IMPERIAL OIL LTD
Form 10-K
February 26, 2014
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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, 2013 **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 2013 second fiscal quarter, the aggregate market value of the voting stock held by non-affiliates of the registrant was Canadian $10,345,478,926 based upon the reported last sale price of such stock on the Toronto Stock Exchange on that date.

The number of common shares outstanding, as of February 13, 2014, 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	**2013**	2012	2011	2010	2009
Rate at end of period	**0.9348**	1.0042	0.9835	0.9991	0.9559
Average rate during period	**0.9665**	1.0006	1.0144	0.9659	0.8793
High	**1.0164**	1.0299	1.0584	1.0040	0.9719
Low	**0.9348**	0.9600	0.9430	0.9280	0.7695

On February 13, 2014, 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 $0.9108 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 .

On February 26, 2013, ExxonMobil Canada acquired Celtic Exploration Ltd. (Celtic). Immediately following the acquisition, Imperial acquired a 50 percent interest in Celtic s assets and liabilities from ExxonMobil Canada for $1.6 billion, financed by a combination of related party and third party debt. Concurrently, a general partnership was formed to hold and operate the assets of Celtic. The name of the general partnership was changed to XTO Energy Canada (XTO Canada). XTO Canada is involved in the exploration for, production of, and transportation and sale of natural gas and crude oil, condensate and natural gas liquids. Details of the transaction are contained in the Financial section of this report under note 18 to the consolidated financial statements: Acquisition . The company s share of financial results and operating information, including reserves, volumes, wells and acreage relating to XTO Canada, are included for the first time in 2013.

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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, 2013, as detailed in the Supplemental information on oil and gas exploration and production activities part of the Financial section, starting on page 31 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, 2013 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	**55**	**368**	**579**	**1,417**	**2,113**
Undeveloped	**7**	**310**	**-**	**1,450**	**1,509**
Total net proved	**62**	**678**	**579**	**2,867**	**3,622**

(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 2013 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 2-D and 3-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.

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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 containing the official company reserves estimates and production data. 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 Engineering Manager is a professional engineer registered in Alberta, Canada and has over 25 years of petroleum industry experience, including 20 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 60 persons with an average of 16 years of relevant technical experience in evaluating reserves, of whom 38 persons are qualified reserves evaluators for purposes of Canadian securities regulatory requirements. The company s internal reserves evaluation management team is made up of 16 persons with an average of 12 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, 2013, approximately 42 percent of the company s proved reserves were proved undeveloped reserves reflecting volumes of 1,509 million oil-equivalent barrels. Nearly all of those undeveloped reserves are associated with either the Kearl project or Cold Lake field. This compared to approximately 65 percent or 2,318 million oil-equivalent barrels of proved undeveloped reserves reported at the end of 2012. Decreased proved undeveloped bitumen reserves in 2013 were largely due to the start-up of the initial development at Kearl in the second quarter, resulting in a migration of proved undeveloped reserves to proved developed. Increased proved undeveloped liquids and natural gas reserves were primarily associated with the company s share of reserves from the Celtic acquisition in 2013.

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 $4.5 billion during the year to progress the development of reported proved undeveloped reserves. The largest project under development in 2013 was the Kearl project. Production from the initial development commenced in the second quarter of 2013. By 2013 year-end, the Kearl expansion project was 72 percent complete and remains on target for a 2015 start-up.

Proved undeveloped reserves at Cold Lake are associated with the ongoing drilling program and the Nabiye project. Imperial moved 19 million oil-equivalent barrels from proved undeveloped to proved developed reserves at Cold Lake through ongoing drilling programs. By 2013 year-end, the Nabiye project was 65 percent complete. Target start-up, although under pressure, remains year-end 2014.

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 35 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, 2013 was as follows. All reported production volumes were from Canada.

thousands of barrels per day		**2013**	2012	2011
Bitumen (a):	- gross (b)	**169**	154	160
	- net (c)	**142**	123	120
Synthetic oil (d):	- gross (b)	**67**	72	72
	- net (c)	**65**	69	67
Liquids:	- gross (b)	**25**	24	23
	- net (c)	**20**	18	17
Total:	- gross (b)	**261**	250	255
	- net (c)	**227**	210	204

(a) 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 (16,000 barrels per day gross, 15,000 net).
(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 sales of natural gas

The company s average daily production and sales of natural gas during the three years ended December 31, 2013 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 35 of this report for a narrative discussion on the material changes.

millions of cubic feet per day	**2013**	2012	2011
Gross production (a) (b)	**201**	192	254
Net production (b) (c)	**189**	195	228
Sales (d)	**167**	177	237

(a) Gross production is the company s share of production (excluding purchases) before deduction of the mineral owners or governments share or both.
(b) Production of natural gas includes amounts used for internal consumption with the exception of the amounts reinjected.
(c)

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.

(d) Includes sales of the company s share of production (before deduction of the mineral owners and/or governments share) and sales of gas purchased, processed and/or resold. Sales of natural gas exclude amounts used for internal consumption.

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	**2013**	2012	2011
Total production oil-equivalent basis:			
- gross (a)	**295**	282	297
- net (b)	**259**	243	242

(a) Gross production is the company s share of production (excluding purchases) before deduction of the mineral owners or governments share or both.

(b) Net production is gross production less the mineral owners or governments share or both.

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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, 2013, were as follows.

dollars per barrel	**2013**	2012	2011
Liquids	**75.61**	71.52	77.34
Synthetic oil	**99.69**	92.48	101.43
Bitumen	**60.57**	59.76	63.95
dollars per thousand cubic feet			
Natural gas	**3.27**	2.33	3.59

Average unit production costs

dollars per barrel	**2013**	2012	2011
Synthetic oil	**53.27**	48.41	48.33
Bitumen	**32.20**	21.98	19.30
Total oil-equivalent basis (a)	**35.93**	29.10	26.63

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

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.

In 2012, unit production costs increased on a net basis primarily due to pre start-up costs associated with the Kearl initial development.

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, 2013.

wells	**2013**	2012	2011
Net productive exploratory	**1**	1	3
Net dry exploratory	**1**	-	-
Net productive development	**157**	39	96
Net dry development	**-**	-	-
Total	**159**	40	99

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.

In 2012, the following wells were drilled to add productive capacity: 28 bitumen 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.

In 2011, the following wells were drilled to add productive capacity: 34 bitumen development wells in undeveloped areas of existing phases at Cold Lake, 60 gas development wells in the shallow gas area and two net tight oil wells in the company s existing conventional acreage.

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Wells drilling

At December 31, 2013, the company was participating in the drilling of the following exploratory and development wells. All wells were located in Canada.

	2013	
wells	Gross	Net
Total	**85**	**78**

Exploratory and development activities regarding oil and gas resources

Cold Lake

In February 2012, the Nabiye expansion at Cold Lake was sanctioned. The expansion is expected to ultimately bring on additional production of 40,000 barrels per day, before royalties. The expansion was 65 percent complete by 2013 year-end. During the fourth quarter of 2013, plant construction progressed somewhat slower than planned due to lower contractor productivity and harsh winter conditions. Target start-up, although under pressure, remains year-end 2014.

To maintain production at Cold Lake, additional wells were drilled on existing phases in 2013. In 2014, a development drilling program is planned within the approved development area to add productive capacity from undeveloped areas of existing Cold Lake phases.

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 costs 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 s interest in its 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, and continued community consultations. No final investment decision has been made.

The company s share of the total work commitment for the Beaufort Sea licence is $441 million.

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Other oil sands activity

In the third quarter of 2013, the company (27.5 percent) and ExxonMobil Canada (72.5 percent) acquired an interest in the Clyden oil sands lease, 150 kilometres south of Fort McMurray, Alberta. The 226,000 gross acre lease is amenable to in-situ recovery techniques.

The company filed a regulatory application for a new in-situ oil sands project at Aspen (south of Kearl) in December 2013. Steam-assisted gravity drainage (SAGD) technology would be used to develop the project in three phases of 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 Grand Rapids and Corner 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. 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 project is located approximately 75 kilometres north of Fort McMurray, Alberta.

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 was 72 percent complete at the end of 2013. The Kearl expansion project remains on schedule for a 2015 start-up and is expected to produce 110,000 barrels of bitumen per day, before royalties, of which the company s share would 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 by about 2020, of which the company s share would be about 245,000 barrels per day.

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

During 2013, average net production at Cold Lake was about 127,000 barrels per day and gross production was about 153,000 barrels per day.

Most of the production from Cold Lake is 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.

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. Royalty rates are based upon a sliding scale determined 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 throughout the remainder of the year. 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. Also in the fourth quarter, sales to unrelated third parties commenced as planned. During 2013, average gross production at Kearl was about 23,000 barrels per day (16,000 barrels per day Imperial s share).

The Province of Alberta, in its capacity as lessor of Kearl oil sands leases, is entitled to a royalty on production at Kearl. Royalty rates are based upon a sliding scale determined 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 the crude bitumen, and to produce a high-quality, light (32 degree API), sweet, synthetic crude oil. The Syncrude operation, located near Fort McMurray, Alberta, mines a portion of the Athabasca oil sands deposit. The produced synthetic crude oil is shipped from the Syncrude site to Edmonton, Alberta by Alberta Oil Sands Pipeline Ltd.

In 2013, the company s share of Syncrude s net production of synthetic crude oil was about 65,000 barrels per day and gross production was about 67,000 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 and currently accounts for about 50 percent of the company s gross production of conventional crude oil. In 2013, gross production of conventional crude oil from Norman Wells was about 11,000 barrels per day.

In 2013, the company commenced marketing of 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, 2013 and December 31, 2012, 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, 2013				Year-ended December 31, 2012			
	Crude oil		Natural gas		Crude oil		Natural gas	
wells	Gross (a)	Net (b)	Gross (a)	Net (b)	Gross (a)	Net (b)	Gross (a) (c)	Net (b) (c)
Total (d)	**5,207**	**4,847**	**3,615**	**1,235**	5,036	4,736	3,328	1,140

(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) Natural gas wells in 2012 reflect revised numbers from properties operated by others.
(d) Multiple completion wells are permanently equipped to produce separately from two or more distinctly different geological formations. At year-end 2013, the company had an interest in four gross wells with multiple completions (2012 - four gross wells).

The total number of wells increased in 2013 primarily due to the acquisition of a 50 percent interest in Celtic s assets and liabilities.

Land holdings

At December 31, 2013 and 2012, the company held the following oil and gas rights, 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		**2013**	2012	**2013**	2012	**2013**	2012
Western provinces:							
Liquids and gas (a)	- gross (b)	**2,337**	2,127	**1,312**	658	**3,649**	2,785
	- net (c)	**764**	687	**662**	359	**1,426**	1,046
Bitumen (a)	- gross (b)	**156**	103	**737**	606	**893**	709
	- net (c)	**130**	103	**370**	345	**500**	448
Synthetic oil	- gross (b)	**118**	118	**135**	135	**253**	253
	- net (c)	**29**	29	**34**	34	**63**	63
Canada lands (d):							
Liquids and gas	- gross (b)	**4**	4	**2,272**	2,314	**2,276**	2,318
	- net (c)	**2**	2	**718**	722	**720**	724
Atlantic offshore:							
Liquids and gas	- gross (b)	**65**	65	**288**	1,780	**353**	1,845
	- net (c)	**6**	6	**46**	270	**52**	276

Total (e):	- gross (b)	**2,680**	2,417	**4,744**	5,493	**7,424**	7,910
	- net (c)	**931**	827	**1,830**	1,730	**2,761**	2,557

(a) Land holdings associated with the acquisition of the Celtic assets in February 2013 are primarily included within western provinces liquids and gas acreage and at 2013 year-end totalled about 191,000 gross developed acres (about 67,000 net developed) and about 694,000 gross undeveloped acres (about 315,000 net undeveloped). Land holdings associated with the acquisition of Celtic assets included in bitumen are de minimis.

(b) Gross acres include the interests of others.

(c) Net acres exclude the interests of others.

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

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

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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, acquired by the company in 2013. 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 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 1,426,000 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. Crude oil and natural gas acreage increased in 2013, largely due to the acquisition of the Celtic assets in February 2013.

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 acreage in the Beaufort Sea of about 252,000 net acres, the Summit Creek area of central Mackenzie Valley totalling about 222,000 net acres and the Mackenzie Delta of about 181,000 net acres.

Exploration licences on Canada lands and Atlantic offshore have a finite term. If a significant discovery is made, a significant discovery licence (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

In 2013, the company assigned its land holdings in the Orphan Basin area totalling about 224,000 net acres to an unrelated third party.

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

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Downstream

Supply

To supply the requirements of its own refineries and condensate requirements for blending with crude bitumen, the company supplements its own production with substantial purchases from others.

The company purchases domestic crude oil at freely negotiated prices from a number of sources. Domestic purchases of crude oil are generally made under renewable contracts with 30 to 60 day cancellation terms.

When required, crude oil from foreign sources is purchased by the company at market prices mainly through Exxon Mobil Corporation (which has beneficial access to major market sources of crude oil throughout the world). Following the conversion of the Dartmouth refinery to a fuels terminal, crude oil from foreign sources is anticipated to decline significantly.

Transportation

Imperial currently transports about 400,000 barrels per day by pipeline and has secured an additional 390,000 barrels per day capacity on 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 200,000 barrels per day over the next several years. These transportation capacities are primarily to ship crude oil.

Refining

The company owns and operates three refineries. The Strathcona and Sarnia refineries process Canadian crude oil and the Nanticoke refinery processes a combination of Canadian and foreign 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 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.

In 2013, capital expenditures of about $82 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, 2013, and the daily rated capacities of the refineries as at December 31, 2013 were as follows.

	Refinery throughput (a) Year-ended December 31			Rated capacities (b) at December 31
thousands of barrels per day	**2013**	2012	2011	**2013**
Strathcona, Alberta	**172**	163	169	**189**

Sarnia, Ontario	**105**	103	102	**119**
Nanticoke, Ontario	**99**	99	93	**113**
Dartmouth, Nova Scotia (c) (d)	**50**	70	66	**n/a**
Total	**426**	435	430	**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 2013, refinery throughput was 88 percent of capacity, two percent higher than the previous year. The higher rate was primarily a result of increased product sales and reduced maintenance activities. Capacity utilization in 2013 is calculated based on the number of days the refineries were operated as a refinery.

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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 company continues to improve its Esso retail service station network, providing more customer services such as car washes and convenience stores, primarily at high volume sites in urban centres.

The Canadian agriculture, residential heating and small commercial markets are served by about 28 branded resellers. The company also sells petroleum products to large industrial and commercial accounts as well as to other refiners and marketers.

The approximate daily volumes of net petroleum products (excluding purchases/sales contracts with the same counterparty) sold during the three years ended December 31, 2013, are set out in the following table.

thousands of barrels per day	**2013**	2012	2011
Gasolines	**223**	221	220
Heating, diesel and jet fuels	**160**	151	157
Heavy fuel oils	**29**	30	29
Lube oils and other products	**42**	43	41
Net petroleum product sales	**454**	445	447

Total Downstream capital expenditures were $187 million in 2013.

Chemical

The company s Chemical operations manufacture and market ethylene, benzene, aromatic and aliphatic solvents, plasticizer intermediates and polyethylene resin. Its major petrochemical and polyethylene manufacturing operations are located in Sarnia, Ontario, adjacent to the company s petroleum refinery. As part of the decision to convert the Dartmouth refinery to a fuels terminal, the heptene and octene plant located at Dartmouth was shut down.

Progress continued on the infrastructure required to implement a long-term supply agreement for ethane from the nearby Marcellus shale gas development. First deliveries of this feedstock to the Sarnia chemical plant are expected in the first quarter of 2014.

The company s total sales volumes of petrochemicals during the three years ended December 31, 2013, were as follows.

thousands of tonnes	**2013**	2012	2011
Total sales of petrochemicals	**940**	1,044	1,016

Lower sales volumes in 2013 were primarily due to lower manufacturing as a result of the plant shutdown at Dartmouth noted above and lower ethylene feed availability.

Capital expenditures in 2013 were $9 million.

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Research

In 2013, the company s total gross research expenditures, before credits, were about $199 million, as compared with $201 million in 2012, and $163 million in 2011. Research expenditures are mainly for developing technologies to reduce the environmental impact and improve bitumen recovery in the Upstream and for supporting environmental and process improvements in the refineries, as well as accessing ExxonMobil s data 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 is concerned with and active in protecting the environment in connection with its various operations. 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 $4.7 billion on environmental protection and facilities. In 2013, the company s environmental capital and operating expenditures totalled approximately $1.5 billion, which was spent primarily on air emissions reductions, water and tailings treatment 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 2014.

Human resources

Career employees (a)	**2013**	2012	2011
Total	**5,300**	5,100	4,900

(a) 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 2013 is primarily associated with start-up of the Kearl oil sands project. About eight 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 2013 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.

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 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.

Competitive factors

The oil and gas industry is highly competitive, particularly in the following areas: searching for and developing new sources of supply; constructing and operating crude oil, natural gas and refined products pipelines and facilities; and the refining, distribution and marketing of petroleum products and chemicals. The company s competitors include major integrated oil and gas companies and numerous other independent oil and gas companies. The petroleum industry also competes with other industries in supplying energy, fuel and related products to customers.

Competitive forces may result in shortages of prospects to drill, services to carry out exploration, development or operating activities and infrastructure to produce and transport production. It may also result in an oversupply of crude oil, natural gas, petroleum products and chemicals. Each of these factors could have a negative impact on costs and prices and, therefore, the company s financial results.

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, 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.

Climate change

The Government of Canada has confirmed its intent to introduce a set of regulations to limit emissions of greenhouse gas and air pollutants from major industrial facilities in Canada and to align Canadian policy in this area with that of the U.S. As these policies and potential regulations remain under development, attempts to assess the impact on the company are premature.

In the Province of Alberta, regulations governing greenhouse gas emissions from large industrial facilities came into effect in 2007. The regulation requires a reduction by 12 percent in the greenhouse gas emissions per unit of production from each facility s average annual intensity. Allowed compliance measures include participation in an Alberta emission-trading system or payment to Alberta s Climate Change and Emissions Management Fund. The impact on the company has not been material.

The Province of British Columbia has established a carbon tax, applicable to purchases of hydrocarbon fuels and emissions of greenhouse gases. The impact on the company has not been material.

The Province of Quebec has implemented a cap-and-trade system which will regulate greenhouse gas emissions from transportation and heating sources in 2015. The impact on the company is not anticipated to be material.

The Province of Ontario has passed legislation authorizing the issuing of regulations for the creation of a provincial cap-and-trade system controlling greenhouse gas emissions. Details on such possible regulations have not been issued so an assessment of impacts is premature.

The Province of British Columbia s Renewable and Low Carbon Fuel Requirement Regulation requires suppliers of transportation fuels to reduce the carbon intensity of fuels sold in the province by an increasing amount over time. To date, there has not been a significant impact to the company s operations.

