IMPERIAL OIL LTD
Form 10-K
February 27, 2013
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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, 2012** **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 2012 second fiscal quarter, the aggregate market value of the voting stock held by non-affiliates of the registrant was Canadian $10,974,195,454 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, 2013, 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 | **2012** | 2011 | 2010 | 2009 | 2008 |
|---|---|---|---|---|---|
| Rate at end of period | **1.0042** | 0.9835 | 0.9991 | 0.9559 | 0.8170 |
| Average rate during period | **1.0006** | 1.0144 | 0.9659 | 0.8793 | 0.9335 |
| High | **1.0299** | 1.0584 | 1.0040 | 0.9719 | 1.0291 |
| Low | **0.9600** | 0.9430 | 0.9280 | 0.7695 | 0.7710 |

On February 13, 2013, 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 $0.9980 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, 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 does not necessarily have the same meaning as under Securities and Exchange Commission ( SEC ) Rule 13q-1 relating to government payment reporting. For example, a single project for purposes of the rule may encompass numerous properties, agreements, investments, developments, phases, work efforts, activities and components, each of which we may also informally describe as a project .

# 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, conventional 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 November 28, 2012, Imperial announced that it would participate as a 50-percent owner with ExxonMobil Canada Ltd. in Celtic Exploration Ltd. ( Celtic ). The acquisition of 100 percent of Celtic by ExxonMobil Canada was approved by Celtic Exploration s shareholders on December 14, 2012 and by regulatory authorities on February 20, 2013. Imperial s participation occurred immediately after the acquisition closed on February 26, 2013, by means of a sale of a 50-percent interest in Celtic s assets and liabilities from ExxonMobil Canada to Imperial. Reference is made to the Financial Section of this report under the sub-section entitled Upstream in the Business environment and risk assessment section of the Management s Discussion and Analysis of Financial Condition and Results of Operations and to Note 17: Subsequent event and Note 14: Long-term debt for further details.

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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, 2012, as detailed in the Oil and gas reserves 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 favorable or adverse event has occurred since December 31, 2012 that would cause a significant change in the estimated proved reserves as of that date. Proved reserves from the Celtic acquisition will be included in 2013 year-end reporting for the first time.

| | 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 | **52** | **373** | **599** | **543** | **1,256** |
| Undeveloped | **1** | **115** | **-** | **2,298** | **2,318** |
| Total net proved | **53** | **488** | **599** | **2,841** | **3,574** |

(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 2012 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 Securities and Exchange Commission ( SEC ) rules and regulations, review of annual changes in reserves estimates, and the reporting of Imperial s proved reserves. In addition, this group provides training to personnel involved in the reserve estimation and reporting processes within Imperial.

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

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containing the official company reserves estimates 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 will require further review and approval of the appropriate level of management within the operating organization, culminating in reviews with and approval by senior management and the company s board of directors.

The Operations Technical Engineering Manager, who is an employee of the company, has evaluated the company s reserves data and filed a report to the Canadian securities regulatory authorities. The company s internal reserves evaluation staff consists of about 61 persons with an average of approximately 15 years of relevant technical experience in evaluating reserves, of whom about 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 about 13 persons with an average of approximately 13 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 of December 31, 2012, approximately 65 percent of the company s proved reserves were proved undeveloped reserves reflecting volumes of 2,318 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 60 percent or 1,904 million oil-equivalent barrels of proved undeveloped reserves reported at the end of 2011. Increased proved undeveloped reserves in 2012 were primarily due to the initial booking of the approved Nabiye expansion at Cold Lake. Other increases in proved undeveloped reserves were primarily a result of increased development scope at Cold Lake and the impact of royalty costs at Kearl.

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 2012 was the Kearl project. By 2012 year-end, construction of the initial development was complete and phased start-up activities were underway. Production of mined diluted bitumen from the first froth treatment train is expected in the first quarter of 2013. Construction of the Kearl expansion was advanced in 2012.

Proved undeveloped reserves at Cold Lake are associated with the ongoing drilling program and Nabiye expansion project. Imperial moved 38 million oil-equivalent barrels from proved undeveloped to proved developed reserves at Cold Lake through ongoing drilling programs. Construction of the Nabiye expansion was advanced in 2012.

Proved undeveloped reserves that have remained undeveloped for five years or more are primarily associated with the initial development at Kearl. Reserves associated with the initial development at Kearl were initially booked as proved undeveloped reserves in 2008 and have remained undeveloped for five years due to the time required to complete development. Construction of the initial development was complete by 2012 year-end and phased start-up activities were underway. The balance of the company s proved undeveloped reserves of five years or more are all located at 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, 2012 was as follows. All reported production volumes were from Canada.

| thousands of barrels a day | | **2012** | 2011 | 2010 |
|---|---|---|---|---|
| Bitumen (c): | - gross (a) | **154** | 160 | 144 |
| | - net (b) | **123** | 120 | 115 |
| Synthetic oil (d): | - gross (a) | **72** | 72 | 73 |
| | - net (b) | **69** | 67 | 67 |
| Liquids: | - gross (a) | **24** | 23 | 30 |
| | - net (b) | **18** | 17 | 22 |
| Total: | - gross (a) | **250** | 255 | 247 |
| | - net (b) | **210** | 204 | 204 |

(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.
(c) All of the company s bitumen production volumes were from the Cold Lake production operation.
(d) All of 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, 2012 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 a day | **2012** | 2011 | 2010 |
|---|---|---|---|
| Gross production (a) (b) | **192** | 254 | 280 |
| Net production (c) | **195** | 228 | 254 |
| Sales (d) | **177** | 237 | 264 |

(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 includes favourable royalty cost adjustments.
(d) Sales are 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.

### *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 a day | **2012** | 2011 | 2010 |
|---|---|---|---|
| Total production oil-equivalent basis: | | | |
| - gross (a) | **282** | 297 | 294 |

| | | | |
|---|---|---|---|
| - net (b) | **243** | 242 | 246 |

(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, 2012, were as follows:

| dollars a barrel | **2012** | 2011 | 2010 |
|---|---|---|---|
| Liquids | **71.52** | 77.34 | 65.84 |
| Synthetic oil | **92.48** | 101.43 | 80.63 |
| Bitumen | **59.76** | 63.95 | 58.36 |
| dollars per thousand cubic feet | | | |
| Natural gas | **2.33** | 3.59 | 4.04 |

*Average unit production costs*

| dollars a barrel | **2012** | 2011 | 2010 |
|---|---|---|---|
| Synthetic oil | **48.41** | 48.33 | 45.17 |
| Bitumen | **21.98** | 19.30 | 18.43 |
| Total oil-equivalent basis (a) | **29.10** | 26.63 | 24.76 |

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

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

In 2011, unit production costs increased on a net basis primarily due to lower net volumes as a result of higher royalty costs, increased maintenance costs at Syncrude and 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 ending December 31, 2012.

| wells | **2012** | 2011 | 2010 |
|---|---|---|---|
| Net productive exploratory | **1** | 3 | 6 |
| Net dry exploratory | **-** | - | - |
| Net productive development | **39** | 96 | 183 |
| Net dry development | **-** | - | - |
| Total | **40** | 99 | 189 |

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.

In 2010, 110 bitumen development wells were drilled to add new productive capacity from undeveloped areas of existing phases at Cold Lake. In addition, 71 gas development wells were drilled in 2010 adding productivity primarily in the shallow gas area.

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## *Wells drilling*

At December 31, 2012, the company was participating in the drilling of the following exploratory and development wells. All wells were located in Canada.

| | 2012 | |
|---|---|---|
| wells | Gross | Net |
| Total | **101** | **94** |

## *Exploratory and development activities regarding oil and gas resources*

*Cold Lake*

To maintain production at Cold Lake, capital expenditures for additional production wells and associated facilities are required periodically. In 2012, the company executed a development drilling program of 28 wells on existing phases.

In February 2012, the Nabiye expansion at Cold Lake was approved by the company s board and appropriated for $2 billion. The expansion is expected to bring on additional production of more than 40,000 barrels a day, before royalties. The expansion was 37 percent complete by 2012 year-end and start-up is expected to be year-end 2014.

In 2013, 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.

*Horn River pilot*

The Horn River pilot started up at its design rate of 30 million cubic feet a day (15 million cubic feet Imperial s share). Pilot data will be used to evaluate full field development economics.

*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.

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, support from northern parties, regulatory approvals, environmental considerations, pipeline participation, fiscal framework and the cost of constructing, operating and abandoning the field production and pipeline facilities.

In October 2004, the company and its co-venturers filed regulatory applications and environmental impact statements for the project with the National Energy Board (NEB) and other boards, panels and agencies responsible for assessing and regulating energy developments in the Northwest Territories. All the scheduled public hearings by the Joint Review Panel (JRP) and the NEB were concluded in late 2007. The JRP report was released in late 2009. In late 2010, the NEB announced its approval of plans to build and operate the project and 264 conditions in areas such as engineering, safety and environmental protection. Federal cabinet approved the project in early 2011. Imperial continues to maintain the right of way agreements and permits required to develop its Mackenzie Delta natural gas resource.

*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 2012, Imperial and its joint venture partners began community consultation regarding potential future exploration activities on the licenses.

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*Other oil sands activity*

Imperial began preparing the regulatory applications for new in situ oil sands projects at Aspen (south of Kearl) and Cold Lake Grand Rapids.

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.

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

*Kearl project*

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 will recover shallow deposits of oil sands using open-pit mining methods. The project is located approximately 40 miles north of Fort McMurray, Alberta.

The Kearl project received 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 is expected to be approximately 110,000 barrels of bitumen a day, before royalties, of which the company s share would be about 78,000 barrels a day. By 2012 year-end, the construction of the initial development was complete and phased start-up activities were underway. Despite U.S. permitting and regulatory issues that continued for almost two years involving transportation of facility modules and significant challenges including an early onset of winter and exceptionally harsh weather during start-up operations, production of mined diluted bitumen from the first froth treatment train is expected in the first quarter of 2013. The final cost for the initial development is expected to be $12.9 billion, of which the company s share is $9.2 billion.

