financing activities was $4,233 million, compared with cash used in financing activities of $162 million in 2012.

The company raised new debt of $4,647 million; $4,572 million was drawn on existing facilities.

In the fourth quarter of 2013, the company entered into an arrangement with an affiliated company of ExxonMobil that provides for a non-interest bearing, revolving demand loan from ExxonMobil to the company of up to $75 million. The loan represents ExxonMobil s share of a working capital facility required to support purchasing, marketing and transportation arrangements for crude oil and diluent products undertaken by Imperial on behalf of ExxonMobil. As at December 31, 2013, the company had drawn $75 million on this agreement.

At the end of 2013, total debt outstanding was $6,287 million, compared with $1,647 million at the end of 2012.

Cash dividends of $407 million were paid in 2013 compared with $398 million in 2012. Per-share dividends paid in 2013 totalled $0.48, up from $0.47 in 2012.

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Management s discussion and analysis of financial condition and results of operations (continued)

Financial percentages and ratios

	2014	2013	2012
Total debt as a percentage of capital (a)	**23**	24	9
Interest coverage ratio earnings basis (b)	**61**	55	239

(a) Current and long-term debt (page 53) and the company s share of equity company debt, divided by debt and shareholders equity (page 53).

(b) Net income (page 51), debt-related interest before capitalization, including the company s share of equity company interest, and income taxes (page 51), divided by debt-related interest before capitalization, including the company s share of equity company interest.

Debt represented 23 percent of the company s capital structure at the end of 2014.

Debt-related interest incurred in 2014, before capitalization of interest, was $82 million, compared with $69 million in 2013. The average effective interest rate on the company s debt was 1.3 percent in 2014, compared with 1.4 percent in 2013.

The company s financial strength, as evidenced by the above financial ratios, represents a competitive advantage of strategic importance. The company s sound financial position gives it the opportunity to access capital markets in 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.

The company does not use any derivative instruments to offset exposures associated with hydrocarbon prices, currency exchange rates and interest rates that arise from existing assets, liabilities and transactions. The company does not engage in speculative derivative activities nor does it use derivatives with leveraged features.

Commitments

The following table shows the company s commitments outstanding at December 31, 2014. It combines data from the consolidated balance sheet and from individual notes to the consolidated financial statements, where appropriate.

	Financial	Payment due by period			
			2016	2020 and	
	statement				Total
millions of dollars	note reference	2015	to 2019	beyond	amount
Long-term debt (a)	Note 14	-	4,816	97	4,913
- Due in one year		22	-	-	22
Operating leases (b)	Note 13	178	288	28	494
Unconditional purchase obligations (c)	Note 9	100	356	225	681
Firm capital commitments (d)		1,257	285	408	1,950
Pension and other post-retirement obligations (e)	Note 4	285	248	1,264	1,797

Asset retirement obligations (f)	Note 5	84	430	778	1,292
Other long-term purchase agreements (g)		567	2,521	7,638	10,726

(a) Long-term debt includes a long-term loan from an affiliated company of ExxonMobil of $4,746 million and capital lease obligations of $189 million, $22 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, primarily cover office buildings, rail cars and service stations.

(c) Unconditional purchase obligations are those long-term commitments that are non-cancelable or cancelable only under certain conditions and that third parties have used to secure financing for the facilities that will provide the contracted goods and services. They mainly pertain to pipeline throughput agreements.

(d) Firm capital commitments related to capital projects, shown on an undiscounted basis. The largest commitments outstanding at year-end 2014 were $1,390 million associated with the company s share of the Kearl project.

(e) The amount by which the benefit obligations exceeded the fair value of fund assets for pension and other post-retirement plans at year-end. The payments by period include expected contributions to funded pension plans in 2015 and estimated benefit payments for unfunded plans in all years.

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

(g) Other long-term purchase agreements are non-cancelable, long-term commitments other than unconditional purchase obligations. They include primarily raw material supply and transportation services agreements.

Management s discussion and analysis of financial condition and results of operations (continued)

Unrecognized tax benefits totalling $151 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 3 to the financial statements on page 61.

Litigation and other contingencies

As discussed in note 9 to the consolidated financial statements on page 70, 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. 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 dollars	**2014**	2013
Upstream (a)	**4,974**	7,755
Downstream	**572**	187
Chemical	**26**	9
Other	**82**	69
Total	**5,654**	8,020

(a) Exploration expenses included.

Total capital and exploration expenditures were $5,654 million in 2014, a decrease of $2,366 million from 2013.

For the Upstream segment, capital expenditures were $4,974 million, compared with $7,755 million in 2013. Investments were primarily directed towards the advancement of the Kearl expansion and Nabiye projects.

Kearl s expansion project construction phase was essentially complete at the end of 2014, and the commissioning of facilities commenced in preparation for start-up. The project is expected to ultimately produce 110,000 barrels per day gross, before royalties, of which the company s share will be about 78,000 barrels. Cold Lake s Nabiye project facilities start-up occurred throughout December 2014 followed by initial steam injection into the reservoir in January 2015. Bitumen production is targeted in the first quarter of 2015, ultimately increasing to 40,000 barrels per day, before royalties.

Planned capital and exploration expenditures in the Upstream segment are forecast at about $3.4 billion for 2015. Investments are mainly planned for continued investment at Kearl.

For the Downstream segment, capital expenditures were $572 million in 2014, compared with $187 million in 2013. In 2014, Downstream capital expenditures included capitalized leases and investment in the Edmonton rail loading joint venture. Other investments included refinery projects to improve reliability, feedstock flexibility, energy efficiency and environmental performance as well as continued upgrades to the Retail network.

Planned capital expenditures for the Downstream segment in 2015 are about $400 million, focused on investment at the Edmonton rail loading joint venture, improving refinery reliability and environmental and safety performance, as well as continuing upgrades to the retail network.

Total capital and exploration expenditures for the company in 2015 are expected to be about $4 billion, including capitalized leases of about $500 million. Actual spending could vary depending on the progress of individual projects.

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Management s discussion and analysis of financial condition and results of operations (continued)

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. In addition, 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. 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 below, which shows the estimated annual effect, under current conditions, on the company s after-tax net income.

