VI. Appendices

Appendix A - Financial section

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Financial summary (U.S. GAAP)

millions of dollars	**2015**	2014	2013	2012	2011
Operating revenues	**26,756**	36,231	32,722	31,053	30,474
Net income by segment:					
Upstream	**(704)**	2,059	1,712	1,888	2,457
Downstream	**1,586**	1,594	1,052	1,772	884
Chemical	**287**	229	162	165	122
Corporate and Other	**(47)**	(97)	(98)	(59)	(92)
Net income	**1,122**	3,785	2,828	3,766	3,371
Cash and cash equivalents at year-end	**203**	215	272	482	1,202
Total assets at year-end	**43,170**	40,830	37,218	29,364	25,429
Long-term debt at year-end	**6,564**	4,913	4,444	1,175	843
Total debt at year-end	**8,516**	6,891	6,287	1,647	1,207
Other long-term obligations at year-end	**3,597**	3,565	3,091	3,983	3,876
Shareholders' equity at year-end	**23,425**	22,530	19,524	16,377	13,321
Cash flow from operating activities	**2,167**	4,405	3,292	4,680	4,489
Per-share information (dollars)					
Net income per share - basic	**1.32**	4.47	3.34	4.44	3.98
Net income per share - diluted	**1.32**	4.45	3.32	4.42	3.95
Dividends declared	**0.54**	0.52	0.49	0.48	0.44

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	**2015**	2014	2013
Business uses: asset and liability perspective			
Total assets	**43,170**	40,830	37,218
Less: total current liabilities excluding notes and loans payable	**(3,441)**	(4,003)	(5,245)
total long-term liabilities excluding long-term debt	**(7,788)**	(7,406)	(6,162)
Add: Imperial's share of equity company debt	**18**	19	23
Total capital employed	**31,959**	29,440	25,834
Total company sources: debt and equity perspective			
Notes and loans payable	**1,952**	1,978	1,843
Long-term debt	**6,564**	4,913	4,444
Shareholders' equity	**23,425**	22,530	19,524
Add: Imperial's share of equity company debt	**18**	19	23
Total capital employed	**31,959**	29,440	25,834

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	**2015**	2014	2013
Net income	**1,122**	3,785	2,828
Financing costs (after tax), including Imperial's share of equity companies	**30**	1	1
Net income excluding financing costs	**1,152**	3,786	2,829
Average capital employed	**30,700**	27,637	21,941
Return on average capital employed (percent) – corporate total	**3.8**	13.7	12.9

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	**2015**	2014	2013
Cash from operating activities	**2,167**	4,405	3,292
Proceeds from asset sales	**142**	851	160
Total cash flow from operating activities and asset sales	**2,309**	5,256	3,452

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	**2015**	2014	2013
From Imperial's Consolidated Statement of Income			
Total expenses	**24,965**	31,945	29,192
Less:			
Purchases of crude oil and products	**15,284**	22,479	20,155
Federal excise tax	**1,568**	1,562	1,423
Financing costs	**39**	4	11
Subtotal	**16,891**	24,045	21,589
Imperial's share of equity company expenses	**40**	39	37
Total operating costs	**8,114**	7,939	7,640

Components of Operating Costs

millions of dollars	**2015**	2014	2013
From Imperial's Consolidated Statement of Income			
Production and manufacturing	**5,434**	5,662	5,288
Selling and general	**1,117**	1,075	1,082
Depreciation and depletion	**1,450**	1,096	1,110
Exploration	**73**	67	123
Subtotal	**8,074**	7,900	7,603
Imperial's share of equity company expenses	**40**	39	37
Total operating costs	**8,114**	7,939	7,640

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. The company's integrated business model, with significant investments in Upstream, Downstream and Chemical segments, reduces the company's risk from changes in commodity prices. While commodity prices are 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 1.8 billion more than in 2014. Coincident with this population increase, the company expects worldwide economic growth to average close to 3 percent per year. As economies and population grow, and as living standards improve for billions of people, the need for energy will continue to rise. Even with significant efficiency gains, global energy demand is projected to rise by about 25 percent from 2014 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 30 percent from 2014 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 65 percent from 2014 to 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. Today, coal-fired generation provides about 40 percent of the world's electricity, however by 2040 coal-fired generation is likely to decline to about 30 percent, in part as a result of policies to improve air quality, reduce greenhouse gas emissions and the risk of climate change. From 2014 to 2040, the amount of electricity generated using natural gas, nuclear power, and renewables are likely to double. By 2040, coal, natural gas and renewables are projected to be generating approximately the same share of electricity worldwide, although significant differences will exist across regions reflecting a wide range of factors including the cost and availability of energy types.