Further federal, provincial or international legislation or regulation controlling greenhouse gas emissions could occur. Such requirements could make our products more expensive; lengthen project implementation times; reduce demand for hydrocarbons and shift hydrocarbon demand toward relatively lower-carbon sources, such as natural gas; and may result in increased capital expenditures and operating costs. Such requirements may have a material adverse effect on the company s financial condition or results of operations, but this cannot be estimated at this time.

Other regulatory risk

The company is subject to a wide range of legislation and regulation governing its operations and industry transportation infrastructure, over which it has no control. Changes may affect every aspect of the company s operations and financial performance. In addition, the company s longer-term development plans may be adversely affected if, for regulatory or other reasons, necessary additional transportation infrastructure is not added in a timely fashion.

Need to replace reserves

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. The business of exploring for, developing or acquiring reserves is capital intensive. 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

To maintain our competitive position, especially in light of the technological nature of our business and the need for continuous efficiency improvement, the research and development organizations of the company and ExxonMobil, with whom the company conducts shared research, must be successful and able to adapt to a changing market and policy environment.

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 and continuous focus to workplace safety and to avoiding spills or other adverse environmental events. For example, we work to minimize spills through 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. The company s insurance may not provide adequate coverage in certain unforeseen circumstances.

Operational efficiency

An important component of the company s competitive performance, especially given the commodity-based nature of many of our business segments, is our ability to operate efficiently, including our ability to manage expenses and improve production yields on an ongoing basis. This requires continuous management focus, including technology improvements, cost control, productivity enhancements, regular reappraisal of our asset portfolio, and the recruitment, development and retention of high caliber employees.

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 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.

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Uncertainty of 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 86 of this report. The closing price for Imperial Oil Limited common shares on the Toronto Stock Exchange was $47.27 as at February 13, 2014.

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.

	2013				2012			
dollars	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Declared dividend per share:	**0.13**	**0.12**	**0.12**	**0.12**	0.12	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 13, 2014 there were 12,215 holders of record of common shares of the company.

During the period October 1, 2013 to December 31, 2013, there were no shares issued by the company to employees or former employees outside the U.S. under its restricted stock unit plan.

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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 87. 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 133 of this report; and

entitled Equity compensation plan information , within the Compensation discussion and analysis section , on page 139 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 (or approximate dollar value) of shares that may yet be purchased under the plans or programs (a)
October 2013 (October 1 October 31)	-	-	-	**1,000,000**
November 2013 (November 1 - November 30)	-	-	-	**1,000,000**
December 2013 (December 1 - December 31)	-	-	-	**1,000,000**

(a) On June 21, 2013, 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, 2013 to June 24, 2014. Unlike prior programs, this maximum amount is not reduced by common shares purchased for the company s employee savings plan, the company s employee retirement plan and from Exxon Mobil Corporation. If not previously terminated, the program will end on June 24, 2014.

Item 6. Selected financial data

millions of dollars	**2013**	2012	2011	2010	2009
Operating revenues	**32,722**	31,053	30,474	24,946	21,292
Net income	**2,828**	3,766	3,371	2,210	1,579
Total assets at year-end	**37,218**	29,364	25,429	20,580	17,473
Long-term debt at year-end	**4,444**	1,175	843	527	31
Total debt at year-end	**6,287**	1,647	1,207	756	140
Other long-term obligations at year-end	**3,091**	3,983	3,876	2,753	2,839
dollars					
Net income per share basic	**3.34**	4.44	3.98	2.61	1.86
Net income per share diluted	**3.32**	4.42	3.95	2.59	1.84
Dividends declared	**0.49**	0.48	0.44	0.43	0.40

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 35 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 48 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 31 of this report:

Consolidated financial statements, together with the report thereon of PricewaterhouseCoopers LLP (PwC) dated February 25, 2014 beginning with the section entitled Report of independent registered public accounting firm on page 54 and continuing through note 18, Acquisition on page 81;

Supplemental information on oil and gas exploration and production activities (unaudited) starting on page 82; and

Quarterly financial and stock trading data (unaudited) on page 86.

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, 2013. 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 53 of this report for Management s report on internal control over financial reporting and page 54 for the Report of independent registered public accounting firm on the company s internal control over financial reporting as of December 31, 2013.

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 87. 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 88 to 96 of this report have been nominated for election at the annual meeting of shareholders to be held April 24, 2014. All of the nominees are directors and have been since the dates indicated. Bruce H. March announced his resignation as a director and as chairman, president and chief executive officer effective March 1, 2013. Richard M. Kruger was elected as a director and as chairman, president and chief executive officer effective March 1, 2013.

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

Director information , on pages 88 to 96 of this report;

The table entitled Audit committee under Board and committee structure , on page 102 of this report; and

Other public company directorships , on page 110 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 116 and page 117 of this report.

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

Largest shareholder , on page 141 of this report; and

Ethical business conduct , starting on page 143 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 87. 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 , on page 109 of this report; and

Directors compensation program , on pages 111 to 115 of this report.

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

Report of executive resources committee on executive compensation , starting on page 118 of this report; and

Compensation discussion and analysis , on pages 120 to 140 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 87. 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 139 of this report.

Reference is made to the section under V. Other important information entitled Largest shareholder , on page 141 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 13, 2014, P.J. Masschelin was the owner of 1,000 common shares of the company and held 77,800 restricted stock units of the company. T.G. Scott was the owner of 10,000 common shares of the company and held 77,275 restricted stock units of the company. B.W. Livingston was the owner of 30,091 common shares of the company and held 112,250 restricted stock units of the company. B.G. Merkel was the owner of 4,866 common shares of the company and held 72,100 restricted stock units of the company.

The directors and the executive officers of the company, whose compensation for the year-ended December 31, 2013 is described in the sections under III. Board of directors starting on page 88 and IV. Company executives and executive compensation starting on page 116, consist of 15 persons, who, as a group, own beneficially 123,442 common shares of the company, being approximately 0.01 percent of the total number of outstanding shares of the company, and 544,460 shares of Exxon Mobil Corporation (including 453,100 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 344,450 common shares of the company, as of February 13, 2014.

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 87. 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 141 of this report.

Reference is made to the section under III. Board of directors entitled Independence of the directors , on page 99 of this report.

D.W. Woods 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 and Supply Company, D.W. Woods 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 87. 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 142 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 31 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)).

(4) The company s long-term debt authorized under any instrument does not exceed 10 percent of the company s consolidated assets. The company agrees to furnish to the Commission upon request a copy of any such instrument.

(10) (ii) (1) Alberta Crown Agreement, dated February 4, 1975, relating to the participation of the Province of Alberta in Syncrude (Incorporated herein by reference to Exhibit 13(a) 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) Amendment to Alberta Crown Agreement, dated January 1, 1983 (Incorporated herein by reference to Exhibit (10)(ii)(2) of the company s Annual Report on Form 10-K for the year ended December 31, 1983 (File No. 2-9259)).

(3) 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)).

(4) 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)).

(5) Norman Wells Pipeline Agreement, dated January 1, 1980, relating to the operation, tolls and financing of the pipeline system from the Norman Wells field (Incorporated herein by reference to Exhibit 10(a)(3) of the company s Annual Report on Form 10-K for the year ended December 31, 1981 (File No. 2-9259)).

(6) Norman Wells Pipeline Amending Agreement, dated April 1, 1982 (Incorporated herein by reference to Exhibit (10)(ii)(5) of the company s Annual Report on Form 10-K for the year ended December 31, 1982 (File No. 2-9259)).

(7) Letter Agreement clarifying certain provisions to the Norman Wells Pipeline Agreement, dated August 29, 1983 (Incorporated herein by reference to Exhibit (10)(ii)(7) of the company s Annual Report on Form 10-K for the year ended December 31, 1983 (File No. 2-9259)).

(8) Norman Wells Pipeline Amending Agreement, made as of February 1, 1985, relating to certain amendments ordered by the National Energy Board (Incorporated herein by reference to Exhibit (10)(ii)(8) of the company s Annual Report on Form 10-K for the year ended December 31, 1986 (File No. 0-12014)).

(9) Norman Wells Pipeline Amending Agreement, made as of April 1, 1985, relating to the definition of Operating Year (Incorporated herein by reference to Exhibit (10)(ii)(9) of the company s Annual

Report on Form 10-K for the year ended December 31, 1986 (File No. 0-12014)).

(10) Norman Wells Expansion Agreement, dated October 6, 1983, relating to the prices and royalties payable for crude oil production at Norman Wells (Incorporated herein by reference to Exhibit (10)(ii)(8) of the company s Annual Report on Form 10-K for the year ended December 31, 1983 (File No. 2-9259)).

(11) 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)).

(12) Amendment to Alberta Crown Agreement, dated January 1, 1986 (Incorporated herein by reference to Exhibit (10)(ii)(12) of the company s Annual Report on Form 10-K for the year ended December 31, 1987 (File No. 0-12014)).

(13) Amendment to Alberta Crown Agreement, dated November 25, 1987 (Incorporated herein by reference to Exhibit (10)(ii)(13) of the company s Annual Report on Form 10-K for the year ended December 31, 1987 (File No. 0-12014)).

(14) 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)).

(15) Amendment to Alberta Crown Agreement, dated August 1, 1991 (Incorporated herein by reference to Exhibit (10)(ii)(15) of the company s Annual Report on Form 10-K for the year ended December 31, 1991 (File No. 0-12014)).

(16) Norman Wells Settlement Agreement, dated July 31, 1996. (Incorporated herein by reference to Exhibit (10)(ii)(16) of the company s Annual Report on Form 10-K for the year ended December 31, 1996 (File No. 0-12014)).

(17) Amendment to Alberta Crown Agreement, dated January 1, 1997. (Incorporated herein by reference to Exhibit (10)(ii)(17) of the company s Annual Report on Form 10-K for the year ended December 31, 1996 (File No. 0-12014)).

(18) Norman Wells Pipeline Amending Agreement, dated December 12, 1997. (Incorporated herein by reference to Exhibit (10)(ii)(18) of the company s Annual Report on Form 10-K for the year ended December 31, 1998 (File No. 0-12014)).

(19) Norman Wells Pipeline 1999 Amending Agreement, dated May 1, 1999. (Incorporated herein by reference to Exhibit (10)(ii)(19) of the company s Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 0-12014)).

(20) 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)).

(21) Amendment to Alberta Crown Agreement effective January 1, 2001 (Incorporated herein by reference to Exhibit (10)(ii)(21) of the company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2002 (File No. 0-12014)).

(22) 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)).

(23) 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)).

(24) Amendment to Alberta Crown Agreement dated November 29, 1995 (Incorporated herein by reference to Exhibit (10)(ii)(24) of the company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2002 (File No. 0-12014)).

(25) 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)).

(26) Project Approval Order No. OSR045 made under the Alberta Mines and Minerals Act and Oil Sands Royalty Regulation, 1997 in respect of the Syncrude Project (Incorporated herein by reference to Exhibit 1.01(10)(ii)(3) 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) Incentive Share Unit Plan and Incentive Share Units granted in 2001 are incorporated herein by reference to Exhibit (10)(iii)(A)(2) of the company s Annual Report on Form 10-K for the year

-ended December 31, 2001. Units granted in 2000 are incorporated herein by reference to Exhibit (10)(iii)(A)(2) of the company s Annual Report on Form 10-K for the year ended December 31, 2000 (File No. 0-12014); units granted in 1999 are incorporated herein by reference to Exhibit (10)(iii)(A)(3) of the company s Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 0-12014); units granted in 1998 are incorporated herein by reference to Exhibit (10)(iii)(A)(3) of the company s Annual Report on Form 10-K for the year ended December 31, 1998 (File No. 0-12014).

(3) Deferred Share Unit Plan. (Incorporated herein by reference to Exhibit(10)(iii)(A)(5) of the company s Annual Report on Form 10-K for the year ended December 31, 1998 (File No. 0-12014)).

(4) 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)).

(5) Form of Earnings Bonus Units (Incorporated herein by reference to Exhibit (10)(iii)(A)(5) of the company s Annual Report on Form 10-K for the year ended December 31, 2003 (File No. 0-12014)) and Earnings Bonus Unit Plan (Incorporated herein by reference to Exhibit (10)(iii)(A)(5) of the company s Annual Report on Form 10-K for the year ended December 31, 2002 (File No. 0-12014)).

(6) Incentive Stock Option Plan and Incentive Stock Options granted in 2002 (Incorporated herein by reference to Exhibit (10)(iii)(A)(6) of the company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2002 (File No. 0-12014)).

(7) Restricted Stock Unit Plan and Restricted Stock Units granted in 2002 (Incorporated herein by reference to Exhibit (10)(iii)(A)(7) of the company s Annual Report on Form 10-K for the year ended December 31, 2002 (File No. 0-12014)).

(8) Restricted Stock Unit Plan and Restricted Stock Units granted in 2003 (Incorporated herein by reference to Exhibit (10)(iii)(A)(8) of the company s Annual Report on Form 10-K for the year ended December 31, 2003 (File No. 0-12014)).

(9) Restricted Stock Unit Plan and general form for Restricted Stock Units, as amended effective December 31, 2004 (Incorporated herein by reference to Exhibit 99.1 of the company s Form 8-K dated December 31, 2004 (File No. 0-12014)).

(10) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2002, as amended effective August 4, 2006 (Incorporated herein by reference to Exhibit 99.10(III)(A)(1) of the company s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006 (File No. 0-12014)).

(11) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2003, as amended effective August 4, 2006 (Incorporated herein by reference to Exhibit 99.10(III)(A)(2) of the company s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006 (File No. 0-12014)).

(12) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2004 and 2005, as amended effective August 4, 2006 (Incorporated herein by reference to Exhibit 99.10(III)(A)(3) of the company s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006 (File No. 0-12014)).

(13) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2006 and subsequent years, as amended effective August 4, 2006 (Incorporated herein by reference to Exhibit 99.10(III)(A)(4) of the company s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006 (File No. 0-12014)).

(14) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2002, as amended effective February 1, 2007 (Incorporated herein by reference to Exhibit 99.1 of the company s Form 8-K filed on February 2, 2007 (File No. 0-12014)).

(15) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2002, as amended effective February 26, 2008 and May 1, 2008 (Incorporated herein by reference to Exhibit 6 [10(iii)(A)(15)] of the company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2008 (File No. 0-12014)).

(16) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2003, as amended effective February 26, 2008 and May 1, 2008 (Incorporated herein by reference to Exhibit 6 [10(iii)(A)(16)] of the company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2008 (File No. 0-12014)).

(17) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2004 and 2005, as amended effective February 26, 2008 and May 1, 2008 (Incorporated herein by reference to

Exhibit 6 [10(iii)(A)(17)] of the company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2008 (File No. 0-12014)).

(18) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2006 and 2007, as amended effective February 26, 2008 and May 1, 2008 (Incorporated herein by reference to Exhibit 6 [10(iii)(A)(18)] of the company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2008 (File No. 0-12014)).

(19) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2008 and subsequent years, as amended effective February 26, 2008 and May 1, 2008 (Incorporated herein by reference to Exhibit 6 [10(iii)(A)(19)] of the company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2008 (File No. 0-12014)).

(20) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2002, as amended effective November 20, 2008 (Incorporated herein by reference to Exhibit 9.01(c)[10(iii)(A)(1)] of the company s Form 8-K filed on November 25, 2008 (File No. 0-12014)).

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(21) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2003, as amended effective November 20, 2008 (Incorporated herein by reference to Exhibit 9.01(c)[10(iii)(A)(2)] of the company s Form 8-K filed on November 25, 2008 (File No. 0-12014)).
(22) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2004 and 2005, as amended effective November 20, 2008 (Incorporated herein by reference to Exhibit 9.01(c)[10(iii)(A)(3)] of the company s Form 8-K filed on November 25, 2008 (File No. 0-12014)).
(23) Amended Restricted Stock Unit Plan with respect to Restricted Stock Units granted in 2006 and 2007, as amended effective November 20, 2008 (Incorporated herein by reference to Exhibit 9.01(c)[10(iii)(A)(4)] of the company s Form 8-K filed on November 25, 2008 (File No. 0-12014)).
(24) 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)).
(25) Amended Deferred Share Unit Plan for selected executives effective November 20, 2008 (Incorporated herein by reference to Exhibit 15(10)(iii)(A)(25) of the company s Form 10-K filed on February 27, 2009) (File No. 0-12014)).
(26) Termination of Deferred Share Unit Plan for selected executives effective February 2, 2010 (Reference is made to the company s Form 8-K filed on February 3, 2010 (File No. 0-12014)).
(27) 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)).
(28) 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, 2013.

(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 25, 2014 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 25, 2014 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/ Sheelagh D. Whittaker	Director
(Sheelagh D. Whittaker)	
/s/ Darren W. Woods	Director
(Darren W. Woods)	
/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	**2013**	2012	2011	2010	2009
Operating revenues	**32,722**	31,053	30,474	24,946	21,292
Net income by segment:					
Upstream	**1,712**	1,888	2,457	1,764	1,324
Downstream	**1,052**	1,772	884	442	278
Chemical	**162**	165	122	69	46
Corporate and Other	**(98)**	(59)	(92)	(65)	(69)
Net income	**2,828**	3,766	3,371	2,210	1,579
Cash and cash equivalents at year-end	**272**	482	1,202	267	513
Total assets at year-end	**37,218**	29,364	25,429	20,580	17,473
Long-term debt at year-end	**4,444**	1,175	843	527	31
Total debt at year-end	**6,287**	1,647	1,207	756	140
Other long-term obligations at year-end	**3,091**	3,983	3,876	2,753	2,839
Shareholders equity at year-end	**19,524**	16,377	13,321	11,177	9,439
Cash flow from operating activities	**3,292**	4,680	4,489	3,207	1,591
Per-share information (dollars)					
Net income per share - basic	**3.34**	4.44	3.98	2.61	1.86
Net income per share - diluted	**3.32**	4.42	3.95	2.59	1.84
Dividends declared	**0.49**	0.48	0.44	0.43	0.40

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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	**2013**	2012	2011
Business uses: asset and liability perspective			
Total assets	**37,218**	29,364	25,429
Less: total current liabilities excluding notes and loans payable	**(5,245)**	(5,433)	(5,585)
total long-term liabilities excluding long-term debt	**(6,162)**	(5,907)	(5,316)
Add: Imperial s share of equity company debt	**23**	24	28
Total capital employed	**25,834**	18,048	14,556
Total company sources: debt and equity perspective			
Notes and loans payable	**1,843**	472	364
Long-term debt	**4,444**	1,175	843
Shareholders equity	**19,524**	16,377	13,321
Add: Imperial s share of equity company debt	**23**	24	28
Total capital employed	**25,834**	18,048	14,556

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	**2013**	2012	2011
Net income	**2,828**	3,766	3,371
Financing costs (after tax), including Imperial s share of equity companies	**1**	1	1

Net income excluding financing costs		**2,829**	3,767	3,372
Average capital employed		**21,941**	16,302	13,261
Return on average capital employed (percent)	corporate total	**12.9**	23.1	25.4

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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	**2013**	2012	2011
Cash from operating activities	**3,292**	4,680	4,489
Proceeds from asset sales	**160**	226	314
Total cash flow from operating activities and asset sales	**3,452**	4,906	4,803

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	**2013**	2012	2011
From Imperial s Consolidated Statement of Income			
Total expenses	**29,192**	26,195	26,308
Less:			
Purchases of crude oil and products	**20,155**	18,476	18,847
Federal excise tax	**1,423**	1,338	1,320
Financing costs	**11**	(1)	3
Subtotal	**21,589**	19,813	20,170
Imperial s share of equity company expenses	**37**	34	39
Total operating costs	**7,640**	6,416	6,177

Components of Operating Costs

millions of dollars	**2013**	2012	2011
From Imperial s Consolidated Statement of Income			
Production and manufacturing	**5,288**	4,457	4,114
Selling and general	**1,082**	1,081	1,168
Depreciation and depletion	**1,110**	761	764

Exploration	**123**	83	92
Subtotal	**7,603**	6,382	6,138
Imperial s share of equity company expenses	**37**	34	39
Total operating costs	**7,640**	6,416	6,177

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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 8.8 billion people, or close to 2 billion more than in 2010. Coincident with this population increase, the company expects worldwide economic growth to average close to 3 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 global growth in transportation demand is likely to account for approximately 70 percent of the growth in liquid fuels demand over this period. Nearly all the world s transportation fleets will continue to run on liquid fuels because they 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 90 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.