Earnings sensitivities (a)

millions of dollars, after tax		
Four dollars (U.S.) per barrel change in crude oil prices	+ (-)	280
Forty cents per thousand cubic feet change in natural gas prices	+ (-)	25
One dollar (U.S.) per barrel change in sales margins for total petroleum products	+ (-)	150
One cent (U.S.) per pound change in sales margins for polyethylene	+ (-)	7
One-quarter percent decrease (increase) in short-term interest rates	+ (-)	12
Nine cents decrease (increase) in the value of the Canadian dollar versus the U.S. dollar	+ (-)	585

(a) The amount quoted to illustrate the impact of each sensitivity represents a change of about 10 percent in the value of the commodity or rate in question at the end of 2014. 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. While these sensitivities are applicable under current conditions, they may not apply proportionately to larger fluctuations.

The sensitivity of net income to changes in crude oil prices increased from 2013 year-end by about $16 million (after tax) a year for each one U.S. dollar per barrel change. The increase was primarily the result of lower royalty costs due to lower crude oil prices at 2014 year-end and higher production volumes. A decrease in the value of the Canadian dollar at 2014 year-end has also increased the impact of U.S. dollar denominated crude oil prices on the company s revenues and earnings.

The sensitivity of net income to changes in natural gas prices increased from 2013 year-end by about $3 million (after tax) a year for each ten-cent per thousand cubic feet change. The increase was primarily the result of higher purchased gas volumes due to higher bitumen production volumes and lower natural gas production volumes due to the impact of properties divested during 2014.

The sensitivity of net income to changes in sales margins for total petroleum products increased from 2013 year-end by about $20 million (after tax) a year for each one U.S. dollar per barrel change. The increase was primarily the result of increased sales volumes. A decrease in the value of the Canadian dollar has also increased the impact of U.S. dollar denominated crude oil and petroleum products prices on the company s revenues and earnings.

The sensitivity of net income to changes in the Canadian dollar versus the U.S. dollar increased from 2013 year-end by about $9 million (after tax) a year for each one-cent change. The increase was primarily the result of wider refining margins as the company s refineries are able to fully access price-advantaged mid-continent North American crude oils partially offset by lower crude oil prices at 2014 year-end.

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 our 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. Instead, where such sales take place, they are the result of efficiencies and competitive advantages of integrated refinery/chemical complexes. Additionally, intersegment sales are at market-based prices. The products bought and sold between segments can also be acquired in worldwide markets that have substantial liquidity, capacity and transportation capabilities. About 70 percent of the company s intersegment sales are

Management s discussion and analysis of financial condition and results of operations (continued)

crude oil produced by the Upstream and sold to the Downstream. Other intersegment sales include those between refineries and chemical plants related to raw materials, feedstocks and finished products.

Although price levels of crude oil and natural gas may rise or fall significantly over the short to medium term, as evidenced in the dramatic decline in global crude oil prices towards the end of 2014, industry economics over the long term will continue to be driven by market supply and demand. Accordingly, the company evaluates the viability of all of its investments over a broad range of future prices. The company s assessment is that its operations will continue to be successful in a variety of market conditions. This is the outcome of disciplined investment and asset management programs. Consequently, the company s near-term investment plans remain largely unchanged. However, the company will continue to closely monitor and respond to market conditions, rigorously examining operating costs and capital investments to maximize value in whatever business environment in which the company operates.

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. The result is an efficient capital base, and the company has seldom had to write down the carrying value of assets, even during periods of low commodity prices.

Industry bitumen production may be subject to limits on transportation capacity to markets. A significant portion of the company s Upstream production is bitumen. The company s longer-term oil sands development plans, results of operations and cash flow may be adversely affected if, for regulatory or other reasons, necessary additional transportation infrastructure is not added in a timely fashion. The company supports increased market access including proposed pipeline expansions to the United States Gulf coast and the Canadian West coast.

The demand for crude oil, natural gas, petroleum products and petrochemical products correlates closely with general economic growth rates. 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. In challenging economic times, the company follows the proven approach to continue focus on the business elements within its controls and take a long-term view of development.

Increased demand for certain services and materials has resulted in higher capital and other project costs in industry oil sands developments. The company works to counter upward pressure on costs through effective and efficient project and procurement management. One such example is the sanctioning of the Kearl expansion project to continue from the initial development such that the initial development s design and development infrastructure can be reused. This continuation also allows the company to retain the experienced labour resources working on the initial development thereby maintaining productivity and limiting cost growth.

To help reduce the risks of dependence on potentially limited supply sources in established, mature conventional producing areas, the company s production is expected to come increasingly from oil sands, unconventional natural gas and tight oil. Technology improvements have played and will continue to play an important role in the economics and the environmental performance of the current and future developments of these unconventional sources.

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 rates. In 2014, Upstream earnings of $2,059 million, Downstream earnings of $1,594 million and record Chemical earnings of $229 million highlighted the strength of the company s value chain integration. The company s financial strength and debt capacity give it the opportunity to advance business plans in the pursuit of maximizing shareholder value in the full range of market conditions. Also, the company progresses large capital projects in a phased manner so that adjustments can be made when significant changes in market conditions occur. As a result, the company does not make use of derivative instruments to mitigate the impact of such changes. The company does not engage in speculative derivative activities or derivative trading activities nor does it use derivatives with leveraged features. Although the company does not engage in speculative derivative activities or derivative trading activities it maintains a system of controls that includes a policy covering the authorization, reporting and monitoring of derivative activity.

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Management s discussion and analysis of financial condition and results of operations (continued)

Critical accounting estimates

The company s financial statements have been prepared in accordance with United States generally accepted accounting principles (GAAP). 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 straightforward business model. 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 56.

Oil and gas reserves

Evaluations of oil and 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. Oil and gas reserve quantities are also used as the basis to calculate unit-of-production depreciation rates and to evaluate impairment.

Oil and gas reserves include both proved and unproved reserves. Proved oil and gas reserves are those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible. Unproved reserves are those with less than reasonable certainty of recoverability and include probable reserves. Probable reserves are reserves that are more likely to be recovered than not.

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 senior level 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.

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 gas price levels.