The Kearl expansion, sanctioned in 2011 for $8.9 billion ($6.3 billion Imperial s share), was 27 percent complete at the end of 2012. The Kearl expansion is expected to bring on additional production of 110,000 barrels of bitumen a day, before royalties, by late 2015, of which the company s share would be about 78,000 barrels a day.

Future debottlenecking of both the initial development and expansion will increase output to reach the regulatory capacity of 345,000 barrels of bitumen a day by 2020, of which the company s share would be about 245,000 barrels a day.

Bitumen from the Kearl project will be extracted from oil sands produced from open-pit mining operations and processed through a bitumen extraction and froth treatment train. The product, a blend of bitumen and diluent, is planned to be shipped via pipelines for distribution to North American markets. Diluent is natural gas condensate or other light hydrocarbons added to the crude bitumen to facilitate transportation to market by pipeline.

A variety of existing and new logistics outlets have been secured or are being developed to move the company s share of production from the Kearl initial development to certain of the company s refineries, ExxonMobil s refineries and to third party refineries.

Kearl will be subject to the revised Alberta generic oil sands royalty regime, which took effect in 2009. Royalty rates are based upon a sliding scale determined by the price of crude oil.

*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 2012, average net production at Cold Lake was about 123,000 barrels a day and gross production was about 154,000 barrels a day.

Most of the production from Cold Lake is sold to refineries in the northern U.S. The majority of 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.

*Syncrude operations*

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 2012, the company s share of Syncrude s net production of synthetic crude oil was about 69,000 barrels a day and gross production was about 72,000 barrels a day.

There are no approved plans for major future expansion projects.

In November 2008, Imperial, along with the other Syncrude joint-venture owners, signed an agreement with the Government of Alberta to amend the existing Syncrude Crown Agreement. 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*

Most of the company s larger fields in the Western provinces have been in production for several decades, and the amount of oil and gas that is produced from conventional fields is declining.

The company s largest conventional oil producing asset is the Norman Wells oil field in the Northwest Territories, which currently accounts for about 70 percent of the company s gross production of conventional crude oil. In 2012, gross production of crude oil from Norman Wells was about 14,000 barrels a day.

## Delivery commitments

In 2013 and 2014, the company is contractually committed to deliver natural gas totaling approximately 18 billion cubic feet in Canada, which is substantially less than the company s current production from its natural gas reserves.

## 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, 2012 and 2011, 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, 2012** | | | | Year-ended December 31, 2011 | | | |
|---|---|---|---|---|---|---|---|---|
| | Crude oil | | Natural gas | | Crude oil | | Natural gas | |
| wells | Gross (a) | Net (b) | Gross (a) | Net (b) | Gross (a) | Net (b) | Gross (a) | Net (b) |
| Total (c) | **5,036** | **4,736** | **2,542** | **875** | 5,138 | 4,802 | 2,404 | 847 |

(a) Gross wells are wells in which the company owns a working interest.

(b) Net wells are the sum of the fractional working interests owned by the company in gross wells, rounded to the nearest whole number.

(c) Multiple completion wells are permanently equipped to produce separately from two or more distinctly different geological formations. At year-end 2012, the company had an interest in four gross wells with multiple completions (2011 - four gross wells).

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*Land holdings*

At December 31, 2012 and 2011, 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:

| | | Acres | | | | | |
|---|---|---|---|---|---|---|---|
| | | Developed | | Undeveloped | | Total | |
| thousands of acres | | **2012** | 2011 | **2012** | 2011 | **2012** | 2011 |
| Western provinces: | | | | | | | |
| Liquids and gas | - gross (a) | **2,127** | 2,156 | **658** | 629 | **2,785** | 2,785 |
| | - net (b) | **687** | 709 | **359** | 341 | **1,046** | 1,050 |
| Bitumen | - gross (a) | **103** | 103 | **606** | 636 | **709** | 739 |
| | - net (b) | **103** | 103 | **345** | 363 | **448** | 466 |
| Synthetic oil | - gross (a) | **118** | 114 | **135** | 139 | **253** | 253 |
| | - net (b) | **29** | 28 | **34** | 35 | **63** | 63 |
| Canada lands (c): | | | | | | | |
| Liquids and gas | - gross (a) | **4** | 4 | **2,314** | 2,314 | **2,318** | 2,318 |
| | - net (b) | **2** | 2 | **722** | 722 | **724** | 724 |
| Atlantic offshore: | | | | | | | |
| Liquids and gas | - gross (a) | **65** | 65 | **1,780** | 1,780 | **1,845** | 1,845 |
| | - net (b) | **6** | 6 | **270** | 270 | **276** | 276 |
| Total (d): | - gross (a) | **2,417** | 2,442 | **5,493** | 5,498 | **7,910** | 7,940 |
| | - net (b) | **827** | 848 | **1,730** | 1,731 | **2,557** | 2,579 |

(a) Gross acres include the interests of others.

(b) Net acres exclude the interests of others.

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

(d) 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 and Peace River areas totaling about 141,000 net acres. In 2012, the company divested about 18,000 undeveloped net acres in these regions.

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

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

The company holds interest in an additional 1,046,000 net acres of developed and undeveloped land in Western Canada related to conventional oil and natural gas. Included in this number is a total acreage position of about 170,000 net acres at Horn River, British Columbia. In 2012, the company divested a total of about 17,000 net acres and relinquished about 9,000 net acres in Western Canada. This was partially offset by acquisitions of about 22,000 net acres.

Petroleum and natural gas leases and licences from Western provinces have an exploration period 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 totaling about 222,000 net acres and the Mackenzie Delta of about 184,000 net acres.

Exploration licences on Canada lands and Atlantic offshore have a finite term which can be extended upon payment of a fee. 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 expects to assign or otherwise relinquish its land holdings in the Orphan Basin area. The company s land holdings in the Orphan Basin totaled about 224,000 net acres at year-end 2012.

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.

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).

## Refining

The company owns and operates four refineries. The Strathcona refinery operates lubricating oil production facilities. The Strathcona and Sarnia refineries process Canadian crude oil, and the Dartmouth and Nanticoke refineries process a combination of Canadian and foreign crude oil. In addition to crude oil, the company purchases finished products to supplement its refinery production.

In the second quarter of 2012, Imperial announced its intention to market the Dartmouth refinery and related supply terminals to prospective buyers. At year-end 2012, the Dartmouth refinery had a rated capacity of 85 thousand barrels a day. The company is also assessing alternatives including conversion to a products terminal. A decision is expected by mid-2013.

In 2012, capital expenditures of about $72 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 five years ended December 31, 2012, and the daily rated capacities of the refineries at December 31, 2012 and 2007, were as follows:

| | Refinery throughput (a) Year-ended December 31 | | | | | Rated capacities (b) at December 31 | |
|---|---|---|---|---|---|---|---|
| thousands of barrels a day | **2012** | 2011 | 2010 | 2009 | 2008 | **2012** | 2007 |
| Strathcona, Alberta | **163** | 169 | 168 | 145 | 155 | **189** | 187 |
| Sarnia, Ontario | **103** | 102 | 102 | 100 | 108 | **119** | 121 |
| Nanticoke, Ontario | **99** | 93 | 104 | 94 | 107 | **113** | 112 |
| Dartmouth, Nova Scotia | **70** | 66 | 70 | 74 | 76 | **85** | 82 |
| Total | **435** | 430 | 444 | 413 | 446 | **506** | 502 |

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

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

Refinery throughput was 86 percent of capacity in 2012, one percent higher than the previous year. The higher rate was primarily a result of improved refinery operations partially offset by higher planned maintenance activities at the Strathcona refinery.

## Distribution

The company maintains a nation-wide 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 600 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 1,770 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 farm, residential heating and small commercial markets are served through about 50 branded agents and 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 five years ended December 31, 2012, are set out in the following table:

| thousands of barrels a day | **2012** | 2011 | 2010 | 2009 | 2008 |
|---|---|---|---|---|---|
| Gasolines | **221** | 220 | 218 | 200 | 204 |
| Heating, diesel and jet fuels | **151** | 157 | 153 | 143 | 157 |
| Heavy fuel oils | **30** | 29 | 28 | 27 | 30 |
| Lube oils and other products | **43** | 41 | 43 | 39 | 47 |
| Net petroleum product sales | **445** | 447 | 442 | 409 | 438 |

Total Downstream capital expenditures were $140 million in 2012 and are expected to be about $200 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. There is also a heptene and octene plant located in Dartmouth, Nova Scotia.

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 around mid-year 2013.

The company s total sales volumes of petrochemicals during the five years ended December 31, 2012, were as follows:

| thousands of tonnes | **2012** | 2011 | 2010 | 2009 | 2008 |
|---|---|---|---|---|---|
| Total sales of petrochemicals | **1,044** | 1,016 | 989 | 1,026 | 1,021 |

Higher volumes in 2012 were primarily due to the improved North American economic conditions.

Capital expenditures in 2012 were $4 million.

# Iran Threat Reduction and Syrian Human Rights Act of 2012

The captioned Act was signed by President Obama on August 10, 2012. Application of the Act to the company took effect on October 10, 2012. Among other things, the Act requires registrants to disclose, in their annual and quarterly reports, activities covered by the Act which occurred anytime during the period covered by the report, even if such activities occurred before the effectiveness of the Act and were permitted at the time.

During the period from January to September, 2012, the company made several fleet sales of motor fuel with an aggregate total sales price of approximately $11,000 to the Iranian Embassy in Canada. The net earnings attributable to these sales were less than $500. These sales were made without the involvement of any U.S. person and were permitted by U.S. laws in effect at the time. No sales occurred after the October 10, 2012, effective date and the company does not expect any such sales to occur in the future.

The embassy sales stated above represent an activity described in paragraph (D)(iii) of paragraph (1) of Section 13(r) of the Securities and Exchange Act of 1934 and therefore are excluded from the required investigation provisions of that statute.

