VI. Appendices

Appendix A - Financial section

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Financial summary (U.S. GAAP)

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

Frequently used terms

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

Capital employed

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

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

Return on average capital employed (ROCE)

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

millions of dollars	**2014**	2013	2012
Net income	**3,785**	2,828	3,766
Financing costs (after tax), including Imperial's share of equity companies	**1**	1	1
Net income excluding financing costs	**3,786**	2,829	3,767
Average capital employed	**27,637**	21,941	16,302
Return on average capital employed (percent) – corporate total	**13.7**	12.9	23.1

Cash flow from operating activities and asset sales

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

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

Operating costs

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

Reconciliation of Operating Costs

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

Components of Operating Costs

millions of dollars	**2014**	2013	2012
From Imperial's Consolidated Statement of Income			
Production and manufacturing	**5,662**	5,288	4,457
Selling and general	**1,075**	1,082	1,081
Depreciation and depletion	**1,096**	1,110	761
Exploration	**67**	123	83
Subtotal	**7,900**	7,603	6,382
Imperial's share of equity company expenses	**39**	37	34
Total operating costs	**7,939**	7,640	6,416

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

Overview

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

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

Imperial, with its resource base, financial strength, disciplined investment approach and technology portfolio, is well-positioned to participate in substantial investments to develop new Canadian energy supplies. While commodity prices remain volatile on a short-term basis depending upon supply and demand, Imperial's investment decisions are based on its long-term business outlook, using a disciplined approach in selecting and pursuing the most attractive investment opportunities. The corporate plan is a fundamental annual management process that is the basis for setting near-term operating and capital objectives, in addition to providing the longer-term economic assumptions used for investment evaluation purposes. Potential investment opportunities are tested over a wide range of economic scenarios to establish the resiliency of each opportunity. Once investments are made, a reappraisal process is completed to ensure relevant lessons are learned and improvements are incorporated into future projects.

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

Business environment and risk assessment

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

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

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

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

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

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

The world's energy mix is highly diverse and will remain so through 2040. Oil is expected to remain the largest source of energy with its share remaining close to one-third in 2040. Coal is currently the second largest source of energy, but it is likely to lose that position to natural gas by approximately 2025 to 2030 timeframe. The share of natural gas is expected to exceed 25 percent by 2040, while the share of coal falls to less than 20 percent. Nuclear power is projected to grow significantly, as many nations expand nuclear capacity to address rising electricity needs as well as energy security and environmental issues. Total renewable energy is likely to reach close to 15 percent of total energy by 2040, with biomass, hydro and geothermal contributing combined share of more than ten percent. Total energy supplied from wind, solar and biofuels is expected to increase close to 450 percent from 2010 to 2040, when they will be approaching four percent of world energy.

The company anticipates that the world's available oil and gas resource base will grow not only from new discoveries, but also from reserve increases in previously discovered fields. Technology will underpin these increases. The cost to develop and supply these resources will be significant. According to the International Energy Agency, the investment required to meet total oil and gas energy needs worldwide over the period 2014 to 2040 will be about $28 trillion (measured in 2013 dollars), or more than one trillion per year on average.

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

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

Upstream

Imperial produces crude oil and natural gas for sale predominately into the North American markets. Imperial's Upstream business strategies guide the company's exploration, development, production, research and gas marketing activities. These strategies include capturing material and accretive opportunities to continually high-grade the resource portfolio, exercising a disciplined approach to investing and cost management, developing and applying high-impact technologies, pursuing productivity and efficiency gains, and growing profitable oil and gas production. These strategies are underpinned by a relentless focus on operational excellence, commitment to innovative technologies, development of employees and investment in the communities within which the company operates.

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

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

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

Downstream

Imperial's Downstream serves predominately Canadian markets with refining, logistics and marketing assets. Imperial's Downstream business strategies guide the company's activities. These strategies include targeting best-in-class operations in all aspects of the business, maximizing value from advanced technologies, capitalizing on integration across Imperial's businesses, selectively investing for resilient and advantaged returns, operating efficiently and effectively, and providing valued products and services to customers.

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

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

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

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

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

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

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

Chemical

In North America, unconventional natural gas continued to provide advantaged ethane feedstock for steam crackers and a favourable margin environment for integrated chemical producers. The company's Sarnia chemical plant achieved a further feedstock cost advantage with access to Marcellus ethane beginning in the second quarter of 2014. The company's strategy for its Chemical business is to reduce costs and maximize value by continuing the integration of its chemical plant in Sarnia with the refinery. The company also benefits from its integration within ExxonMobil's North American chemical businesses, enabling Imperial to maintain a leadership position in its key market segments.

Results of operations

Consolidated

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

2014

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

2013

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

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

Upstream

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

2014

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

2013
Net income for the year was $1,712 million, versus $1,888 million in 2012. Earnings decreased primarily due to higher Kearl costs of about $180 million as production contribution since start-up in late April was more than offset by year-to-date start-up and operating costs, lower volumes at Syncrude of about $120 million, and higher diluent and energy costs at Cold Lake totalling about $120 million. These factors were partially offset by higher liquids realizations of about $125 million and the impact of a weaker Canadian dollar of about $125 million.

Average realizations

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

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

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

Crude oil and NGLs - production and sales (a)

thousands of barrels per day	**2014**		2013		2012	
	gross	**net**	gross	net	gross	net
Bitumen (b)	**197**	**161**	169	142	154	123
Synthetic oil (c)	**64**	**60**	67	65	72	69
Conventional crude oil	**18**	**14**	21	17	20	15
Total crude oil production	**279**	**235**	257	224	246	207
NGLs available for sale	**3**	**2**	4	3	4	3
Total crude oil and NGL production	**282**	**237**	261	227	250	210
Bitumen sales, including diluent (d)	**259**		219		201	
NGL sales	**8**		9		8	

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

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

(a) Barrels per day metric is calculated by dividing the volume for the period by the number of calendar days in the period. Gross production is the company's share of production (excluding purchases) before deduction of the mineral owners' or governments' share or both. Net production excludes those shares.
(b) The company's bitumen production volumes included production volumes from the Cold Lake operation for all years presented in the table above and, beginning in 2013, also included production volumes from the Kearl initial development (2014 - 51,000 barrels per day gross, 47,000 barrels net; 2013 - 16,000 barrels gross, 15,000 barrels net).
(c) The company's synthetic oil production volumes were from the company's share of production volumes in the Syncrude joint venture.
(d) Diluent is natural gas condensate or other light hydrocarbons added to bitumen to facilitate transportation to market by pipeline.
(e) Cubic feet per day metric is calculated by dividing the volume for the period by the number of calendar days in the period.
(f) Production of natural gas includes amounts used for internal consumption with the exception of the amounts reinjected.
(g) Net production is gross production less the mineral owners' or governments' share or both. Net natural gas production in 2012 included favourable royalty cost adjustments. Net production reported in the above table is consistent with production quantities in the net proved reserves disclosure.
(h) Includes sales of the company's share of net production and excludes amounts used for internal consumption.

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

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

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

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

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

2013
Gross production of Cold Lake bitumen was 153,000 barrels per day, compared to 154,000 barrels in 2012.

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

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

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

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

Downstream

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

2014
Downstream net income was $1,594 million, up $542 million from 2013. Earnings in 2013 included a charge of $280 million associated with the conversion of the Dartmouth refinery to a fuels terminal. Earnings also increased due to the impacts of improved refinery reliability and accessing advantaged crudes of about $330 million, a weaker Canadian dollar of about $130 million and higher marketing margins and sales volumes totalling about $105 million. These factors were partially offset by lower refining margins of about $230 million.