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 112 million barrels of oil-equivalent per day, an increase of almost 20 percent from 2014. 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 from 2014 to 2040, meeting about 40 percent of energy demand growth. Global demand is expected to rise about 50 percent from 2014 to 2040, with about 45 percent 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. In total, about 60 percent of the growth in natural gas supplies is expected to be from unconventional sources. However, it is expected conventionally-produced natural gas will remain the cornerstone of supply meeting about two-thirds of global demand in 2040.

The world's energy mix is highly diverse and will remain so through 2040. Oil is expected to remain the largest source of energy with its share remaining close to one-third in 2040. Coal is currently the second largest source of energy, but it is likely to lose that position to natural gas in the 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 10 percent. Total energy supplied from wind, solar and biofuels is expected to increase close to 250 percent from 2014 to 2040, when they will be approaching 4 percent of world energy.

The company anticipates that the world's available oil and gas resource base will grow not only from new discoveries, but also from reserve increases in previously discovered fields. Technology will underpin these increases. The cost to develop and supply these resources will be significant. According to the International Energy Agency, the investment required to meet total oil and gas supply requirements worldwide over the period 2015 to 2040 will be about US$25 trillion (measured in 2014 dollars) or approximately US$1 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 predominantly 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.

Imperial has a significant oil and gas resource base and a large inventory of potential projects. The company continues to evaluate opportunities to support the company's long-term growth. 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 2015, the average WTI crude oil price, in U.S. dollars, was lower versus 2014. The upstream industry environment has been challenged throughout 2015 with abundant crude oil supply causing commodity prices to decrease to levels not seen since 2004, while natural gas prices remained depressed. However, current market conditions are not necessarily indicative of future conditions. The markets for crude oil and natural gas have a history of significant price volatility. 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. On the supply side, prices may be significantly impacted by political events, the actions of the Organization of Petroleum Exporting Countries (OPEC) and other large government resource owners, and other factors. 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 exhibit strong performance over the long-term. This is the outcome of disciplined investment, cost management, asset enhancement programs and application of advanced technologies.

Downstream

Imperial's Downstream serves predominantly 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 primary distribution terminals.

Growth in global demand, stimulated by lower prices for crude oil and transportation fuels, resulted in higher refinery utilization and margins outside of North America. Refineries in North America continue to benefit from lower raw material and energy costs due to the abundant supply of crude oil and natural gas.

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 the North American refining industry will remain intensely competitive. 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 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 stations. The company is evaluating ways of extending the branded wholesaler operating model to the remaining company-owned retail stations as part of Imperial's Esso branded 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 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	**2015**	2014	2013
Net income	**1,122**	3,785	2,828

2015

Net income in 2015 was $1,122 million, or $1.32 per share on a diluted basis, versus $3,785 million or $4.45 per share in 2014. Upstream recorded a net loss of $704 million, compared to a net income of $2,059 million in 2014. Downstream earnings decreased by $8 million and Chemical earnings increased by $58 million.

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.

Upstream

millions of dollars	**2015**	2014	2013
Net income	**(704)**	2,059	1,712

2015

Upstream recorded a net loss of $704 million in 2015, compared to net income of $2,059 million in the same period of 2014. Earnings in 2015 reflected lower crude oil and gas realizations of about $3,790 million, a net charge of $327 million associated with increased Alberta corporate income taxes, higher depreciation expense of about $180 million, lower liquids and gas volumes of about $80 million reflecting the impact of divested properties in the prior year and a net charge of about $60 million associated with the inventory carrying value. These factors were partially offset by the impact of a weaker Canadian dollar of about $770 million, the favourable impact of lower royalties of about $700 million, higher volumes from Kearl and Cold Lake of about $670 million and lower energy costs of about $140 million.

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.

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

Average realizations

Canadian dollars	**2015**	2014	2013
Bitumen realizations (per barrel)	**32.48**	67.20	60.57
Synthetic oil realizations (per barrel)	**61.33**	99.58	99.69
Conventional crude oil realizations (per barrel)	**36.58**	76.03	82.41
Natural gas liquids realizations (per barrel)	**14.70**	49.11	39.26
Natural gas realizations (per thousand cubic feet)	**2.78**	4.54	3.27

2015

The average price for WTI, the main benchmark crude for North America, decreased by 47 percent compared to the same period in 2014. The company’s average Canadian dollar realizations for synthetic crude oil and bitumen decreased about 38 and 52 percent in 2015 to $61.33 and $32.48 per barrel respectively, as the decline in benchmark crude and increased light-heavy differentials were partially offset by the weaker Canadian dollar. The company’s average realizations on sales of natural gas of $2.78 per thousand cubic feet in 2015, were lower by $1.76 per thousand cubic feet, versus 2014.

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 5 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.