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# Research

In 2012, the company s total gross research expenditures, before credits, were about $201 million, as compared with $163 million in 2011, and $119 million in 2010. Total gross research expenditures included capital expenditures of $1 million, $1 million and $3 million in 2012, 2011 and 2010, respectively. These expenditures were used 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 $3.8 billion on environmental protection and facilities. In 2012, the company s environmental capital and operating expenditures totaled approximately $1.0 billion, which was spent primarily on emissions reductions, water 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 $1.6 billion in 2013.

# Human resources

| Career employees (a) | **2012** | 2011 | 2010 |
|---|---|---|---|
| Total | **5,100** | 4,900 | 5,000 |

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

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 escalating 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 2012 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 royalty rates 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 U.S. 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

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reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

# 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, proven 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.

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## 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.

The company s activities in deep water oil and gas exploration are limited. However, 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 such as a deep water well blowout. 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

In April 2007, the Government of Canada announced its intent to introduce a set of regulations to limit emissions of greenhouse gas and air pollutants from major industrial facilities in Canada. In the fall of 2009, the Government further expressed its intent that Canadian policy in this area be aligned with that of the U.S. These policies and potential regulations remain under development. Consequently, attempts to assess the impact on the company are premature. The company will continue to monitor the development of legal requirements in this area.

In the Province of Alberta, regulations governing greenhouse gas emissions from large industrial facilities came into effect July 1, 2007. These regulations cover industrial facilities emitting more than 100,000 tonnes (carbon dioxide equivalent) of greenhouse gas emissions annually and require a reduction by 12 percent in the greenhouse gas emissions per unit of production from each facility s average annual intensity compared with the period 2003 through 2005. Allowed compliance measures include participation in an Alberta emission-trading system or payment (at a rate of $15 per excess tonne of emissions) to Alberta s Climate Change and Emissions Management Fund. Impact on the overall operations of the company has not been material.

The Province of British Columbia introduced a carbon tax in 2008 at an initial rate of $10 per tonne of carbon dioxide and applicable to purchases of hydrocarbon fuels and emissions of greenhouse gases. The applicable tax rate was increased to $30 per tonne in 2012, and no further increases have been announced. Impacts on the company and its operations have not been material.

The Province of Quebec announced in 2011 that it would regulate greenhouse gas emissions from industrial facilities starting in 2012 and from transportation sources in 2015, with a cap-and-trade system. There are no company operations affected by the regulations for industrial facilities. As there is currently limited data on the planned inclusion of the transportation sources in the cap-and-trade system, attempts to assess the impact of these plans on the company are premature.

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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. However, details on such possible regulations have not been provided and consequently attempts to assess any impacts on the company are premature.

The Province of British Columbia has introduced the Renewable and Low Carbon Fuel Requirement Regulations, requiring suppliers of transportation fuels to report the carbon intensity of fuels sold in British Columbia, and beginning in 2013 to reduce the carbon intensity by an increasing amount over a 10-year period. The company s marketing operations in British Columbia are not expected to be significantly impacted in the early years of the regulation. California has introduced similar requirements and some other U.S. states are considering comparable measures. Such measures in California and other U.S. states may have implications for the company s marketing of oil sands production, but the impact cannot be determined at this time.

The U.S. Energy Independence and Security Act of 2007 precludes agencies of the U.S. Federal Government from procuring motive fuels from non-conventional petroleum sources that have lifecycle greenhouse gas emissions greater than equivalent conventional fuel. To date, sales of the company s oil sands production have not been affected by this Act.

Further federal or provincial legislation or regulation controlling greenhouse gas emissions could occur and result in increased capital expenditures and operating costs, affect demand and have a material adverse effect on the company s financial condition or results of operations, but any potential impact 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.

## Other business risks

Exploring for, producing and transporting petroleum substances involve many risks, which even a combination of experience, knowledge and careful evaluation may not be able to mitigate. These activities are subject to a number of hazards, which may result in fires, explosions, spills, blow-outs or other unexpected or dangerous conditions causing personal injury, property damage, environmental damage and interruption of operations. The company s insurance may not provide adequate coverage in certain unforeseen circumstances.

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

Not applicable.

# 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.

### 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:

| | **2012** | | | | 2011 | | | |
|---|---|---|---|---|---|---|---|---|
| dollars | **Q1** | **Q2** | **Q3** | **Q4** | Q1 | Q2 | Q3 | Q4 |
| Declared dividend per share: | **0.12** | **0.12** | **0.12** | **0.12** | 0.11 | 0.11 | 0.11 | 0.11 |

### 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% or more of the shares of the company.

Reference is made to the Quarterly financial and stock trading data portion of the Financial section on page 85 of this report.

As of February 13, 2013 there were 12,466 holders of record of common shares of the company.

During the period October 1, 2012 to December 31, 2012, there were no shares issued by the company to employees or former employees outside the U.S. under its restricted stock unit plan.

In June, 2012 the company received approval from the Toronto Stock Exchange for a new normal course issuer bid to replace its existing share-purchase program that expired on June 24, 2012. The new share-purchase program enables the company to repurchase up to about 42 million shares during the period from June 25, 2012 to June 24, 2013, including shares purchased for the company s employee savings plan, the company s employee retirement plan and from ExxonMobil. If not previously terminated, the program will end on June 24, 2013.

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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 86. 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 |
|---|---|---|---|---|
| October 2012<br>(October 1 October 31) | - | - | - | **42,026,677** |
| November 2012<br>(November 1 - November 30) | - | - | - | **41,944,532** |
| December 2012<br>(December 1 - December 31) | - | - | - | **41,861,583** |

# Item 6. Selected financial data

| millions of dollars | **2012** | 2011 | 2010 | 2009 | 2008 |
|---|---|---|---|---|---|
| Operating revenues | **31,053** | 30,474 | 24,946 | 21,292 | 31,240 |
| Net income | **3,766** | 3,371 | 2,210 | 1,579 | 3,878 |
| Total assets at year-end | **29,364** | 25,429 | 20,580 | 17,473 | 17,035 |
| Long term debt at year-end | **1,175** | 843 | 527 | 31 | 34 |
| Total debt at year-end | **1,647** | 1,207 | 756 | 140 | 143 |
| Other long term obligations at year-end | **3,983** | 3,876 | 2,753 | 2,839 | 2,254 |
| dollars | | | | | |
| Net income/share basic | **4.44** | 3.98 | 2.61 | 1.86 | 4.39 |
| Net income/share diluted | **4.42** | 3.95 | 2.59 | 1.84 | 4.36 |
| Dividends/share | **0.48** | 0.44 | 0.43 | 0.40 | 0.38 |

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 26, 2013, beginning with the section entitled Report of independent registered public accounting firm on page 54 and continuing through note 17, Subsequent event on page 80;

Supplemental information on oil and gas exploration and production activities (unaudited) starting on page 81; and

Quarterly financial and stock trading data (unaudited) on page 85

# 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, 2012. 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, 2012.

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 86. 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 87 to 95 of this report have been nominated for election at the annual meeting of shareholders to be held April 25, 2013. All of the nominees, with the exception of Darren W. Woods, are now directors and have been since the dates indicated. Robert C. Olsen is a current director and has chosen not to be nominated for re-election. 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 87 to 95 of this report;

The table entitled Audit committee under Board and committee structure , on page 101 of this report; and

Other public company directorships , on page 109 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 115 and page 116 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 86. 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 for directors , on page 108 of this report; and

Directors compensation program , on pages 110 to 114 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 117 of this report; and

Compensation discussion and analysis , on pages 119 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 86. 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, 2013, P.J. Masschelin was the owner of 6,554 common shares of the company and held 65,600 restricted stock units of the company. T.G. Scott did not own any common shares of the company and held 64,550 restricted stock units of the company. B.W. Livingston was the owner of 36,462 common shares of the company and held 112,000 restricted stock units of the company. R.G. Courtemanche was the owner of 66,876 common shares of the company and held 103,450 restricted stock units of the company.

The directors and the executive officers of the company, whose compensation for the year-ended December 31, 2012 is described in the sections under III. Board of directors starting on pages 87 and IV. Company executives and executive compensation starting on pages 115, consist of 13 persons, who, as a group, own beneficially 225,929 common shares of the company, being approximately 0.03 percent of the total number of outstanding shares of the company, and 538,898 shares of Exxon Mobil Corporation (including 300,250 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 472,550 common shares of the company, as of February 13, 2013.

# 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 86. 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 98 of this report.

R.C. Olsen 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 Production Company, R.C. Olsen 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 86. 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

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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 Royalty Amending Agreement, dated November 18, 2008, setting out various items, including the amount of additional royalties that are to be paid to the Province of Alberta in the period from January 1, 2010 to December 31, 2015 in return for certain assurances from the Government of Alberta (Incorporated herein by reference to Exhibit 1.01(10)(ii)(1) of the company s Form 8-K filed on November 19, 2008 (File No. 0-12014)).

(26) 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)).

(27) 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)).

(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, 2012.

(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 26, 2013 by the undersigned, thereunto duly authorized.