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

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

Refinery utilization

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

Sales

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

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

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

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

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

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

Chemical

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

Sales

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

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

2013
Chemical net income was $162 million, versus 2012’s record high of $165 million.

Corporate and Other

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

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

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

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

Liquidity and capital resources

Sources and uses of cash

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

Investments in 2014 were primarily funded by internally generated cash flow and proceeds from asset sales, supplemented by the issuance of long-term debt and commercial paper. Cash that may be temporarily available as surplus to the company's immediate needs is carefully managed through counterparty quality and investment guidelines to ensure that it is secure and readily available to meet the company's cash requirements and to optimize returns.

Cash flows from operating activities are highly dependent on crude oil and natural gas prices, as well as petroleum and chemical product margins. In addition, to provide for cash flow in future periods, the company needs to continually find and develop new resources, and continue to develop and apply new technologies to existing fields in order to maintain or increase production. Projects are planned or underway to increase production capacity. However, these volume increases are subject to a variety of risks, including project execution, operational outages, reservoir performance, crude oil and natural gas prices, weather events and regulatory changes.

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

An independent actuarial valuation of the company's registered retirement benefit plans was completed as at December 31, 2013. As a result of the valuation, the company contributed $362 million to the registered retirement benefit plans in 2014. The next required independent actuarial valuation will be as at December 31, 2016 and the company will continue to contribute within the requirements of pension regulations. Future funding requirements are not expected to affect the company's existing capital investment plans or its ability to pursue new investment opportunities.

Cash flow from operating activities

2014
Cash flow generated from operating activities was $4,405 million, compared with $3,292 million in 2013. Higher cash flow was primarily due to higher net income.

2013
Cash flow generated from operating activities was $3,292 million, compared with $4,680 million in 2012. Lower cash flow was primarily due to lower net income and working capital effects.

Cash flow used in investing activities

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

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

Cash flow from financing activities

2014
Cash provided by financing activities was $100 million, compared with cash provided by financing activities of $4,233 million in 2013.

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

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

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

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

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

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

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

2013
Cash provided by financing activities was $4,233 million, compared with cash used in financing activities of $162 million in 2012.

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

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

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

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

Financial percentages and ratios

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

(a) Current and long-term debt (page A26) and the company's share of equity company debt, divided by debt and shareholders' equity (page A26).
(b) Net income (page A24), debt-related interest before capitalization, including the company's share of equity company interest, and income taxes (page A24), divided by debt-related interest before capitalization, including the company's share of equity company interest.

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

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

The company's financial strength, as evidenced by the above financial ratios, represents a competitive advantage of strategic importance. The company's sound financial position gives it the opportunity to access capital markets in the full range of market conditions and enables the company to take on large, long-term capital commitments in the pursuit of maximizing shareholder value.

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

Commitments

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

millions of dollars	Financial statement note reference	Payment due by period 2015	2016 to 2019	2020 and beyond	Total amount
Long-term debt (a)	Note 14	-	4,816	97	4,913
- Due in one year		22	-	-	22
Operating leases (b)	Note 13	178	288	28	494
Unconditional purchase obligations (c)	Note 9	100	356	225	681
Firm capital commitments (d)		1,257	285	408	1,950
Pension and other post-retirement obligations (e)	Note 4	285	248	1,264	1,797
Asset retirement obligations (f)	Note 5	84	430	778	1,292
Other long-term purchase agreements (g)		567	2,521	7,638	10,726

(a) Long-term debt includes a long-term loan from an affiliated company of ExxonMobil of $4,746 million and capital lease obligations of $189 million, $22 million of which is due in one year. The payment by period for the related party long-term loan is estimated based on the right of the related party to cancel the loan on at least 370 days advance written notice.
(b) Minimum commitments for operating leases, shown on an undiscounted basis, primarily cover office buildings, rail cars and service stations.
(c) Unconditional purchase obligations are those long-term commitments that are non-cancelable or cancelable only under certain conditions and that third parties have used to secure financing for the facilities that will provide the contracted goods and services. They mainly pertain to pipeline throughput agreements.
(d) Firm capital commitments related to capital projects, shown on an undiscounted basis. The largest commitments outstanding at year-end 2014 were $1,390 million associated with the company's share of the Kearl project.
(e) The amount by which the benefit obligations exceeded the fair value of fund assets for pension and other post-retirement plans at year-end. The payments by period include expected contributions to funded pension plans in 2015 and estimated benefit payments for unfunded plans in all years.
(f) Asset retirement obligations represent the fair value of legal obligations associated with site restoration on the retirement of assets with determinable useful lives.
(g) Other long-term purchase agreements are non-cancelable, long-term commitments other than unconditional purchase obligations. They include primarily raw material supply and transportation services agreements.

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

Unrecognized tax benefits totalling $151 million have not been included in the company's commitments table because the company does not expect there will be any cash impact from the final settlements as sufficient funds have been deposited with the Canada Revenue Agency. Further details on the unrecognized tax benefits can be found in note 3 to the financial statements on page A34.

Litigation and other contingencies

As discussed in note 9 to the consolidated financial statements on page A43, a variety of claims have been made against Imperial and its subsidiaries. Based on a consideration of all relevant facts and circumstances, the company does not believe the ultimate outcome of any currently pending lawsuits against the company will have a material adverse effect on the company's operations, financial condition, or financial statements taken as a whole. There are no events or uncertainties beyond those already included in reported financial information that would indicate a material change in future operating results or financial condition.

Capital and exploration expenditures

millions of dollars	**2014**	2013
Upstream (a)	**4,974**	7,755
Downstream	**572**	187
Chemical	**26**	9
Other	**82**	69
Total	**5,654**	8,020

(a) Exploration expenses included.

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

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

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

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

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

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

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

Market risks and other uncertainties

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

Earnings sensitivities (a)

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

(a) The amount quoted to illustrate the impact of each sensitivity represents a change of about 10 percent in the value of the commodity or rate in question at the end of 2014. Each sensitivity calculation shows the impact on net income resulting from a change in one factor, after tax and royalties and holding all other factors constant. While these sensitivities are applicable under current conditions, they may not apply proportionately to larger fluctuations.

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

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

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

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

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

In general, segment results are not dependent on the ability to sell and/or purchase products to/from other segments. Instead, where such sales take place, they are the result of efficiencies and competitive advantages of integrated refinery/chemical complexes. Additionally, intersegment sales are at market-based prices. The products bought and sold between segments can also be acquired in worldwide markets that have substantial liquidity, capacity and transportation capabilities. About 70 percent of the company's intersegment sales are crude oil produced by the Upstream and sold to the Downstream. Other intersegment sales include those between refineries and chemical plants related to raw materials, feedstocks and finished products.

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

The company has an active asset management program in which underperforming assets are either improved to acceptable levels or considered for divestment. The asset management program includes a disciplined, regular review to ensure that all assets are contributing to the company's strategic objectives. The result is an efficient capital base, and the company has seldom had to write down the carrying value of assets, even during periods of low commodity prices.

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

The demand for crude oil, natural gas, petroleum products and petrochemical products correlates closely with general economic growth rates. The occurrence of recessions or other periods of low or negative economic growth will typically have a direct adverse impact on the company's financial results. In challenging economic times, the company follows the proven approach to continue focus on the business elements within its controls and take a long-term view of development.