Crude oil and NGLs - production and sales (a)

thousands of barrels per day	**2015**		2014		2013	
	gross	**net**	gross	net	gross	net
Bitumen	**266**	**245**	197	161	169	142
Synthetic oil (b)	**62**	**58**	64	60	67	65
Conventional crude oil	**15**	**14**	18	14	21	17
Total crude oil production	**343**	**317**	279	235	257	224
NGLs available for sale	**1**	**1**	3	2	4	3
Total crude oil and NGL production	**344**	**318**	282	237	261	227
Bitumen sales, including diluent (c)	**349**		259		219	
NGL sales	**5**		8		9	

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

millions of cubic feet per day	**2015**		2014		2013	
	gross	**net**	gross	net	gross	net
Production (e) (f)	**130**	**125**	168	156	201	189
Production available for sale (g)		**94**		124		152

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

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

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

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

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

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

2015
Gross production of Cold Lake bitumen averaged 158,000 barrels per day in 2015, up from 146,000 barrels from the same period last year, with new production from Nabiye offsetting cycle timing of the base operations.

Gross production of Kearl bitumen averaged 152,000 barrels per day during 2015 (108,000 barrels Imperial's share) up from 72,000 barrels per day (51,000 barrels Imperial's share) in 2014, reflecting early start-up of the Kearl expansion project and improved reliability of the initial development.

During 2015, the company's share of gross production from Syncrude averaged 62,000 barrels per day, compared to 64,000 barrels in 2014.

Gross production of conventional crude oil averaged 15,000 barrels per day during 2015, compared to 18,000 barrels in 2014. The lower production volume was primarily due to the impact of properties divested during the first half of 2014.

Gross production of natural gas during 2015 was 130 million cubic feet per day, down from 168 million cubic feet in the same period last year, reflecting the impact of divested properties and natural reservoir decline.

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.

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.

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.

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.

Downstream

millions of dollars	**2015**	2014	2013
Net income	**1,586**	1,594	1,052

2015
Downstream net income was $1,586 million, compared to $1,594 million in the same period of 2014. Earnings decreased due to the impact of lower refinery margins of about $590 million and higher operating costs of about $70 million mainly associated with the Edmonton rail terminal. These factors were partially offset by the favourable impact of a weaker Canadian dollar of about $390 million, higher fuels marketing margins and volumes of about $170 million, lower energy costs of about $80 million and a 2015 gain of $17 million from the sale of assets.

2014
Downstream net income was $1,594 million, up $542 million from 2013. Earnings from 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 totaling about $105 million. These factors were partially offset by lower refining margins of about $230 million.

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

Refinery utilization

thousands of barrels per day (a)	**2015**	2014	2013
Total refinery throughput (b)	**386**	394	426
Refinery capacity at December 31	**421**	421	421
Utilization of total refinery capacity (percent) (c)	**92**	94	88

Sales

thousands of barrels per day (a)	**2015**	2014	2013
Gasolines	**247**	244	223
Heating, diesel and jet fuels	**170**	179	160
Heavy fuel oils	**16**	22	29
Lube oils and other products	**45**	40	42
Net petroleum product sales	**478**	485	454

(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.

2015
Total refinery throughput was 386,000 barrels per day. Refinery throughput was 92 percent of capacity in 2015, 2 percent lower than the previous year. The lower rate was primarily a result of planned maintenance. Total net petroleum sales decreased to 478,000 barrels per day, compared with 485,000 barrels in 2014.

2014
Total refinery throughput was 394,000 barrels per day. Refinery throughput was 94 percent of capacity in 2014, 6 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.

Chemical

millions of dollars	**2015**	2014	2013
Net income	**287**	229	162

Sales

thousands of tonnes	**2015**	2014	2013
Polymers and basic chemicals	**735**	741	712
Intermediate and others	**210**	212	228
Total petrochemical sales	**945**	953	940

2015
Chemical net income was a record $287 million in 2015, an increase of $58 million over the same period in 2014, primarily due to the impact of a weaker Canadian dollar, lower feedstock costs and higher sales of polyethylene.

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.

Corporate and Other

millions of dollars	**2015**	2014	2013
Net income	**(47)**	(97)	(98)

2015
In 2015, net income effects from Corporate & Other were negative $47 million, compared to negative $97 million in 2014, primarily due to lower share-based compensation charges and the impact of the Alberta corporate income tax rate increase.

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.

Liquidity and capital resources

Sources and uses of cash

millions of dollars	**2015**	2014	2013
Cash provided by/(used in)			
Operating activities	**2,167**	4,405	3,292
Investing activities	**(2,884)**	(4,562)	(7,735)
Financing activities	**705**	100	4,233
Increase/(decrease) in cash and cash equivalents	**(12)**	(57)	(210)
Cash and cash equivalents at end of year	**203**	215	272

Investments in 2015 were primarily funded by internally generated cash flow and proceeds from asset sales, supplemented by the issuance of long-term debt. 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.