Imperial Oil Limited

*By* */s/ Bruce H. March*
(Bruce H. March, 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 26, 2013 by the following persons on behalf of the registrant and in the capacities indicated.

| Signature | Title |
|---|---|
| */s/ Bruce H. March*<br>(Bruce H. March) | Chairman of the Board, President and<br>Chief Executive Officer and Director<br>(Principal Executive Officer) |
| */s/ Paul J. Masschelin*<br>(Paul J. Masschelin) | Senior Vice-President,<br>Finance and Administration, and Controller<br>(Principal Financial Officer and Principal<br>Accounting Officer) |
| */s/ Krystyna T. Hoeg*<br>(Krystyna T. Hoeg) | Director |
| */s/ Jack M. Mintz*<br>(Jack M. Mintz) | Director |

| | |
|---|---|
| */s/ Robert C. Olsen* | Director |
| (Robert C. Olsen) | |
| */s/ David S. Sutherland* | Director |
| (David S. Sutherland) | |
| */s/ Sheelagh D. Whittaker* | Director |
| (Sheelagh D. Whittaker) | |
| */s/ Victor L. Young* | Director |
| (Victor L. Young) | |

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# Financial section

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# Financial summary (U.S. GAAP)

| millions of dollars | **2012** | 2011 | 2010 | 2009 | 2008 |
|---|---|---|---|---|---|
| Operating revenues | **31,053** | 30,474 | 24,946 | 21,292 | 31,240 |
| | | | | | |
| Net income by segment: | | | | | |
| Upstream | **1,888** | 2,457 | 1,764 | 1,324 | 2,923 |
| Downstream | **1,772** | 884 | 442 | 278 | 796 |
| Chemical | **165** | 122 | 69 | 46 | 100 |
| Corporate and other | **(59)** | (92) | (65) | (69) | 59 |
| Net income | **3,766** | 3,371 | 2,210 | 1,579 | 3,878 |
| | | | | | |
| Cash and cash equivalents at year end | **482** | 1,202 | 267 | 513 | 1,974 |
| Total assets at year end | **29,364** | 25,429 | 20,580 | 17,473 | 17,035 |
| | | | | | |
| Long-term debt at year end | **1,175** | 843 | 527 | 31 | 34 |
| Total debt at year end | **1,647** | 1,207 | 756 | 140 | 143 |
| Other long-term obligations at year end | **3,983** | 3,876 | 2,753 | 2,839 | 2,254 |
| | | | | | |
| Shareholders equity at year-end | **16,377** | 13,321 | 11,177 | 9,439 | 9,065 |
| Cash flow from operating activities | **4,680** | 4,489 | 3,207 | 1,591 | 4,263 |
| | | | | | |
| Per-share information (dollars) | | | | | |
| Net income per share - basic | **4.44** | 3.98 | 2.61 | 1.86 | 4.39 |
| Net income per share - diluted | **4.42** | 3.95 | 2.59 | 1.84 | 4.36 |
| Dividends | **0.48** | 0.44 | 0.43 | 0.40 | 0.38 |

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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 | **2012** | 2011 | 2010 |
|---|---|---|---|
| Business uses: asset and liability perspective | | | |
| Total assets | **29,364** | 25,429 | 20,580 |
| Less: total current liabilities excluding notes and loans payable | **(5,433)** | (5,585) | (4,348) |
| total long-term liabilities excluding long-term debt | **(5,907)** | (5,316) | (4,299) |
| Add: Imperial s share of equity company debt | **24** | 28 | 33 |
| Total capital employed | **18,048** | 14,556 | 11,966 |
| | | | |
| Total company sources: debt and equity perspective | | | |
| Notes and loans payable | **472** | 364 | 229 |
| Long-term debt | **1,175** | 843 | 527 |
| Shareholders equity | **16,377** | 13,321 | 11,177 |
| Add: Imperial s share of equity company debt | **24** | 28 | 33 |
| Total capital employed | **18,048** | 14,556 | 11,966 |

**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 | **2012** | 2011 | 2010 |
|---|---|---|---|
| Net income | **3,766** | 3,371 | 2,210 |
| Financing costs (after tax), including Imperial s share of equity companies | **1** | 1 | 2 |
| Net income excluding financing costs | **3,767** | 3,372 | 2,212 |
| | | | |
| Average capital employed | **16,302** | 13,261 | 10,791 |
| Return on average capital employed (percent) corporate total | **23.1** | 25.4 | 20.5 |

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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 | **2012** | 2011 | 2010 |
|---|---|---|---|
| Cash from operating activities | **4,680** | 4,489 | 3,207 |
| Proceeds from asset sales | **226** | 314 | 144 |
| Total cash flow from operating activities and asset sales | **4,906** | 4,803 | 3,351 |

**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 | **2012** | 2011 | 2010 |
|---|---|---|---|
| **From Imperial s Consolidated Statement of Income** | | | |
| Total expenses | **26,195** | 26,308 | 22,138 |
| Less: | | | |
| Purchases of crude oil and products | **18,476** | 18,847 | 14,811 |
| Federal excise tax | **1,338** | 1,320 | 1,316 |
| Financing costs | **(1)** | 3 | 7 |
| Subtotal | **19,813** | 20,170 | 16,134 |
| Imperial s share of equity company expenses | **34** | 39 | 39 |
| Total operating costs | **6,416** | 6,177 | 6,043 |

**Components of Operating Costs**

| millions of dollars | **2012** | 2011 | 2010 |
|---|---|---|---|
| **From Imperial s Consolidated Statement of Income** | | | |
| Production and manufacturing | **4,457** | 4,114 | 3,996 |
| Selling and general | **1,081** | 1,168 | 1,070 |
| Depreciation and depletion | **761** | 764 | 747 |
| Exploration | **83** | 92 | 191 |
| Subtotal | **6,382** | 6,138 | 6,004 |
| Imperial s share of equity company expenses | **34** | 39 | 39 |
| Total operating costs | **6,416** | 6,177 | 6,043 |

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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 does not necessarily have the same meaning as under SEC Rule 13q-1 relating to government payment reporting. For example, a single project for purposes of the rule may encompass numerous properties, agreements, investments, developments, phases, work efforts, activities and components, each of which we may also informally describe as a project .

## Business environment and risk assessment

### Long-term business outlook

By 2040, the world s population is projected to grow to approximately 8.7 billion people, or about 1.9 billion more than in 2010. Coincident with this population increase, the company expects worldwide economic growth to average close to 3 percent per year. Expanding prosperity across a growing global population is expected to coincide with an increase in primary energy demand of about 35 percent by 2040 versus 2010, even with substantial efficiency gains around the world. This demand increase is expected to be concentrated in emerging and developing countries (i.e., those that are not member nations of the Organization for Economic Cooperation and Development).

As economic progress for billions of people drives demand higher, increasing penetration of energy-efficient and lower-emission fuels, technologies and practices are expected to contribute to significantly lower levels of energy consumption and emissions per unit of economic output over time. Efficiency gains will result from anticipated improvements in the transportation and power generation sectors, driven by the penetration of advanced technologies, as well as many other improvements that span the residential, commercial and industrial sectors.

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 provide a large quantity of energy in small volumes, making them easy to transport and widely available.

Demand for electricity around the world is estimated to increase approximately 85 percent by 2040, led by growth in developing countries. Consistent with this projection, power generation is expected to remain the largest and fastest-growing major segment of global energy demand. Meeting the expected growth in power demand will require a diverse set of energy sources. Natural gas demand is likely to grow most significantly and become the leading source of generated electricity by 2040, reflecting the efficiency of gas-fired power plants.

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

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 wind, are expected to grow significantly over the period.

Liquid fuels provide the largest share of energy supply today due to their broad-based availability, affordability and ease of transport to meet consumer needs. By 2040, global demand for liquids is expected to grow to approximately 113 million barrels of oil-equivalent a day, an increase of about 30 percent from 2010. Global demand for liquid fuels will be met by a wide variety of sources. Conventional crude and condensate production is expected to remain relatively flat through 2040. However, growth is expected from a wide variety of sources, including deep-water resources, oil sands, tight oil, 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 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 increases in major regions around the world requiring new sources of supply. 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. By 2040, unconventional gas is likely to approach one-third of global gas supplies, up from less than 15 percent in 2010. 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, including 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 3 to 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 ExxonMobil s long-term Energy Outlook, 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 set on West Texas Intermediate (WTI) oil markets, a common benchmark for mid-continent North American markets. In 2012, the

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

average price of WTI crude oil and the company s Western Canadian liquids realizations 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.

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 in which the company operates.

Imperial s proven development approach supported the company s continued investment in several key growth projects during a weak and uncertain economic environment following the global financial crisis in 2008. The company continues a decade-long growth strategy in which about $40 billion will be invested to meet its plan of doubling upstream production by the end of this decade. Actual spending and production volumes could vary depending on the progress of individual projects. To support the company s long-term growth in oil sands production, 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, which helps reduce the risks of dependence on potentially limited supply sources in the Upstream. With the relative maturity of conventional production in established producing areas, Imperial s production is expected to come increasingly from unconventional and frontier sources, particularly oil sands, unconventional natural gas and from Canada s North, where Imperial has large undeveloped resource opportunities.

**Subsequent event**

On February 26, 2013, ExxonMobil Canada acquired 100 percent of 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.

Imperial acquired a 50-percent participating interest in 545,000 net acres in the liquids-rich Montney shale, 104,000 net acres in the Duvernay shale and additional acreage in other areas of Alberta, Canada. Current net production of the acreage is about 70 million cubic feet a day of natural gas and about 3,900 barrels a day of crude oil, condensate and natural gas liquids. The resources contained in these acreages, together with Imperial s and ExxonMobil s technical expertise and financial strength, should enable development of additional supplies of unconventional natural gas and liquid resources.

The acquisition should be accretive to Imperial s production growth and cash flow. However, it is not likely to have a material impact to Imperial s near-term earnings per share.

Reference is made to Financial Statement note 17: Subsequent event for further details.

**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. The average prices the company paid for most of its crude oil processed at three of the company s four refineries are set on Western Canadian crude oil markets. In 2012, the average prices of Western Canadian crude oils continued to be markedly 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. Stronger industry refining margins in 2012 were the result of the widened 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.

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

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 four refineries in Canada, with aggregate distillation capacity of 506,000 barrels a day. Imperial s fuels marketing business includes retail operations across Canada serving customers through more than 1,770 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.

In the second quarter of 2012, Imperial announced its intention to market the Dartmouth refinery and related supply terminals to prospective buyers. At year-end 2012, the Dartmouth refinery had a rated capacity of 85 thousand barrels a day. The company is also assessing alternatives including conversion to a products terminal. A decision is expected in 2013.

**Chemical**

The North American petrochemical industry continued to improve in 2012 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. 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 cost-advantage feedstock to the company s Sarnia chemical plant are expected around mid-2013. The company s strategy for its Chemical business is to reduce costs and maximize value by continuing to increase the integration of its chemical plants at Sarnia and Dartmouth with the refineries. 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 | **2012** | 2011 | 2010 |
|---|---|---|---|
| Net income | **3,766** | 3,371 | 2,210 |

2012

Net income in 2012 was $3,766 million or $4.42 a share on a diluted basis, versus $3,371 million or $3.95 a 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.