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

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

Risk management

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

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 A29.

Oil and gas reserves
Evaluations of oil and gas reserves are important to the effective management of Upstream assets. They are an integral part of investment decisions about oil and gas properties such as whether development should proceed. Oil and gas reserve quantities are also used as the basis to calculate unit-of-production depreciation rates and to evaluate impairment.

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

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

Although the company is reasonably certain that proved reserves will be produced, the timing and amount recovered can be affected by a number of factors, including completion of development projects, reservoir performance, regulatory approvals and significant changes in long-term oil and gas price levels.

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

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

Impact of oil and gas reserves and prices on testing for impairment
Proved oil and gas properties held and used by the company are reviewed for impairment whenever events or circumstances indicate that the carrying amounts may not be recoverable. Assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets.

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

Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are recorded based on the estimated economic chance of success and the length of time that the company expects to hold the properties. Properties that are not individually significant are aggregated by groups and amortized based on development risk and average holding period.

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

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

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

Pension benefits

The company’s pension plan is managed in compliance with the requirements of governmental authorities and meets funding levels as determined by independent third-party actuaries. Pension accounting requires explicit assumptions regarding, among others, the discount rate for the benefit obligations, the expected rate of return on plan assets and the long-term rate of future compensation increases. All pension assumptions are reviewed annually by senior management. These assumptions are adjusted only as appropriate to reflect long-term changes in market rates and outlook. The long-term expected rate of return on plan assets of 6.25 percent used in 2014 compares to actual returns of 6.90 percent and 8.80 percent achieved over the last 10- and 20-year periods ending December 31, 2014. If different assumptions are used, the expense and obligations could increase or decrease as a result. The company’s potential exposure to changes in assumptions is summarized in note 4 to the consolidated financial statements on page A35. At Imperial, differences between actual returns on plan assets and the long-term expected returns are not recorded in pension expense in the year the differences occur. Such differences are deferred, along with other actuarial gains and losses, and are amortized into pension expense over the expected average remaining service life of employees. Employee benefit expense represented about one percent of total expenses in 2014.

Asset retirement obligations and other environmental liabilities

Legal obligations associated with site restoration on the retirement of assets with determinable useful lives are recognized when they are incurred, which is typically at the time the assets are installed. The obligations are initially measured at fair value and discounted to present value. Over time, the discounted asset retirement obligation amount will be accreted for the change in its present value, with this effect included in production and manufacturing expenses. As payments to settle the obligations occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed 25 years, the discount rate will be adjusted only as appropriate to reflect long-term changes in market rates and outlook. For 2014, the obligations were discounted at six percent and the accretion expense was $105 million, before tax, which was significantly less than one percent of total expenses in the year. There would be no material impact on the company's reported financial results if a different discount rate had been used.

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

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

Suspended exploratory well costs

The company continues capitalization of exploratory well costs when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project. Exploratory well costs not meeting these criteria are charged to expense. The facts and circumstances that support continued capitalization of suspended wells at year-end are disclosed in note 15 to the consolidated financial statements on page A47.

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 A34.

Recently issued accounting standards

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

Management's report on internal control over financial reporting

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

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

/s/ Richard M. Kruger

R.M. Kruger
Chairman, president and
chief executive officer

/s/ Paul J. Masschelin

P.J. Masschelin
Senior vice-president,
finance and administration, and controller
(Principal accounting officer and principal financial officer)

February 24, 2015

Report of independent registered public accounting firm

To the Shareholders of Imperial Oil Limited

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

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

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

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

/s/ PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta, Canada
February 24, 2015

Consolidated statement of income (U.S. GAAP)

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

(a) Operating revenues include federal excise tax of $1,562 million (2013 - $1,423 million, 2012 - $1,338 million).
(b) Operating revenues include amounts from related parties of $3,752 million (2013 - $2,385 million, 2012 - $2,907 million), (note 16).
(c) Purchases of crude oil and products include amounts from related parties of $3,950 million (2013 - $4,104 million, 2012 - $3,033 million), (note 16).
(d) Production and manufacturing expenses include amounts to related parties of $366 million (2013 - $319 million, 2012 - $241 million), (note 16).

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

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

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

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

Consolidated balance sheet (U.S. GAAP)

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

(a) Notes and loans payable includes amounts to related parties of $75 million (2013 – $75 million), (note 16).
(b) Accounts payable and accrued liabilities include amounts payable to related parties of $174 million (2013 – $170 million), (note 16).
(c) Long-term debt includes amounts to related parties of $4,746 million (2013 – $4,316 million), (note 16).
(d) Other long-term obligations include amounts to related parties of $96 million (2013 – nil), (note 16).
(e) Number of common shares outstanding was 848 million (2013 - 848 million), (note 10).
The information in the Notes to Consolidated Financial Statements is an integral part of these statements.

Approved by the directors

/s/ Richard M. Kruger

R.M. Kruger
Chairman, president and
chief executive officer

/s/ Paul J. Masschelin

P.J. Masschelin
Senior vice-president,
finance and administration, and controller

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

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

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

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

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

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

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

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

Notes to consolidated financial statements

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

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

The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America (GAAP). GAAP requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. All amounts are in Canadian dollars unless otherwise indicated.

1. Summary of significant accounting policies

Principles of consolidation
The consolidated financial statements include the accounts of subsidiaries the company controls. Intercompany accounts and transactions are eliminated. Subsidiaries include those companies in which Imperial has both an equity interest and the continuing ability to unilaterally determine strategic, operating, investing and financing policies. Significant subsidiaries included in the consolidated financial statements include Imperial Oil Resources Limited, Imperial Oil Resources N.W.T. Limited, Imperial Oil Resources Ventures Limited and McColl-Frontenac Petroleum Inc. All of the above companies are wholly owned. The consolidated financial statements also include the company’s share of the undivided interest in certain upstream assets, liabilities, revenues and expenses, including its 25 percent interest in the Syncrude joint venture and its 70.96 percent interest in the Kearl joint venture.

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

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

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

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

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

The company uses the successful-efforts method to account for its exploration and development activities. Under this method, costs are accumulated on a field-by-field basis. Costs incurred to purchase, lease, or otherwise acquire a property (whether unproved or proved) are capitalized when incurred. Exploratory well costs are carried as an asset when the well has found a sufficient quantity of reserves to justify its completion as a producing well and where the company is making sufficient progress assessing the reserves and the economic and operating viability of the project. Exploratory well costs not meeting these criteria are charged to expense. Other exploratory expenditures, including geophysical costs and annual lease rentals are expensed as incurred. Development costs including costs of productive wells and development dryholes are capitalized.

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

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

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

Proved oil and gas properties held and used by the company are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable. Assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets.

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

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

Significant unproved properties are assessed for impairment individually and valuation allowances against the capitalized costs are recorded based on the estimated economic chance of success and the length of time the company expects to hold the properties. Properties that are not individually significant are aggregated by groups and amortized based on development risk and average holding period. The valuation allowances are reviewed at least annually.