Revisions can include upward or downward changes in previously estimated volumes of proved reserves for existing fields due to the evaluation or revaluation of already available geologic, reservoir or production data; new geologic, reservoir or production data; or changes in 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.

Impact of oil and gas reserves on depreciation

The calculation of unit-of-production depreciation is a critical accounting estimate that measures the depreciation of upstream assets. It is the ratio of actual volumes produced to total proved reserves or proved developed reserves (those reserves recoverable through existing wells with existing equipment and operating methods) applied to the asset cost. The volumes produced and asset cost are known and, while proved reserves have a high probability of recoverability, they are based on estimates that are subject to some variability. While the revisions the company has made in the past are an indicator of variability, they have had little impact on the unit-of-production rates of depreciation.

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

Proved oil and gas properties held and used by the company are reviewed for impairment whenever events or circumstances indicate that the carrying amounts may not be recoverable. 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.

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Management s discussion and analysis of financial condition and results of operations (continued)

The company estimates the future undiscounted cash flows of the affected properties to judge the recoverability of carrying amounts. Impairment analyses are generally based on reserve estimates used for internal planning and capital investment decisions. Where probable reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the impairment evaluation. An asset group would be impaired if its undiscounted cash flows were less than the asset s carrying value. Impairments are measured by the amount by which the carrying value exceeds fair value.

Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are 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.

The company performs asset valuation analyses on an ongoing basis as a part of its asset management program. These analyses assist the company in assessing whether the carrying amounts of any of its assets may not be recoverable. In addition to estimating oil and gas reserve volumes in conducting these analyses, it is also necessary to estimate future oil and gas prices. Potential trigger events for impairment evaluations include a significant decrease in current and projected reserve volumes, an accumulation of project costs significantly in excess of the amount originally expected, and current period operating losses combined with a history or forecast of operating or cash flow losses.

In general, the company does not view temporarily low prices or margins as a triggering event for conducting the impairment tests. The markets for crude oil and natural gas have a history of significant price volatility. Although prices will occasionally drop significantly, the relative growth/decline in supply versus demand will determine industry prices over the long term, and these cannot be accurately predicted. Accordingly, any impairment tests that the company performs make use of the company s price assumptions developed in the annual planning and budgeting process for the crude oil and natural gas markets, petroleum products and chemicals. These are the same price assumptions that are used for capital investment decisions. Volumes are based on field production profiles, which are also updated annually.

Supplemental information regarding oil and gas results of operations, capitalized costs and reserves is provided following the notes to the consolidated financial statements. Future prices used for any impairment tests will vary from the one used in the supplemental oil and gas disclosure and could be lower or higher for any given year.

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 6.25 percent used in 2014 compares to actual returns of 6.90 percent and 8.80 percent achieved over the last 10- and 20-year periods ending December 31, 2014. 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 4 to the consolidated financial statements on page 62. 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 one percent of total expenses in 2014.

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 2014, the obligations were discounted

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Management s discussion and analysis of financial condition and results of operations (continued)

at six percent and the accretion expense was $105 million, before tax, which was significantly less than one 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 15 to the consolidated financial statements on page 74.

Tax contingencies

The operations of the company are complex, and related tax interpretations, regulations and legislation are continually changing. Significant management judgment is required in the accounting for income tax contingencies and tax disputes because the outcomes are often difficult to predict.

The benefits of uncertain tax positions that the company has taken or expects to take in its income tax returns are recognized in the financial statements if management concludes that it is more likely than not that the position will be sustained with the tax authorities. For a position that is likely to be sustained, the benefit recognized in the financial statements is measured at the largest amount that is greater than 50 percent likely of being realized. A reserve is established for the difference between a position taken or expected to be taken in an income tax return and the amount recognized in the financial statements. The company s unrecognized tax benefits and a description of open tax years are summarized in note 3 to the consolidated financial statements on page 61.

Recently issued accounting standards

In May 2014, the Financial Accounting Standards Board issued a new standard, *Revenue from Contracts with Customers*. The standard establishes a single revenue recognition model for all contracts with customers, eliminates industry specific requirements and expands disclosure requirements. The standard is required to be adopted beginning January 1, 2017. Imperial is evaluating the standard and its effect on the company s financial statements.

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Management s report on internal control over financial reporting

Management, including the company s chief executive officer and principal accounting officer and principal financial officer, is responsible for establishing and maintaining adequate internal control over the company s financial reporting. Management conducted an evaluation of the effectiveness of internal control over financial reporting based on criteria established in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Imperial Oil Limited s internal control over financial reporting was effective as of December 31, 2014.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the company s internal control over financial reporting as of December 31, 2014, as stated in their report which is included herein.

/s/ Richard M. Kruger

R.M. Kruger

Chairman, president and

chief executive officer

/s/ Paul J. Masschelin

P.J. Masschelin

Senior vice-president,

finance and administration, and controller

(Principal accounting officer and principal financial officer)

February 24, 2015

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Report of independent registered public accounting firm

To the Shareholders of Imperial Oil Limited

We have audited the accompanying consolidated balance sheet of Imperial Oil Limited as of December 31, 2014 and December 31, 2013 and the related consolidated statements of income, comprehensive income, shareholders equity and cash flows for each of the years in the three-year period ended December 31, 2014. In addition, we have audited Imperial Oil Limited s internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying management s report on internal control over financial reporting. Our responsibility is to express an opinion on these consolidated financial statements and an opinion on the company s internal control over financial reporting based on our integrated audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the consolidated financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall consolidated financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Imperial Oil Limited as of December 31, 2014 and December 31, 2013 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, Imperial Oil Limited maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014 based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

/s/ PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta, Canada

February 24, 2015

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Consolidated statement of income (U.S. GAAP)

millions of Canadian dollars

For the years ended December 31	**2014**	2013	2012
Revenues and other income			
Operating revenues (a)(b)	**36,231**	32,722	31,053
Investment and other income (note 8)	**735**	207	135
Total revenues and other income	**36,966**	32,929	31,188
Expenses			
Exploration	**67**	123	83
Purchases of crude oil and products (c)	**22,479**	20,155	18,476
Production and manufacturing (d)	**5,662**	5,288	4,457
Selling and general	**1,075**	1,082	1,081
Federal excise tax (a)	**1,562**	1,423	1,338
Depreciation and depletion	**1,096**	1,110	761
Financing costs (note 12)	**4**	11	(1)
Total expenses	**31,945**	29,192	26,195
Income before income taxes	**5,021**	3,737	4,993
Income taxes (note 3)	**1,236**	909	1,227
Net income	**3,785**	2,828	3,766
Per-share information (Canadian dollars)			
Net income per common share basic (note 10)	**4.47**	3.34	4.44
Net income per common share diluted (note 10)	**4.45**	3.32	4.42
Dividends per common share	**0.52**	0.49	0.48

(a) Operating revenues include federal excise tax of $1,562 million (2013 - $1,423 million, 2012 - $1,338 million).