2011

Net income in 2011 was $3,371 million or $3.95 a share on a diluted basis, versus $2,210 million or $2.59 a share in 2010. Increased earnings were primarily attributable to higher crude oil commodity prices, stronger industry refining margins and increased Cold Lake bitumen production. These factors were partially offset by the unfavourable impacts of higher royalty costs, the stronger Canadian dollar and lower conventional crude oil volumes due to third-party pipeline reliability issues. 2011 earnings also included higher gains of about $70 million on asset divestments.

In 2011, there was an unusually large spread between the prices of Brent crude oil and WTI crude oil, two common benchmarks for world oil markets. Increase in 2011 in the average Brent crude oil price more than doubled that of the average WTI price due to continued weakness in WTI crude oil markets. Increases in the company s Upstream realizations in 2011 followed more closely the trend of WTI prices, while margins in the company s Downstream segment benefited as the overall cost of crude oil processed at three of the company s four refineries were more in line with WTI prices.

### Upstream

| millions of dollars | **2012** | 2011 | 2010 |
|---|---|---|---|
| Net income | **1,888** | 2,457 | 1,764 |

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.

2011

Net income for the year was $2,457 million, up $693 million from 2010. Earnings increased primarily due to the impacts of higher crude oil commodity prices of about $925 million and increased Cold Lake bitumen production of about $260 million. These factors were partially offset by the unfavourable effects of higher royalty costs due to higher crude oil commodity prices of about $245 million, the stronger Canadian dollar of about $150 million, and lower conventional crude oil volumes of about $150 million, of which about $80 million was a result of third-

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

party pipeline reliability issues. Included in 2011 earnings were gains of $116 million on asset divestments, about $95 million higher than 2010.

**Average realizations**

| Canadian dollars | **2012** | 2011 | 2010 |
|---|---|---|---|
| Conventional crude oil realizations (a barrel) | **77.19** | 85.22 | 71.64 |
| Natural gas liquids realizations (a barrel) | **42.06** | 59.08 | 50.09 |
| Natural gas realizations (a thousand cubic feet) | **2.33** | 3.59 | 4.04 |
| Synthetic oil realizations (a barrel) | **92.48** | 101.43 | 80.63 |
| Bitumen realizations (a barrel) | **59.76** | 63.95 | 58.36 |

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 a 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.

2011

The average price of Brent crude oil in U.S. dollars, a common benchmark for Atlantic Basin oil markets, was $111.29 a barrel in 2011, up about 40 percent from the previous year. Increase in the average price of West Texas Intermediate (WTI) crude oil, a common benchmark for mid-continent North American oil markets, was limited to 19 percent, due to the continued weakness in WTI crude oil markets. Increases in the company s average realizations on sales of Canadian conventional crude oil and synthetic crude oil were in line with that of WTI.

The company s average bitumen realizations in Canadian dollars in 2011 increased ten percent to $63.95 per barrel as the price spread between light crude oil and Cold Lake bitumen widened.

Canadian natural gas prices in 2011 were lower than the previous year. The average of 30-day spot prices for natural gas in Alberta at $3.67 a thousand cubic feet were down from $4.39 in 2010. The company s realizations for natural gas averaged $3.59 a thousand cubic feet, down from $4.04 in 2010.

**Crude oil and NGLs - production and sales** (a)

| thousands of barrels a day | **2012** | | 2011 | | 2010 | |
|---|---|---|---|---|---|---|
| | **gross** | **net** | gross | net | gross | net |
| Bitumen | **154** | **123** | 160 | 120 | 144 | 115 |
| Synthetic oil | **72** | **69** | 72 | 67 | 73 | 67 |
| Conventional crude oil | **20** | **15** | 18 | 13 | 23 | 17 |
| Total crude oil production | **246** | **207** | 250 | 200 | 240 | 199 |
| NGLs available for sale | **4** | **3** | 5 | 4 | 7 | 5 |
| Total crude oil and NGL production | **250** | **210** | 255 | 204 | 247 | 204 |
| Cold Lake sales, including diluent (b) | **201** | | 209 | | 188 | |
| NGL sales | **8** | | 9 | | 10 | |

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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 a day | **2012** | | 2011 | | 2010 | |
|---|---|---|---|---|---|---|
| | **gross** | **net** | gross | net | gross | net |
| Production (c) | **192** | **195 (d)** | 254 | 228 | 280 | 254 |
| Sales | **177** | | 237 | | 264 | |

(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) Diluent is natural gas condensate or other light hydrocarbons added to Cold Lake bitumen to facilitate transportation to market by pipeline.
(c) Production of natural gas includes amounts used for internal consumption with the exception of the amounts re-injected.
(d) Net production included favourable royalty cost adjustments.

2012

Gross production of Cold Lake bitumen averaged 154,000 barrels a 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 a day, unchanged from 2011.

Gross production of conventional crude oil averaged 20,000 barrels a 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 a day, down from 254 million cubic feet in 2011. The lower production volume was primarily a result of producing properties divestments completed in 2011.

2011

Gross production of Cold Lake bitumen increased to a record 160,000 barrels a day in 2011 from 144,000 barrels in 2010. Increased volumes were due to contributions from new wells steamed in 2010 and 2011, increased recoveries as a result of technology applications and the cyclic nature of production at Cold Lake.

The company s share of gross production from Syncrude averaged 72,000 barrels a day, in line with 73,000 barrels in 2010.

Gross production of conventional crude oil averaged 18,000 barrels a day, compared with 23,000 barrels in 2010. Lower volumes were primarily due to third-party pipeline unplanned downtime, which reduced production at the Norman Wells field, along with natural reservoir decline.

Gross production of natural gas in 2011 was 254 million cubic feet a day, down from 280 million cubic feet in 2010. The lower production volume was primarily a result of natural reservoir decline.

In 2011, the company sold its interests in shallow gas properties in the Medicine Hat, Alberta area, the Coleville-Hoosier natural gas producing property in Saskatchewan and the Rainbow Lake producing property in Alberta, realizing a gain of about $76 million. Production for the company s share of the properties averaged about 56 million cubic feet of natural gas a day and one thousand barrels of crude oil a day in 2010. Also in the year, the company recorded a gain of about $40 million from an exchange of oil sands leases with a third party.

**Downstream**

| millions of dollars | **2012** | 2011 | 2010 |
|---|---|---|---|

| | | | |
|---|---|---|---|
| Net income | **1,772** | 884 | 442 |

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.

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

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.

2011

Net income was $884 million, an increase of $442 million over 2010. Higher earnings were primarily due to the favourable impact of stronger industry refining margins of about $590 million. Refining margins benefited as the overall cost of crude oil processed at three of the company s four refineries followed the trend of WTI prices.

This factor was partially offset by the unfavourable impacts of higher maintenance activities on refinery operations and expenses totaling about $60 million and the stronger Canadian dollar of about $55 million. Earnings in 2010 included a gain of about $25 million from sale of non-operating assets.

**Refinery utilization**

| thousands of barrels a day (a) | **2012** | 2011 | 2010 |
|---|---|---|---|
| Total refinery throughput (b) | **435** | 430 | 444 |
| Refinery capacity at December 31 | **506** | 506 | 502 |
| Utilization of total refinery capacity (percent) | **86** | 85 | 88 |

**Sales**

| thousands of barrels a day (a) | **2012** | 2011 | 2010 |
|---|---|---|---|
| Gasolines | **221** | 220 | 218 |
| Heating, diesel and jet fuels | **151** | 157 | 153 |
| Heavy fuel oils | **30** | 29 | 28 |
| Lube oils and other products | **43** | 41 | 43 |
| Net petroleum product sales | **445** | 447 | 442 |

(a) Volumes a 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.

2012

Total refinery throughput was 435,000 barrels a day, up from 2011, 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 a day, 2,000 barrels lower than 2011.

2011

Total refinery throughput was 430,000 barrels a day, down from 2010, and average refinery capacity utilization decreased to 85 percent from the previous year s 88 percent. Lower volumes and utilization were primarily a result of higher planned and unplanned maintenance activities. Total net petroleum sales increased to 447,000 barrels a day, 5,000 barrels higher than 2010.

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

**Chemical**

| millions of dollars | **2012** | 2011 | 2010 |
|---|---|---|---|
| Net income | **165** | 122 | 69 |

**Sales**

| thousands of tonnes | **2012** | 2011 | 2010 |
|---|---|---|---|
| Polymers and basic chemicals | **767** | 748 | 711 |
| Intermediate and others | **277** | 268 | 278 |
| Total petrochemical sales | **1,044** | 1,016 | 989 |

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.

2011

Net income was $122 million, up $53 million from 2010. Improved margins for intermediate and aromatic products, lower costs due to lower planned maintenance activities and higher polyethylene sales volumes were the main contributors to the increase. These factors were partially offset by lower margins for polyethylene products.

**Corporate & Other**

| millions of dollars | **2012** | 2011 | 2010 |
|---|---|---|---|
| Net income | **(59)** | (92) | (65) |

2012

Net income effects from Corporate & Other were negative $59 million, compared with negative $92 million in 2011. Favourable effects were due to lower share-based compensation charges.

2011

Net income effects were negative $92 million, versus negative $65 million reported last year. Unfavourable effects in 2011 were primarily due the impact of the share price change on 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 | **2012** | 2011 | 2010 |
|---|---|---|---|
| Cash provided by/(used in) | | | |
| Operating activities | **4,680** | 4,489 | 3,207 |
| Investing activities | **(5,238)** | (3,593) | (3,709) |
| Financing activities | **(162)** | 39 | 256 |
| Increase/(decrease) in cash and cash equivalents | **(720)** | 935 | (246) |
| | | | |
| Cash and cash equivalents at end of year | **482** | 1,202 | 267 |

Although the company issues long-term debt from time to time and maintains a commercial paper program, internally generated funds cover the majority of its financial requirements. 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, 2011. As a result of the valuation, the company contributed $594 million to the registered retirement benefit plans in 2012. The next required independent actuarial valuation will be as at December 31, 2012 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**

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.