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

Liquid fuels provide the largest share of 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 112 million barrels of oil-equivalent per day, an increase of about 25 percent from 2010. This demand will be met by a wide variety of sources. Globally, conventional crude production will likely decline slightly through 2040. However, this decline is expected to be more than offset by rising production from a wide variety of emerging supply sources - 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 demand likely to increase in all major regions of the world. 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 65 percent of the growth in natural gas supplies is expected to be from unconventional sources, which will account for about one-third of global gas supplies by 2040. Growing natural gas demand will also stimulate significant growth in the worldwide liquefied natural gas (LNG) market, which is expected to reach about 15 percent of global gas demand by 2040.

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. 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, albeit at a slower pace than otherwise expected in the aftermath of the Fukushima incident in Japan following the earthquake and tsunami in March 2011. Total renewable energy is likely to reach close to 15 percent of total energy by 2040, with biomass, hydro and geothermal at a combined share of about 11 percent. Total energy supplied from wind, solar and biofuels is expected to increase close to 450 percent from 2010 to 2040, reaching a combined share of about 4 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 2012- 2035 will be close to $19 trillion (measured in 2011 dollars), or close to $800 billion 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 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 into the North American markets. 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. 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 2013, the average WTI crude oil price was higher versus 2012, leading to higher western Canadian liquids realizations for the company.

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

Imperial s Upstream business strategies guide the company s exploration, development, production, research and gas marketing activities. These strategies include identifying and selectively capturing the highest quality opportunities, and maximizing the profitability of existing production and resource value through high-impact technologies. These strategies are underpinned by a relentless focus on operational excellence, commitment 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 2013. Other investments included the Celtic and Clyden acquisitions. 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.

Downstream

The downstream industry environment is expected to continue being very competitive in the mature North America market. Crude oil, the primary raw material in a refinery operation, and its many refined products are widely traded with published international prices. Prices for these commodities are determined by the marketplace and are affected by many factors, including global and regional supply/demand balances, inventory levels, refinery operations, import/export balances, transportation logistics, currency fluctuations, seasonality and weather. With the closure of the Dartmouth refinery in the third quarter of 2013, the average prices the company paid for most of its crude oil processed at the company s three refineries are largely set on western Canadian crude oil markets. In 2013, the average prices of western Canadian crude oils continued to be lower than that of Brent crude oil. Canadian wholesale prices of refined products in particular are largely determined by wholesale prices in adjacent U.S. regions, where wholesale prices are predominantly tied to international product markets. Lower industry refining margins in 2013 were the result of the narrower differential between product prices and cost of crude oil processed. These prices and factors are continually monitored and provide input to operating decisions about which raw materials to buy, facilities to operate and products to make. However, there are no reliable indicators of future market factors that accurately predict changes in margins from period to period.

The company will continue to focus on the business elements within its control. Imperial s Downstream strategies are to provide customers with quality, valued products and services at the lowest total cost offer, have the lowest unit costs among industry competitors, ensure efficient and effective use of capital, maximize value from leading edge technologies and capitalize on the integration with the company s other businesses.

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, of which about 470 are company-owned or leased, as well as wholesale and industrial operations through a network of 22 primary distribution terminals, as well as a secondary distribution network.

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

Chemical

The North American petrochemical industry environment remained favourable in 2013 reflecting improving North American economic conditions. In North America, unconventional natural gas continued to provide advantaged ethane feedstock for steam crackers and a favourable margin environment for integrated chemical producers. Feedstock to the company s Sarnia chemical plant will achieve further cost advantages with the transition to Marcellus ethane which is expected in the first 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.

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

Results of operations

Consolidated

millions of dollars	**2013**	2012	2011
Net income	**2,828**	3,766	3,371

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.

2012

Net income in 2012 was $3,766 million or $4.42 per share on a diluted basis, versus $3,371 million or $3.95 per share in 2011. Increased earnings were primarily attributable to stronger industry refining margins of about $975 million and lower royalty costs of about $300 million due to lower Upstream realizations. These factors were partially offset by the impacts of lower Upstream realizations of about $580 million, higher Kearl production readiness costs of about $125 million and higher refinery planned maintenance of about $80 million. Gains on asset divestments were also lower by about $85 million in 2012.

In 2012, the average price of West Texas Intermediate (WTI) crude oil and western Canadian crude oils continued to be markedly lower than that of Brent crude oil, a common benchmark for Atlantic Basin oil markets, due to supply/demand imbalances in mid-continent North American markets. This price discount negatively impacted the company s western Canadian liquids realizations. Refining margins in the company s Downstream segment, however, benefited as the overall cost of crude oil processed at three of the company s four refineries followed the trend of western Canadian crude oils.

Upstream

millions of dollars	**2013**	2012	2011
Net income	**1,712**	1,888	2,457

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.

2012

Net income for the year was $1,888 million, down $569 million from 2011. Earnings were lower primarily due to the impacts of lower realizations of about $580 million, higher Kearl production readiness costs of about $125 million and lower Cold Lake volumes of about $75 million. Gains on asset divestments were also lower by about $85 million in 2012. These factors were partially offset by lower royalty costs of about $300 million due to lower realizations and higher conventional volumes of about $45 million.

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

Average realizations

Canadian dollars	**2013**	2012	2011
Conventional crude oil realizations (per barrel)	**82.41**	77.19	85.22
Natural gas liquids realizations (per barrel)	**39.26**	42.06	59.08
Natural gas realizations (per thousand cubic feet)	**3.27**	2.33	3.59
Synthetic oil realizations (per barrel)	**99.69**	92.48	101.43
Bitumen realizations (per barrel)	**60.57**	59.76	63.95

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.

2012

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. Compared to 2011, the average WTI crude price in U.S. dollars was lower by $0.96 per barrel or about one percent in 2012. The company s western Canadian liquids realizations were also impacted by market discounts caused by supply/demand imbalances in mid-continent North America. In 2012, the company s conventional and synthetic crude oil realizations in Canadian dollars decreased by about nine percent and bitumen realizations in Canadian dollars decreased by about seven percent compared to 2011.

The company s average realizations on natural gas sales were lower by about 35 percent in 2012 in line with the decline in the average of 30-day spot prices for natural gas in Alberta.

Crude oil and NGLs - production and sales (a)

thousands of barrels per day	**2013**		2012		2011	
	gross	**net**	gross	net	gross	net
Bitumen (b)	**169**	**142**	154	123	160	120
Synthetic oil (c)	**67**	**65**	72	69	72	67
Conventional crude oil	**21**	**17**	20	15	18	13
Total crude oil production	**257**	**224**	246	207	250	200
NGLs available for sale	**4**	**3**	4	3	5	4
Total crude oil and NGL production	**261**	**227**	250	210	255	204
Bitumen sales, including diluent (d)	**219**		201		209	
NGL sales	**9**		8		9	

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

Natural gas - production and sales (a)

millions of cubic feet per day	**2013**		2012		2011	
	gross	**net**	gross	net	gross	net
Production (e)	**201**	**189**	192	195 (g)	254	228
Sales (f)	**167**		177		237	

(a) Daily volumes are calculated by dividing total volumes for the year by the number of days in the year. Gross production is the company s share of production (excluding purchases) before deducting the share of mineral owners or governments 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 (16,000 barrels per day gross, 15,000 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) Production of natural gas includes amounts used for internal consumption with the exception of the amounts re-injected.
(f) Includes sales of the company s share of production (before deduction of the mineral owners and/or governments share) and sales of gas purchased, processed and/or resold. Sales of natural gas exclude amounts used for internal consumption.
(g) Net production included favourable royalty cost adjustments.

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 throughout the remainder of the year. 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.

2012

Gross production of Cold Lake bitumen averaged 154,000 barrels per day in 2012 compared with 160,000 barrels in 2011. Lower volumes were primarily due to the cyclic nature of production at Cold Lake.

The company s share of Syncrude s gross production averaged 72,000 barrels per day, unchanged from 2011.

Gross production of conventional crude oil averaged 20,000 barrels per day, up from the 18,000 barrels in 2011 when third-party pipeline downtime reduced production at the Norman Wells field.

Gross production of natural gas in 2012 was 192 million cubic feet per day, down from 254 million cubic feet in 2011. The lower production volume was primarily a result of producing properties divestments completed in 2011.

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

Downstream

millions of dollars	**2013**	2012	2011
Net income	**1,052**	1,772	884

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.

2012

Downstream net income was $1,772 million, an increase of $888 million over 2011. Earnings in 2012 were the best annual earnings on record and were primarily due to stronger industry refining margins, partially offset by increased operating expenditures due to the impact of a higher level of refinery planned maintenance activities compared with 2011.

The overall cost of crude oil processed at three of the company s four refineries 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. Stronger industry refining margins are the result of the widened differential between product prices and cost of crude oil processed.

Refinery utilization

thousands of barrels per day (a)	**2013**	2012	2011
Total refinery throughput (b)	**426**	435	430
Refinery capacity at December 31	**421**	506	506
Utilization of total refinery capacity (percent) (c)	**88**	86	85

Sales

thousands of barrels per day (a)	**2013**	2012	2011
Gasolines	**223**	221	220
Heating, diesel and jet fuels	**160**	151	157
Heavy fuel oils	**29**	30	29
Lube oils and other products	**42**	43	41
Net petroleum product sales	**454**	445	447

(a) Volumes per day are calculated by dividing total volumes for the year by the number of 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.

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.

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 reduced 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.

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

2012

Total refinery throughput was 435,000 barrels per day and average refinery capacity utilization increased to 86 percent from the previous year s 85 percent. Higher volumes and utilization were primarily a result of improved refinery operations partially offset by higher planned maintenance activities at the Strathcona refinery. Total net petroleum sales decreased to 445,000 barrels per day, 2,000 barrels lower than 2011.

Chemical

millions of dollars	**2013**	2012	2011
Net income	**162**	165	122

Sales

thousands of tonnes	**2013**	2012	2011
Polymers and basic chemicals	**712**	767	748
Intermediate and others	**228**	277	268
Total petrochemical sales	**940**	1,044	1,016

2013

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

2012

Net income was $165 million, up $43 million from 2011. Earnings in 2012 were the best annual earnings on record. Strong operating performance along with higher polyethylene margins and sales volumes were the main contributors to the increase.

Corporate and Other

millions of dollars	**2013**	2012	2011
Net income	**(98)**	(59)	(92)

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.

2012

Net income effects from Corporate and Other were negative $59 million, compared with negative $92 million in 2011. Favourable effects were due to lower 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	**2013**	2012	2011
Cash provided by/(used in)			
Operating activities	**3,292**	4,680	4,489
Investing activities	**(7,735)**	(5,238)	(3,593)
Financing activities	**4,233**	(162)	39
Increase/(decrease) in cash and cash equivalents	**(210)**	(720)	935
Cash and cash equivalents at end of year	**272**	482	1,202

Investments in 2013 were partly financed by the issuance of long-term debt and commercial paper and partly funded by internally generated funds. 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 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, 2012. As a result of the valuation, the company contributed $600 million to the registered retirement benefit plans in 2013. The next required independent actuarial valuation will be as at December 31, 2013 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

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.

2012

Cash flow generated from operating activities was $4,680 million, compared with $4,489 million in 2011. Higher cash flow was primarily due to deferred income tax effects and higher net income partially offset by 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

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.

2012

Investing activities used net cash of $5,238 million in 2012, compared to $3,593 million in 2011. Additions to property, plant and equipment were $5,478 million, compared with $3,919 million last year. Proceeds from asset sales were $226 million compared with $314 million in 2011.

Cash flow from financing activities

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 (Canadian). 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.

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.

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.

2012

Cash used in financing activities was $162 million, compared with cash provided by financing activities of $39 million in 2011.

The company raised new debt of $325 million by drawing on existing facilities. Obligations under capital leases, which is a non-cash item, also increased by $115 million. At the end of 2012, total debt outstanding was $1,647 million, compared with $1,207 million at the end of 2011.

During 2012, the company did not make any share repurchases except those to offset the dilutive effects from the exercise of share-based awards. The company will continue to evaluate its share repurchase program in the context of its operating performance and overall capital project activities.

Cash dividends of $398 million were paid in 2012 compared with $373 million in 2011. Per-share dividends paid in 2012 totalled $0.47, up from $0.44 in 2011.

In the third quarter of 2012, the company increased the amount of its existing stand-by long-term bank credit facility from $200 million to $300 million and extended the maturity date to August 2014. The company has not drawn on the facility.

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

Financial percentages and ratios

	2013	2012	2011
Total debt as a percentage of capital (a)	**24**	9	9
Interest coverage ratio earnings basis (b)	**55**	239	260

(a) Current and long-term debt (page 57) and the company s share of equity company debt, divided by debt and shareholders equity (page 57).

(b) Net income (page 55), debt-related interest before capitalization, including the company s share of equity company interest, and income taxes (page 55), divided by debt-related interest before capitalization, including the company s share of equity company interest.

Debt represented 24 percent of the company s capital structure at the end of 2013.

Debt-related interest incurred in 2013, before capitalization of interest, was $69 million, compared with $20 million in 2012. The average effective interest rate on the company s debt was 1.4 percent in 2013, compared with 1.6 percent in 2012.

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, 2013. It combines data from the consolidated balance sheet and from individual notes to the consolidated financial statements, where appropriate.

	Financial		Payment due by period		
			2015		
	statement			2019	Total
millions of dollars	note reference	2014	to 2018	and beyond	amount
Long-term debt (a)	Note 14	-	4,342	102	4,444
- Due in one year		7	-	-	7
Operating leases (b)	Note 13	177	180	32	389
Unconditional purchase obligations (c)	Note 9	91	329	237	657
Firm capital commitments (d)		2,390	556	297	3,243
Pension and other post-retirement obligations (e)	Note 4	475	231	795	1,501

Asset retirement obligations (f)	Note 5	91	381	765	1,237
Other long-term purchase agreements (g)		473	2,372	8,036	10,881

(a) Long-term debt includes a long-term loan from an affiliated company of ExxonMobil of $4,316 million and capital lease obligations of $135 million, $7 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 2013 were $2,005 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 2014 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)

In 2013, the company entered into additional long-term transportation agreements, which have a total commitment of about $3.5 billion, to ship heavy crude oil blend and diluent. These agreements will support the company s long-term growth in oil sands production. The company expects to fulfill these commitments in the normal course of business. The new commitment amounts are included in the Other long term purchase agreements line in the table above.

Unrecognized tax benefits totaling $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 65.

Litigation and other contingencies

As discussed in note 9 to the consolidated financial statements on page 74, a variety of claims have been made against Imperial Oil Limited 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	**2013**	2012
Upstream (a)	**7,755**	5,518
Downstream	**187**	140
Chemical	**9**	4
Other	**69**	21
Total	**8,020**	5,683

(a) Exploration expenses included.

Total capital and exploration expenditures were $8,020 million in 2013, an increase of $2,337 million from 2012.

For the Upstream segment, capital expenditures were $7,755 million, compared with $5,518 million in 2012. Expenditures included $1.9 billion on the Celtic and Clyden acquisitions and post-acquisition investments. Other investments were primarily directed towards the advancement of the Kearl expansion and Nabiye projects.

Kearl s expansion project continued to progress per plan. At 2013 year-end, the project was 72 percent complete and remains on target for a 2015 start-up. The project is expected to produce 110,000 barrels per day gross (78,000 Imperial s share). Cold Lake s Nabiye project was 65 percent complete at the end of the year. In the fourth quarter, plant construction progressed somewhat slower than planned due to lower contractor productivity and harsh winter conditions. Target start-up, although under pressure, remains year-end 2014 with ultimate production of 40,000 barrels per day.

Planned capital and exploration expenditures in the Upstream segment are forecast at about $5 billion for 2014. Investments are mainly planned for the continued investment in the Kearl and Nabiye growth projects.

For the Downstream segment, capital expenditures were $187 million in 2013, compared with $140 million in 2012. In 2013, Downstream capital expenditures focused mainly on refinery projects to improve reliability, feedstock flexibility, energy efficiency and environmental performance.

Planned capital expenditures for the Downstream segment in 2014 are about $450 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 2014 are expected to be about $5.5 billion. Actual spending could vary depending on the progress of individual projects.

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, of the company s after-tax net income.

Earnings sensitivities (a)

millions of dollars, after tax		
Eight dollars (U.S.) per barrel change in crude oil prices	+ (-)	435
Thirty cents per thousand cubic feet change in natural gas prices	+ (-)	9
One dollar (U.S.) per barrel change in sales margins for total petroleum products	+ (-)	130
One cent (U.S.) per pound change in sales margins for polyethylene	+ (-)	6
One-quarter percent decrease (increase) in short-term interest rates	+ (-)	11
Nine cents decrease (increase) in the value of the Canadian dollar versus the U.S. dollar	+ (-)	500

(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 2013. 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 2012 year-end by about $5 million (after tax) a year for each one U.S. dollar change. The sensitivity of net income to changes in natural gas prices increased from 2012 year-end by about $1 million (after tax) a year for each ten-cent change. The sensitivity of net income to changes in the Canadian dollar versus the U.S. dollar increased from 2012 year-end by about $7 million (after tax) a year for each one-cent change. The increase in these areas was primarily a result of the impact of production from the Kearl initial development which began in 2013.