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 $225 million to the registered retirement benefit plans in 2015. 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

2015
Cash flow generated from operating activities was $2,167 million, compared with $4,405 million in 2014. Lower cash flow was due to lower earnings.

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.

Cash flow used in investing activities
2015
Cash used in investing activities of $2,884 million, compared with $4,562 million in 2014, mainly reflecting the decline in additions to property, plant and equipment.

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 totaled $5,413 million, compared with $7,899 million in 2013, which included acquisitions of $1,602 million. Proceeds from asset sales were $851 million compared with $160 million in 2013.

Cash flow from financing activities
2015
Cash provided by financing activities was $705 million, compared with $100 million in 2014.

The company drew on existing loan facilities of $1,206 million.

At the end of 2015, total debt outstanding was $8,516 million, compared with $6,891 million at the end of 2014.

In March 2015, the company extended the maturity date of its existing $500 million 364-day short-term unsecured committed bank credit facility to March 2016. The company has not drawn on the facility.

In July 2015, the company increased the capacity of its existing floating rate loan facility with an affiliated company of ExxonMobil from $6.25 billion to $7.75 billion. All terms and conditions of the agreement remained unchanged.

In August 2015, the company extended the maturity date of its existing $500 million long-term bank credit facility to August 2017. The company has not drawn on the facility.

Cash dividends of $449 million were paid in 2015 compared with $441 million in 2014. Per-share dividends paid in 2015 totaled $0.53, up from $0.52 in 2014.

Subsequent to December 31, 2015 and up to February 10, 2016, the company increased its total debt by $328 million by drawing on an existing facility. The increased debt was used to supplement normal operations and capital projects.

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 totaled $0.52, up from $0.48 in 2013.

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

Financial percentages and ratios

	2015	2014	2013
Total debt as a percentage of capital (a)	**27**	23	24
Interest coverage ratio – earnings basis (b)	**20**	61	55

(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 27 percent of the company's capital structure at the end of 2015.

Debt-related interest incurred in 2015, before capitalization of interest, was $102 million, compared with $82 million in 2014. The average effective interest rate on the company's debt was 1.3 percent in 2015, compared with 1.3 percent in 2014.

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, 2015. 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 2016	2017 to 2020	2021 and beyond	Total amount
Long-term debt (a)	Note 14	-	6,050	514	6,564
- Due in one year		28	-	-	28
Operating leases (b)	Note 13	185	237	33	455
Unconditional purchase obligations (c)	Note 9	100	382	154	636
Firm capital commitments (d)		588	130	-	718
Pension and other post-retirement obligations (e)	Note 4	225	260	1,044	1,529
Asset retirement obligations (f)	Note 5	67	614	890	1,571
Other long-term purchase agreements (g)		697	2,571	7,905	11,173

(a) Long-term debt includes a long-term loan from an affiliated company of ExxonMobil of $5,952 million and capital lease obligations of $640 million, $28 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 2015 were $381 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 2016 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.

Unrecognized tax benefits totaling $132 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 A35.

Litigation and other contingencies

As discussed in note 9 to the consolidated financial statements on page A44, 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	**2015**	2014
Upstream (a)	**3,135**	4,974
Downstream	**340**	572
Chemical	**52**	26
Other	**68**	82
Total	**3,595**	5,654

(a) Exploration expenses included.

Total capital and exploration expenditures were $3,595 million in 2015, a decrease of $2,059 million from 2014.

For the Upstream segment, capital expenditures were $3,135 million, compared with $4,974 million in 2014. Investments were primarily in support of completion of upstream growth projects.

The Nabiye expansion project at Cold Lake and the Kearl expansion project were completed in 2015, with production commencing at Nabiye in the first quarter and Kearl in the second quarter of 2015.

Planned capital and exploration expenditures in the Upstream segment are forecast at about $1.2 billion for 2016. Investments are mainly planned for sustaining activity.

For the Downstream segment, capital expenditures were $340 million in 2015, compared with $572 million in 2014. In 2015, Downstream capital expenditures included capitalized leases, investment in the Edmonton rail terminal, railcar acquisitions, refinery projects to improve reliability, feedstock flexibility, energy efficiency and environmental performance, and continued upgrades to the retail network.