(b) Operating revenues include amounts from related parties of $3,752 million (2013 - $2,385 million, 2012 - $2,907 million), (note 16).

(c) Purchases of crude oil and products include amounts from related parties of $3,950 million (2013 - $4,104 million, 2012 - $3,033 million), (note 16).

(d) Production and manufacturing expenses include amounts to related parties of $366 million (2013 - $319 million, 2012 - $241 million), (note 16).

The information in the Notes to Consolidated Financial Statements is an integral part of these statements.

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Consolidated statement of comprehensive income (U.S. GAAP)

millions of Canadian dollars

For the years ended December 31	**2014**	2013	2012
Net income	**3,785**	2,828	3,766
Other comprehensive income, net of income taxes			
Post-retirement benefits liability adjustment (excluding amortization)	**(483)**	529	(415)
Amortization of post-retirement benefits liability adjustment included in net periodic benefit costs	**145**	205	198
Total other comprehensive income/(loss)	**(338)**	734	(217)
Comprehensive income	**3,447**	3,562	3,549

The information in the Notes to Consolidated Financial Statements is an integral part of these statements.

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Consolidated balance sheet (U.S. GAAP)

millions of Canadian dollars

At December 31	**2014**	2013
Assets		
Current Assets		
Cash	**215**	272
Accounts receivable, less estimated doubtful amounts	**1,539**	2,084
Inventories of crude oil and products (note 11)	**1,121**	1,030
Materials, supplies and prepaid expenses	**380**	342
Deferred income tax assets (note 3)	**314**	559
Total current assets	**3,569**	4,287
Long-term receivables, investments and other long-term assets	**1,406**	1,332
Property, plant and equipment, less accumulated depreciation and depletion (note 2)	**35,574**	31,320
Goodwill	**224**	224
Other intangible assets, net	**57**	55
Total assets (note 2)	**40,830**	37,218
Liabilities		
Current liabilities		
Notes and loans payable (a)(note 12)	**1,978**	1,843
Accounts payable and accrued liabilities (b)(note 11)	**3,969**	4,518
Income taxes payable	**34**	727
Total current liabilities	**5,981**	7,088
Long-term debt (c)(note 14)	**4,913**	4,444
Other long-term obligations (d)(note 5)	**3,565**	3,091
Deferred income tax liabilities (note 3)	**3,841**	3,071
Total liabilities	**18,300**	17,694
Commitments and contingent liabilities (note 9)		
Shareholders equity		
Common shares at stated value (e)(note 10)	**1,566**	1,566
Earnings reinvested	**23,023**	19,679
Accumulated other comprehensive income	**(2,059)**	(1,721)
Total shareholders equity	**22,530**	19,524
Total liabilities and shareholders equity	**40,830**	37,218

(a) Notes and loans payable includes amounts to related parties of $75 million (2013 $75 million), (note 16).

(b) Accounts payable and accrued liabilities include amounts payable to related parties of $174 million (2013 $170 million), (note 16).

(c) Long-term debt includes amounts to related parties of $4,746 million (2013 $4,316 million), (note 16).

(d) Other long-term obligations include amounts to related parties of $96 million (2013 nil), (note 16).
(e) Number of common shares outstanding was 848 million (2013 - 848 million), (note 10).

The information in the Notes to Consolidated Financial Statements is an integral part of these statements.

Approved by the directors

/s/ Richard M. Kruger	*/s/ Paul J. Masschelin*
R.M. Kruger Chairman, president and chief executive officer	P.J. Masschelin Senior vice-president, finance and administration, and controller

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Consolidated statement of shareholders equity (U.S. GAAP)

millions of Canadian dollars

At December 31	**2014**	2013	2012
Common shares at stated value (note 10)			
At beginning of year	**1,566**	1,566	1,528
Issued under the stock option plan	**-**	-	43
Share purchases at stated value	**-**	-	(5)
At end of year	**1,566**	1,566	1,566
Earnings reinvested			
At beginning of year	**19,679**	17,266	14,031
Net income for the year	**3,785**	2,828	3,766
Share purchases in excess of stated value	**-**	-	(123)
Dividends	**(441)**	(415)	(408)
At end of year	**23,023**	19,679	17,266
Accumulated other comprehensive income			
At beginning of year	**(1,721)**	(2,455)	(2,238)
Other comprehensive income	**(338)**	734	(217)
At end of year	**(2,059)**	(1,721)	(2,455)
Shareholders equity at end of year	**22,530**	19,524	16,377

The information in the Notes to Consolidated Financial Statements is an integral part of these statements.