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

Notes to consolidated financial statements (continued)

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

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

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

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

No asset retirement obligations are set up for those manufacturing, distribution and marketing facilities with an indeterminate useful life. Asset retirement obligations for these facilities generally become firm at the time the facilities are permanently shut down and dismantled. These obligations may include the costs of asset disposal and additional soil remediation. However, these sites have indeterminate lives based on plans for continued operations, and as such, the fair value of the conditional legal obligations cannot be measured, since it is impossible to estimate the future settlement dates of such obligations. Provision for environmental liabilities of these assets is made when it is probable that obligations have been incurred and the amount can be reasonably estimated. Provisions for environmental liabilities are determined based on engineering estimated costs, taking into account the anticipated method and extent of remediation consistent with legal requirements, current technology and the possible use of the location. These liabilities are not discounted.

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

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

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

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

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

Share-based compensation

The company awards share-based compensation to certain employees in the form of restricted stock units. Compensation expense is measured each reporting period based on the company's current stock price and is recorded as "selling and general" expenses in the consolidated statement of income over the requisite service period of each award. See note 7 to the consolidated financial statements on page A41 for further details.

Consumer taxes

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

Recently issued accounting standards

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

2. Business segments

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

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

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

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

Notes to consolidated financial statements (continued)

	Upstream			Downstream			Chemical		
millions of dollars	**2014**	2013	2012	**2014**	2013	2012	**2014**	2013	2012
Revenues and other income									
Operating revenues (a)	**8,408**	6,016	4,674	**26,400**	25,450	25,077	**1,423**	1,256	1,302
Intersegment sales	**4,087**	4,026	4,110	**1,359**	1,978	2,603	**381**	318	299
Investment and other income	**667**	145	46	**65**	59	81	**-**	-	-
	13,162	10,187	8,830	**27,824**	27,487	27,761	**1,804**	1,574	1,601
Expenses									
Exploration	**67**	123	83	**-**	-	-	**-**	-	-
Purchases of crude oil and products	**5,628**	3,778	3,056	**21,476**	21,628	21,316	**1,196**	1,065	1,115
Production and manufacturing (b)	**3,882**	3,389	2,704	**1,564**	1,695	1,569	**216**	210	185
Selling and general	**3**	5	1	**887**	886	935	**70**	66	67
Federal excise tax	**-**	-	-	**1,562**	1,423	1,338	**-**	-	-
Depreciation and depletion (b)	**857**	636	498	**216**	452	242	**12**	12	12
Financing costs (note 12)	**4**	9	(1)	**-**	2	-	**-**	-	-
Total expenses	**10,441**	7,940	6,341	**25,705**	26,086	25,400	**1,494**	1,353	1,379
Income before income taxes	**2,721**	2,247	2,489	**2,119**	1,401	2,361	**310**	221	222
Income taxes (note 3)									
Current	**(219)**	(14)	72	**296**	395	486	**76**	62	67
Deferred	**881**	549	529	**229**	(46)	103	**5**	(3)	(10)
Total income tax expense	**662**	535	601	**525**	349	589	**81**	59	57
Net income	**2,059**	1,712	1,888	**1,594**	1,052	1,772	**229**	162	165
Cash flows from (used in) operating activities	**2,519**	1,690	2,625	**1,666**	1,453	1,961	**250**	198	127
Capital and exploration expenditures (c)	**4,974**	7,755	5,518	**572**	187	140	**26**	9	4
Property, plant and equipment									
Cost	**42,142**	38,819	30,602	**7,460**	7,146	7,038	**798**	771	765
Accumulated depreciation and depletion	**(10,103)**	(10,749)	(10,146)	**(4,459)**	(4,347)	(3,967)	**(601)**	(586)	(576)
Net property, plant and equipment (d)	**32,039**	28,070	20,456	**3,001**	2,799	3,071	**197**	185	189
Total assets	**34,421**	30,553	22,317	**5,823**	5,732	6,409	**372**	397	372

	Corporate and Other			Eliminations			Consolidated		
millions of dollars	**2014**	2013	2012	**2014**	2013	2012	**2014**	2013	2012
Revenues and other income									
Operating revenues (a)	**-**	-	-	**-**	-	-	**36,231**	32,722	31,053
Intersegment sales	**-**	-	-	**(5,827)**	(6,322)	(7,012)	**-**	-	-
Investment and other income	**3**	3	8	**-**	-	-	**735**	207	135
	3	3	8	**(5,827)**	(6,322)	(7,012)	**36,966**	32,929	31,188
Expenses									
Exploration	**-**	-	-	**-**	-	-	**67**	123	83
Purchases of crude oil and products	**-**	-	-	**(5,821)**	(6,316)	(7,011)	**22,479**	20,155	18,476
Production and manufacturing (b)	**-**	-	-	**-**	(6)	(1)	**5,662**	5,288	4,457
Selling and general	**121**	125	78	**(6)**	-	-	**1,075**	1,082	1,081
Federal excise tax	**-**	-	-	**-**	-	-	**1,562**	1,423	1,338
Depreciation and depletion (b)	**11**	10	9	**-**	-	-	**1,096**	1,110	761
Financing costs (note 12)	**-**	-	-	**-**	-	-	**4**	11	(1)
Total expenses	**132**	135	87	**(5,827)**	(6,322)	(7,012)	**31,945**	29,192	26,195
Income before income taxes	**(129)**	(132)	(79)	**-**	-	-	**5,021**	3,737	4,993
Income taxes (note 3)									
Current	**(47)**	(18)	(32)	**-**	-	-	**106**	425	593
Deferred	**15**	(16)	12	**-**	-	-	**1,130**	484	634
Total income tax expense	**(32)**	(34)	(20)	**-**	-	-	**1,236**	909	1,227
Net income	**(97)**	(98)	(59)	**-**	-	-	**3,785**	2,828	3,766
Cash flows from (used in) operating activities	**(30)**	(49)	(33)	**-**	-	-	**4,405**	3,292	4,680
Capital and exploration expenditures (c)	**82**	69	21	**-**	-	-	**5,654**	8,020	5,683
Property, plant and equipment									
Cost	**511**	429	360	**-**	-	-	**50,911**	47,165	38,765
Accumulated depreciation and depletion	**(174)**	(163)	(154)	**-**	-	-	**(15,337)**	(15,845)	(14,843)
Net property, plant and equipment (d)	**337**	266	206	**-**	-	-	**35,574**	31,320	23,922
Total assets	**565**	581	704	**(351)**	(45)	(438)	**40,830**	37,218	29,364

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

3. Income taxes

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

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

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

millions of dollars	**2014**	2013	2012
Depreciation and amortization	**3,777**	2,949	2,434
Successful drilling and land acquisitions	**827**	815	399
Pension and benefits	**(438)**	(376)	(717)
Site restoration	**(304)**	(287)	(284)
Capitalized interest	**82**	69	53
Other	**(103)**	(99)	39
Net long-term deferred income tax liabilities	**3,841**	3,071	1,924
LIFO inventory valuation	**(201)**	(450)	(478)
Other	**(113)**	(109)	(49)
Net current deferred income tax assets	**(314)**	(559)	(527)
Valuation allowance	**-**	-	-
Net deferred income tax liabilities	**3,527**	2,512	1,397

Notes to consolidated financial statements (continued)

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

The following table summarizes the movement in unrecognized tax benefits:

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

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

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

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

4. Employee retirement benefits

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

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

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

Notes to consolidated financial statements (continued)