Planned capital expenditures for the Downstream segment in 2016 are $300 million and focus on 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 2016 are expected to be about $1.8 billion. 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		
Three dollars (U.S.) per barrel change in crude oil prices	+ (-)	270
Twenty-five cents per thousand cubic feet change in natural gas prices	+ (-)	15
One dollar (U.S.) per barrel change in sales margins for total petroleum products	+ (-)	180
One cent (U.S.) per pound change in sales margins for polyethylene	+ (-)	8
One-quarter percent decrease (increase) in short-term interest rates	+ (-)	14
Seven cents decrease (increase) in the value of the Canadian dollar versus the U.S. dollar	+ (-)	505

(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 2015. 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 2014 year-end by about $20 million (after tax) a year for each one U.S. dollar per barrel change. The increase was primarily the effect of a decrease in the value of the Canadian dollar at 2015 year-end, higher production volumes and lower royalty costs due to lower crude oil prices.

The sensitivity of net income to changes in sales margins for total petroleum products increased from 2014 year-end by about $30 million (after tax) a year for each one U.S. dollar per barrel change. The increase was primarily the effect of a decrease in the value of the Canadian dollar increasing 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 2014 year-end by about $7 million (after tax) a year for each one-cent change. The increase was primarily the result of higher production volumes and the higher impact of a one-cent change at lower exchange rates.

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 66 percent of the company's intersegment sales are crude oil produced by the Upstream and sold to the Downstream. Other intersegment sales include those between refineries and the chemical plant related to raw materials, feedstocks and finished products.

Although price levels of crude oil and natural gas may rise or fall significantly over the short to medium term, due to global economic conditions, political events, decisions of OPEC and other major government resource owners and other factors, industry economics over the long term will continue to be driven by market supply and demand. Accordingly, the company evaluates the viability of all of its investments over a broad range of prices. The company's assessment is that its operations will continue to be successful over the long term in a variety of market conditions. This is the outcome of disciplined investment and asset management programs. 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 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. To mitigate uncertainty associated with the timing of industry pipeline projects and pipeline capacity constraints, the company has developed rail infrastructure.

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 to focus on the business elements within its control and take a long-term view of development.

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 and unconventional sources. 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 2015, Downstream earnings of $1,586 million, and Chemical earnings of $287 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 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, together with proved reserves, are as likely as not to be recovered.

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 re-evaluation 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.

When crude oil and natural gas prices are in the range seen in late 2015 and early 2016 for an extended period of time, under the SEC definition of proved reserves, certain quantities of oil and natural gas, such as oil sands operations, could temporarily not qualify as proved reserves. Amounts required to be de-booked as proved reserves on an SEC basis are subject to being re-booked as proved reserves at some point in the future when price levels recover. Under the terms of certain contractual arrangements or government royalty regimes, lower prices can also increase proved reserves attributable to the company. It is not expected that any temporary changes in reported proved reserves under SEC definitions would affect the operation of the underlying projects or alter the outlook for future production volumes.

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. In the event that the unit-of-production method does not result in an equitable allocation of cost over the economic life of an upstream asset, an alternative such as the straight-line method is used. 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 and margins on testing for impairment
The company performs impairment assessments whenever events or circumstances indicate that the carrying amounts of its long-lived assets (or group of assets) may not be recoverable through future operations or disposition. 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 for this assessment.

Potential trigger events for impairment evaluation include:

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

The company performs asset valuation analyses on an ongoing basis as a part of its asset management program. These analyses and other profitability reviews assist the company in assessing whether the carrying amounts of any of its assets may not be recoverable.

In general, the company does not view temporarily low prices or margins as a trigger event for conducting impairment tests. The markets for crude oil, natural gas and petroleum products have a history of significant price volatility. Although prices will occasionally drop significantly, industry prices over the long term will continue to be driven by market supply and demand. On the supply side, industry production from mature fields is declining, but this is being offset by production from new discoveries and field developments. OPEC production policies also have an impact on world oil supplies. The demand side is largely a function of global economic growth. The relative growth/decline in supply versus demand will determine industry prices over the long term, and these cannot be accurately predicted.

If there is a trigger event, the company estimates the future undiscounted cash flows of the affected properties, throughput or sales to judge the recoverability of carrying amounts. Cash flows used in impairment evaluations are developed using estimates for future crude oil and natural gas commodity prices, refining and chemical margins, and foreign currency exchange rates. Volumes are based on projected field and facility production profiles, throughput or sales. These evaluations make use of the company's price, margin, volume, and cost assumptions developed in the annual planning and budgeting process, and are consistent with the criteria management uses to evaluate investment opportunities. Where unproved reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the 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.

In light of continued weakness in the upstream industry environment in late 2015, the company undertook an effort to assess its major long-lived assets most at risk for potential impairment. The results of this assessment confirm the absence of a trigger event and indicate that the future undiscounted cash flows associated with these assets substantially exceed the carrying value of the assets. The assessment reflects crude and natural gas prices that are generally consistent with the long-term price forecasts published by third-party industry experts. Critical to the long-term recoverability of certain assets is the assumption that either by supply and demand changes, or due to general inflation, prices will rise in the future. Should increases in long-term prices not materialize, certain of the company's assets will be at risk for impairment. Due to the inherent difficulty in predicting future commodity prices, and the relationship between industry prices and costs, it is not practicable to reasonably estimate a range of potential future impairments related to the company's long-lived assets.