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Consolidated statement of cash flows (U.S. GAAP)

millions of Canadian dollars

Inflow/(outflow)

For the years ended December 31	**2014**	2013	2012
Operating activities			
Net income	**3,785**	2,828	3,766
Adjustments for non-cash items:			
Depreciation and depletion	**1,096**	1,110	761
(Gain)/loss on asset sales (note 8)	**(696)**	(150)	(94)
Deferred income taxes and other	**1,123**	482	619
Changes in operating assets and liabilities:			
Accounts receivable	**545**	(74)	300
Inventories, materials, supplies and prepaid expenses	**(129)**	(260)	(106)
Income taxes payable	**(693)**	(457)	(84)
Accounts payable and accrued liabilities	**(549)**	191	(67)
All other items - net (a)	**(77)**	(378)	(415)
Cash flows from (used in) operating activities	**4,405**	3,292	4,680
Investing activities			
Additions to property, plant and equipment	**(5,290)**	(6,297)	(5,478)
Acquisition (note 18)	**-**	(1,602)	-
Additional investments	**(123)**	-	-
Proceeds from asset sales	**851**	160	226
Repayment of loan from equity company	**-**	4	14
Cash flows from (used in) investing activities	**(4,562)**	(7,735)	(5,238)
Financing activities			
Short-term debt - net	**120**	1,371	105
Long-term debt issued	**430**	3,276	220
Reduction in capitalized lease obligations	**(9)**	(7)	(4)
Issuance of common shares under stock option plan	**-**	-	43
Common shares purchased (note 10)	**-**	-	(128)
Dividends paid	**(441)**	(407)	(398)
Cash flows from (used in) financing activities	**100**	4,233	(162)
Increase (decrease) in cash	**(57)**	(210)	(720)
Cash at beginning of year	**272**	482	1,202
Cash at end of year (b)	**215**	272	482

(a) Includes contribution to registered pension plans of $362 million (2013 - $600 million, 2012 - $594 million).

(b) Cash is composed of cash in bank and cash equivalents at cost. Cash equivalents are all highly liquid securities with maturity of three months or less when purchased.

The information in the Notes to Consolidated Financial Statements is an integral part of these statements.

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Notes to consolidated financial statements

The accompanying consolidated financial statements and the supporting and supplemental material are the responsibility of the management of Imperial Oil Limited.

The company s principal business is energy, involving the exploration, production, transportation and sale of crude oil and natural gas and the manufacture, transportation and sale of petroleum products. The company is also a major manufacturer and marketer of petrochemicals.

The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America (GAAP). 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. All amounts are in Canadian dollars unless otherwise indicated.

1. Summary of significant accounting policies

Principles of consolidation

The consolidated financial statements include the accounts of subsidiaries the company controls. Intercompany accounts and transactions are eliminated. Subsidiaries include those companies in which Imperial has both an equity interest and the continuing ability to unilaterally determine strategic, operating, investing and financing policies. Significant subsidiaries included in the consolidated financial statements include Imperial Oil Resources Limited, Imperial Oil Resources N.W.T. Limited, Imperial Oil Resources Ventures Limited and McColl-Frontenac Petroleum Inc. All of the above companies are wholly owned. The consolidated financial statements also include the company s share of the undivided interest in certain upstream assets, liabilities, revenues and expenses, including its 25 percent interest in the Syncrude joint venture and its 70.96 percent interest in the Kearl joint venture.

Inventories

Inventories are recorded at the lower of cost or current market value. The cost of crude oil and products is determined primarily using the last-in, first-out (LIFO) method. LIFO was selected over the alternative first-in, first-out and average cost methods because it provides a better matching of current costs with the revenues generated in the period.

Inventory costs include expenditures and other charges, including depreciation, directly or indirectly incurred in bringing the inventory to its existing condition and final storage prior to delivery to a customer. Selling and general expenses are reported as period costs and excluded from inventory costs.

Investments

The company s interests in the underlying net assets of affiliates it does not control, but over which it exercises significant influence, are accounted for using the equity method. They are recorded at the original cost of the investment plus Imperial s share of earnings since the investment was made, less dividends received. Imperial s share of the after-tax earnings of these investments is included in investment and other income in the consolidated statement of income. Other investments are recorded at cost. Dividends from these other investments are included in investment and other income.

These investments represent interests in non-publicly traded pipeline companies and a rail loading joint venture that facilitate the sale and purchase of liquids in the conduct of company operations. Other parties who also have an equity interest in these investments share in the risks and rewards according to their percentage of ownership. Imperial does not invest in these investments in order to remove liabilities from its balance sheet.

Property, plant and equipment

Property, plant and equipment are recorded at cost. Investment tax credits and other similar grants are treated as a reduction of the capitalized cost of the asset to which they apply.

The company uses the successful-efforts method to account for its exploration and development activities. Under this method, costs are accumulated on a field-by-field basis. Costs incurred to purchase, lease, or otherwise acquire a property (whether unproved or proved) are capitalized when incurred. Exploratory well costs are carried as an asset when the well has found a sufficient quantity of reserves to justify its completion as a producing well and where the company is making sufficient progress assessing the reserves and the

Notes to consolidated financial statements (continued)

economic and operating viability of the project. Exploratory well costs not meeting these criteria are charged to expense. Other exploratory expenditures, including geophysical costs and annual lease rentals are expensed as incurred. Development costs including costs of productive wells and development dryholes are capitalized.

Maintenance and repair costs, including planned major maintenance, are expensed as incurred. Improvements that increase or prolong the service life or capacity of an asset are capitalized.

Production involves lifting the oil and gas to the surface and gathering, treating, field processing and field storage of the oil and gas. The production function normally terminates at the outlet valve on the lease or field production storage tank. Production costs are those incurred to operate and maintain the company s wells and related equipment and facilities and are expensed as incurred. They become part of the cost of oil and gas produced. These costs, sometimes referred to as lifting costs, include such items as labour cost to operate the wells and related equipment; repair and maintenance costs on the wells and equipment; materials, supplies and energy costs required to operate the wells and related equipment; and administrative expenses related to the production activity.

Acquisition costs of proved properties are amortized using a unit-of-production method, computed on the basis of total proved oil and gas reserves. Depreciation and depletion for assets associated with producing properties begin at the time when production commences on a regular basis. Depreciation for other assets begins when the asset is in place and ready for its intended use. Assets under construction are not depreciated or depleted. Unit-of-production depreciation is applied to those wells, plant and equipment assets associated with productive depletable properties, and the unit-of-production rates are based on the amount of proved developed reserves of oil and gas. Investments in extraction and upgrading facilities at oil sands mining properties are depreciated on a unit-of-production method based on proved developed reserves. Investments in mining and transportation systems at oil sands mining properties are depreciated on a straight-line basis over a maximum of 15 years. Depreciation of other plant and equipment is calculated using the straight-line method, based on the estimated service life of the asset. In general, refineries are depreciated over 25 years; other major assets, including chemical plants and service stations, are depreciated over 20 years.