The sensitivity of net income to changes in short-term interest rates increased from 2012 year-end by about $8 million (after tax) a year for each one-quarter percent change as a result of the higher debt levels at 2013 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 two-thirds of the company s intersegment sales are crude oil produced by the Upstream and sold to the Downstream. Other intersegment sales include those between refineries and 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, industry economics over the long term will continue to be driven by market supply and demand. Accordingly, the company tests 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.

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.

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

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. The benefit of integration is demonstrated by the financial results in 2013 when increases in western Canadian crude oil prices benefited the company s Upstream realizations but negatively impacted refining margins in the Downstream segment. 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. The company 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 60.

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 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 developed 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.

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 2013 compares to actual returns of 6.50 percent and 8.00 percent achieved over the last 10- and 20-year periods ending December 31, 2013. 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 66. 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 less than two percent of total expenses in 2013.

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 2013, the obligations were discounted

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.

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 65.

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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 (1992)* 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, 2013.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the company s internal control over financial reporting as of December 31, 2013, 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 25, 2014

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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, 2013 and December 31, 2012 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, 2013. We also have audited Imperial Oil Limited s internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control - Integrated Framework (1992) 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, 2013 and December 31, 2012 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2013 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, 2013 based on criteria established in Internal Control - Integrated Framework (1992) issued by the COSO.

/s/ PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta, Canada

February 25, 2014

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Consolidated statement of income (U.S. GAAP)

millions of Canadian dollars

For the years ended December 31	**2013**	2012	2011
Revenues and other income			
Operating revenues (a)(b)	**32,722**	31,053	30,474
Investment and other income (note 8)	**207**	135	240
Total revenues and other income	**32,929**	31,188	30,714
Expenses			
Exploration	**123**	83	92
Purchases of crude oil and products (c)	**20,155**	18,476	18,847
Production and manufacturing (d)	**5,288**	4,457	4,114
Selling and general	**1,082**	1,081	1,168
Federal excise tax (a)	**1,423**	1,338	1,320
Depreciation and depletion	**1,110**	761	764
Financing costs (note 12)	**11**	(1)	3
Total expenses	**29,192**	26,195	26,308
Income before income taxes	**3,737**	4,993	4,406
Income taxes (note 3)	**909**	1,227	1,035
Net income	**2,828**	3,766	3,371
Per-share information (Canadian dollars)			
Net income per common share basic (note 10)	**3.34**	4.44	3.98
Net income per common share diluted (note 10)	**3.32**	4.42	3.95
Dividends	**0.49**	0.48	0.44

(a) Operating revenues include federal excise tax of $1,423 million (2012 - $1,338 million, 2011 - $1,320 million).

(b) Operating revenues include amounts from related parties of $2,385 million (2012 - $2,907 million, 2011 - $2,818 million), (note 16).

(c) Purchases of crude oil and products include amounts from related parties of $4,104 million (2012 - $3,033 million, 2011 - $3,636 million), (note 16).

(d) Production and manufacturing expenses include amounts to related parties of $319 million (2012 - $241 million, 2011 - $217 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	**2013**	2012	2011
Net income	**2,828**	3,766	3,371
Other comprehensive income, net of income taxes			
Post-retirement benefits liability adjustment (excluding amortization)	**529**	(415)	(953)
Amortization of post-retirement benefits liability adjustment included in net periodic benefit costs	**205**	198	139
Total other comprehensive income/(loss)	**734**	(217)	(814)
Comprehensive income	**3,562**	3,549	2,557

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	**2013**	2012
Assets		
Current Assets		
Cash	**272**	482
Accounts receivable, less estimated doubtful amounts	**2,084**	1,976
Inventories of crude oil and products (note 11)	**1,030**	827
Materials, supplies and prepaid expenses	**342**	280
Deferred income tax assets (note 3)	**559**	527
Total current assets	**4,287**	4,092
Long-term receivables, investments and other long-term assets	**1,332**	1,090
Property, plant and equipment, less accumulated depreciation and depletion (note 2)	**31,320**	23,922
Goodwill (note 2)	**224**	204
Other intangible assets, net	**55**	56
Total assets (note 2)	**37,218**	29,364
Liabilities		
Current liabilities		
Notes and loans payable (a)(note 12)	**1,843**	472
Accounts payable and accrued liabilities (b)(note 11)	**4,518**	4,249
Income taxes payable	**727**	1,184
Total current liabilities	**7,088**	5,905
Long-term debt (c)(note 14)	**4,444**	1,175
Other long-term obligations (note 5)	**3,091**	3,983
Deferred income tax liabilities (note 3)	**3,071**	1,924
Total liabilities	**17,694**	12,987
Commitments and contingent liabilities (note 9)		
Shareholders equity		
Common shares at stated value (d)(note 10)	**1,566**	1,566
Earnings reinvested	**19,679**	17,266
Accumulated other comprehensive income	**(1,721)**	(2,455)
Total shareholders equity	**19,524**	16,377
Total liabilities and shareholders equity	**37,218**	29,364

(a) Notes and loans payable includes amounts to related parties of $75 million (2012 nil)

(b) Accounts payable and accrued liabilities include amounts payable to related parties of $170 million (2012 amounts receivable of $9 million), (note 16).

(c) Long-term debt includes amounts to related parties of $4,316 million (2012 $1,040 million).

(d) Number of common shares outstanding was 848 million (2012 - 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	**2013**	2012	2011
Common shares at stated value (note 10)			
At beginning of year	**1,566**	1,528	1,511
Issued under the stock option plan	**-**	43	19
Share purchases at stated value	**-**	(5)	(2)
At end of year	**1,566**	1,566	1,528
Earnings reinvested			
At beginning of year	**17,266**	14,031	11,090
Net income for the year	**2,828**	3,766	3,371
Share purchases in excess of stated value	**-**	(123)	(57)
Dividends	**(415)**	(408)	(373)
At end of year	**19,679**	17,266	14,031
Accumulated other comprehensive income			
At beginning of year	**(2,455)**	(2,238)	(1,424)
Other comprehensive income	**734**	(217)	(814)
At end of year	**(1,721)**	(2,455)	(2,238)
Shareholders equity at end of year	**19,524**	16,377	13,321

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	**2013**	2012	2011
Operating activities			
Net income	**2,828**	3,766	3,371
Adjustments for non-cash items:			
Depreciation and depletion	**1,110**	761	764
(Gain)/loss on asset sales	**(150)**	(94)	(197)
Deferred income taxes and other	**482**	619	71
Changes in operating assets and liabilities:			
Accounts receivable	**(74)**	300	(302)
Inventories, materials, supplies and prepaid expenses	**(260)**	(106)	(228)
Income taxes payable	**(457)**	(84)	390
Accounts payable and accrued liabilities	**191**	(67)	846
All other items - net (a)	**(378)**	(415)	(226)
Cash flows from (used in) operating activities	**3,292**	4,680	4,489
Investing activities			
Additions to property, plant and equipment	**(6,297)**	(5,478)	(3,919)
Acquisition (note 18)	**(1,602)**	-	-
Proceeds from asset sales	**160**	226	314
Repayment of loan from equity company	**4**	14	12
Cash flows from (used in) investing activities	**(7,735)**	(5,238)	(3,593)
Financing activities			
Short-term debt - net	**1,371**	105	135
Long-term debt issued	**3,276**	220	320
Reduction in capitalized lease obligations	**(7)**	(4)	(3)
Issuance of common shares under stock option plan	**-**	43	19
Common shares purchased (note 10)	**-**	(128)	(59)
Dividends paid	**(407)**	(398)	(373)
Cash flows from (used in) financing activities	**4,233**	(162)	39
Increase (decrease) in cash	**(210)**	(720)	935
Cash at beginning of year	**482**	1,202	267
Cash at end of year (b)	**272**	482	1,202

(a) Includes contribution to registered pension plans of $600 million (2012 - $594 million, 2011 - $361 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.

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. Certain reclassifications to prior years have been made to conform to the 2013 presentation. 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 project.

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 with certain exploratory expenditures and exploratory dry holes being expensed as incurred. Costs of productive wells and development dry holes are capitalized and amortized using the unit-of-production method. The company carries as an asset exploratory

Notes to consolidated financial statements (continued)

well costs 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 economic and operating viability of the project. Other exploratory expenditures, including geophysical costs and annual lease rentals are expensed as incurred.

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.

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 72 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.

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	**2013**	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Revenues and other income									
Operating revenues (a)	**6,016**	4,674	5,278	**25,450**	25,077	23,909	**1,256**	1,302	1,287
Intersegment sales	**4,026**	4,110	4,460	**1,978**	2,603	2,784	**318**	299	354
Investment and other income	**145**	46	168	**59**	81	63	**-**	-	-
	10,187	8,830	9,906	**27,487**	27,761	26,756	**1,574**	1,601	1,641
Expenses									
Exploration	**123**	83	92	**-**	-	-	**-**	-	-
Purchases of crude oil and products	**3,778**	3,056	3,581	**21,628**	21,316	21,642	**1,065**	1,115	1,222
Production and manufacturing (b)	**3,389**	2,704	2,484	**1,695**	1,569	1,451	**210**	185	179
Selling and general	**5**	1	7	**886**	935	973	**66**	67	64
Federal excise tax	**-**	-	-	**1,423**	1,338	1,320	**-**	-	-
Depreciation and depletion (b)	**636**	498	528	**452**	242	214	**12**	12	13
Financing costs (note 12)	**9**	(1)	2	**2**	-	(1)	**-**	-	-
Total expenses	**7,940**	6,341	6,694	**26,086**	25,400	25,599	**1,353**	1,379	1,478
Income before income taxes	**2,247**	2,489	3,212	**1,401**	2,361	1,157	**221**	222	163
Income taxes (note 3)									
Current	**(14)**	72	593	**395**	486	372	**62**	67	43
Deferred	**549**	529	162	**(46)**	103	(99)	**(3)**	(10)	(2)
Total income tax expense	**535**	601	755	**349**	589	273	**59**	57	41
Net income	**1,712**	1,888	2,457	**1,052**	1,772	884	**162**	165	122
Cash flows from (used in) operating activities	**1,690**	2,625	3,252	**1,453**	1,961	1,315	**198**	127	53
Capital and exploration expenditures (c)	**7,755**	5,518	3,880	**187**	140	166	**9**	4	4
Property, plant and equipment									
Cost	**38,819**	30,602	25,327	**7,146**	7,038	6,990	**771**	765	760
Accumulated depreciation and	**(10,749)**	(10,146)	(9,747)	**(4,347)**	(3,967)	(3,803)	**(586)**	(576)	(560)

depletion									
Net property, plant and equipment (d)	**28,070**	20,456	15,580	**2,799**	3,071	3,187	**185**	189	200
Total assets (e)	**30,553**	22,317	17,222	**5,732**	6,409	6,700	**397**	372	397

	Corporate and Other			Eliminations			Consolidated		
millions of dollars	**2013**	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Revenues and other income									
Operating revenues (a)	**-**	-	-	**-**	-	-	**32,722**	31,053	30,474
Intersegment sales	**-**	-	-	**(6,322)**	(7,012)	(7,598)	**-**	-	-
Investment and other income	**3**	8	9	**-**	-	-	**207**	135	240
	3	8	9	**(6,322)**	(7,012)	(7,598)	**32,929**	31,188	30,714
Expenses									
Exploration	**-**	-	-	**-**	-	-	**123**	83	92
Purchases of crude oil and products	**-**	-	-	**(6,316)**	(7,011)	(7,598)	**20,155**	18,476	18,847
Production and manufacturing (b)	**-**	-	-	**(6)**	(1)	-	**5,288**	4,457	4,114
Selling and general	**125**	78	124	**-**	-	-	**1,082**	1,081	1,168
Federal excise tax	**-**	-	-	**-**	-	-	**1,423**	1,338	1,320
Depreciation and depletion (b)	**10**	9	9	**-**	-	-	**1,110**	761	764
Financing costs (note 12)	**-**	-	2	**-**	-	-	**11**	(1)	3
Total expenses	**135**	87	135	**(6,322)**	(7,012)	(7,598)	**29,192**	26,195	26,308
Income before income taxes	**(132)**	(79)	(126)	-	-	-	**3,737**	4,993	4,406
Income taxes (note 3)									
Current	**(18)**	(32)	(53)	**-**	-	-	**425**	593	955
Deferred	**(16)**	12	19	**-**	-	-	**484**	634	80
Total income tax expense	**(34)**	(20)	(34)	**-**	-	-	**909**	1,227	1,035
Net income	**(98)**	(59)	(92)	**-**	-	-	**2,828**	3,766	3,371
Cash flows from (used in) operating activities	**(49)**	(33)	(131)	**-**	-	-	**3,292**	4,680	4,489
Capital and exploration expenditures (c)	**69**	21	16	**-**	-	-	**8,020**	5,683	4,066
Property, plant and equipment									
Cost	**429**	360	339	**-**	-	-	**47,165**	38,765	33,416
Accumulated depreciation and depletion	**(163)**	(154)	(144)	**-**	-	-	**(15,845)**	(14,843)	(14,254)

Net property, plant and equipment (d)	**266**	206	195	**-**	-	-	**31,320**	23,922	19,162
Total assets (e)	**581**	704	1,418	**(45)**	(438)	(308)	**37,218**	29,364	25,429

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Notes to consolidated financial statements (continued)

(a) Includes export sales to the United States of $5,217 million (2012 - $4,358 million, 2011 - $4,175 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 2013, amounts incurred associated with decommissioning, environmental and employee-related costs totalled $40 million.
(c) Capital and exploration expenditures (CAPEX) include exploration expenses, additions to property, plant, equipment and intangibles and additions to capital leases.
(d) Includes property, plant and equipment under construction of $9,234 million (2012 - $13,846 million).
(e) The majority of the goodwill has been assigned to the Downstream segment. Goodwill of $20 million was recognized in 2013 in the Upstream segment as a result of the Celtic acquisition (note 18). There have been no goodwill impairment losses or write-offs due to sales in the past three years. Fair value used in quantitative goodwill impairment tests was Level 3 (unobservable inputs).

3. Income taxes

millions of dollars	**2013**	2012	2011
Current income tax expense	**425**	593	955
Deferred income tax expense (a)	**484**	634	80
Total income tax expense (b)	**909**	1,227	1,035
Statutory corporate tax rate (percent)	**25.4**	25.5	25.4
Increase/(decrease) resulting from:			
Enacted tax rate change	**-**	-	-
Other	**(1.1)**	(0.9)	(1.9)
Effective income tax rate	**24.3**	24.6	23.5

(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 2013, 2012 and 2011.
(b) Cash outflow from income taxes, plus investment credits earned, was $911 million in 2013 (2012 $871 million, 2011 $667 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	**2013**	2012	2011
Depreciation and amortization	**2,949**	2,434	1,948
Successful drilling and land acquisitions	**815**	399	378
Pension and benefits	**(376)**	(717)	(720)

Site restoration	**(287)**	(284)	(267)
Capitalized interest	**69**	53	50
Other	**(99)**	39	51
Net long-term deferred income tax liabilities	**3,071**	1,924	1,440
LIFO inventory valuation	**(450)**	(478)	(560)
Other	**(109)**	(49)	(30)
Net current deferred income tax assets	**(559)**	(527)	(590)
Valuation allowance	**-**	-	-
Net deferred income tax liabilities	**2,512**	1,397	850

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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. 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 s effective tax rate will be reduced if any of these tax benefits are subsequently recognized.

The following table summarizes the movement in unrecognized tax benefits:

millions of dollars	**2013**	2012	2011
Balance as at January 1	**143**	134	147
Additions based on current year s tax position	**10**	4	-
Additions for prior years tax positions	**2**	10	20
Reductions for prior years tax positions	**(4)**	(3)	(31)
Reductions due to lapse of the statute of limitations	**-**	(2)	(2)
Balance as at December 31	**151**	143	134

The 2013, 2012 and 2011 changes in unrecognized tax benefits did not have a material effect on the company s net income or cash flow. The company s tax filings from 2006 to 2013 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 2014. The impact on unrecognized tax benefits and the company s effective income tax rate from these matters is not expected to be material.

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. At 2013 year-end, the company adopted mortality assumptions presented in the new Canadian pensioners mortality research report, per guidance provided by the Canadian Institute of Actuaries.

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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	
	2013	2012	**2013**	2012
Assumptions used to determine benefit obligations at December 31 (percent)				
Discount rate	**4.75**	3.75	**4.75**	3.75
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	**7,336**	6,646	**547**	508
Current service cost	**181**	160	**11**	8
Interest cost	**281**	288	**21**	21
Actuarial loss/(gain)	**(504)**	616	**(50)**	40
Amendments	**-**	-	**-**	-
Benefits paid (a)	**(424)**	(374)	**(26)**	(30)
Projected benefit obligation at December 31	**6,870**	7,336	**503**	547
Accumulated benefit obligation at December 31	**6,263**	6,560		

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 2014 and subsequent years.

	Pension benefits		Other post-retirement benefits	
millions of dollars	**2013**	2012	**2013**	2012
Change in plan assets				
Fair value at January 1	**5,114**	4,461		
Actual return/(loss) on plan assets	**491**	374		
Company contributions	**600**	594		
Benefits paid (b)	**(333)**	(315)		
Fair value at December 31	**5,872**	5,114		

Plan assets in excess of/(less than) projected benefit obligation at December 31				
Funded plans	**(424)**	(1,602)		
Unfunded plans	**(574)**	(620)	**(503)**	(547)
Total (c)	**(998)**	(2,222)	**(503)**	(547)

(a) Benefit payments for funded and unfunded plans.

(b) Benefit payments for funded plans only.

(c) Fair value of assets less projected benefit obligation shown above.

Funding of registered retirement plans complies with federal and provincial pension regulations, and the company makes contributions to the plans based on an independent actuarial valuation. In accordance with authoritative guidance relating to the accounting for defined pension and other post-retirement benefits plans, the underfunded status of the company s defined benefit post-retirement plans was recorded as a liability in the balance sheet, and the changes in that funded status in the year in which the changes occurred was recognized through other comprehensive income.

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Notes to consolidated financial statements (continued)

millions of dollars	Pension benefits **2013**	Pension benefits 2012	Other post-retirement benefits **2013**	Other post-retirement benefits 2012
Amounts recorded in the consolidated balance sheet consist of:				
Current liabilities	**(25)**	(24)	**(28)**	(28)
Other long-term obligations	**(973)**	(2,198)	**(475)**	(519)
Total recorded	**(998)**	(2,222)	**(503)**	(547)
Amounts recorded in accumulated other comprehensive income consist of:				
Net actuarial loss/(gain)	**2,303**	3,210	**64**	124
Prior service cost	**62**	85	**-**	-
Total recorded in accumulated other comprehensive income, before tax	**2,365**	3,295	**64**	124

The company establishes the long-term expected rate of return on plan assets by developing a forward-looking long-term return assumption for each asset class, taking into account factors such as the expected real return for the specific asset class and inflation. A single, long-term rate of return is then calculated as the weighted average of the target asset allocation percentages and the long-term return assumption for each asset class. The 2013 long-term expected return of 6.25 percent used in the calculations of pension expense compares to an actual rate of return of 6.50 percent and 8.00 percent over the last 10- and 20-year periods ending December 31, 2013.