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.

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

Inventories
Crude oil, products and merchandise inventories are carried at the lower of current market value or cost (generally determined under the last-in, first-out method – LIFO). If crude oil and petroleum product prices continue in the range seen in early 2016, the company could be subject to a lower of cost or market inventory valuation adjustment.

Pension benefits
The company's pension plan is managed in compliance with the requirements of governmental authorities and meets funding levels as determined by independent third-party actuaries. Pension accounting requires explicit assumptions regarding, among others, the discount rate for the benefit obligations, the expected rate of return on plan assets and the long-term rate of future compensation increases. All pension assumptions are reviewed annually by senior management. These assumptions are adjusted only as appropriate to reflect long-term changes in market rates and outlook. The long-term expected rate of return on plan assets of 5.75 percent used in 2015 compares to actual returns of 6.60 percent and 8.30 percent achieved over the last 10- and 20-year periods ending December 31, 2015. 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 A36. 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 2 percent of total expenses in 2015.

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 2015, the obligations were discounted at 6 percent and the accretion expense was $84 million, before tax, which was significantly less than 1 percent of total expenses in the year. There would be no material impact on the company's reported financial results if a different discount rate had been used.

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

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

Suspended exploratory well costs

The company continues capitalization of exploratory well costs when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project. Exploratory well costs not meeting these criteria are charged to expense. The facts and circumstances that support continued capitalization of suspended wells at year-end are disclosed in note 15 to the consolidated financial statements on page A48.

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 A35.

Recently issued accounting standards

In May 2014, the Financial Accounting Standards Board (FASB) 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 will be adopted beginning January 1, 2018.

"Operating Revenue" on the Consolidated statement of income includes sales and excise taxes on sales transactions. When the company adopts the standard, revenue will exclude sales-based taxes collected on behalf of third parties. This change in reporting will not impact earnings. Imperial continues to evaluate other areas of 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, 2015.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the company’s internal control over financial reporting as of December 31, 2015, as stated in their report which is included herein.

/s/ Richard M. Kruger

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

/s/ Beverley A. Babcock

B.A. Babcock
Senior vice-president,
finance and administration, and controller
(Principal accounting officer and principal financial officer)

February 23, 2016

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, 2015 and December 31, 2014 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, 2015. In addition, we have audited Imperial Oil Limited's internal control over financial reporting as of December 31, 2015, 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 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, as well as 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, 2015 and December 31, 2014 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2015 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, 2015, based on criteria established in Internal Control - Integrated Framework (2013) issued by COSO.

/s/ PricewaterhouseCoopers LLP

Chartered Professional Accountants
Calgary, Alberta, Canada
February 23, 2016

Consolidated statement of income (U.S. GAAP)

millions of Canadian dollars For the years ended December 31	**2015**	2014	2013
Revenues and other income			
Operating revenues (a) (b)	**26,756**	36,231	32,722
Investment and other income (note 8)	**132**	735	207
Total revenues and other income	**26,888**	36,966	32,929
Expenses			
Exploration	**73**	67	123
Purchases of crude oil and products (c)	**15,284**	22,479	20,155
Production and manufacturing (d)	**5,434**	5,662	5,288
Selling and general	**1,117**	1,075	1,082
Federal excise tax (a)	**1,568**	1,562	1,423
Depreciation and depletion	**1,450**	1,096	1,110
Financing costs (note 12)	**39**	4	11
Total expenses	**24,965**	31,945	29,192
Income before income taxes	**1,923**	5,021	3,737
Income taxes (note 3)	**801**	1,236	909
Net income	**1,122**	3,785	2,828
Per-share information (Canadian dollars)			
Net income per common share – basic (note 10)	**1.32**	4.47	3.34
Net income per common share – diluted (note 10)	**1.32**	4.45	3.32
Dividends per common share	**0.54**	0.52	0.49

(a) Operating revenues include federal excise tax of $1,568 million (2014 - $1,562 million, 2013 - $1,423 million).
(b) Operating revenues include amounts from related parties of $3,340 million (2014 - $3,752 million, 2013 - $2,385 million) (note 16).
(c) Purchases of crude oil and products include amounts to related parties of $3,383 million (2014 - $3,950 million, 2013 - $4,104 million), (note 16).
(d) Production and manufacturing expenses include amounts to related parties of $442 million (2014 - $366 million, 2013 - $319 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	**2015**	2014	2013
Net income	**1,122**	3,785	2,828
Other comprehensive income, net of income taxes			
Post-retirement benefits liability adjustment (excluding amortization)	**64**	(483)	529
Amortization of post-retirement benefits liability adjustment included in net periodic benefit costs	**167**	145	205
Total other comprehensive income/(loss)	**231**	(338)	734
Comprehensive income	**1,353**	3,447	3,562