2011

Cash flow generated from operating activities was $4,489 million, an increase of $1,282 million from 2010 and in line with the earnings increase versus 2010.

**Cash flow from investing activities**

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.

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

2011

Investing activities used net cash of $3,593 million in 2011, compared to $3,709 million in 2010. Additions to property, plant and equipment were $3,919 million, compared with $3,856 million last year. Proceeds from asset sales were $314 million compared with $144 million in 2010.

**Cash flow from financing activities**

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 totaled $0.48, 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. Subsequent to year-end, in February 2013, this long-term bank credit facility was increased by an additional $200 million to $500 million with the maturity date unchanged. The company has not drawn on the facility.

In February 2013, the company increased its long-term debt by $1.3 billion by drawing on an existing facility with an affiliated company of Exxon Mobil Corporation and increased short-term debt by $0.5 billion by issuing additional commercial paper. The majority of the increased debt was used to finance the acquisition of a 50-percent interest in Celtic s assets and liabilities.

2011

Cash from financing activities was $39 million, compared with $256 million in 2010.

The company raised new debt of $455 million by drawing on existing facilities. At the end of 2011, total debt outstanding was $1,207 million, compared with $756 million at the end of 2010.

During 2011, 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 $373 million were paid in 2011 compared with $356 million in 2010. Per-share dividends paid in 2011 totaled $0.44, up from $0.42 in 2010.

In the second quarter, the company extended the maturity date of its existing stand-by $200 million long term bank credit facility to July 2013. The company has not drawn on this facility.

**Financial percentages and ratios**

| | **2012** | 2011 | 2010 |
|---|---|---|---|
| Total debt as a percentage of capital (a) | **9** | 9 | 7 |
| Interest coverage ratio earnings basis (b) | **239** | 260 | 370 |

(a) Current and long-term debt (page 56) and the company s share of equity company debt, divided by debt and shareholders equity (page 56).

(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.

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

Debt represented nine percent of the company s capital structure at the end of 2012, unchanged from 2011.

Debt-related interest incurred in 2012, before capitalization of interest, was $20 million, compared with $16 million in 2011. The average effective interest rate on the company s debt was 1.6 percent in 2012, compared with 1.5 percent in 2011.

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, 2012. It combines data from the consolidated balance sheet and from individual notes to the consolidated financial statements, where appropriate.

| millions of dollars | Financial statement note reference | Payment due by period 2013 | 2014 to 2017 | 2018 and beyond | Total amount |
|---|---|---|---|---|---|
| Long-term debt (a) | Note 14 | - | 1,066 | 109 | 1,175 |
| - Due in one year | | 7 | - | - | 7 |
| Operating leases (b) | Note 13 | 180 | 306 | 25 | 511 |
| Unconditional purchase obligations (c) | Note 9 | 77 | 217 | 176 | 470 |
| Firm capital commitments (d) | | 3,554 | 1,573 | 99 | 5,226 |
| Pension and other post-retirement obligations (e) | Note 4 | 733 | 227 | 1,809 | 2,769 |
| Asset retirement obligations (f) | Note 5 | 105 | 378 | 483 | 966 |
| Other long-term purchase agreements (g) | | 346 | 1,894 | 4,747 | 6,987 |

(a) Long-term debt includes a long-term loan from an affiliated company of Exxon Mobil Corporation of $1,040 million and capital lease obligations of $142 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 cancellable 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 2012 were $3,293 million associated with the company s share of the Kearl project and $840 million associated with the Cold Lake Nabiye expansion 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 2013 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.

In 2012, the company entered into additional long-term pipeline transportation agreements, which have a total commitment of about $4.4 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 $143 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

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

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 | **2012** | 2011 |
|---|---|---|
| Upstream (a) | **5,518** | 3,880 |
| Downstream | **140** | 166 |
| Chemical | **4** | 4 |
| Other | **21** | 16 |
| Total | **5,683** | 4,066 |

(a) Exploration expenses included.

Total capital and exploration expenditures were $5,683 million in 2012, an increase of $1,617 million from 2011.

For the Upstream segment, capital expenditures were $5,518 million, compared with $3,880 million in 2011. Expenditures were primarily directed towards the advancement of Kearl initial development and expansion. Other investments included advancing the Nabiye expansion project at Cold Lake and sustaining capital for Syncrude mining and tailing projects.

By 2012 year end, the construction of the Kearl initial development was complete and phased start-up activities were underway. Despite U.S. permitting and regulatory issues that continued for almost two years involving transportation of facility modules and significant challenges including an early onset of winter and exceptionally harsh weather during current start-up operations, production of mined diluted bitumen from the first froth treatment train is expected to be in the first quarter of 2013. The final cost for the initial development is expected to be $12.9 billion, of which the company s share is $9.2 billion.

Planned capital and exploration expenditures in the Upstream segment are forecast at about $6.8 billion for 2013. Investments are mainly planned for the continued investment in the Kearl and Nabiye growth projects, along with sustaining capital for Syncrude mining and tailing projects. The planned capital and exploration expenditures also include $1.6 billion associated with Imperial s 50 percent participation in the acquisition of Celtic.

For the Downstream segment, capital expenditures were $140 million in 2012, compared with $166 million in 2011. In 2012, 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 2013 are about $200 million, focused on improving refinery reliability and environmental and safety performance, as well as continuing upgrades to the retail network.

The company continues a decade-long growth strategy in which about $40 billion will be invested. Total capital and exploration expenditures for the company in 2013 are expected to be about $7 billion. Actual spending could vary depending on the progress of individual projects.

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

## Market risks and other uncertainties

Crude oil, natural gas, petroleum product and chemical prices have fluctuated in response to changing market forces. The impacts of these price fluctuations on earnings from Upstream, Downstream and Chemical operations have varied. In addition, industry crude oil and natural gas commodity prices and petroleum and chemical product prices are commonly benchmarked in U.S. dollars. The majority of Imperial s sales and purchases are related to these industry U.S. dollar benchmarks. As the company records and reports its financial results in Canadian dollars, to the extent that the Canadian/U.S. dollar exchange rate fluctuates, the company s earnings will be affected. The company s potential exposure to commodity price and margin and Canadian/U.S. dollar exchange rate fluctuations is summarized in the earnings sensitivities table below, which shows the estimated annual effect, under current conditions, of the company s after-tax net income.

**Earnings sensitivities** (a)

| millions of dollars, after tax | | |
|---|---|---|
| Seven dollars (U.S.) a barrel change in crude oil prices | + (-) | 340 |
| Thirty cents a thousand cubic feet change in natural gas prices | + (-) | 5 |
| Two dollars (U.S.) a barrel change in sales margins for total petroleum products | + (-) | 250 |
| One cent (U.S.) a pound change in sales margins for polyethylene | + (-) | 6 |
| One-quarter percent decrease (increase) in short-term interest rates | + (-) | 3 |
| Ten cents decrease (increase) in the value of the Canadian dollar versus the U.S. dollar | + (-) | 490 |

(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 2012. 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 year-end 2011 by about $16 million (after tax) a year for each one U.S. dollar change. The increase was primarily a result of the impact of lower royalty costs for bitumen production due to lower prices for Cold Lake bitumen at 2012 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 59 percent of the company s intersegment sales are crude oil produced by the Upstream and sold to the Downstream. Other intersegment sales include those between refineries and 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.

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

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

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 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 2012 when market discounts to Western Canadian crude oil prices negatively impacted the company s Upstream realizations but positively 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.

## 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 integral to making investment decisions about oil and gas properties such as whether development should proceed. Oil and gas reserve quantities are also used as the basis for calculating unit-of-production depreciation rates and for evaluating 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

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

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 is an ongoing process based on rigorous technical evaluations, commercial and market assessment, 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.

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.

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

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 2012 compares to actual returns of 7.3 percent and 8.5 percent achieved over the last 10- and 20-year periods ending December 31, 2012. 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 2012.

**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 2012, the obligations were discounted at six percent and the accretion expense was $86 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.

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

**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 as of year-end 2012 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* 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, 2012.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the company s internal control over financial reporting as of December 31, 2012, as stated in their report which is included herein.

*/s/ Bruce H. March*

B.H. March

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 26, 2013

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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, 2012 and December 31, 2011 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, 2012. We also have audited Imperial Oil Limited s internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control - Integrated Framework 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, 2012 and December 31, 2011 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2012 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, 2012, based on criteria established in Internal Control - Integrated Framework issued by the COSO.

*/s/ PricewaterhouseCoopers LLP*

Chartered Accountants

Calgary, Alberta, Canada

February 26, 2013

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

millions of Canadian dollars

| For the years ended December 31 | **2012** | 2011 | 2010 |
|---|---|---|---|
| **Revenues and other income** | | | |
| Operating revenues (a)(b) | **31,053** | 30,474 | 24,946 |
| Investment and other income (note 8) | **135** | 240 | 146 |
| **Total revenues and other income** | **31,188** | 30,714 | 25,092 |
| **Expenses** | | | |
| Exploration | **83** | 92 | 191 |
| Purchases of crude oil and products (c) | **18,476** | 18,847 | 14,811 |
| Production and manufacturing (d) | **4,457** | 4,114 | 3,996 |
| Selling and general | **1,081** | 1,168 | 1,070 |
| Federal excise tax (a) | **1,338** | 1,320 | 1,316 |
| Depreciation and depletion | **761** | 764 | 747 |
| Financing costs (note 12) | **(1)** | 3 | 7 |
| **Total expenses** | **26,195** | 26,308 | 22,138 |
| **Income before income taxes** | **4,993** | 4,406 | 2,954 |
| **Income taxes** (note 3) | **1,227** | 1,035 | 744 |
| **Net income** | **3,766** | 3,371 | 2,210 |
| **Per-share information** (Canadian dollars) | | | |
| Net income per common share - basic (note 10) | **4.44** | 3.98 | 2.61 |
| Net income per common share - diluted (note 10) | **4.42** | 3.95 | 2.59 |
| Dividends | **0.48** | 0.44 | 0.43 |