	Pension benefits **2013**	Pension benefits 2012	Pension benefits 2011	Other post-retirement benefits **2013**	Other post-retirement benefits 2012	Other post-retirement benefits 2011
Assumptions used to determine net periodic benefit cost for years ended December 31 (percent)						
Discount rate	**3.75**	4.25	5.50	**3.75**	4.25	5.50
Long-term rate of return on funded assets	**6.25**	6.25	7.00	**-**	-	-
Long-term rate of compensation increase	**4.50**	4.50	4.50	**4.50**	4.50	4.50
millions of dollars						
Components of net periodic benefit cost						
Current service cost	**181**	160	122	**11**	8	6
Interest cost	**281**	288	314	**21**	21	23
Expected return on plan assets	**(331)**	(288)	(308)	**-**	-	-
Amortization of prior service cost	**23**	23	21	**-**	-	-
Amortization of actuarial loss/(gain)	**243**	235	162	**10**	8	3
Net periodic benefit cost	**397**	418	311	**42**	37	32

Changes in amounts recorded in accumulated

other comprehensive income						
Net actuarial loss/(gain)	**(664)**	530	1,112	**(50)**	40	81
Amortization of net actuarial (loss)/gain included in net periodic benefit cost	**(243)**	(235)	(162)	**(10)**	(8)	(3)
Prior service cost	**-**	-	86	**-**	-	-
Amortization of prior service cost included in net periodic benefit cost	**(23)**	(23)	(21)	**-**	-	-
Total recorded in other comprehensive income	**(930)**	272	1,015	**(60)**	32	78
Total recorded in net periodic benefit cost and other comprehensive income, before tax	**(533)**	690	1,326	**(18)**	69	110

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Notes to consolidated financial statements (continued)

Costs for defined contribution plans, primarily the employee savings plan, were $37 million in 2013 (2012 - $36 million, 2011 - $36 million).

A summary of the change in accumulated other comprehensive income is shown in the table below:

	Total pension and other post-retirement benefits		
millions of dollars	**2013**	2012	2011
(Charge)/credit to other comprehensive income, before tax	**990**	(304)	(1,093)
Deferred income tax (charge)/credit (note 17)	**(256)**	87	279
(Charge)/credit to other comprehensive income, after tax	**734**	(217)	(814)

The company s investment strategy for pension plan assets reflects a long-term view, a careful assessment of the risks inherent in various asset classes and broad diversification to reduce the risk of the portfolio. Consistent with the long-term nature of the liability, the plan assets are primarily invested in global, market-cap-weighted indexed equity and domestic indexed bond funds to diversify risk while minimizing costs. The equity funds hold Imperial Oil stock only to the extent necessary to replicate the relevant equity index. The balance of the plan assets is largely invested in high-quality corporate and government debt securities. Studies are periodically conducted to establish the preferred target asset allocation. The target asset allocation for equity securities is 46 percent. The target allocation for debt securities is 49 percent. Plan assets for the remaining 5 percent are invested in venture capital partnerships that pursue a strategy of investment in U.S. and international early stage ventures.

The 2013 fair value of the pension plan assets, including the level within the fair value hierarchy, is shown in the table below:

		Fair value measurements at December 31, 2013, using:			
millions of dollars	Total	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)		Significant unobservable inputs (Level 3)
Asset class					
Equity securities					
Canadian	932		932	(a)	
Non-Canadian	1,911		1,911	(a)	
Debt securities - Canadian					

Corporate	654		654	(b)		
Government	2,161		2,161	(b)		
Asset backed	-					
Mortgage funds	1				1	(c)
Equities Venture capital	188				188	(d)
Cash	25	12	13	(e)		
Total plan assets at fair value	5,872	12	5,671		189	

(a) For company equity securities held in the form of fund units that are redeemable at the measurement date, the unit value is treated as a Level 2 input. The fair value of the securities owned by the funds is based on observable quoted prices on active exchanges, which are Level 1 inputs.

(b) For corporate, government and asset-backed debt securities, fair value is based on observable inputs of comparable market transactions.

(c) For mortgage funds, fair value represents the principal outstanding which is guaranteed by Canada Mortgage and Housing Corporation.

(d) For venture capital partnership investments, fair value is generally established by using revenue or earnings multiples or other relevant market data including Initial Public Offerings.

(e) For cash balances that are held in Level 2 funds prior to investment in those fund units, the cash value is treated as a Level 2 input.

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Notes to consolidated financial statements (continued)

The change in the fair value of Level 3 assets, which use significant unobservable inputs to measure fair value, is shown in the table below:

millions of dollars	Mortgage funds	Venture capital
Fair value at January 1, 2013	1	158
Net realized gains/(losses)	-	(17)
Net unrealized gains/(losses)	-	44
Net purchases/(sales)	-	3
Fair value at December 31, 2013	1	188

The 2012 fair value of the pension plan assets, including the level within the fair value hierarchy, is shown in the table below:

		Fair value measurements at December 31, 2012, using:				
millions of dollars	Total	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)		Significant unobservable inputs (Level 3)	
Asset class						
Equity securities						
Canadian	811		811	(a)		
Non-Canadian	1,657		1,657	(a)		
Debt securities - Canadian						
Corporate	473		473	(b)		
Government	1,982		1,982	(b)		
Asset backed	5		5	(b)		
Mortgage funds	1				1	(c)
Equities Venture capital	158				158	(d)
Cash	27	9	18	(e)		
Total plan assets at fair value	5,114	9	4,946		159	

(a) For company equity securities held in the form of fund units that are redeemable at the measurement date, the unit value is treated as a Level 2 input. The fair value of the securities owned by the funds is based on observable quoted prices on active exchanges, which are Level 1 inputs.

(b)

For corporate, government and asset-backed debt securities, fair value is based on observable inputs of comparable market transactions.

(c) For mortgage funds, fair value represents the principal outstanding which is guaranteed by Canada Mortgage and Housing Corporation.

(d) For venture capital partnership investments, fair value is generally established by using revenue or earnings multiples or other relevant market data including Initial Public Offerings.

(e) For cash balances that are held in Level 2 funds prior to investment in those fund units, the cash value is treated as a Level 2 input.

The change in the fair value of Level 3 assets, which use significant unobservable inputs to measure fair value, is shown in the table below:

millions of dollars	Mortgage funds	Venture capital
Fair value at January 1, 2012	1	148
Net realized gains/(losses)	-	(11)
Net unrealized gains/(losses)	-	8
Net purchases/(sales)	-	13
Fair value at December 31, 2012	1	158

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Notes to consolidated financial statements (continued)

A summary of pension plans with accumulated benefit obligations in excess of plan assets is shown in the table below:

	Pension benefits	
millions of dollars	**2013**	2012
For funded pension plans with accumulated benefit obligations in excess of plan assets:		
Projected benefit obligation	**-**	6,716
Accumulated benefit obligation	**-**	6,025
Fair value of plan assets	**-**	5,114
Accumulated benefit obligation less fair value of plan assets	**-**	911
For unfunded plans covered by book reserves:		
Projected benefit obligation	**574**	620
Accumulated benefit obligation	**496**	535

Estimated 2014 amortization from accumulated other comprehensive income

millions of dollars	Pension benefits	Other post-retirement benefits
Net actuarial loss/(gain) (a)	169	5
Prior service cost (b)	23	-

(a) The company amortizes the net balance of actuarial loss/(gain) as a component of net periodic benefit cost over the average remaining service period of active plan participants.

(b) The company amortizes prior service cost on a straight-line basis.

Cash flows

Benefit payments expected in:

millions of dollars	Pension benefits	Other post-retirement benefits
2014	365	28
2015	375	28
2016	384	28
2017	393	28
2018	401	28
2019 - 2023	2,078	145

In 2014, the company expects to make cash contributions of about $420 million to its pension plans.

Sensitivities

A one percent change in the assumptions at which retirement liabilities could be effectively settled is as follows:

Increase/(decrease) millions of dollars	One percent increase	One percent decrease
Rate of return on plan assets:		
Effect on net benefit cost, before tax	(50)	50
Discount rate:		
Effect on net benefit cost, before tax	(80)	100
Effect on benefit obligation	(850)	1,050
Rate of pay increases:		
Effect on net benefit cost, before tax	50	(45)
Effect on benefit obligation	170	(150)

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Notes to consolidated financial statements (continued)

A one percent change in the assumed health-care cost trend rate would have the following effects:

Increase/(decrease) millions of dollars	One percent increase	One percent decrease
Effect on service and interest cost components	4	(3)
Effect on benefit obligation	45	(35)

5. Other long-term obligations

millions of dollars	**2013**	2012
Employee retirement benefits (note 4)(a)	**1,448**	2,717
Asset retirement obligations and other environmental liabilities (b)	**1,258**	957
Share-based incentive compensation liabilities (note 7)	**140**	117
Other obligations	**245**	192
Total other long-term obligations	**3,091**	3,983

(a) Total recorded employee retirement benefit obligations also include $53 million in current liabilities (2012 $52 million).

(b) Total asset retirement obligations and other environmental liabilities also include $154 million in current liabilities (2012 $168 million).

Asset retirement obligations incurred in the current period were Level 3 (unobservable inputs) fair value measurements. The following table summarizes the activity in the liability for asset retirement obligations:

millions of dollars	**2013**	2012
Balance as at January 1	**966**	936
Additions	**251**	61
Reductions due to property sales	**-**	(8)
Accretion	**105**	86
Settlement	**(85)**	(109)
Balance as at December 31	**1,237**	966

6. Derivatives and financial instruments

The company did not enter into any derivative instruments to offset exposures associated with hydrocarbon prices, foreign currency exchange rates and interest rates that arose from existing assets, liabilities and transactions in the past three years. The company did not engage in speculative derivative activities or derivative trading activities nor did it use derivatives with leveraged features. The company maintains a system of controls that includes a policy covering the authorization, reporting and monitoring of derivative activity.

The fair value of the company s financial instruments is determined by reference to various market data and other appropriate valuation techniques. There are no material differences between the fair values of the company s financial instruments and the recorded book value. The fair value hierarchy for long-term debt is primarily Level 2 (observable input).

7. Share-based incentive compensation programs

Share-based incentive compensation programs are designed to retain selected employees, reward them for high performance and promote individual contribution to sustained improvement in the company s future business performance and shareholder value.

Restricted stock units and deferred share units

Under the restricted stock unit plan, each unit entitles the recipient to the conditional right to receive from the company, upon exercise, an amount equal to the five-day average of the closing price of the company s common shares on the Toronto Stock Exchange on and immediately prior to the exercise dates. Fifty percent of the units are exercised three years following the grant date, and the remainder is exercised seven years following the grant date. The company may also issue units where 50 percent of the units are exercisable five years following the grant date and the remainder is exercisable on the later of ten years following the grant date or the retirement date of the recipient.

Notes to consolidated financial statements (continued)

The deferred share unit plan is made available to nonemployee directors. The nonemployee directors can elect to receive all or part of their directors fees in units. The number of units granted is determined at the end of each calendar quarter by dividing the dollar amount of the nonemployee director s fees for that calendar quarter elected to be received as deferred share units by the average closing price of the company s shares for the five consecutive trading days immediately prior to the last day of the calendar quarter. Additional units are granted based on the cash dividend payable on the company s shares divided by the average closing price immediately prior to the payment date for that dividend and multiplying the resulting number by the number of deferred share units held by the recipient, as adjusted for any share splits. Deferred share units cannot be exercised until after resignation as a director and must be exercised no later than December 31 of the year following resignation. On the exercise date, the cash value to be received for the units is determined based on the average closing price of the company s shares for the five consecutive trading days immediately prior to the date of exercise, as adjusted for any share splits.

All units require settlement by cash payments with the following exceptions. The restricted stock unit program provides that, for units granted to Canadian residents, the recipient may receive one common share of the company per unit or elect to receive the cash payment for the units to be exercised in the seventh year following the grant date. For units where 50 percent are exercisable five years following the grant date and the remainder exercisable on the later of ten years following the grant date or the retirement date of the recipient, the recipient may receive one common share of the company per unit or elect to receive cash payment for all units to be exercised.

The company accounts for all units by using the fair-value-based method. The fair value of awards in the form of restricted stock and deferred share units is the market price of the company s stock. Under this method, compensation expense related to the units of these programs is measured each reporting period based on the company s current stock price and is recorded in the consolidated statement of income over the requisite service period of each award.

The following table summarizes information about these units for the year ended December 31, 2013:

	Restricted stock units	Deferred share units
Outstanding at January 1, 2013	**8,943,104**	**85,505**
Granted	**1,654,540**	**12,731**
Exercised	**(1,841,408)**	**-**
Forfeited and cancelled	**(41,382)**	**-**
Outstanding at December 31, 2013	**8,714,854**	**98,236**

In 2013, the compensation expense charged against income for these programs was $92 million (2012 - $58 million, 2011 - $91 million). Income tax benefit recognized in income related to compensation expense for the year was $33 million (2012 - $20 million, 2011 - $33 million). Cash payments of $88 million were made for these programs in 2013 (2012 - $97 million, 2011 - $173 million).

As of December 31, 2013, there was $194 million of total before-tax unrecognized compensation expense related to non-vested restricted stock units based on the company s share price at the end of the current reporting period. The weighted average vesting period of nonvested restricted stock units is 3.7 years. All units under the deferred share programs have vested as of December 31, 2013.

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Notes to consolidated financial statements (continued)

8. Investment and other income

Investment and other income includes gains and losses on asset sales as follows:

millions of dollars	**2013**	2012	2011
Proceeds from asset sales	**160**	226	314
Book value of assets sold	**10**	132	117
Gain/(loss) on asset sales, before tax (a)	**150**	94	197
Gain/(loss) on asset sales, after tax (a)	**120**	72	153

(a) 2013 included a gain of $85 million ($73 million after tax) for the sale of non-operating assets.

9. Litigation and other contingencies

A variety of claims have been made against Imperial Oil Limited and its subsidiaries in a number of lawsuits. Management has regular litigation reviews, including updates from corporate and outside counsel, to assess the need for accounting recognition or disclosure of these contingencies. The company accrues an undiscounted liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The company does not record liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavourable outcome is reasonably possible and which are significant, the company discloses the nature of the contingency and, where feasible, an estimate of the possible loss. For purposes of the company s contingency disclosures, significant includes material matters as well as other matters which management believes should be disclosed. Based on a consideration of all relevant facts and circumstances, the company does not believe the ultimate outcome of any currently pending lawsuits against the company will have a material adverse effect on the company s operations, financial condition, or financial statements taken as a whole.

Additionally, the company has other commitments arising in the normal course of business for operating and capital needs, all of which are expected to be fulfilled with no adverse consequences material to the company s operations or financial condition. Unconditional purchase obligations, as defined by accounting standards, 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.

	Payments due by period						
millions of dollars	2014	2015	2016	2017	2018	After 2018	Total
Unconditional purchase obligations (a)	**91**	**80**	**82**	**83**	**84**	**237**	**657**

(a) Undiscounted obligations of $657 million mainly pertain to pipeline throughput agreements. Total payments under unconditional purchase obligations were $95 million (2012 - $86 million, 2011 - $73 million). The present value of these commitments, excluding imputed interest of $178 million, totalled $479 million.

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Notes to consolidated financial statements (continued)

10. Common shares

thousands of shares	**As at Dec. 31 2013**	As at Dec. 31 2012
Authorized	**1,100,000**	1,100,000

From 1995 through 2012, the company purchased shares under eighteen 12-month normal course issuer bid share repurchase programs, as well as an auction tender. On June 25, 2013, another 12-month normal course issuer bid program was implemented with an allowable purchase of up to a maximum of one million shares. Unlike prior programs, this maximum amount is not reduced by common shares purchased for the company s employee savings plan, the company s employee retirement plan and from Exxon Mobil Corporation. The results of these activities are as shown below.

Year	Purchased shares (thousands)	Millions of dollars
1995 to 2011	903,765	15,580
2012	2,776	128
2013	**-**	**-**
Cumulative purchases to date	906,541	15,708

ExxonMobil s participation in the above maintained its ownership interest in Imperial at 69.6 percent.

The excess of the purchase cost over the stated value of shares purchased has been recorded as a distribution of earnings reinvested.

The company s common share activities are summarized below:

	Thousands of shares	Millions of dollars
Balance as at January 1, 2011	847,599	1,511
Issued under employee share-based awards	1,262	19
Purchases at stated value	(1,262)	(2)
Balance as at December 31, 2011	847,599	1,528
Issued under employee share-based awards	2,776	43
Purchases at stated value	(2,776)	(5)
Balance as at December 31, 2012	847,599	1,566

Issued under employee share-based awards	**-**	**-**
Purchases at stated value	**-**	**-**
Balance as at December 31, 2013	**847,599**	**1,566**

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Notes to consolidated financial statements (continued)

The following table provides the calculation of basic and diluted earnings per share:

	2013	2012	2011
Net income per common share basic			
Net income (millions of dollars)	**2,828**	3,766	3,371
Weighted average number of common shares outstanding (millions of shares)	**847.6**	847.7	847.7
Net income per common share (dollars)	**3.34**	4.44	3.98
Net income per common share - diluted			
Net income (millions of dollars)	**2,828**	3,766	3,371
Weighted average number of common shares outstanding (millions of shares)	**847.6**	847.7	847.7
Effect of employee share-based awards (millions of shares)	**3.0**	3.4	5.9
Weighted average number of common shares outstanding, assuming dilution (millions of shares)	**850.6**	851.1	853.6
Net income per common share (dollars)	**3.32**	4.42	3.95

11. Miscellaneous financial information

In 2013, net income included an after-tax gain of $24 million (2012 $45 million gain, 2011 $10 million gain) attributable to the effect of changes in last-in, first-out (LIFO) inventories. The replacement cost of inventories was estimated to exceed their LIFO carrying values at December 31, 2013 by $1,787 million (2012 $1,769 million). Inventories of crude oil and products at year-end consisted of the following:

millions of dollars	**2013**	2012
Crude oil	**628**	473
Petroleum products	**340**	284
Chemical products	**54**	60
Natural gas and other	**8**	10
Total inventories of crude oil and products	**1,030**	827

Net research and development costs charged to expenses in 2013 were $154 million (2012 $147 million, 2011 $120 million). These costs are included in expenses due to the uncertainty of future benefits.

Accounts payable and accrued liabilities included accrued taxes other than income taxes of $380 million at December 31, 2013 (2012 - $377 million).