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

	Pension benefits		Other post-retirement benefits	
	2014	2013	**2014**	2013
Assumptions used to determine benefit obligations at December 31 (percent)				
Discount rate	**3.75**	4.75	**3.75**	4.75
Long-term rate of compensation increase	**4.50**	4.50	**4.50**	4.50

millions of dollars				
Change in projected benefit obligation				
Projected benefit obligation at January 1	**6,870**	7,336	**503**	547
Current service cost	**152**	181	**9**	11
Interest cost	**322**	281	**26**	21
Actuarial loss/(gain)	**1,083**	(504)	**123**	(50)
Amendments	**-**	-	**-**	-
Benefits paid (a)	**(457)**	(424)	**(27)**	(26)
Projected benefit obligation at December 31	**7,970**	6,870	**634**	503
Accumulated benefit obligation at December 31	**7,292**	6,263		

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

	Pension benefits		Other post-retirement benefits	
millions of dollars	**2014**	2013	**2014**	2013
Change in plan assets				
Fair value at January 1	**5,872**	5,114		
Actual return/(loss) on plan assets	**923**	491		
Company contributions	**362**	600		
Benefits paid (b)	**(350)**	(333)		
Fair value at December 31	**6,807**	5,872		
Plan assets in excess of/(less than) projected benefit obligation at December 31				
Funded plans	**(589)**	(424)		
Unfunded plans	**(574)**	(574)	**(634)**	(503)
Total (c)	**(1,163)**	(998)	**(634)**	(503)

(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.

Notes to consolidated financial statements (continued)

millions of dollars	Pension benefits 2014	Pension benefits 2013	Other post-retirement benefits 2014	Other post-retirement benefits 2013
Amounts recorded in the consolidated balance sheet consist of:				
Current liabilities	**(29)**	(25)	**(29)**	(28)
Other long-term obligations	**(1,134)**	(973)	**(605)**	(475)
Total recorded	**(1,163)**	(998)	**(634)**	(503)
Amounts recorded in accumulated other comprehensive income consist of:				
Net actuarial loss/(gain)	**2,666**	2,303	**180**	64
Prior service cost	**39**	62	**-**	-
Total recorded in accumulated other comprehensive income, before tax	**2,705**	2,365	**180**	64

The company establishes the long-term expected rate of return on plan assets by developing a forward-looking long-term return assumption for each asset class, taking into account factors such as the expected real return for the specific asset class and inflation. A single, long-term rate of return is then calculated as the weighted average of the target asset allocation percentages and the long-term return assumption for each asset class. The 2014 long-term expected return of 6.25 percent used in the calculations of pension expense compares to an actual rate of return of 6.90 percent and 8.80 percent over the last 10- and 20-year periods ending December 31, 2014.

	Pension benefits 2014	Pension benefits 2013	Pension benefits 2012	Other post-retirement benefits 2014	Other post-retirement benefits 2013	Other post-retirement benefits 2012
Assumptions used to determine net periodic benefit cost for years ended December 31 (percent)						
Discount rate	**4.75**	3.75	4.25	**4.75**	3.75	4.25
Long-term rate of return on funded assets	**6.25**	6.25	6.25	**-**	-	-
Long-term rate of compensation increase	**4.50**	4.50	4.50	**4.50**	4.50	4.50
millions of dollars						
Components of net periodic benefit cost						
Current service cost	**152**	181	160	**9**	11	8
Interest cost	**322**	281	288	**26**	21	21
Expected return on plan assets	**(369)**	(331)	(288)	**-**	-	-
Amortization of prior service cost	**23**	23	23	**-**	-	-
Amortization of actuarial loss/(gain)	**166**	243	235	**7**	10	8
Net periodic benefit cost	**294**	397	418	**42**	42	37
Changes in amounts recorded in accumulated other comprehensive income						
Net actuarial loss/(gain)	**529**	(664)	530	**123**	(50)	40
Amortization of net actuarial (loss)/gain included in net periodic benefit cost	**(166)**	(243)	(235)	**(7)**	(10)	(8)
Amortization of prior service cost included in net periodic benefit cost	**(23)**	(23)	(23)	**-**	-	-
Total recorded in other comprehensive income	**340**	(930)	272	**116**	(60)	32
Total recorded in net periodic benefit cost and other comprehensive income, before tax	**634**	(533)	690	**158**	(18)	69

Costs for defined contribution plans, primarily the employee savings plan, were $40 million in 2014 (2013 - $37 million, 2012 - $36 million).

Notes to consolidated financial statements (continued)

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

	Total pension and other post-retirement benefits		
millions of dollars	**2014**	2013	2012
(Charge)/credit to other comprehensive income, before tax	**(456)**	990	(304)
Deferred income tax (charge)/credit (note 17)	**118**	(256)	87
(Charge)/credit to other comprehensive income, after tax	**(338)**	734	(217)

The company's investment strategy for pension plan assets reflects a long-term view, a careful assessment of the risks inherent in various asset classes and broad diversification to reduce the risk of the portfolio. Consistent with the long-term nature of the liability, the plan assets are primarily invested in global, market-cap-weighted indexed equity and domestic indexed bond funds to diversify risk while minimizing costs. The equity funds hold Imperial Oil Limited stock only to the extent necessary to replicate the relevant equity index. The balance of the plan assets is largely invested in high-quality corporate and government debt securities. Studies are periodically conducted to establish the preferred target asset allocation. The target asset allocation for equity securities is 37 percent. The target allocation for debt securities is 58 percent. Plan assets for the remaining five percent are invested in venture capital partnerships that pursue a strategy of investment in U.S. and international early stage ventures.

The 2014 fair value of the pension plan assets, including the level within the fair value hierarchy, is shown in the table below:

		Fair value measurements at December 31, 2014, using:				
millions of dollars	Total	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)		Significant unobservable inputs (Level 3)	
Asset class						
Equity securities						
Canadian	460		460	(a)		
Non-Canadian	2,153		2,153	(a)		
Debt securities - Canadian						
Corporate	922		922	(b)		
Government	3,033		3,033	(b)		
Asset backed	5		5	(b)		
Equities – Venture capital	211				211	(c)
Cash	23	8	15	(d)		
Total plan assets at fair value	6,807	8	6,588		211	

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

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

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

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

Notes to consolidated financial statements (continued)

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

millions of dollars	Mortgage funds	Venture capital
Fair value at January 1, 2014	1	188
Net realized gains/(losses)	-	(16)
Net unrealized gains/(losses)	-	40
Net purchases/(sales)	(1)	(1)
Fair value at December 31, 2014	-	211

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

		Fair value measurements at December 31, 2013, using:				
millions of dollars	Total	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)		Significant unobservable inputs (Level 3)	
Asset class						
Equity securities						
Canadian	932		932	(a)		
Non-Canadian	1,911		1,911	(a)		
Debt securities - Canadian						
Corporate	654		654	(b)		
Government	2,161		2,161	(b)		
Asset backed	-					
Mortgage funds	1				1	(c)
Equities – Venture capital	188				188	(d)
Cash	25	12	13	(e)		
Total plan assets at fair value	5,872	12	5,671		189	

(a) For company equity securities held in the form of fund units that are redeemable at the measurement date, the unit value is treated as a Level 2 input. The fair value of the securities owned by the funds is based on observable quoted prices on active exchanges, which are Level 1 inputs.
(b) For corporate, government and asset-backed debt securities, fair value is based on observable inputs of comparable market transactions.
(c) For mortgage funds, fair value represents the principal outstanding which is guaranteed by Canada Mortgage and Housing Corporation.
(d) For venture capital partnership investments, fair value is generally established by using revenue or earnings multiples or other relevant market data including Initial Public Offerings.
(e) For cash balances that are held in Level 2 funds prior to investment in those fund units, the cash value is treated as a Level 2 input.