(a) Operating revenues include federal excise tax of $1,338 million (2011 - $1,320 million, 2010 - $1,316 million).
(b) Operating revenues include amounts from related parties of $2,907 million (2011 - $2,818 million, 2010 - $2,250 million), (note 16).
(c) Purchases of crude oil and products include amounts from related parties of $3,033 million (2011 - $3,636 million, 2010 - $2,828 million), (note 16).
(d) Production and manufacturing expenses include amounts to related parties of $241 million (2011 - $217 million, 2010 - $233 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 | **2012** | 2011 | 2010 |
|---|---|---|---|
| **Net income** | **3,766** | 3,371 | 2,210 |
| | | | |
| Other comprehensive income, net of income taxes (note 4) | | | |
| Post-retirement benefits liability adjustment (excluding amortization) | **(415)** | (953) | (217) |
| Amortization of post-retirement benefits liability adjustment included in net periodic benefit costs | **198** | 139 | 114 |
| **Total other comprehensive income/(loss)** | **(217)** | (814) | (103) |
| | | | |
| **Comprehensive income** | **3,549** | 2,557 | 2,107 |

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 | **2012** | 2011 |
|---|---|---|
| **Assets** | | |
| Current Assets | | |
| Cash | **482** | 1,202 |
| Accounts receivable, less estimated doubtful amounts | **1,976** | 2,290 |
| Inventories of crude oil and products (note 11) | **827** | 762 |
| Materials, supplies and prepaid expenses | **280** | 239 |
| Deferred income tax assets (note 3) | **527** | 590 |
| Total current assets | **4,092** | 5,083 |
| Long-term receivables, investments and other long-term assets | **1,090** | 920 |
| Property, plant and equipment, less accumulated depreciation and depletion (note 2) | **23,922** | 19,162 |
| Goodwill (note 2) | **204** | 204 |
| Other intangible assets, net | **56** | 60 |
| **Total assets** (note 2) | **29,364** | 25,429 |
| | | |
| **Liabilities** | | |
| Current liabilities | | |
| Notes and loans payable | **472** | 364 |
| Accounts payable and accrued liabilities (a) (note 11) | **4,249** | 4,317 |
| Income taxes payable | **1,184** | 1,268 |
| Total current liabilities | **5,905** | 5,949 |
| Long-term debt (b)(note 14) | **1,175** | 843 |
| Other long-term obligations (note 5) | **3,983** | 3,876 |
| Deferred income tax liabilities (note 3) | **1,924** | 1,440 |
| **Total liabilities** | **12,987** | 12,108 |
| | | |
| Commitments and contingent liabilities (note 9) | | |
| | | |
| **Shareholders equity** | | |
| Common shares at stated value (c)(note 10) | **1,566** | 1,528 |
| Earnings reinvested | **17,266** | 14,031 |
| Accumulated other comprehensive income | **(2,455)** | (2,238) |
| **Total shareholders equity** | **16,377** | 13,321 |
| | | |
| **Total liabilities and shareholders equity** | **29,364** | 25,429 |

(a) Accounts payable and accrued liabilities include amounts receivable from related parties of $9 million (2011 amounts payable of $215 million), (note 16).
(b) Long-term debt includes amounts to related parties of $1,040 million (2011 $820 million).
(c) Number of common shares outstanding was 848 million (2011 - 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/ Bruce H. March*

B.H. March
Chairman, president and
chief executive officer

*/s/ Paul J. Masschelin*

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 | **2012** | 2011 | 2010 |
|---|---|---|---|
| **Common shares at stated value** (note 10) | | | |
| At beginning of year | **1,528** | 1,511 | 1,508 |
| Issued under the stock option plan | **43** | 19 | 3 |
| Share purchases at stated value | **(5)** | (2) | - |
| At end of year | **1,566** | 1,528 | 1,511 |
| | | | |
| **Earnings reinvested** | | | |
| At beginning of year | **14,031** | 11,090 | 9,252 |
| Net income for the year | **3,766** | 3,371 | 2,210 |
| Share purchases in excess of stated value | **(123)** | (57) | (8) |
| Dividends | **(408)** | (373) | (364) |
| At end of year | **17,266** | 14,031 | 11,090 |
| | | | |
| **Accumulated other comprehensive income** | | | |
| At beginning of year | **(2,238)** | (1,424) | (1,321) |
| Other comprehensive income | **(217)** | (814) | (103) |
| At end of year | **(2,455)** | (2,238) | (1,424) |
| | | | |
| **Shareholders equity at end of year** | **16,377** | 13,321 | 11,177 |

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 | **2012** | 2011 | 2010 |
|---|---|---|---|
| **Operating activities** | | | |
| Net income | **3,766** | 3,371 | 2,210 |
| Adjustments for non-cash items: | | | |
| Depreciation and depletion | **761** | 764 | 747 |
| (Gain)/loss on asset sales | **(94)** | (197) | (95) |
| Deferred income taxes and other | **619** | 71 | 152 |
| Changes in operating assets and liabilities: | | | |
| Accounts receivable | **300** | (302) | (289) |
| Inventories, materials, supplies and prepaid expenses | **(106)** | (228) | 38 |
| Income taxes payable | **(84)** | 390 | 30 |
| Accounts payable and accrued liabilities | **(67)** | 846 | 651 |
| All other items - net (a) | **(415)** | (226) | (237) |
| **Cash flows from (used in) operating activities** | **4,680** | 4,489 | 3,207 |
| | | | |
| **Investing activities** | | | |
| Additions to property, plant and equipment | **(5,478)** | (3,919) | (3,856) |
| Proceeds from asset sales | **226** | 314 | 144 |
| Repayment of loan from equity company | **14** | 12 | 3 |
| **Cash flows from (used in) investing activities** | **(5,238)** | (3,593) | (3,709) |
| | | | |
| **Financing activities** | | | |
| Short-term debt - net | **105** | 135 | 120 |
| Long-term debt issued | **220** | 320 | 500 |
| Reduction in capitalized lease obligations | **(4)** | (3) | (3) |
| Issuance of common shares under stock option plan | **43** | 19 | 3 |
| Common shares purchased (note 10) | **(128)** | (59) | (8) |
| Dividends paid | **(398)** | (373) | (356) |
| **Cash flows from (used in) financing activities** | **(162)** | 39 | 256 |
| | | | |
| **Increase (decrease) in cash** | **(720)** | 935 | (246) |
| **Cash at beginning of year** | **1,202** | 267 | 513 |
| **Cash at end of year** (b) | **482** | 1,202 | 267 |

(a) Includes contribution to registered pension plans of $594 million (2011- $361 million, 2010 - $421 million).

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

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

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# Notes to consolidated financial statements

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

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

The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America (GAAP). GAAP requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Certain reclassifications to prior years have been made to conform to the 2012 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 and liabilities, 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 companies 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 that facilitate the sale and purchase of liquids in the conduct of company operations. Other parties who also have an equity interest in these companies share in the risks and rewards according to their percentage of ownership. Imperial does not invest in these companies 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 well costs when the well has found a sufficient quantity of reserves to justify its completion as a producing

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**Notes to consolidated financial statements** (continued)

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 costs are expensed as incurred. 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. 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. 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.

**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.

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## Notes to consolidated financial statements (continued)

**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.

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.

## Notes to consolidated financial statements (continued)

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 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 | **2012** | 2011 | 2010 | **2012** | 2011 | 2010 | **2012** | 2011 | 2010 |
| **Revenues and other income** | | | | | | | | | |
| Operating revenues (a) | **4,674** | 5,278 | 4,283 | **25,077** | 23,909 | 19,565 | **1,302** | 1,287 | 1,098 |
| Intersegment sales | **4,110** | 4,460 | 3,802 | **2,603** | 2,784 | 1,973 | **299** | 354 | 285 |
| Investment and other income | **46** | 168 | 59 | **81** | 63 | 81 | **-** | - | 3 |
| | **8,830** | 9,906 | 8,144 | **27,761** | 26,756 | 21,619 | **1,601** | 1,641 | 1,386 |
| **Expenses** | | | | | | | | | |
| Exploration | **83** | 92 | 191 | **-** | - | - | **-** | - | - |
| Purchases of crude oil and products | **3,056** | 3,581 | 2,692 | **21,316** | 21,642 | 17,169 | **1,115** | 1,222 | 1,009 |
| Production and manufacturing | **2,704** | 2,484 | 2,375 | **1,569** | 1,451 | 1,413 | **185** | 179 | 209 |
| Selling and general (b) | **1** | 7 | 5 | **935** | 973 | 918 | **67** | 64 | 63 |
| Federal excise tax | **-** | - | - | **1,338** | 1,320 | 1,316 | **-** | - | - |
| Depreciation and depletion | **498** | 528 | 514 | **242** | 214 | 213 | **12** | 13 | 12 |
| Financing costs (note 12) | **(1)** | 2 | 3 | **-** | (1) | 1 | **-** | - | - |
| **Total expenses** | **6,341** | 6,694 | 5,780 | **25,400** | 25,599 | 21,030 | **1,379** | 1,478 | 1,293 |
| **Income before income taxes** | **2,489** | 3,212 | 2,364 | **2,361** | 1,157 | 589 | **222** | 163 | 93 |
| **Income taxes** (note 3) | | | | | | | | | |
| Current | **72** | 593 | 477 | **486** | 372 | 141 | **67** | 43 | 18 |
| Deferred | **529** | 162 | 123 | **103** | (99) | 6 | **(10)** | (2) | 6 |
| **Total income tax expense** | **601** | 755 | 600 | **589** | 273 | 147 | **57** | 41 | 24 |
| **Net income** | **1,888** | 2,457 | 1,764 | **1,772** | 884 | 442 | **165** | 122 | 69 |
| **Cash flows from (used in) operating activities** | **2,625** | 3,252 | 2,494 | **1,961** | 1,315 | 787 | **127** | 53 | 65 |
| **Capital and exploration expenditures** (c) | **5,518** | 3,880 | 3,844 | **140** | 166 | 184 | **4** | 4 | 10 |
| **Property, plant and equipment** | | | | | | | | | |
| Cost | **30,602** | 25,327 | 21,990 | **7,038** | 6,990 | 6,933 | **765** | 760 | 758 |
| Accumulated depreciation and depletion | **(10,146)** | (9,747) | (9,740) | **(3,967)** | (3,803) | (3,678) | **(576)** | (560) | (546) |
| **Net property, plant and equipment** (d) | **20,456** | 15,580 | 12,250 | **3,071** | 3,187 | 3,255 | **189** | 200 | 212 |
| **Total assets** (e) | **22,317** | 17,222 | 13,852 | **6,409** | 6,700 | 6,315 | **372** | 397 | 425 |