12. Financing costs and additional notes and loans payable information

millions of dollars	**2013**	2012	2011
Debt-related interest	**69**	20	16
Capitalized interest	**(69)**	(20)	(16)
Net interest expense	**-**	-	-
Other interest	**11**	(1)	3
Total financing costs (a)	**11**	(1)	3

(a) Cash interest payments in 2013 were $69 million (2012 $20 million, 2011 $16 million). The weighted average interest rate on short-term borrowings in 2013 was 1.1 percent (2012 1.1 percent).

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Notes to consolidated financial statements (continued)

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 (Canadian). 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.

In the first quarter of 2013, to further support the commercial paper program, the company entered into an unsecured committed bank credit facility in the amount of $250 million that matures in March 2014. In the second quarter, the amount of this facility increased to $500 million. The company has not drawn on the facility.

13. Leased facilities

At December 31, 2013, the company held non-cancelable operating leases covering office buildings, rail cars, service stations and other properties with minimum undiscounted lease commitments totaling $389 million as indicated in the following table:

	Payments due by period						
millions of dollars	2014	2015	2016	2017	2018	After 2018	Total
Lease payments under minimum commitments (a)	**177**	**88**	**47**	**33**	**12**	**32**	**389**

(a) Net rental cost under cancelable and non-cancelable operating leases incurred in 2013 was $287 million (2012 $271 million, 2011 $226 million). Related rental income was not material.

14. Long-term debt

millions of dollars	**As at Dec. 31 2013**	As at Dec. 31 2012
Long-term debt (a)	**4,316**	1,040
Capital leases (b)	**128**	135
Total long-term debt	**4,444**	1,175

(a) Borrowed under an existing agreement with an affiliated company of ExxonMobil that provides for a long-term, variable-rate loan from ExxonMobil to the company of up to $5 billion (Canadian) at interest equivalent to Canadian market rates. The agreement is effective until July 31, 2020, cancelable if ExxonMobil provides at least 370 days advance written notice. Average effective rate for the loan was 1.3 percent in 2013.

(b) Capitalized lease obligations primarily relate to capital leases for pipeline transportation and marine services agreements. The average imputed rate was 7.0 percent in 2013 (2012 9.6 percent). Total capitalized lease obligations also include $7 million in current liabilities (2012 - $7 million). Principal payments on capital leases of approximately $7 million per year are due in each of the next four years after December 31, 2014.

In the first quarter of 2013, the company increased the amount of its existing stand-by long term bank credit facility from $300 million to $500 million. In the third quarter, the company extended the maturity date of this facility to August 2015. The company has not drawn on the facility.

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.

Notes to consolidated financial statements (continued)

15. Accounting for 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. 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.

The following two tables provide details of the changes in the balance of suspended exploratory well costs as well as an aging summary of those costs.

Change in capitalized suspended exploratory well costs:

millions of dollars	**2013**	2012	2011
Balance as at January 1	**167**	163	120
Additions pending the determination of proved reserves	**12**	16	43
Charged to expense	**-**	-	-
Reclassification to wells, facilities and equipment based on the determination of proved reserves	**(6)**	(12)	-
Balance as at December 31	**173**	167	163

Period end capitalized suspended exploratory well costs:

millions of dollars	**2013**	2012	2011
Capitalized for a period of one year or less	**6**	16	43
Capitalized for a period of between one and five years	**167**	151	120
Capitalized for a period of greater than one year	**167**	151	120
Total	**173**	167	163

Exploration activity often involves drilling multiple wells, over a number of years, to fully evaluate a project. The table below provides a numerical breakdown of the number of projects with suspended exploratory well costs which had their first capitalized well drilled in the preceding 12 months and those that have had exploratory well costs capitalized for a period greater than 12 months.

	2013	2012	2011
	-	-	1

Number of projects with first capitalized well drilled in the preceding 12 months			
Number of projects that have exploratory well costs capitalized for a period of greater than 12 months	**1**	1	1
Total	**1**	1	2

The project with exploratory well costs capitalized for a period greater than 12 months as of December 31, 2013 had drilling in the preceding 12 months.

Notes to consolidated financial statements (continued)

16. Transactions with related parties

Revenues and expenses of the company also include the results of transactions with Exxon Mobil Corporation and affiliated companies (ExxonMobil) in the normal course of operations. These were conducted on terms comparable to those which would have been conducted with unrelated parties and primarily consisted of the purchase and sale of crude oil, natural gas, petroleum and chemical products, as well as technical, engineering and research and development costs. Transactions with ExxonMobil also included amounts paid and received in connection with the company s participation in a number of upstream activities conducted jointly in Canada.

In addition, the company has existing agreements with ExxonMobil to:

a) provide computer and customer support services to the company and to share common business and operational support services that allow the companies to consolidate duplicate work and systems;

b) operate certain western Canada production properties owned by ExxonMobil as well as provide for the delivery of management, business and technical services to ExxonMobil in Canada. These agreements are designed to provide organizational efficiencies and to reduce costs. No separate legal entities were created from these arrangements. Separate books of account continue to be maintained for the company and ExxonMobil. The company and ExxonMobil retain ownership of their respective assets, and there is no impact on operations or reserves;

c) provide for the delivery of management, business and technical services to Syncrude Canada Ltd. by ExxonMobil; and

d) provide for the option of equal participation in new upstream opportunities.

Certain charges from ExxonMobil have been capitalized; they are not material in the aggregate.

As at December 31, 2013, the company had outstanding long-term loans of $4,316 million (2012 $1,040 million) and short-term loans of $75 million (2012 nil) from ExxonMobil (see note 14, long-term debt, on page 77 and note 12, financing costs and additional notes and loans payable, on page 76 for further details).

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Notes to consolidated financial statements (continued)

17. Other comprehensive income information

Changes in accumulated other comprehensive income:

millions of dollars	**2013**	2012	2011
Balance as at January 1	**(2,455)**	(2,238)	(1,424)
Post-retirement benefits liability adjustment:			
Current period change excluding amounts reclassified from accumulated other comprehensive income	**529**	(415)	(953)
Amounts reclassified from accumulated other comprehensive income	**205**	198	139
Balance as at December 31	**(1,721)**	(2,455)	(2,238)

Amounts reclassified out of accumulated other comprehensive income before tax income/(expense)

millions of dollars	**2013**	2012	2011
Amortization of post-retirement benefits liability adjustment included in net periodic benefit cost (a)	**(276)**	(266)	(186)

(a) This accumulated other comprehensive income component is included in the computation of net periodic benefit cost (note 4).

Income tax expense/(credit) for components of other comprehensive income

millions of dollars	**2013**	2012	2011
Post-retirement benefits adjustments:			
Post-retirement benefits liability adjustment (excluding amortization)	**185**	(155)	(326)
Amortization of post-retirement benefits liability adjustment included in net periodic benefit cost	**71**	68	47
Total	**256**	(87)	(279)

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Notes to consolidated financial statements (continued)

18. Acquisition

Description of the Transaction: On February 26, 2013, ExxonMobil Canada acquired Celtic Exploration Ltd. (Celtic). Immediately following the acquisition, Imperial acquired a 50 percent interest in Celtic s assets and liabilities from ExxonMobil Canada for $1.6 billion, financed by a combination of related party and third party debt. Concurrently, a general partnership was formed to hold and operate the assets of Celtic. The name of the general partnership was changed to XTO Energy Canada (XTO Canada). XTO Canada is involved in the exploration for, production of, and transportation and sale of natural gas and crude oil, condensate and natural gas liquids.

Recording of Assets Acquired and Liabilities Assumed: Imperial used the acquisition method of accounting to record its pro-rata share of the assets acquired and liabilities assumed. This method requires, among other things, that assets acquired and liabilities assumed be recognized at their fair values as of the acquisition date. The following table summarizes the assets acquired and liabilities assumed:

millions of dollars	
Cash	6
Accounts receivable	38
Materials, supplies and prepaid expenses	5
Property, plant and equipment (a)	2,045
Goodwill (b)	20
Total assets acquired	2,114
Accounts payable and accrued liabilities	62
Deferred income tax liabilities (c)	377
Other long-term obligations	67
Total liabilities assumed	506
Net assets acquired	1,608

(a) Property, plant and equipment were measured primarily using an income approach. The fair value measurements of the oil and gas assets were based, in part, on significant inputs not observable in the market and thus represent a Level 3 measurement. The significant inputs included Celtic resources, assumed future production profiles, commodity prices (mainly based on observable market inputs), risk adjusted discount rate of 10 percent, inflation of 2 percent and assumptions on the timing and amount of future development and operating costs. The property, plant and equipment additions were segmented to the Upstream business, with all of the assets in Canada.

(b) Goodwill was the excess of the consideration transferred over the net assets recognized and represents the future economic benefits arising from other assets acquired that could not be individually identified and separately recognized. Goodwill was recognized in the Upstream reporting unit. Goodwill is not amortized and is not deductible for tax purposes.

(c) Deferred income taxes reflect the future tax consequences on the temporary differences between the amount of assets and liabilities recognized for financial reporting purposes and such amounts recognized for tax purposes. The deferred income taxes recorded as part of the acquisition were:

millions of dollars	
Property, plant and equipment	414
Total deferred income tax liabilities	414
Asset retirement obligations	(17)
Other	(20)
Total deferred income tax assets	(37)
Net deferred income tax liabilities	377

Actual and Pro Forma Impact of the Acquisition: Revenues for XTO Canada from the acquisition date included in the company s consolidated financial statement of income for the twelve months ended December 31, 2013 were $89 million. After-tax earnings for XTO Canada from the acquisition date through December 31, 2013 were de minimis.

Transaction costs related to the acquisition were expensed as incurred and were de minimis in the twelve months ended December 31, 2013.

Unaudited pro forma revenues, earnings and basic and diluted earnings per share information as if the acquisition had occurred at the beginning of 2013 or the comparable prior reporting period is not presented, since the effect on Imperial s consolidated annual financial results for the year ended December 31, 2013 and the comparable prior reporting periods, would not have been material.

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Supplemental information on oil and gas exploration and production activities (unaudited)

The information on pages 82 to 83 excludes items not related to oil and natural gas extraction, such as administrative and general expenses, pipeline operations, gas plant processing fees and gains or losses on asset sales. The company s 25 percent interest in proved synthetic oil reserves in the Syncrude joint-venture and 70.96 percent interest in proved bitumen reserves in the Kearl project are included as part of the company s total proved oil and gas reserves in accordance with U.S. Securities and Exchange Commission (SEC) and U.S. Financial Accounting Standards Board (FASB) rules. Similarly, the company s share of proved synthetic oil reserves from Syncrude and proved bitumen reserves from Kearl are included in the calculation of the standardized measure of discounted future cash flows. Results of operations, costs incurred in property acquisitions, exploration and development activities, and capitalized costs include the company s share of Syncrude, Kearl and other unproved mineable acreages in the following tables.

The company s share of results of operations, costs incurred in property acquisitions, exploration and development activities and capitalized costs relating to Celtic (XTO Canada) are included in the following tables for the first time in 2013. Similarly, the company s share of proved reserves for Celtic (XTO Canada) are included as part of the company s total proved oil and gas reserves and in the calculation of the standardized measure of discounted future cash flows.

Results of operations

millions of dollars	**2013**	2012	2011
Sales to customers (a)	**2,282**	2,074	2,185
Intersegment sales (a)(b)	**3,905**	3,534	3,828
	6,187	5,608	6,013
Production expenses	**3,392**	2,589	2,352
Exploration expenses	**123**	83	90
Depreciation and depletion	**586**	498	530
Income taxes	**512**	584	718
Results of operations	**1,574**	1,854	2,323

The amounts reported as costs incurred in property acquisitions, exploration and development activities include both capitalized costs and costs charged to expense during the year. Costs incurred also include new asset retirement obligations established in the current year, as well as increases or decreases to the asset retirement obligation resulting from changes in cost estimates or abandonment date.

Costs incurred in property acquisitions, exploration and development activities

millions of dollars	**2013**	2012	2011
Property costs (c)			
Proved	**34**	-	-
Unproved	**2,013**	33	114
Exploration costs	**124**	109	133
Development costs	**5,847**	5,125	3,792
Total costs incurred in property acquisitions, exploration and development activities	**8,018**	5,267	4,039

(a) Sales to customers or intersegment sales do not include the sale of natural gas and natural gas liquids purchased for resale, as well as royalty payments. These items are reported gross in note 2 in operating revenues , intersegment sales and in purchases of crude oil and products .

(b) Sales of crude oil to consolidated affiliates are at market value, using posted field prices. Sales of natural gas liquids to consolidated affiliates are at prices estimated to be obtainable in a competitive, arm s-length transaction.

(c) Property costs are payments for rights to explore for petroleum and natural gas and for purchased reserves (acquired tangible and intangible assets such as gas plants, production facilities and producing-well costs are included under producing assets). Proved represents areas where successful drilling has delineated a field capable of production. Unproved represents all other areas.

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Supplemental information on oil and gas exploration and production activities (unaudited) (continued)

Capitalized costs

millions of dollars	**2013**	2012
Property costs (c)		
Proved	**3,017**	2,974
Unproved	**2,621**	616
Producing assets	**23,811**	13,322
Incomplete construction	**8,286**	13,062
Total capitalized cost	**37,735**	29,974
Accumulated depreciation and depletion	**(10,686)**	(10,140)
Net capitalized costs	**27,049**	19,834

(c) Property costs are payments for rights to explore for petroleum and natural gas and for purchased reserves (acquired tangible and intangible assets such as gas plants, production facilities and producing-well costs are included under producing assets). Proved represents areas where successful drilling has delineated a field capable of production. Unproved represents all other areas.

Standardized measure of discounted future cash flows

As required by the FASB, the standardized measure of discounted future net cash flows is computed by applying first-day-of-the-month average prices, year-end costs and legislated tax rates and a discount factor of 10 percent to net proved reserves. The standardized measure includes costs for future dismantlement, abandonment and remediation obligations. The company believes the standardized measure does not provide a reliable estimate of the company s expected future cash flows to be obtained from the development and production of its oil and gas properties or of the value of its proved oil and gas reserves. The standardized measure is prepared on the basis of certain prescribed assumptions, including first-day-of-the-month average prices, which represent discrete points in time and therefore may cause significant variability in cash flows from year to year as prices change.

Standardized measure of discounted future net cash flows related to proved oil and gas reserves

millions of dollars	**2013**	2012	2011
Future cash flows	**231,873**	227,253	224,130
Future production costs	**(92,926)**	(83,600)	(82,903)
Future development costs	**(32,126)**	(31,051)	(27,259)
Future income taxes	**(23,707)**	(25,902)	(26,671)
Future net cash flows	**83,114**	86,700	87,297
Annual discount of 10 percent for estimated timing of cash flows	**(58,204)**	(61,864)	(61,277)
Discounted future cash flows	**24,910**	24,836	26,020

Changes in standardized measure of discounted future net cash flows related to proved oil and gas reserves

Balance at beginning of year	**24,836**	26,020	21,251
Changes resulting from:			
Sales and transfers of oil and gas produced, net of production costs	**(3,026)**	(3,116)	(3,764)
Net changes in prices, development costs and production costs	**(17,683)**	(6,810)	2,845
Extensions, discoveries, additions and improved recovery, less related costs	**31**	2,698	1,694
Development costs incurred during the year	**5,500**	5,086	3,583
Revisions of previous quantity estimates	**12,321**	(805)	165
Accretion of discount	**1,703**	997	1,725
Net change in income taxes	**1,228**	766	(1,479)
Net change	**74**	(1,184)	4,769
Balance at end of year	**24,910**	24,836	26,020

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Supplemental information on oil and gas exploration and production activities (unaudited) (continued)

Net Proved Reserves (a)

	Liquids (b)	Natural gas	Synthetic oil	Bitumen	Total oil-equivalent basis (c)
	millions of barrels	billions of cubic feet	millions of barrels	millions of barrels	millions of barrels
Beginning of year 2011	57	576	681	1,715	2,549
Revisions	4	11	(4)	36	38
Improved recovery	-	-	-	-	-
(Sale)/purchase of reserves in place	-	(103)	-	-	(17)
Discoveries and extensions	-	21	-	706	709
Production	(6)	(83)	(24)	(44)	(88)
End of year 2011	55	422	653	2,413	3,191
Revisions	5	98	(29)	239	231
Improved recovery	-	-	-	-	-
(Sale)/purchase of reserves in place	-	(7)	-	-	(1)
Discoveries and extensions	-	47	-	234	242
Production	(7)	(72)	(25)	(45)	(89)
End of year 2012	53	488	599	2,841	3,574
Revisions	**6**	**(2)**	**4**	**78**	**88**
Improved recovery	**-**	**-**	**-**	**-**	**-**
(Sale)/purchase of reserves in place	**10**	**261**	**-**	**-**	**54**
Discoveries and extensions	**-**	**-**	**-**	**-**	**-**
Production	**(7)**	**(69)**	**(24)**	**(52)**	**(94)**
End of year 2013	**62**	**678**	**579**	**2,867**	**3,622**
Net Proved Developed Reserves included above, as of					
January 1, 2011	56	507	681	519	1,340
December 31, 2011	55	360	653	519	1,287
December 31, 2012	52	373	599	543	1,256
December 31, 2013	**55**	**368**	**579**	**1,417**	**2,113**
Net Proved Undeveloped Reserves included above, as of					

January 1, 2011	1	69	-	1,196	1,209
December 31, 2011	-	62	-	1,894	1,904
December 31, 2012	1	115	-	2,298	2,318
December 31, 2013	**7**	**310**	**-**	**1,450**	**1,509**

(a) Net reserves are the company s share of reserves after deducting the shares of mineral owners or governments or both. All reported reserves are located in Canada. Reserves of natural gas are calculated at a pressure of 14.73 pounds per square inch at 60°F.

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

(c) Gas converted to oil-equivalent at 6 million cubic feet per one thousand barrels.

The information above describes changes during the years and balances of proved oil and gas reserves at year-end 2011, 2012 and 2013. The definitions used are in accordance with the U.S. Securities and Exchange Commission s (SEC) Rule 4-10 (a) of Regulation S-X.

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expire. In some cases, substantial new investments in additional wells and other facilities will be required to recover these proved reserves.

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Supplemental information on oil and gas exploration and production activities (unaudited) (continued)

In accordance with SEC rules, the year-end reserves volumes as well as the reserves change categories shown in the proved reserves tables were calculated using average prices during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period. These reserves quantities were also used in calculating unit-of-production depreciation rates and in calculating the standardized measure of discounted net cash flow.

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 costs that are used in the estimation of reserves. This category can also include significant changes in either development strategy or production equipment/facility capacity.

In 2013, the quantities of proved liquids and natural gas reserves shown in the sale/purchase category reflected the company s share of reserves from the Celtic acquisition.