Proved oil and gas properties held and used by the company are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable. 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.

The company estimates the future undiscounted cash flows of the affected properties to judge the recoverability of carrying amounts. Cash flows used in impairment evaluations are developed using annually updated corporate plan investment evaluation assumptions for crude oil and natural gas commodity prices and foreign-currency exchange rates. Annual volumes are based on field production profiles, which are also updated annually.

Impairment analyses are generally based on reserve estimates used for internal planning and capital investment decisions. Where probable reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the impairment evaluation. An asset group would be impaired if the undiscounted cash flows were less than its carrying value. Impairments are measured by the amount the carrying value exceeds fair value.

Significant unproved properties are assessed for impairment individually and valuation allowances against the capitalized costs are recorded based on the estimated economic chance of success and the length of time 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. The valuation allowances are reviewed at least annually.

Gains or losses on assets sold are included in investment and other income in the consolidated statement of income.

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Notes to consolidated financial statements (continued)

Interest capitalization

Interest costs relating to major capital projects under construction are capitalized as part of property, plant and equipment. The project construction phase commences with the development of the detailed engineering design and ends when the constructed assets are ready for their intended use.

Goodwill and other intangible assets

Goodwill is not subject to amortization. Goodwill is tested for impairment annually or more frequently if events or circumstances indicate it might be impaired. Impairment losses are recognized in current period earnings. The evaluation for impairment of goodwill is based on a comparison of the carrying values of goodwill and associated operating assets with the estimated present value of net cash flows from those operating assets.

Intangible assets with determinable useful lives are amortized over the estimated service lives of the assets. Computer software development costs are amortized over a maximum of 15 years and customer lists are amortized over a maximum of 10 years. The amortization is included in depreciation and depletion in the consolidated statement of income.

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. These obligations primarily relate to soil reclamation and remediation and costs of abandonment and demolition of oil and gas wells and related facilities. The company uses estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an asset retirement obligation, technical assessments of the assets, estimated amounts and timing of settlements, the credit-adjusted risk-free rate to be used, and inflation rates. The obligations are initially measured at fair value and discounted to present value. A corresponding amount equal to that of the initial obligation is added to the capitalized costs of the related asset. Over time, the discounted asset retirement obligation amount will be accreted for the change in its present value, and the initial capitalized costs will be depreciated over the useful lives of the related assets.

No asset retirement obligations are set up for those manufacturing, distribution and marketing facilities 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. Provision for environmental liabilities of these assets is made when it is probable that obligations have been incurred and the amount can be reasonably estimated. Provisions for environmental liabilities are determined 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. These liabilities are not discounted.

Foreign-currency translation

Monetary assets and liabilities in foreign currencies have been translated at the rates of exchange prevailing on December 31. Any exchange gains or losses are recognized in income.

Fair value

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. Hierarchy Levels 1, 2 or 3 are terms for the priority of inputs to valuation techniques used to measure fair value. Hierarchy Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Hierarchy Level 2 inputs are inputs other than quoted prices included within Level 1 that are directly or indirectly observable for the asset or liability. Hierarchy Level 3 inputs are inputs that are not observable in the market.

Revenues

Revenues associated with sales of crude oil, natural gas, petroleum and chemical products and other items are recorded when the products are delivered. Delivery occurs when the customer has taken title and has assumed the risks and rewards of ownership, prices are fixed or determinable and collectability is reasonably assured. The company does not enter into ongoing arrangements whereby it is required to repurchase its products, nor does the company provide the customer with a right of return.

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Notes to consolidated financial statements (continued)

Revenues include amounts billed to customers for shipping and handling. Shipping and handling costs incurred up to the point of final storage prior to delivery to a customer are included in purchases of crude oil and products in the consolidated statement of income. Delivery costs from final storage to customer are recorded as a marketing expense in selling and general expenses.

Purchases and sales of inventory with the same counterparty that are entered into in contemplation of one another are combined and recorded as exchanges measured at the book value of the item sold.

Share-based compensation

The company awards share-based compensation to certain employees in the form of restricted stock units. Compensation expense is measured each reporting period based on the company s current stock price and is recorded as selling and general expenses in the consolidated statement of income over the requisite service period of each award. See note 7 to the consolidated financial statements on page 68 for further details.

Consumer taxes

Taxes levied on the consumer and collected by the company are excluded from the consolidated statement of income. These are primarily provincial taxes on motor fuels, the federal goods and services tax and the federal/provincial harmonized sales tax.

Recently issued accounting standards

In May 2014, the Financial Accounting Standards Board issued a new standard, *Revenue from Contracts with Customers*. The standard establishes a single revenue recognition model for all contracts with customers, eliminates industry specific requirements and expands disclosure requirements. The standard is required to be adopted beginning January 1, 2017. Imperial is evaluating the standard and its effect on the company s financial statements.

2. Business segments

The company operates its business in Canada. The Upstream, Downstream and Chemical functions best define the operating segments of the business that are reported separately. The factors used to identify these reportable segments are based on the nature of the operations that are undertaken by each segment and the structure of the company s internal organization. The Upstream segment is organized and operates to explore for and ultimately produce crude oil and its equivalent, and natural gas. The Downstream segment is organized and operates to refine crude oil into petroleum products and the distribution and marketing of these products. The Chemical segment is organized and operates to manufacture and market hydrocarbon-based chemicals and chemical products. The above segmentation has been the long-standing practice of the company and is broadly understood across the petroleum and petrochemical industries.

These functions have been defined as the operating segments of the company because they are the segments (a) that engage in business activities from which revenues are earned and expenses are incurred; (b) whose operating results are regularly reviewed by the company s chief operating decision maker to make decisions about resources to be allocated to each segment and assess its performance; and (c) for which discrete financial information is available.

Corporate and Other includes assets and liabilities that do not specifically relate to business segments primarily cash, capitalized interest costs, short-term borrowings, long-term debt and liabilities associated with incentive compensation and post-retirement benefits liability adjustment. Net income in this segment primarily includes debt-related financing costs, interest income and share-based incentive compensation expenses.