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	**2015**	2014
Assets		
Current Assets		
Cash	**203**	215
Accounts receivable, less estimated doubtful accounts (a)	**1,581**	1,539
Inventories of crude oil and products (note 11)	**1,190**	1,121
Materials, supplies and prepaid expenses	**424**	380
Deferred income tax assets (note 3)	**272**	314
Total current assets	**3,670**	3,569
Long-term receivables, investments and other long-term assets	**1,414**	1,406
Property, plant and equipment, less accumulated depreciation and depletion (note 2)	**37,799**	35,574
Goodwill	**224**	224
Other intangible assets, net	**63**	57
Total assets (note 2)	**43,170**	40,830
Liabilities		
Current liabilities		
Notes and loans payable (b) (note 12)	**1,952**	1,978
Accounts payable and accrued liabilities (a) (note 11)	**2,989**	3,969
Income taxes payable	**452**	34
Total current liabilities	**5,393**	5,981
Long-term debt (c) (note 14)	**6,564**	4,913
Other long-term obligations (d) (note 5)	**3,597**	3,565
Deferred income tax liabilities (note 3)	**4,191**	3,841
Total liabilities	**19,745**	18,300
Commitments and contingent liabilities (note 9)		
Shareholders' equity		
Common shares at stated value (e) (note 10)	**1,566**	1,566
Earnings reinvested	**23,687**	23,023
Accumulated other comprehensive income	**(1,828)**	(2,059)
Total shareholders' equity	**23,425**	22,530
Total liabilities and shareholders' equity	**43,170**	40,830

(a) Accounts receivable, less estimated doubtful accounts included amounts receivable from related parties of $129 million (2014 - accounts payable and accrued liabilities included amounts payable to related parties of $174 million), (note 16).
(b) Notes and loans payable includes amounts to related parties of $75 million (2014 – $75 million), (note 16).
(c) Long-term debt includes amounts to related parties of $5,952 million (2014 – $4,746 million), (note 16).
(d) Other long-term obligations include amounts to related parties of $146 million (2014 – $96 million), (note 16).
(e) Number of common shares authorized and outstanding were 1,100 million and 848 million, respectively (2014 – 1,100 million and 848 million, respectively), (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/ Beverley A. Babcock

B.A. Babcock
Senior vice-president,
finance and administration, and controller

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

millions of Canadian dollars At December 31	**2015**	2014	2013
Common shares at stated value (note 10)			
At beginning of year	**1,566**	1,566	1,566
Issued under the stock option plan	**-**	-	-
Share purchases at stated value	**-**	-	-
At end of year	**1,566**	1,566	1,566
Earnings reinvested			
At beginning of year	**23,023**	19,679	17,266
Net income for the year	**1,122**	3,785	2,828
Share purchases in excess of stated value	**-**	-	-
Dividends	**(458)**	(441)	(415)
At end of year	**23,687**	23,023	19,679
Accumulated other comprehensive income			
At beginning of year	**(2,059)**	(1,721)	(2,455)
Other comprehensive income	**231**	(338)	734
At end of year	**(1,828)**	(2,059)	(1,721)
Shareholders' equity at end of year	**23,425**	22,530	19,524

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	**2015**	2014	2013
Operating activities			
Net income	**1,122**	3,785	2,828
Adjustments for non-cash items:			
Depreciation and depletion	**1,450**	1,096	1,110
(Gain)/loss on asset sales (note 8)	**(97)**	(696)	(150)
Inventory write-down to current market value (note 11)	**59**	-	-
Deferred income taxes and other	**367**	1,123	482
Changes in operating assets and liabilities:			
Accounts receivable	**(42)**	545	(74)
Inventories, materials, supplies and prepaid expenses	**(172)**	(129)	(260)
Income taxes payable	**418**	(693)	(457)
Accounts payable and accrued liabilities	**(1,030)**	(549)	191
All other items - net (a)	**92**	(77)	(378)
Cash flows from (used in) operating activities	**2,167**	4,405	3,292
Investing activities			
Additions to property, plant and equipment	**(2,994)**	(5,290)	(6,297)
Acquisition	**-**	-	(1,602)
Additional investments	**(32)**	(123)	-
Proceeds from asset sales (note 8)	**142**	851	160
Repayment of loan from equity company	**-**	-	4
Cash flows from (used in) investing activities	**(2,884)**	(4,562)	(7,735)
Financing activities			
Short-term debt - net	**(32)**	120	1,371
Long-term debt issued (note 14)	**1,206**	430	3,276
Reduction in capitalized lease obligations	**(20)**	(9)	(7)
Dividends paid	**(449)**	(441)	(407)
Cash flows from (used in) financing activities	**705**	100	4,233
Increase (decrease) in cash	**(12)**	(57)	(210)
Cash at beginning of year	**215**	272	482
Cash at end of year (b)	**203**	215	272

(a) Includes contribution to registered pension plans of $225 million (2014 - $362 million, 2013 - $600 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.