Net proved reserves are determined by deducting the estimated future share of mineral owners or governments or both. For liquids and natural gas, net proved reserves are based on estimated future royalty rates as of the date the estimate is made incorporating the applicable governments oil and gas royalty regimes. For bitumen, net proved reserves are based on the company s best estimate of average royalty rates over the life of each of the Cold Lake and Kearl projects, and they incorporate the Alberta government s revised oil sands royalty regime. For synthetic oil, net proved reserves are based on the company s best estimate of average royalty rates over the life of the project, and they incorporate amendments to the Syncrude Crown Agreement. In all cases, actual future royalty rates may vary with production, price and costs.

Net proved developed reserves are those volumes that are expected to be recovered through existing wells and facilities with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well or facility. Net proved undeveloped reserves are those volumes that are expected to be recovered as a result of future investments to drill new wells, to recomplete existing wells and/or to install facilities to collect and deliver the production from existing and future wells and facilities.

In 2013, increased proved developed bitumen reserves were largely due to the start-up of the initial development at Kearl in the second quarter of 2013, resulting in a migration of proved undeveloped reserves to proved developed.

No independent qualified reserves evaluator or auditor was involved in the preparation of the reserves data.

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Quarterly financial and stock trading data (a)

	2013				2012			
	three months ended				three months ended			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**	Dec. 31	Sept. 30	June 30	Mar. 31
Financial data (millions of dollars)								
Total revenues and other income	**8,363**	**8,594**	**7,958**	**8,014**	7,804	8,336	7,515	7,533
Total expenses	**6,985**	**7,737**	**7,526**	**6,944**	6,390	6,949	6,675	6,181
Income before income taxes	**1,378**	**857**	**432**	**1,070**	1,414	1,387	840	1,352
Income taxes	**322**	**210**	**105**	**272**	338	347	205	337
Net income	**1,056**	**647**	**327**	**798**	1,076	1,040	635	1,015
Segmented net income (millions of dollars)								
Upstream	**411**	**604**	**397**	**300**	488	498	360	542
Downstream	**625**	**46**	**(97)**	**478**	549	536	232	455
Chemical	**46**	**39**	**42**	**35**	44	37	49	35
Corporate and Other	**(26)**	**(42)**	**(15)**	**(15)**	(5)	(31)	(6)	(17)
Net income	**1,056**	**647**	**327**	**798**	1,076	1,040	635	1,015
Per-share information (dollars)								
Net earnings basic	**1.25**	**0.76**	**0.39**	**0.94**	1.27	1.22	0.75	1.20
Net earnings diluted	**1.24**	**0.76**	**0.38**	**0.94**	1.26	1.22	0.75	1.19
Dividends (declared quarterly)	**0.13**	**0.12**	**0.12**	**0.12**	0.12	0.12	0.12	0.12
Share prices (dollars) (b)								
Toronto Stock Exchange								
High	**47.57**	**46.10**	**41.82**	**45.44**	46.25	48.32	46.68	49.26
Low	**43.19**	**40.32**	**38.58**	**41.42**	41.44	41.43	39.77	43.72
Close	**47.04**	**45.23**	**40.15**	**41.52**	42.73	45.25	42.59	45.32
NYSE MKT (U.S. dollars) (b)								
High	**45.67**	**44.65**	**41.15**	**45.16**	47.02	50.00	47.36	49.32
Low	**41.55**	**38.22**	**37.09**	**40.68**	42.06	40.50	38.16	43.72
Close	**44.23**	**43.96**	**38.21**	**40.86**	43.00	46.03	41.72	45.39
Shares traded (thousands) (c)	**67,673**	**77,781**	**95,600**	**103,979**	44,615	52,065	66,394	64,643

(a) Quarterly data has not been audited by the company s independent auditors.

(b) Imperial s shares are listed on the Toronto Stock Exchange. The company s shares also trade in the United States of America on the NYSE MKT LLC. Imperial has unlisted privileges on the NYSE MKT LLC, a subsidiary of NYSE Euronext. The symbol on these exchanges for Imperial s common shares is IMO. Share prices were obtained from stock exchange records. U.S. dollar share price presented is based on consolidated U.S. market data.

(c) The number of shares traded is based on transactions on the above stock exchanges. For 2012, share volumes in the U.S. included NYSE and alternative platform trades and TSX volumes for Canada. Commencing in 2013 share volumes include trades on alternative Canadian platforms, information that was previously unavailable.

Proxy information section

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III. Board of directors

Director information

The tables on the following pages provide information on the seven nominees proposed for election to the board of directors of the company. All of the nominees are now directors and have been since the dates indicated.

Included in these tables is information relating to the director nominees biographies, independence status, expertise, committee memberships, attendance, public board memberships, non-profit sector affiliations and shareholdings in the company, as well as any shareholdings in Exxon Mobil Corporation. The information is as of February 13, 2014, the effective date of this circular, unless otherwise indicated.

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Krystyna T. Hoeg

Toronto, Ontario, Canada

Ms. Hoeg was the president and chief executive officer of Corby Distilleries Limited from 1996 until her retirement in February 2007. She previously held several positions in the finance and controllers functions of Allied Domecq PLC and Hiram Walker & Sons Limited. Prior to that, she spent five years in public practice as a chartered accountant with the accounting firm of Touche Ross. She is currently a director of Sun Life Financial Inc., Shoppers Drug Mart Corporation, Canadian Pacific Railway Limited and Canadian Pacific Railway Company, and is also a director of Samuel, Son & Co. Limited, a privately owned corporation. Ms. Hoeg sits on the board of the Toronto East General Hospital.

Age: 64

Current Position:

Nonemployee director

Independent

Director since May 1, 2008

Normally ineligible for re-election in 2022

Board and Committee Membership	**Attendance in 2013**	
Imperial Oil Limited board	8 of 8	100%
Audit committee	5 of 5	100%
Executive resources committee **(Chair)**	10 of 10	100%
Environment, health and safety committee	3 of 3	100%
Nominations and corporate governance committee	4 of 4	100%
Contributions committee	3 of 3	100%
Annual meeting of shareholders	1 of 1	100%

Skills and experience:

- Leadership of large organizations
- Project management
- Global experience
- Strategy development
- Audit committee financial expert

Overall Attendance 100%

Imperial Oil Limited Equity Ownership (a) (b) (c) (d)

As at	Common	Deferred	Restricted	Total Common

Financial expertise Executive compensation		Shares (% of class)	Share Units (DSU)	Stock Units (RSU)	Shares, DSU and RSU	Total Market Value of Common Shares, DSU and RSU ($)
Voting Results of 2013 Annual General Meeting:	February 13, 2014	0	18,093	9,000	27,093	1,280,686
Votes For: 739,037,993 (99.83%) **Votes Withheld:** 1,231,781 (0.17%) **Total Votes:** 740,269,711	February 13, 2013	0	14,678	8,000	22,678	968,351
	Change	0	3,415	1,000	4,415	312,335

Share ownership guidelines have been met.

Exxon Mobil Corporation Equity Ownership (a) (c) (e)

As at	Common Shares (% of class)	Restricted Stock	Total Common Shares and Restricted Stock	Total Market Value of Common Shares and Restricted Stock ($)
February 13, 2014	0	0	0	0

Public Company Directorships in the Past Five Years

Sun Life Financial Inc. (2002 Present)

Shoppers Drug Mart Corporation (2006 Present)

Canadian Pacific Railway Limited (2007 Present)

Canadian Pacific Railway Company (2007 Present)

Cineplex Galaxy Income Fund (2006 2010)

Public Board Interlocks

None

Other Positions in the Past Five Years (position, date office held and status of employer)

No other positions held in the last five years

Non-profit sector affiliations

Toronto East General Hospital (Board of Directors)

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Richard M. Kruger

Calgary, Alberta, Canada

Age: 54

Current Position: Chairman, president and chief executive officer, Imperial Oil Limited (as of March 1, 2013)

Not independent

Director since March 1, 2013

Skills and experience:

- Leadership of large organizations
- Operations/technical
- Project management
- Global experience
- Strategy development

Mr. Kruger was appointed chairman, president and chief executive officer of Imperial Oil Limited effective March 1, 2013. Mr. Kruger has worked for Exxon Mobil Corporation and its predecessor companies since 1981 in various upstream and downstream assignments with responsibilities in the United States, the former Soviet Union, the Middle East, Africa and Southeast Asia. In his previous position, Mr. Kruger was vice-president of Exxon Mobil Corporation and president of ExxonMobil Production Company, a division of Exxon Mobil Corporation, with responsibility for ExxonMobil s global oil and gas producing operations.

Board and Committee Membership	**Attendance in 2013**	
Imperial Oil Limited board **(Chair)** (appointed March 1, 2013)	6 of 6	100%
Contributions committee (appointed March 1, 2013)	2 of 2	100%
Annual meeting of shareholders	1 of 1	100%
	Overall Attendance	**100%**

Imperial Oil Limited Equity Ownership (a) (b) (c) (d)

As at	Common Shares (% of class)	Deferred Share Units (DSU)	Restricted Stock Units (RSU)	Total Common Shares, DSU and RSU	Total Market Value of Common Shares, DSU and RSU ($)
	0	0	91,400	91,400	4,320,478

Financial expertise

Government relations

Executive compensation

February 13, 2014

Share ownership guidelines are expected to be met in 2014.

Voting Results of 2013

Annual General Meeting:

Votes For: 721,250,808 (97.43%)

Votes Withheld: 19,024,883 (2.57%)

Total Votes: 740,275,691

Exxon Mobil Corporation Equity Ownership (a) (c) (e)

As at	Common Shares (% of class)	Restricted Stock	Total Common Shares and Restricted Stock	Total Market Value Common Shares and Restricted Stock ($)
February 13, 2014	8,868 (<0.01%)	229,300	238,168	23,909,719

Public Company Directorships in the Past Five Years

None

Public Board Interlocks

None

Other Positions in the Past Five Years (position, date office held and status of employer)

Vice-president, Exxon Mobil Corporation and President, ExxonMobil Production Company, a division of Exxon Mobil Corporation (2008 - 2013) (Affiliate)

Non-profit sector affiliations

United Way of Calgary and Area (Board of Directors)

University of Minnesota s College of Engineering and Science (Advisory Board)

Canadian Council of Chief Executives (Member)

Society of Petroleum Engineers (Member)

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Jack M. Mintz

Dr. Mintz is currently the Palmer Chair in Public Policy for the University of Calgary. Prior to that he was a professor at the Joseph L. Rotman School of Management at the University of Toronto from 1989. Dr. Mintz is a director of Morneau Shepell Inc. Dr. Mintz has published widely in the fields of public economics and fiscal federalism and has frequently published articles in national newspapers and magazines.

Calgary, Alberta, Canada

Age: 62

Current Position:

Nonemployee director

Independent

Director since April 21, 2005

Normally ineligible for re-election in 2023

Board and Committee Membership	**Attendance in 2013**	
Imperial Oil Limited board	8 of 8	100%
Audit committee	5 of 5	100%
Executive resources committee	10 of 10	100%
Environment, health and safety committee **(Chair)**	3 of 3	100%
Nominations and corporate governance committee	4 of 4	100%
Contributions committee	3 of 3	100%
Annual meeting of shareholders	1 of 1	100%

Overall Attendance 100%

Skills and experience:

- Global experience
- Strategy development
- Financial expertise
- Government relations
- Academic/research

Imperial Oil Limited Equity Ownership (a) (b) (c) (d)

As at	Common Shares	Deferred Share Units	Restricted Stock Units	Total Common Shares, DSU	Total Market Value

Executive compensation		(% of class)	(DSU)	(RSU)	and RSU	of Common Shares, DSU and RSU ($)
Voting Results of 2013 Annual General Meeting:	February 13, 2014	1,000	14,840	10,000	25,840	1,221,457
Votes For: 739,080,916 (99.84%) **Votes Withheld:** 1,188,775 (0.16%) **Total Votes:** 740,269,691	February 13, 2013	1,000 (<0.01%)	11,878	10,500	23,378	998,241
	Change	0	2,962	(500)	2,462	223,216

Share ownership guidelines have been met.

Exxon Mobil Corporation Equity Ownership (a) (c) (e)

As at	Common Shares (% of class)	Restricted Stock	Total Common Shares and Restricted Stock	Total Market Value of Common Shares and Restricted Stock ($)
February 13, 2014	0	0	0	0

Public Company Directorships in the Past Five Years

Morneau Shepell Inc. (2010 - Present)

Brookfield Asset Management Inc. (formerly Brascan Corporation) (2002 2012)

Public Board Interlocks

None

Other Positions in the Past Five Years (position, date office held and status of employer)

No other positions held in the last five years

Non-profit sector affiliations

Social Science and Humanities Research Council of Canada (Vice-president and chair of the governing council)

Centre for Economic Studies (CES) Ifo Institute, Germany (Research fellow)

Oxford Centre on Business Taxation, UK (Research fellow)

Literary Review of Canada (Board of Directors)

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David S. Sutherland

Waterloo, Ontario, Canada

Age: 64

Current Position:

Nonemployee director

Independent

Director since April 29, 2010

Normally ineligible for re-election in 2022

Skills and experience:

Leadership of large organizations

Operations/technical

Global experience

Strategy development

In July 2007, Mr. Sutherland retired as president and chief executive officer of the former IPSCO, Inc. after spending 30 years with the company and more than five years as president and chief executive officer. Mr. Sutherland is the chairman of the board of United States Steel Corporation and a director of GATX Corporation and Graham Construction. Mr. Sutherland is a former chairman of the American Iron and Steel Institute and served as a member of the board of directors of the Steel Manufacturers Association, the International Iron and Steel Institute, the Canadian Steel Producers Association and the National Association of Manufacturers.

Board and Committee Membership	**Attendance in 2013**	
Imperial Oil Limited board	8 of 8	100%
Audit committee	5 of 5	100%
Executive resources committee	10 of 10	100%
Environment, health and safety committee	3 of 3	100%
Nominations and corporate governance committee	4 of 4	100%
Contributions committee **(Chair)**	3 of 3	100%
Annual meeting of shareholders	1 of 1	100%

Overall Attendance 100%

Imperial Oil Limited Equity Ownership (a) (b) (c) (d)

Audit committee financial expert

Financial expertise

Government relations

Executive compensation

As at	Common Shares (% of class)	Deferred Share Units (DSU)	Restricted Stock Units (RSU)	Total Common Shares, DSU and RSU	Total Market Value of Common Shares DSU and RSU ($)
February 13, 2014	45,000	11,736	7,000	63,736	3,012,801
February 13, 2013	45,000 (<0.01%)	8,393	6,000	59,393	2,536,081
Change	0	3,343	1,000	4,343	476,720

Voting Results of 2013 Annual General Meeting:

Votes For: 739,229,928 (99.86%)

Votes Withheld: 1,039,763 (0.14%)

Total Votes: 740,269,691

Share ownership guidelines have been met.

Exxon Mobil Corporation Equity Ownership (a) (c) (e)

As at	Common Shares (% of class)	Restricted Stock	Total Common Shares and Restricted Stock	Total Market Value of Common Shares and Restricted Stock ($)
February 13, 2014	5,730	0	5,730	575,236

(<0.01%)

Public Company Directorships in the Past Five Years

GATX Corporation (2007 - Present)

United States Steel Corporation, (2008 Present) (Chairman since January 1, 2014)

ZCL Composites Inc. (2008 2010)

Public Board Interlocks

None

Other Positions in the Past Five Years (position, date office held and status of employer)

No other positions held in the last five years

Non-profit sector affiliations

KidsAbility, Centre for Child Development (Finance Committee)

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Sheelagh D. Whittaker

London, England

Age: 66

Current Position:

Nonemployee director

Independent

Director since April 19, 1996

Normally ineligible for re-election in 2019

Ms. Whittaker spent much of her early business career as director and partner with The Canada Consulting Group, now Boston Consulting Group. From 1989 she was president and chief executive officer of Canadian Satellite Communications (Cancom). In 1993, Ms. Whittaker joined Electronic Data Systems of Plano, Texas, then one of the world s foremost providers of information technology services. Initially spending several years as president and chief executive officer of EDS Canada, Ms. Whittaker then undertook other key leadership roles globally, ultimately serving the company as managing director, United Kingdom, Middle East and Africa, until her retirement from EDS in November 2005. Ms. Whittaker is also a director of Standard Life Canada.

Board and Committee Membership	**Attendance in 2013**	
Imperial Oil Limited board	8 of 8	100%
Audit committee	5 of 5	100%
Executive resources committee	10 of 10	100%
Environment, health and safety committee	3 of 3	100%
Nominations and corporate governance committee **(Chair)**	4 of 4	100%
Contributions committee	3 of 3	100%
Annual meeting of shareholders	1 of 1	100%

Skills and experience:

Leadership of large organizations

Global experience

Strategy development

Audit committee financial expert

Financial expertise

Overall Attendance 100%

Imperial Oil Limited Equity Ownership (a) (b) (c) (d)

As at

Government relations

Information technology

Executive compensation

Voting Results of 2013

Annual General Meeting:

Votes For: 738,522,124

(99.76%)

Votes Withheld: 1,747,567

(0.24%)

Total Votes: 740,269,691

As at	Common Shares (% of class)	Deferred Share Units (DSU)	Restricted Stock Units (RSU)	Total Common Shares, DSU and RSU	Total Market Val of Common Shar DSU and RSU ($)
February 13, 2014	9,350	43,183	10,000	62,533	2,955,935
February 13, 2013	9,350 (<0.01%)	41,092	10,500	60,942	2,602,223
Change	0	2,091	(500)	1,591	353,712

Share ownership guidelines have been met.

Exxon Mobil Corporation Equity Ownership (a) (c) (e)

As at	Common Shares (% of class)	Restricted Stock	Total Common Shares and Restricted Stock	Total Market Value Common Shares and Restricted Stock ($)
February 13, 2014	0	0	0	0

Public Company Directorships in the Past Five Years

Standard Life plc (2009 2013)

Public Board Interlocks

None

Other Positions in the Past Five Years (position, date office held and status of employer)

No other positions held in the last five years

Non-profit sector affiliations

Member of the VIP Advisory Board of the European Professional Women s Network

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Darren W. Woods

Fairfax, Virginia, United States of America

Age: 49

Current Position: Vice-president, Exxon Mobil Corporation and president ExxonMobil Refining and Supply Company

Not independent

Director since April 25, 2013

Skills and experience:

Leadership of large organizations

Operations/technical

Project management

Mr. Woods is a vice-president of Exxon Mobil Corporation and is the president of ExxonMobil Refining and Supply Company, a division of Exxon Mobil Corporation, with responsibility for ExxonMobil s global refining and supply operations. He is located in Fairfax, Virginia. Mr. Woods has worked for ExxonMobil in a range of downstream and chemical management assignments, investor relations in the United States, as well as international assignments in England, Scotland and Brussels.