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

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

Notes to consolidated financial statements (continued)

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

millions of dollars	Pension benefits **2014**	2013
For funded pension plans with accumulated benefit obligations in excess of plan assets:		
Projected benefit obligation	**-**	-
Accumulated benefit obligation	**-**	-
Fair value of plan assets	**-**	-
Accumulated benefit obligation less fair value of plan assets	**-**	-
For unfunded plans covered by book reserves:		
Projected benefit obligation	**574**	574
Accumulated benefit obligation	**542**	496

Estimated 2015 amortization from accumulated other comprehensive income

millions of dollars	Pension benefits	Other post-retirement benefits
Net actuarial loss/(gain) (a)	191	12
Prior service cost (b)	18	-

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

Cash flows

Benefit payments expected in:

millions of dollars	Pension benefits	Other post-retirement benefits
2015	385	29
2016	395	29
2017	405	30
2018	410	30
2019	420	30
2020 - 2024	2,140	155

In 2015, the company expects to make cash contributions of about $225 million to its pension plans.

Sensitivities

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

Increase/(decrease) millions of dollars	One percent increase	One percent decrease
Rate of return on plan assets:		
Effect on net benefit cost, before tax	(60)	60
Discount rate:		
Effect on net benefit cost, before tax	(70)	90
Effect on benefit obligation	(1,100)	1,400
Rate of pay increases:		
Effect on net benefit cost, before tax	35	(30)
Effect on benefit obligation	190	(170)

Notes to consolidated financial statements (continued)

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

Increase/(decrease) millions of dollars	One percent increase	One percent decrease
Effect on service and interest cost components	4	(3)
Effect on benefit obligation	70	(55)

5. Other long-term obligations

millions of dollars	**2014**	2013
Employee retirement benefits (a)(note 4)	**1,739**	1,448
Asset retirement obligations and other environmental liabilities (b)	**1,325**	1,258
Share-based incentive compensation liabilities (note 7)	**154**	140
Other obligations (note 16)	**347**	245
Total other long-term obligations	**3,565**	3,091

(a) Total recorded employee retirement benefit obligations also include $58 million in current liabilities (2013 – $53 million).

(b) Total asset retirement obligations and other environmental liabilities also include $143 million in current liabilities (2013 – $154 million).

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

millions of dollars	**2014**	2013
Balance as at January 1	**1,237**	966
Additions	**184**	251
Reductions due to property sales	**(153)**	-
Accretion	**105**	105
Settlement	**(81)**	(85)
Balance as at December 31	**1,292**	1,237

6. Derivatives and financial instruments

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

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

7. Share-based incentive compensation programs

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

Restricted stock units and deferred share units

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

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

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

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

The following table summarizes information about these units for the year ended December 31, 2014:

	Restricted stock units	Deferred share units
Outstanding at January 1, 2014	**8,714,854**	**98,236**
Granted	**1,427,460**	**8,963**
Exercised	**(1,719,387)**	**-**
Forfeited and cancelled	**(45,442)**	**-**
Outstanding at December 31, 2014	**8,377,485**	**107,199**

In 2014, the compensation expense charged against income for these programs was $90 million (2013 - $92 million, 2012 - $58 million). Income tax benefit recognized in income related to compensation expense for the year was $31 million (2013 - $33 million, 2012 - $20 million). Cash payments of $94 million were made for these programs in 2014 (2013 - $88 million, 2012 - $97 million).

As of December 31, 2014, there was $191 million of total before-tax unrecognized compensation expense related to non-vested restricted stock units based on the company's share price at the end of the current reporting period. The weighted average vesting period of non-vested restricted stock units is 3.5 years. All units under the deferred share programs have vested as of December 31, 2014.

8. Investment and other income

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

millions of dollars	**2014**	2013	2012
Proceeds from asset sales	**851**	160	226
Book value of assets sold	**155**	10	132
Gain/(loss) on asset sales, before tax (a)(b)	**696**	150	94
Gain/(loss) on asset sales, after tax (a)(b)	**526**	120	72

(a) 2014 included a gain of $638 million ($478 million, after tax) for the sale of the company's interest in producing conventional assets located in Boundary Lake, Cynthia/West Pembina and Rocky Mountain House.
(b) 2013 included a gain of $85 million ($73 million, after tax) for the sale of non-operating assets.

9. Litigation and other contingencies

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

Additionally, the company has other commitments arising in the normal course of business for operating and capital needs, all of which are expected to be fulfilled with no adverse consequences material to the company's operations or financial condition. Unconditional purchase obligations, as defined by accounting standards, are those long-term commitments that are non-cancelable or cancelable only under certain conditions and that third parties have used to secure financing for the facilities that will provide the contracted goods and services.

	Payments due by period						
millions of dollars	2015	2016	2017	2018	2019	After 2019	Total
Unconditional purchase obligations (a)	**100**	**84**	**85**	**88**	**99**	**225**	**681**

(a) Undiscounted obligations of $681 million mainly pertain to pipeline throughput agreements. Total payments under unconditional purchase obligations were $112 million (2013 - $95 million, 2012 - $86 million). The present value of these commitments, excluding imputed interest of $125 million, totalled $556 million.

10. Common shares

thousands of shares	**As at Dec. 31 2014**	As at Dec. 31 2013
Authorized	**1,100,000**	1,100,000

From 1995 through 2014 the company purchased shares under nineteen 12-month normal course issuer bid share repurchase programs, as well as an auction tender. Cumulative purchases to date under these programs totalled 906,543 thousand shares and $15,708 million. ExxonMobil's participation in these programs maintained its ownership interest in Imperial at 69.6 percent. On June 25, 2014, another 12-month normal course issuer bid program was implemented with an allowable purchase of up to a maximum of one million shares.

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

The company's common share activities are summarized below:

	Thousands of shares	Millions of dollars
Balance as at January 1, 2012	847,599	1,528
Issued under employee share-based awards	2,776	43
Purchases at stated value	(2,776)	(5)
Balance as at December 31, 2012	847,599	1,566
Issued under employee share-based awards	-	-
Purchases at stated value	-	-
Balance as at December 31, 2013	847,599	1,566
Issued under employee share-based awards	**2**	**-**
Purchases at stated value	**(2)**	**-**
Balance as at December 31, 2014	**847,599**	**1,566**

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

	2014	2013	2012
Net income per common share – basic			
Net income (millions of dollars)	**3,785**	2,828	3,766
Weighted average number of common shares outstanding (millions of shares)	**847.6**	847.6	847.7
Net income per common share (dollars)	**4.47**	3.34	4.44
Net income per common share - diluted			
Net income (millions of dollars)	**3,785**	2,828	3,766
Weighted average number of common shares outstanding (millions of shares)	**847.6**	847.6	847.7
Effect of employee share-based awards (millions of shares)	**3.0**	3.0	3.4
Weighted average number of common shares outstanding, assuming dilution (millions of shares)	**850.6**	850.6	851.1
Net income per common share (dollars)	**4.45**	3.32	4.42

11. Miscellaneous financial information

In 2014, net income included an after-tax gain of $29 million (2013 – $24 million gain, 2012 – $45 million gain) attributable to the effect of changes in last-in, first-out (LIFO) inventories. The replacement cost of inventories was estimated to exceed their LIFO carrying values at December 31, 2014 by $857 million (2013 – $1,787 million). Inventories of crude oil and products at year-end consisted of the following:

millions of dollars	**2014**	2013
Crude oil	**650**	628
Petroleum products	**409**	340
Chemical products	**53**	54
Natural gas and other	**9**	8
Total inventories of crude oil and products	**1,121**	1,030

Net research and development costs charged to expenses in 2014 were $128 million (2013 – $154 million, 2012 – $147 million). These costs are included in expenses due to the uncertainty of future benefits.