Segment accounting policies are the same as those described in the summary of significant accounting policies. Upstream, Downstream and Chemical expenses include amounts allocated from the Corporate and Other segment. The allocation is based on a combination of fee for service, proportional segment expenses and a three-year average of capital expenditures. Transfers of assets between segments are recorded at book amounts. Intersegment sales are made essentially at prevailing market prices. Assets and liabilities that are not identifiable by segment are allocated.

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Notes to consolidated financial statements (continued)

	Upstream			Downstream			Chemical		
millions of dollars	**2014**	2013	2012	**2014**	2013	2012	**2014**	2013	2012
Revenues and other income									
Operating revenues (a)	**8,408**	6,016	4,674	**26,400**	25,450	25,077	**1,423**	1,256	1,302
Intersegment sales	**4,087**	4,026	4,110	**1,359**	1,978	2,603	**381**	318	299
Investment and other income	**667**	145	46	**65**	59	81	**-**	-	-
	13,162	10,187	8,830	**27,824**	27,487	27,761	**1,804**	1,574	1,601
Expenses									
Exploration	**67**	123	83	**-**	-	-	**-**	-	-
Purchases of crude oil and products	**5,628**	3,778	3,056	**21,476**	21,628	21,316	**1,196**	1,065	1,115
Production and manufacturing (b)	**3,882**	3,389	2,704	**1,564**	1,695	1,569	**216**	210	185
Selling and general	**3**	5	1	**887**	886	935	**70**	66	67
Federal excise tax	**-**	-	-	**1,562**	1,423	1,338	**-**	-	-
Depreciation and depletion (b)	**857**	636	498	**216**	452	242	**12**	12	12
Financing costs (note 12)	**4**	9	(1)	**-**	2	-	**-**	-	-
Total expenses	**10,441**	7,940	6,341	**25,705**	26,086	25,400	**1,494**	1,353	1,379
Income before income taxes	**2,721**	2,247	2,489	**2,119**	1,401	2,361	**310**	221	222
Income taxes (note 3)									
Current	**(219)**	(14)	72	**296**	395	486	**76**	62	67
Deferred	**881**	549	529	**229**	(46)	103	**5**	(3)	(10)
Total income tax expense	**662**	535	601	**525**	349	589	**81**	59	57
Net income	**2,059**	1,712	1,888	**1,594**	1,052	1,772	**229**	162	165
Cash flows from (used in) operating activities	**2,519**	1,690	2,625	**1,666**	1,453	1,961	**250**	198	127
Capital and exploration expenditures (c)	**4,974**	7,755	5,518	**572**	187	140	**26**	9	4
Property, plant and equipment									
Cost	**42,142**	38,819	30,602	**7,460**	7,146	7,038	**798**	771	765

Accumulated depreciation and depletion	**(10,103)**	(10,749)	(10,146)	**(4,459)**	(4,347)	(3,967)	**(601)**	(586)	(576)
Net property, plant and equipment (d)	**32,039**	28,070	20,456	**3,001**	2,799	3,071	**197**	185	189
Total assets	**34,421**	30,553	22,317	**5,823**	5,732	6,409	**372**	397	372

	Corporate and Other			Eliminations			Consolidated		
millions of dollars	**2014**	2013	2012	**2014**	2013	2012	**2014**	2013	2012
Revenues and other income									
Operating revenues (a)	**-**	-	-	**-**	-	-	**36,231**	32,722	31,053
Intersegment sales	**-**	-	-	**(5,827)**	(6,322)	(7,012)	**-**	-	-
Investment and other income	**3**	3	8	**-**	-	-	**735**	207	135
	3	3	8	**(5,827)**	(6,322)	(7,012)	**36,966**	32,929	31,188
Expenses									
Exploration	**-**	-	-	**-**	-	-	**67**	123	83
Purchases of crude oil and products	**-**	-	-	**(5,821)**	(6,316)	(7,011)	**22,479**	20,155	18,476
Production and manufacturing (b)	**-**	-	-	**-**	(6)	(1)	**5,662**	5,288	4,457
Selling and general	**121**	125	78	**(6)**	-	-	**1,075**	1,082	1,081
Federal excise tax	**-**	-	-	**-**	-	-	**1,562**	1,423	1,338
Depreciation and depletion (b)	**11**	10	9	**-**	-	-	**1,096**	1,110	761
Financing costs (note 12)	**-**	-	-	**-**	-	-	**4**	11	(1)
Total expenses	**132**	135	87	**(5,827)**	(6,322)	(7,012)	**31,945**	29,192	26,195
Income before income taxes	**(129)**	(132)	(79)	-	-	-	**5,021**	3,737	4,993
Income taxes (note 3)									
Current	**(47)**	(18)	(32)	**-**	-	-	**106**	425	593
Deferred	**15**	(16)	12	**-**	-	-	**1,130**	484	634
Total income tax expense	**(32)**	(34)	(20)	**-**	-	-	**1,236**	909	1,227
Net income	**(97)**	(98)	(59)	**-**	-	-	**3,785**	2,828	3,766
Cash flows from (used in) operating activities	**(30)**	(49)	(33)	**-**	-	-	**4,405**	3,292	4,680
Capital and exploration expenditures (c)	**82**	69	21	**-**	-	-	**5,654**	8,020	5,683

Property, plant and equipment									
Cost	**511**	429	360	**-**	-	-	**50,911**	47,165	38,765
Accumulated depreciation and depletion	**(174)**	(163)	(154)	**-**	-	-	**(15,337)**	(15,845)	(14,843)
Net property, plant and equipment (d)	**337**	266	206	**-**	-	-	**35,574**	31,320	23,922
Total assets	**565**	581	704	**(351)**	(45)	(438)	**40,830**	37,218	29,364

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Notes to consolidated financial statements (continued)

(a) Includes export sales to the United States of $5,940 million (2013 - $5,217 million, 2012 - $4,358 million). Export sales to the United States were recorded in all operating segments, with the largest effects in the Upstream segment.
(b) A 2013 charge in the Downstream segment of $377 million ($280 million, after-tax) associated with the company s decision to convert the Dartmouth refinery to a terminal included the write-down of refinery plant and equipment not included in the terminal conversion of $245 million, reported as part of depreciation and depletion expenses, and decommissioning, environmental and employee-related costs of $132 million, reported as part of production and manufacturing expenses. By the end of 2014, amounts incurred associated with decommissioning, environmental and employee-related costs totalled $90 million.
(c) Capital and exploration expenditures (CAPEX) include exploration expenses, additions to property, plant and equipment, additions to capital leases, additional investments and acquisitions.
(d) Includes property, plant and equipment under construction of $12,535 million (2013 - $9,234 million).