Board and Committee Membership	**Attendance in 2013**	
Imperial Oil Limited board	6 of 6	100%
Executive resources committee	6 of 6	100%
Environment, health and safety committee	2 of 2	100%
Nominations and corporate governance committee	2 of 2	100%
Contributions committee	2 of 2	100%
Annual meeting of shareholders	1 of 1	100%
(became a director and a member of the four committees noted above on April 25, 2013)	**Overall Attendance 100%**	

Imperial Oil Limited Securities Held (a) (b) (c) (d)

As at	Common Shares (% of class)	Deferred Share Units (DSU)	Restricted Stock Units (RSU)	Total Common Shares, DSU	Total Market Valu of Common Share

Global experience					and RSU	DSU and RSU ($)
Strategy development						
Financial expertise						
Executive compensation	February 13, 2014	0	0	0	0	0

Voting Results of 2013

Annual General Meeting:

Votes For: 738,015,858

(99.90%)

Votes Withheld: 732,833

(0.10%)

Total Votes: 738,748,691

No share ownership guidelines apply.

Exxon Mobil Corporation Equity Ownership (a) (c) (e)

As at	Common Shares (% of class)	Restricted Stock	Total Common Shares and Restricted Stock	Total Market Value of Common Shares and Restricted Stock ($)
February 13, 2014	22,452 (<0.01%)	124,250	146,702	14,727,434

Public Company Directorships in the Past Five Years

None

Public Board Interlocks

None

Other Positions in the Past Five Years (position, date office held and status of employer)
Vice President, Supply & Transportation, ExxonMobil Refining & Supply Company (2010 - 2012) (Affiliate) Refining Director, Europe, Africa & Middle East, ExxonMobil Refining & Supply Company (2008 - 2010) (Affiliate)
Non-profit sector affiliations
National Association of Manufacturers (Executive Committee) American Petroleum Institute (Downstream Committee)

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Victor L. Young, O.C.

From November 1984 until May 2001, Mr. Young served as chairman and chief executive officer of Fishery Products International Limited, a frozen seafood products company. He is a director of Royal Bank of Canada and McCain Foods Limited. Mr. Young was appointed an Officer of the Order of Canada in 1996, and is currently the chair of the advisory committee on red tape reduction established by the Government of Canada.

St. John s, Newfoundland and

Labrador, Canada

Age: 68

Current Position:

Nonemployee director

Independent

Director since April 23, 2002

Normally ineligible for re-election in 2018

Board and Committee Membership	**Attendance in 2013**	
Imperial Oil Limited board	8 of 8	100%
Audit committee **(Chair)**	5 of 5	100%
Executive resources committee	10 of 10	100%
Environment, health and safety committee	3 of 3	100%
Nominations and corporate governance committee	4 of 4	100%
Contributions committee	3 of 3	100%
Annual meeting of shareholders	1 of 1	100%

Overall Attendance 100%

Skills and experience:

- Leadership of large organizations
- Strategy development
- Audit committee financial expert
- Financial expertise

Imperial Oil Limited Equity Ownership (a) (b) (c) (d)

As at	Common Shares	Deferred Share Units	Restricted Stock Units	Total Common Total Market Val

Government relations

Executive compensation

Voting Results of 2013

Annual General Meeting:

Votes For: 737,699,275 (99.85%)

Votes Withheld: 1,080,416 (0.15%)

Total Votes: 738,779,691

	(% of class)	(DSU)	(RSU)	Shares, DSU and RSU	of Common Shares, DSU and RSU ($)
February 13, 2014	21,000	10,384	10,000	41,384	1,956,222
February 13, 2013	20,000 (<0.01%)	9,464	10,500	39,964	1,706,463
Change	1,000	920	(500)	1,420	249,759

Share ownership guidelines have been met.

Exxon Mobil Corporation Equity Ownership (a) (c) (e)

As at	Common Shares (% of class)	Restricted Stock	Total Common Shares and Restricted Stock	Total Market Value Common Shares and Restricted Stock ($)
February 13, 2014	0	0	0	0

Public Company Directorships in the Past Five Years

Royal Bank of Canada (1991 Present)

Bell Aliant (2002 2010)

BCE Inc. (1995 2010)

Public Board Interlocks

None

Other Positions in the Past Five Years (position, date office held and status of employer)

No other positions held in the last five years

Non-profit sector affiliations

Advisory committee on red tape reduction established by the Government of Canada (Chair)

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Footnotes to Directors Tables on pages 89 through 95:

(a) The information includes the beneficial ownership of common shares of Imperial Oil Limited and shares of Exxon Mobil Corporation, which information not being within the knowledge of the company has been provided by the nominees individually.
(b) The company s plan for restricted stock units for nonemployee directors is described on page 113. The company s plan for deferred share units for nonemployee directors is described on page 112. The company s plan for restricted stock units for selected employees is described on page 126.
(c) The numbers for the company s restricted stock units represent the total of the restricted stock units received in 2007 through 2013 and deferred share units received since directors appointment. The numbers for Exxon Mobil Corporation restricted stock include restricted stock and restricted stock units granted under its restricted stock plan which is similar to the company s restricted stock unit plan.
(d) The value for Imperial Oil Limited common shares, deferred share units, restricted stock units is based on the closing price for Imperial Oil Limited common shares on the Toronto Stock Exchange of $47.27 on February 13, 2014 and $42.70 on February 13, 2013.
(e) The value for Exxon Mobil Corporation common shares and restricted stock is based on the closing price for Exxon Mobil Corporation common shares of $91.43 U.S., which is converted to Canadian dollars at the noon rate of exchange of $1.0980 provided by the Bank of Canada for February 13, 2014.

Director qualification and selection process

The nominations and corporate governance committee is responsible for identifying and recommending new candidates for board nomination. The process for selection is described in paragraph 9(a) of the Board of Directors Charter attached as Appendix B. The committee maintains a list of potential director candidates for future consideration and reviews such list annually.

In considering the qualifications of potential nominees for election as directors, the nominations and corporate governance committee considers the work experience and other areas of expertise of the potential nominees. The following key criteria are considered to be relevant to the work of the board of directors and its committees:

Work Experience

- Experience in leadership of businesses or other large organizations (Leadership of large organizations)
- Operations/technical experience (Operations/technical)
- Project management experience (Project management)
- Experience in working in a global work environment (Global experience)
- Experience in development of business strategy (Strategy development)

Other Expertise

- Audit committee financial expert (also see the financial expert section in the audit committee chart on page 102)
- Expertise in financial matters (Financial expertise)
- Expertise in managing relations with government (Government relations)
- Experience in academia or in research (Academic/research)
- Expertise in information technology (Information technology)
- Expertise in executive compensation policies and practices (Executive compensation)

In addition, the nominations and corporate governance committee may consider the following additional factors in assessing potential nominees:

possessing expertise in any of the following areas: law, science, marketing, administration, social/political environment or community and civic affairs; and

providing diversity of viewpoint, individual competencies in business, other areas of endeavour in contributing to the collective experience of the directors, age, gender or regional association.

The nominations and corporate governance committee assesses the work experience and other expertise each existing director possesses and whether each nominee is able to fill any gaps in such experience and expertise. Consideration is also given to whether candidates possess the ability to contribute to the broad range of issues with which the board and its committees must deal, are able to devote the necessary amount of time to prepare for and attend board and committee meetings and are free of any potential legal impediment or conflict of interest. Candidates are expected to remain qualified to serve for a minimum of five years and independent directors are expected to achieve ownership of no less than 15,000 common shares, deferred share units and restricted share units within five years of becoming an independent director.

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When the committee is recommending candidates for re-nomination, it assesses such candidates against the criteria for re-nomination as set out in paragraph 9(b) of the Board of Directors Charter found in Appendix B of this circular. Candidates for re-nomination are expected to not change their principal position or thrust of involvement or regional association that would significantly detract from his or her value as a director of the corporation and are expected to continue to be compatible with the criteria that led to their selection as nominees.

Skills and Experience of the Director Nominees

The current nominees for election as director collectively have experience and expertise required to ensure effective stewardship and governance of the company. The key areas of work experience and skills and experience along with individual involvement in the not-for-profit sector for each of the nominees for election as directors can also be found in each of the directors tables on pages 89 through 95 of this circular.

The table below sets out the particular experience, qualifications, attributes, and skills of each director nominee that led the Board to conclude that such person should serve as a director of the company.

	K.T. Hoeg	R.M. Kruger	J.M. Mintz	D.S. Sutherland	S.D. Whittaker	D.W. Woods	V.L. Young
Leadership of Large Organizations	ü	ü		ü	ü	ü	ü
Operations/ Technical		ü		ü		ü	
Project Management	ü	ü				ü	
Global Experience	ü	ü	ü	ü	ü	ü	

Strategy Development	ü	ü	ü	ü	ü	ü	ü
Audit Committee Financial Expert	ü			ü	ü		ü
Financial Expertise	ü	ü	ü	ü	ü	ü	ü
Government Relations		ü	ü	ü	ü		ü
Academic/ Research			ü				
Information Technology					ü		
Executive Compensation	ü	ü	ü	ü	ü	ü	ü

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Director orientation, education, development, tenure and performance assessment

Orientation, education and development

The corporate secretary organizes an orientation program for all new directors. In a series of briefings over several days, new directors are briefed by staff and functional managers on all significant areas of the company s operations, industry specific topics, risk oversight and regulatory issues. New directors are also briefed on significant company policies, security, information technology management and on critical planning and reserves processes. They also receive a comprehensive board manual which contains a record of historical information about the company, the charters of the board and its committees and other relevant company business information.

Continuing education is provided to board members by regular presentations by management on the main areas of company business. Each year the board has an extended meeting that focuses on a particular area of the company s operations and includes a visit to one or more of the company s operating sites or a site of relevance to the company s operations. In June 2013, the board visited the Kearl site in Alberta, Canada. The site visit included a tour of the site and the Kearl project opening ceremony. In September, 2013, the board visited Toronto, Ontario. The site visit included a retail site tour and presentations relating to retail strategy. Some of the other continuing education events in 2013, presented to all directors, included a review of corporate governance and regulatory issues, a review of various aspects of risk management, a review of the science of climate change, a review of environmental public policy issues, a review of community and stakeholder engagement, a financing update, a review of crude logistics and an overview of rail operations.

Members of the board also receive an extensive package of materials prior to each board meeting that provides a comprehensive summary on each agenda item to be discussed. Similarly, the committee members also receive a comprehensive summary on each agenda item to be discussed by that particular committee.

As part of its annual assessment process, the board members are canvassed as to whether there are any additional topics that they would like to see addressed. In addition, the directors meet prior to most regularly scheduled board meetings and this provides an opportunity for informal discussion. In some cases, where senior management is present, these gatherings provide an opportunity for a review of selected topics of interest.

Tenure

Collectively, the seven nominees for election as directors have 51 years of experience on this company s board. The board charter provides that incumbent directors will not be renominated if they have attained the age of 72, except under exceptional circumstances at the request of the chief executive officer. The company does not have term limits for independent directors because it values the comprehensive knowledge of the company that long serving directors possess and independent directors are expected to remain qualified to serve for a minimum of five years. The following chart shows the current years of service of the members of the board of directors and the year they would normally be expected to retire from the board.

Name of Director	Years of service on the board	Year of expected retirement from the

		board for independent directors
K.T. Hoeg	6 years	2022
R.M. Kruger	1 year	-
J.M. Mintz	9 years	2023
D.S. Sutherland	4 years	2022
S.D. Whittaker	18 years	2019
D.W. Woods	1 year	-
V.L. Young	12 years	2018

Total of 51 years of experience on the board.

The average tenure is 7.2 years.

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Board performance assessment

The board and its committees, as well as the performance of the directors, are assessed on an annual basis. In 2013, the directors provided their written response to a series of questions to evaluate the responsibility and effectiveness of the board and its committees. This response formed the basis for a discussion with the nominations and corporate governance committee at its January 2014 meeting to review the effectiveness of the board and its committees. The committee also assesses the company s response to issues raised in the previous year s survey. Given the small board size, the directors are able to provide continuous peer performance feedback as required. The chairman, president and chief executive officer also meets with directors to discuss their performance.

Independence of the directors

The board is composed of seven directors, the majority of whom (five out of seven) are independent. The five independent directors are not employees of the company.

The Board determines independence on the basis of the standards specified by Multilateral Instrument 52-110 Audit Committees, the U.S. Securities and Exchange Commission rules and the listing standards of the NYSE MKT LLC, a subsidiary of NYSE Euronext and the New York Stock Exchange. The Board has reviewed relevant relationships between the company and each non-employee director and director nominee to determine compliance with these standards.

Based on the directors response to an annual questionnaire, the board determined that none of the independent directors has any interest, business or other relationship that could or could reasonably be perceived to constitute a material relationship with the company. R.M. Kruger was appointed as a director and chairman, president and chief executive officer of the company on March 1, 2013 and not considered to be independent. The board believes that the extensive knowledge of the business of the company and Exxon Mobil Corporation held by R.M. Kruger is beneficial to the other directors and his participation enhances the effectiveness of the board.

D.W. Woods is also a non-independent director as he is an officer of Exxon Mobil Corporation. The company believes that D.W. Woods, although deemed non-independent under the relevant standards by virtue of his employment, can be viewed as independent of the company s management and that his ability to reflect the perspective of the company s shareholders enhances the effectiveness of the board.

Name of director	Management	Independent	Not independent	Reason for non-independent status
K.T. Hoeg		ü		
R.M. Kruger	ü		ü	

			R.M. Kruger is a director and chairman, president and chief executive officer of Imperial Oil Limited effective March 1, 2013
J.M. Mintz	ü		
D.S. Sutherland	ü		
S.D. Whittaker	ü		
D.W. Woods		ü	D.W. Woods is an officer of Exxon Mobil Corporation.
V.L. Young	ü		

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Board and committee structure

Leadership structure

The company has chosen to combine the positions of chairman, president and chief executive officer. R.M. Kruger has held these positions since March 1, 2013. The board believes the interests of all shareholders are best served at the present time through a leadership model with a combined chairman and chief executive officer position. The company does not have a lead director. While the chairman of the board is not an independent director, S.D. Whittaker, chair of the executive sessions, provides leadership for the independent directors. The duties of the chair of the executive sessions include presiding at executive sessions of the board, and reviewing and modifying, if necessary, the agenda of the meetings of the board in advance to ensure that the board may successfully carry out its duties. The position description of the chair of the executive sessions is described in paragraph 8(3) of the Board of Directors Charter attached as Appendix B.

Independent director executive sessions

The executive sessions of the board are meetings of the independent directors and are held in conjunction with every board meeting. These meetings are held in the absence of management. The independent directors held eight executive sessions in 2013. The purposes of the executive sessions of the board include the following:

- raising substantive issues that are more appropriately discussed in the absence of management;
- discussing the need to communicate to the chairman of the board any matter of concern raised by any committee or director;
- addressing issues raised but not resolved at meetings of the board and assessing any follow-up needs with the chairman of the board;
- discussing the quality, quantity, and timeliness of the flow of information from management that is necessary for the independent directors to effectively and responsibly perform their duties, and advising the chairman of the board of any changes required; and
- seeking feedback about board processes.

In camera sessions of the board committees

Various committees also regularly hold in camera sessions without management present. The audit committee regularly holds private sessions of the committee members as well as private meetings of the committee with each of the external auditor, the internal auditor and senior management as part of every regularly scheduled committee meeting.

Committee structure

The board has created five committees to help carry out its duties. Each committee is chaired by a different independent director and all of the five independent directors are members of each committee. D.W. Woods is also a member of each committee, with the exception of the audit committee which is composed entirely of independent directors. R.M. Kruger is also a member of the contributions committee. Board committees work on key issues in greater detail than would be possible at full board meetings allowing directors to more effectively discharge their stewardship responsibilities. The five independent chairs of the five committees are able to take a leadership role in executing the board s responsibility with respect to a specific area of the company s operations falling within the responsibility of the committee he or she chairs. The board and each committee have a written charter that can be found in Appendix B of this circular. The charters are reviewed and approved by the board annually. The charters set out the structure, position description for the chair and the process and responsibilities of that committee. The five committees of the board are:

audit committee,

executive resources committee,

environment, health and safety committee,

nominations and corporate governance committee, and

contributions committee.

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The following tables provide additional information about the board and its five committees:

Board of Directors	
Directors	R.M. Kruger (chair) K.T. Hoeg J.M. Mintz D.S. Sutherland S.D. Whittaker D.W. Woods V.L. Young
Number of meetings in 2013	Eight meetings of the board of directors were held in 2013. The independent directors hold executive sessions of the board in conjunction with every board meeting. These meetings are held in the absence of management. The independent directors held eight executive sessions in 2013.
Mandate	The board of directors is responsible for the stewardship of the corporation. The stewardship process is carried out by the board directly or through one or more of the committees of the board. The formal mandate of the board can be found within the Board of Directors Charter in Appendix B of this circular.
Highlights of 2013	Oversight of the Kearl project. Reviewed other long-term growth strategies and projects (Nabiye, Aspen, etc.).

Reviewed risk management activities.

Reviewed critical strategic elements affecting shareholder value.

Strong safety record.

Kearl site visit and retail site tour.

Role in Risk Management	The chairman, president and chief executive officer is charged with identifying, for review with the board of directors, the principal risks of the corporation s business, and ensuring appropriate systems are in place to manage such risks. The company s financial, execution and operational risk rests with corporate and business management and the company is governed by well-established risk management systems. The board of directors carefully considers these risks in evaluating the company s strategic plans and specific proposals for capital expenditures and budget additions.
Disclosure Policy	The company is committed to full, true and plain public disclosure of all material information in a timely manner, in order to keep security holders and the investing public informed about the company s operations. The full details of the corporate disclosure policy can be found on the company s internet site at **www.imperialoil.ca**.
Independence	The current board of directors is composed of seven directors, the majority of whom (five out of seven) are independent. The five independent directors are not employees of the company.

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Audit Committee

Committee Members	V.L. Young (chair) S.D. Whittaker (vice-chair) K.T. Hoeg J.M. Mintz D.S. Sutherland
Number of meetings in 2013	Five meetings of the audit committee were held in 2013. The committee members met in camera without management present at every meeting and also separately with the internal auditor and the external auditor at all meetings.
Mandate	The role of the audit committee includes selecting and overseeing the independent auditor, reviewing the scope and results of the audit conducted by the independent auditor, assisting the board in overseeing the integrity of the company s financial statements, the company s compliance with legal and regulatory requirements and the quality and effectiveness of internal controls, reviewing the adequacy of the company s insurance program, approving any changes in accounting principles and practices, reviewing the results of monitoring activity under the company s business ethics compliance program and reviewing senior management s expense accounts. The formal mandate of the audit committee can be found within the Audit Committee Charter in Appendix B of this circular.
Highlights of 2013	Reviewed the scope of PwC audit in light of risks to company. Reviewed the interim and annual financial statements and MD&A. Reviewed and assessed the results of the internal auditor s audit program. Reviewed a