Accounts payable and accrued liabilities included accrued taxes other than income taxes of $408 million at December 31, 2014 (2013 – $380 million).

12. Financing costs and additional notes and loans payable information

millions of dollars	**2014**	2013	2012
Debt-related interest	**82**	69	20
Capitalized interest	**(82)**	(69)	(20)
Net interest expense	**-**	-	-
Other interest	**4**	11	(1)
Total financing costs (a)	**4**	11	(1)

(a) Cash interest payments in 2014 were $82 million (2013 – $69 million, 2012 – $20 million). The weighted average interest rate on short-term borrowings in 2014 was 1.1 percent (2013 – 1.1 percent).

As at December 31, 2014, the company had borrowed $75 million under an arrangement with an affiliated company of ExxonMobil that provides for a non-interest bearing, revolving demand loan from ExxonMobil to the company of up to $75 million. The loan represents ExxonMobil's share of a working capital facility required to support purchasing, marketing and transportation arrangements for crude oil and diluent products undertaken by Imperial on behalf of ExxonMobil.

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

13. Leased facilities

At December 31, 2014, the company held non-cancelable operating leases covering office buildings, rail cars, service stations and other properties with minimum undiscounted lease commitments totalling $494 million as indicated in the following table:

	Payments due by period						
millions of dollars	2015	2016	2017	2018	2019	After 2019	Total
Lease payments under minimum commitments (a)	**178**	**126**	**93**	**39**	**30**	**28**	**494**

(a) Net rental cost under cancelable and non-cancelable operating leases incurred in 2014 was $315 million (2013 – $287 million, 2012 – $271 million). Related rental income was not material.

14. Long-term debt

millions of dollars	**As at Dec. 31 2014**	As at Dec. 31 2013
Long-term debt (a)	**4,746**	4,316
Capital leases (b)	**167**	128
Total long-term debt	**4,913**	4,444

(a) Borrowed under an existing agreement with an affiliated company of ExxonMobil that provides for a long-term, variable-rate loan from ExxonMobil to the company of up to $6.25 billion at interest equivalent to Canadian market rates. The agreement is effective until July 31, 2020, cancelable if ExxonMobil provides at least 370 days advance written notice. Average effective rate for the loan was 1.2 percent in 2014.

(b) Capital leases are primarily associated with transportation facilities and services agreements. The average imputed rate was 7.0 percent in 2014 (2013 – 7.0 percent). Total capitalized lease obligations also include $22 million in current liabilities (2013 - $7 million). Principal payments on capital leases of approximately $19 million per year are due in each of the next four years after December 31, 2015.

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

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

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

15. Accounting for suspended exploratory well costs

The company continues capitalization of exploratory well costs when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project. The term "project" as used in this report can refer to a variety of different activities and does not necessarily have the same meaning as in any government payment transparency reports.

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

Change in capitalized suspended exploratory well costs:

millions of dollars	**2014**	2013	2012
Balance as at January 1	**173**	167	163
Additions pending the determination of proved reserves	**5**	12	16
Charged to expense	**-**	-	-
Reclassification to wells, facilities and equipment based on the determination of proved reserves	**(11)**	(6)	(12)
Balance as at December 31	**167**	173	167

Period end capitalized suspended exploratory well costs:

millions of dollars	**2014**	2013	2012
Capitalized for a period of one year or less	**-**	6	16
Capitalized for a period of between one and five years	**167**	167	151
Capitalized for a period of greater than one year	**167**	167	151
Total	**167**	173	167

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

	2014	2013	2012
Number of projects with first capitalized well drilled in the preceding 12 months	**-**	-	-
Number of projects that have exploratory well costs capitalized for a period of greater than 12 months	**1**	1	1
Total	**1**	1	1

The project with exploratory well costs capitalized for a period greater than 12 months as of December 31, 2014 has exploratory activity planned in the next two years.

16. Transactions with related parties

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

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

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

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

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

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

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

As at December 31, 2014, the company had outstanding long-term loans of $4,746 million (2013 – $4,316 million) and short-term loans of $75 million (2013 – $75 million) from ExxonMobil (see note 14, long-term debt, on page A46 and note 12, financing costs and additional notes and loans payable information, on page A45 for further details).

As at December 31, 2014, the company had outstanding obligations of $123 million (2013 – nil) due to a rail loading joint venture, in which the company has ownership interest. These obligations are associated with assets under construction at the rail loading facilities.

17. Other comprehensive income information

Changes in accumulated other comprehensive income:

millions of dollars	**2014**	2013	2012
Balance as at January 1	**(1,721)**	(2,455)	(2,238)
Post-retirement benefits liability adjustment:			
Current period change excluding amounts reclassified from accumulated other comprehensive income	**(483)**	529	(415)
Amounts reclassified from accumulated other comprehensive income	**145**	205	198
Balance as at December 31	**(2,059)**	(1,721)	(2,455)

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

millions of dollars	**2014**	2013	2012
Amortization of post-retirement benefits liability adjustment included in net periodic benefit cost (a)	**(196)**	(276)	(266)

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

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

millions of dollars	**2014**	2013	2012
Post-retirement benefits adjustments:			
Post-retirement benefits liability adjustment (excluding amortization)	**(169)**	185	(155)
Amortization of post-retirement benefits liability adjustment included in net periodic benefit cost	**51**	71	68
Total	**(118)**	256	(87)

18. Acquisition

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

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

millions of dollars	
Current assets	49
Property, plant and equipment (a)	2,045
Goodwill (b)	20
Total assets acquired	2,114
Current liabilities	62
Deferred income tax liabilities (c)	377
Other long-term obligations	67
Total liabilities assumed	506
Net assets acquired	1,608

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

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

(c) Deferred income taxes reflect the future tax consequences on the temporary differences between the amount of assets and liabilities recognized for financial reporting purposes and such amounts recognized for tax purposes.

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

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

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

The information on pages A51 to A52 excludes items not related to oil and natural gas extraction, such as administrative and general expenses, pipeline operations, gas plant processing fees and gains or losses on asset sales. The company's 25 percent interest in proved synthetic oil reserves in the Syncrude joint-venture and 70.96 percent interest in proved bitumen reserves in the Kearl project are included as part of the company's total proved oil and gas reserves in accordance with U.S. Securities and Exchange Commission (SEC) and U.S. Financial Accounting Standards Board (FASB) rules. Similarly, the company's share of proved synthetic oil reserves from Syncrude and proved bitumen reserves from Kearl are included in the calculation of the standardized measure of discounted future cash flows. Results of operations, costs incurred in property acquisitions, exploration and development activities, and capitalized costs include the company's share of Syncrude, Kearl and other unproved mineable acreages in the following tables.