| | Corporate and other | | | Eliminations | | | Consolidated | | |
|---|---|---|---|---|---|---|---|---|---|
| millions of dollars | **2012** | 2011 | 2010 | **2012** | 2011 | 2010 | **2012** | 2011 | 2010 |
| **Revenues and other income** | | | | | | | | | |
| Operating revenues (a) | **-** | - | - | **-** | - | - | **31,053** | 30,474 | 24,946 |
| Intersegment sales | **-** | - | - | **(7,012)** | (7,598) | (6,060) | **-** | - | - |
| Investment and other income | **8** | 9 | 3 | **-** | - | - | **135** | 240 | 146 |
| | **8** | 9 | 3 | **(7,012)** | (7,598) | (6,060) | **31,188** | 30,714 | 25,092 |
| **Expenses** | | | | | | | | | |
| Exploration | **-** | - | - | **-** | - | - | **83** | 92 | 191 |
| Purchases of crude oil and products | **-** | - | - | **(7,011)** | (7,598) | (6,059) | **18,476** | 18,847 | 14,811 |
| Production and manufacturing | **-** | - | - | **(1)** | - | (1) | **4,457** | 4,114 | 3,996 |
| Selling and general (b) | **78** | 124 | 84 | **-** | - | - | **1,081** | 1,168 | 1,070 |
| Federal excise tax | **-** | - | - | **-** | - | - | **1,338** | 1,320 | 1,316 |
| Depreciation and depletion | **9** | 9 | 8 | **-** | - | - | **761** | 764 | 747 |
| Financing costs (note 12) | **-** | 2 | 3 | **-** | - | - | **(1)** | 3 | 7 |
| **Total expenses** | **87** | 135 | 95 | **(7,012)** | (7,598) | (6,060) | **26,195** | 26,308 | 22,138 |
| **Income before income taxes** | **(79)** | (126) | (92) | **-** | - | - | **4,993** | 4,406 | 2,954 |
| **Income taxes** (note 3) | | | | | | | | | |
| Current | **(32)** | (53) | (47) | **-** | - | - | **593** | 955 | 589 |
| Deferred | **12** | 19 | 20 | **-** | - | - | **634** | 80 | 155 |
| **Total income tax expense** | **(20)** | (34) | (27) | **-** | - | - | **1,227** | 1,035 | 744 |
| **Net income** | **(59)** | (92) | (65) | **-** | - | - | **3,766** | 3,371 | 2,210 |
| **Cash flows from (used in) operating activities** | **(33)** | (131) | (139) | **-** | - | - | **4,680** | 4,489 | 3,207 |
| **Capital and exploration expenditures** (c) | **21** | 16 | 7 | **-** | - | - | **5,683** | 4,066 | 4,045 |
| **Property, plant and equipment** | | | | | | | | | |
| Cost | **360** | 339 | 323 | **-** | - | - | **38,765** | 33,416 | 30,004 |
| Accumulated depreciation and depletion | **(154)** | (144) | (135) | **-** | **-** | - | **(14,843)** | (14,254) | (14,099) |
| **Net property, plant and equipment** (d) | **206** | 195 | 188 | **-** | **-** | - | **23,922** | 19,162 | 15,905 |
| **Total assets** (e) | **704** | 1,418 | 314 | **(438)** | (308) | (326) | **29,364** | 25,429 | 20,580 |

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## Notes to consolidated financial statements (continued)

(a) Includes export sales to the United States of $4,358 million (2011- $4,175 million, 2010- $3,650 million). Export sales to the United States were recorded in all operating segments, with the largest effects in the Upstream segment.
(b) Includes delivery costs from final storage areas to customers of $254 million in 2012 (2011 - $286 million, 2010 - $280 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 $13,846 million (2011 - $9,147 million).
(e) All goodwill has been assigned to the Downstream segment. There have been no goodwill acquisitions, 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 | **2012** | 2011 | 2010 |
|---|---|---|---|
| Current income tax expense | **593** | 955 | 589 |
| Deferred income tax expense (a) | **634** | 80 | 155 |
| Total income tax expense (b) | **1,227** | 1,035 | 744 |
| Statutory corporate tax rate (percent) | **25.5** | 25.4 | 27.0 |
| Increase/(decrease) resulting from: | | | |
| Enacted tax rate change | **-** | - | - |
| Other | **(0.7)** | (1.9) | (1.8) |
| Effective income tax rate | **24.8** | 23.5 | 25.2 |

(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 2012, 2011 and 2010.
(b) Cash outflow from income taxes, plus investment credits earned, was $871 million in 2012 (2011 $667 million, 2010 $603 million).

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

| millions of dollars | **2012** | 2011 | 2010 |
|---|---|---|---|
| Post-retirement benefits liability adjustment: | | | |
| Post-retirement benefits adjustment (excluding amortization) | **155** | 326 | 74 |
| Amortization of post-retirement benefits liability adjustment included in net periodic benefit cost | **(68)** | (47) | (39) |
| Total post-retirement benefits liability adjustment | **87** | 279 | 35 |

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 | **2012** | 2011 | 2010 |
|---|---|---|---|
| Depreciation and amortization | **2,434** | 1,948 | 1,790 |
| Successful drilling and land acquisitions | **399** | 378 | 330 |
| Pension and benefits | **(717)** | (720) | (414) |
| Site restoration | **(284)** | (267) | (224) |
| Capitalized interest | **53** | 50 | 48 |
| Other | **39** | 51 | 16 |
| Deferred income tax liabilities | **1,924** | 1,440 | 1,546 |
| | | | |
| LIFO inventory valuation | **(478)** | (560) | (450) |
| Other | **(49)** | (30) | (48) |
| Deferred income tax assets | **(527)** | (590) | **(498)** |
| Valuation allowance | **-** | - | - |

| | | | |
|---|---|---|---|
| Net deferred income tax liabilities | **1,397** | 850 | 1,048 |

**Unrecognized tax benefits**

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

## Notes to consolidated financial statements (continued)

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 | **2012** | 2011 | 2010 |
|---|---|---|---|
| January 1 balance | **134** | 147 | 165 |
| Additions based on current year s tax position | **4** | - | - |
| Additions for prior years tax positions | **10** | 20 | 24 |
| Reductions for prior years tax positions | **(3)** | (31) | (37) |
| Reductions due to lapse of the statute of limitations | **(2)** | (2) | (5) |
| December 31 balance | **143** | 134 | 147 |

The 2012, 2011 and 2010 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 2008 to 2011 are subject to examination by the tax authorities. The Canada Revenue Agency has proposed certain adjustments to the company s filings for several years in the period 1994 to 2007. Management is currently evaluating those proposed adjustments. Management believes that a number of outstanding matters before 2008 are expected to be resolved in 2013. 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 United States generally accepted accounting principles and actuarial procedures. The process for determining retirement-income expense and related obligations includes making certain long-term assumptions regarding the discount rate, rate of return on plan assets and rate of compensation increases. The obligation and pension expense can vary significantly with changes in the assumptions used to estimate the obligation and the expected return on plan assets.

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## **Notes to consolidated financial statements** (continued)

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

| | Pension benefits | | Other post-retirement benefits | |
|---|---|---|---|---|
| | **2012** | 2011 | **2012** | 2011 |
| Assumptions used to determine benefit obligations at December 31 (percent) | | | | |
| Discount rate | **3.75** | 4.25 | **3.75** | 4.25 |
| Long-term rate of compensation increase | **4.50** | 4.50 | **4.50** | 4.50 |
| millions of dollars | | | | |
| **Change in projected benefit obligation** | | | | |
| Projected benefit obligation at January 1 | **6,646** | 5,562 | **508** | 421 |
| Current service cost | **160** | 122 | **8** | 6 |
| Interest cost | **288** | 314 | **21** | 23 |
| Actuarial loss/(gain) | **616** | 897 | **40** | 81 |
| Amendments | **-** | 86 | **-** | - |
| Benefits paid (a) | **(374)** | (335) | **(30)** | (23) |
| Projected benefit obligation at December 31 | **7,336** | 6,646 | **547** | 508 |
| Accumulated benefit obligation at December 31 | **6,560** | 5,970 | | |

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 2013 and subsequent years.

| | Pension benefits | | Other post-retirement benefits | |
|---|---|---|---|---|
| millions of dollars | **2012** | 2011 | **2012** | 2011 |
| **Change in plan assets** | | | | |
| Fair value at January 1 | **4,461** | 4,296 | | |
| Actual return/(loss) on plan assets | **374** | 93 | | |
| Company contributions | **594** | 361 | | |
| Benefits paid (b) | **(315)** | (289) | | |
| Fair value at December 31 | **5,114** | 4,461 | | |
| Plan assets in excess of/(less than) projected benefit obligation at December 31 | | | | |
| Funded plans | **(1,602)** | (1,595) | | |
| Unfunded plans | **(620)** | (590) | **(547)** | (508) |
| Total (c) | **(2,222)** | (2,185) | **(547)** | (508) |

(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 2012 | 2011 | Other post-retirement benefits 2012 | 2011 |
|---|---|---|---|---|
| Amounts recorded in the consolidated balance sheet consist of: | | | | |
| Current liabilities | **(24)** | (24) | **(28)** | (24) |
| Other long-term obligations | **(2,198)** | (2,161) | **(519)** | (484) |
| Total recorded | **(2,222)** | (2,185) | **(547)** | |