3. Income taxes

millions of dollars	**2014**	2013	2012
Current income tax expense	**106**	425	593
Deferred income tax expense (a)	**1,130**	484	634
Total income tax expense (b)	**1,236**	909	1,227
Statutory corporate tax rate (percent)	**25.5**	25.4	25.5
Increase/(decrease) resulting from:			
Enacted tax rate change	**-**	-	-
Other	**(0.9)**	(1.1)	(0.9)
Effective income tax rate	**24.6**	24.3	24.6

(a) There were no material net (charges)/credits for the effect of changes in tax laws and rates included in the provisions for deferred income taxes in 2014, 2013 and 2012.
(b) Cash outflow from income taxes, plus investment credits earned, was $811 million in 2014 (2013 $911 million, 2012 $871 million).

Deferred income taxes are based on differences between the accounting and tax values of assets and liabilities. These differences in value are re-measured at each year-end using the tax rates and tax laws expected to apply when those differences are realized or settled in the future. Components of deferred income tax liabilities and assets as at December 31 were:

millions of dollars	**2014**	2013	2012
Depreciation and amortization	**3,777**	2,949	2,434
Successful drilling and land acquisitions	**827**	815	399
Pension and benefits	**(438)**	(376)	(717)
Site restoration	**(304)**	(287)	(284)
Capitalized interest	**82**	69	53
Other	**(103)**	(99)	39
Net long-term deferred income tax liabilities	**3,841**	3,071	1,924

LIFO inventory valuation	**(201)**	(450)	(478)
Other	**(113)**	(109)	(49)
Net current deferred income tax assets	**(314)**	(559)	(527)
Valuation allowance	**-**	-	-
Net deferred income tax liabilities	**3,527**	2,512	1,397

Notes to consolidated financial statements (continued)

Unrecognized tax benefits

Unrecognized tax benefits reflect the difference between positions taken or expected to be taken on income tax returns and the amounts recognized in the financial statements.

The following table summarizes the movement in unrecognized tax benefits:

millions of dollars	**2014**	2013	2012
Balance as at January 1	**151**	143	134
Additions based on current year s tax position	**4**	10	4
Additions for prior years tax positions	**-**	2	10
Reductions for prior years tax positions	**(4)**	(4)	(3)
Reductions due to lapse of the statute of limitations	**-**	-	(2)
Balance as at December 31	**151**	151	143

The unrecognized tax benefit balances shown above are predominately related to tax positions that would reduce the company s effective tax rate if the positions are favourably resolved. Unfavourable resolution of these tax positions generally would not increase the effective tax rate. The 2014, 2013 and 2012 changes in unrecognized tax benefits did not have a material effect on the company s net income. The company s tax filings from 2007 to 2014 are subject to examination by the tax authorities. The Canada Revenue Agency has proposed certain adjustments to the company s filings. Management is currently evaluating those proposed adjustments and believes that a number of outstanding matters are expected to be resolved in 2015. The impact on unrecognized tax benefits and the company s effective income tax rate from these matters is not expected to be material.

Resolution of the related tax positions will take many years to complete. It is difficult to predict the timing of resolution for tax positions, since such timing is not entirely within the control of the company.

The company classifies interest on income tax related balances as interest expense or interest income and classifies tax related penalties as operating expense.

4. Employee retirement benefits

Retirement benefits, which cover almost all retired employees and their surviving spouses, include pension income and certain health care and life insurance benefits. They are met through funded registered retirement plans and through unfunded supplementary benefits that are paid directly to recipients.

Pension income benefits consist mainly of company-paid defined benefit plans that are based on years of service and final average earnings. The company shares in the cost of health care and life insurance benefits. The company s benefit obligations are based on the projected benefit method of valuation that includes employee service to date and present compensation levels as well as a projection of salaries to retirement.

The expense and obligations for both funded and unfunded benefits are determined in accordance with accepted actuarial practices and United States generally accepted accounting principles. The process for determining retirement-income expense and related obligations includes making certain long-term assumptions regarding the discount rate, rate of return on plan assets and rate of compensation increases. The obligation and pension expense can vary significantly with changes in the assumptions used to estimate the obligation and the expected return on plan assets.

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Notes to consolidated financial statements (continued)

The benefit obligations and plan assets associated with the company s defined benefit plans are measured on December 31.

	Pension benefits		Other post-retirement benefits	
	2014	2013	**2014**	2013
Assumptions used to determine benefit obligations at December 31 (percent)				
Discount rate	**3.75**	4.75	**3.75**	4.75
Long-term rate of compensation increase	**4.50**	4.50	**4.50**	4.50
millions of dollars				
Change in projected benefit obligation				
Projected benefit obligation at January 1	**6,870**	7,336	**503**	547
Current service cost	**152**	181	**9**	11
Interest cost	**322**	281	**26**	21
Actuarial loss/(gain)	**1,083**	(504)	**123**	(50)
Amendments	**-**	-	**-**	-
Benefits paid (a)	**(457)**	(424)	**(27)**	(26)
Projected benefit obligation at December 31	**7,970**	6,870	**634**	503
Accumulated benefit obligation at December 31	**7,292**	6,263		

The discount rate for calculating year-end post-retirement liabilities is based on the yield for high-quality, long-term Canadian corporate bonds at year-end with an average maturity (or duration) approximately that of the liabilities. The measurement of the accumulated post-retirement benefit obligation assumes a health care cost trend rate of 4.50 percent in 2015 and subsequent years.

	Pension benefits		Other post-retirement benefits	
millions of dollars	**2014**	2013	**2014**	2013
Change in plan assets				
Fair value at January 1	**5,872**	5,114		
Actual return/(loss) on plan assets	**923**			