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

Results of operations

millions of dollars	**2014**	2013	2012
Sales to customers (a)	**2,921**	2,282	2,074
Intersegment sales (a)(b)	**3,862**	3,905	3,534
	6,783	6,187	5,608
Production expenses	**3,860**	3,392	2,589
Exploration expenses	**67**	123	83
Depreciation and depletion	**789**	586	498
Income taxes	**513**	512	584
Results of operations	**1,554**	1,574	1,854

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

Costs incurred in property acquisitions, exploration and development activities

millions of dollars	**2014**	2013	2012
Property costs (c)			
Proved	**-**	34	-
Unproved	**-**	2,013	33
Exploration costs	**74**	124	109
Development costs	**4,710**	5,847	5,125
Total costs incurred in property acquisitions, exploration and development activities	**4,784**	8,018	5,267

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

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

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

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

Capitalized costs

millions of dollars	**2014**	2013
Property costs (a)		
Proved	**2,202**	3,017
Unproved	**2,575**	2,621
Producing assets	**25,126**	23,811
Incomplete construction	**11,171**	8,286
Total capitalized cost	**41,074**	37,735
Accumulated depreciation and depletion	**(10,084)**	(10,686)
Net capitalized costs	**30,990**	27,049

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

Standardized measure of discounted future cash flows

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

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

millions of dollars	**2014**	2013	2012
Future cash flows	**292,376**	231,873	227,253
Future production costs	**(127,070)**	(92,926)	(83,600)
Future development costs	**(39,814)**	(32,126)	(31,051)
Future income taxes	**(27,853)**	(23,707)	(25,902)
Future net cash flows	**97,639**	83,114	86,700
Annual discount of 10 percent for estimated timing of cash flows	**(66,582)**	(58,204)	(61,864)
Discounted future cash flows	**31,057**	24,910	24,836

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

Balance at beginning of year	**24,910**	24,836	26,020
Changes resulting from:			
Sales and transfers of oil and gas produced, net of production costs	**(3,282)**	(3,026)	(3,116)
Net changes in prices, development costs and production costs	**655**	(17,683)	(6,810)
Extensions, discoveries, additions and improved recovery, less related costs	**(374)**	31	2,698
Development costs incurred during the year	**4,414**	5,500	5,086
Revisions of previous quantity estimates	**4,907**	12,321	(805)
Accretion of discount	**1,634**	1,703	997
Net change in income taxes	**(1,807)**	1,228	766
Net change	**6,147**	74	(1,184)
Balance at end of year	**31,057**	24,910	24,836

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

Net proved reserves (a)

	Liquids (b)	Natural gas	Synthetic oil	Bitumen	Total oil-equivalent basis (c)
	millions of barrels	billions of cubic feet	millions of barrels	millions of barrels	millions of barrels
Beginning of year 2012	55	422	653	2,413	3,191
Revisions	5	98	(29)	239	231
Improved recovery	-	-	-	-	-
(Sale)/purchase of reserves in place	-	(7)	-	-	(1)
Discoveries and extensions	-	47	-	234	242
Production	(7)	(72)	(25)	(45)	(89)
End of year 2012	53	488	599	2,841	3,574
Revisions	6	(2)	4	78	88
Improved recovery	-	-	-	-	-
(Sale)/purchase of reserves in place	10	261	-	-	54
Discoveries and extensions	-	-	-	-	-
Production	(7)	(69)	(24)	(52)	(94)
End of year 2013	62	678	579	2,867	3,622
Revisions	**1**	**9**	**(23)**	**466**	**445**
Improved recovery	**-**	**-**	**-**	**-**	**-**
(Sale)/purchase of reserves in place	**(14)**	**(48)**	**-**	**-**	**(22)**
Discoveries and extensions	**3**	**45**	**-**	**-**	**10**
Production	**(6)**	**(57)**	**(22)**	**(59)**	**(96)**
End of year 2014	**46**	**627**	**534**	**3,274**	**3,959**
Net proved developed reserves included above, as of					
January 1, 2012	55	360	653	519	1,287
December 31, 2012	52	373	599	543	1,256
December 31, 2013	55	368	579	1,417	2,113
December 31, 2014	**36**	**300**	**534**	**1,635**	**2,255**
Net proved undeveloped reserves included above, as of					
January 1, 2012	-	62	-	1,894	1,904
December 31, 2012	1	115	-	2,298	2,318
December 31, 2013	7	310	-	1,450	1,509
December 31, 2014	**10**	**327**	**-**	**1,639**	**1,704**

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

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

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

The information above describes changes during the years and balances of proved oil and gas reserves at year-end 2012, 2013 and 2014. The definitions used are in accordance with the U.S. Securities and Exchange Commission's (SEC) Rule 4-10 (a) of Regulation S-X.

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

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

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

Revisions can include upward or downward changes in previously estimated volumes of proved reserves for existing fields due to the evaluation or revaluation of already available geologic, reservoir or production data; new geologic, reservoir or production data; or changes in prices and costs that are used in the estimation of reserves. This category can also include significant changes in either development strategy or production equipment/facility capacity.

In 2014, upward revisions of proved developed and undeveloped bitumen reserves were primarily associated with the conclusion of technical studies supporting the lengthening of the expected useful life of the Kearl operating assets under routine maintenance and sustaining capital conditions.

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

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

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

Quarterly financial and stock trading data (a)

	2014 three months ended				2013 three months ended			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**	Dec. 31	Sept. 30	June 30	Mar. 31
Financial data (millions of dollars)								
Total revenues and other income	**8,030**	**9,658**	**10,049**	**9,226**	8,363	8,594	7,958	8,014
Total expenses	**7,160**	**8,413**	**8,403**	**7,966**	6,985	7,737	7,526	6,944
Income before income taxes	**870**	**1,245**	**1,646**	**1,260**	1,378	857	432	1,070
Income taxes	**199**	**309**	**414**	**314**	322	210	105	272
Net income	**671**	**936**	**1,232**	**946**	1,056	647	327	798
Segmented net income (millions of dollars)								
Upstream	**218**	**532**	**857**	**452**	411	604	397	300
Downstream	**397**	**343**	**366**	**488**	625	46	(97)	478
Chemical	**63**	**66**	**57**	**43**	46	39	42	35
Corporate and Other	**(7)**	**(5)**	**(48)**	**(37)**	(26)	(42)	(15)	(15)
Net income	**671**	**936**	**1,232**	**946**	1,056	647	327	798
Per-share information (dollars)								
Net earnings – basic	**0.80**	**1.10**	**1.45**	**1.12**	1.25	0.76	0.39	0.94
Net earnings – diluted	**0.79**	**1.10**	**1.45**	**1.11**	1.24	0.76	0.38	0.94
Dividends (declared quarterly)	**0.13**	**0.13**	**0.13**	**0.13**	0.13	0.12	0.12	0.12
Share prices (dollars) (b)								
Toronto Stock Exchange								
High	**55.76**	**57.96**	**56.94**	**51.89**	47.57	46.10	41.82	45.44
Low	**45.52**	**52.05**	**50.36**	**44.99**	43.19	40.32	38.58	41.42
Close	**50.05**	**52.91**	**56.23**	**51.48**	47.04	45.23	40.15	41.52
NYSE MKT (U.S. dollars) (b)								
High	**49.55**	**54.09**	**53.10**	**47.08**	45.67	44.65	41.15	45.16
Low	**39.14**	**46.85**	**46.01**	**40.20**	41.55	38.22	37.09	40.68
Close	**43.03**	**47.22**	**52.63**	**46.55**	44.23	43.96	38.21	40.86
Shares traded (thousands) (c)	**113,657**	**69,107**	**78,236**	**87,465**	67,673	77,781	95,600	103,979

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

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

(c) The number of shares traded is based on transactions on the above stock exchanges.