Non-cash transactions

In 2015, a capital lease of approximately $480 million was not included in "Additions to property, plant and equipment" or "Long-term debt issued" lines on the Consolidated statement of cash flows.

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 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.

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. In the event that the unit-of-production method does not result in an equitable allocation of cost over the economic life of an upstream asset, an alternative such as the straight-line method is used. 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.

Production involves open pit mining and 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, mines, 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, mines, and related equipment; repair and maintenance costs on the wells and equipment; materials, supplies and energy costs required to operate the wells, mines, and related equipment; and administrative expenses related to the production activity.

The company performs impairment assessments whenever events or circumstances indicate that the carrying amounts of its long-lived assets (or group of assets) may not be recoverable through future operations or disposition. 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 for this assessment.

Potential trigger events for impairment evaluation include:

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

The company performs asset valuation analyses on an ongoing basis as a part of its asset management program. These analyses and other profitability reviews assist the company in assessing whether the carrying amounts of any of its assets may not be recoverable.

In general, the company does not view temporarily low prices or margins as a trigger event for conducting the impairment tests. The markets for crude oil, natural gas and petroleum products, have a history of significant price volatility. Although prices will occasionally drop significantly, industry prices over the long term will continue to be driven by market supply and demand. On the supply side, industry production from mature fields is declining, but this is being offset by production from new discoveries and field developments. OPEC production policies also have an impact on world oil supplies. The demand side is largely a function of global economic growth. The relative growth/decline in supply versus demand will determine industry prices over the long term, and these cannot be accurately predicted.

If there is a trigger event, 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 estimates for future crude oil and natural gas commodity prices, refining and chemical margins, and foreign currency exchange rates. Volumes are based on projected field and facility production profiles. These evaluations make use of the company's price, margin, volume, and cost assumptions developed in the annual planning and budgeting process, and are consistent with the criteria management uses to evaluate investment opportunities. Where probable reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the 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 valuation allowances are reviewed at least annually.

Gains on sales of proved and unproved properties are only recognized when there is neither uncertainty about the recovery of costs applicable to any interest retained nor any substantial obligation for future performance by the company.

Losses on properties sold are recognized when incurred or when the properties are held for sale and the fair value of the properties is less than the carrying value.

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

Interest capitalization

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

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 A42 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 FASB 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 will be adopted beginning January 1, 2018.

“Operating Revenue” on the Consolidated statement of income includes sales and excise taxes on sales transactions. When the company adopts the standard, revenue will exclude sales-based taxes collected on behalf of third parties. This change in reporting will not impact earnings. Imperial continues to evaluate other areas of 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 to distribute and market 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	**2015**	2014	2013	**2015**	2014	2013	**2015**	2014	2013
Revenues and other income									
Operating revenues (a)	**5,776**	8,408	6,016	**19,796**	26,400	25,450	**1,184**	1,423	1,256
Intersegment sales	**2,486**	4,087	4,026	**1,019**	1,359	1,978	**234**	381	318
Investment and other income	**22**	667	145	**104**	65	59	**-**	-	-
	8,284	13,162	10,187	**20,919**	27,824	27,487	**1,418**	1,804	1,574
Expenses									
Exploration	**73**	67	123	**-**	-	-	**-**	-	-
Purchases of crude oil and products	**3,768**	5,628	3,778	**14,526**	21,476	21,628	**725**	1,196	1,065
Production and manufacturing (b)	**3,766**	3,882	3,389	**1,461**	1,564	1,695	**207**	216	210
Selling and general	**(2)**	3	5	**986**	887	886	**87**	70	66
Federal excise tax	**-**	-	-	**1,568**	1,562	1,423	**-**	-	-
Depreciation and depletion (b)	**1,193**	857	636	**233**	216	452	**11**	12	12
Financing costs (note 12)	**5**	4	9	**-**	-	2	**-**	-	-
Total expenses	**8,803**	10,441	7,940	**18,774**	25,705	26,086	**1,030**	1,494	1,353
Income before income taxes	**(519)**	2,721	2,247	**2,145**	2,119	1,401	**388**	310	221
Income taxes (note 3)									
Current	**(77)**	(219)	(14)	**476**	296	395	**97**	76	62
Deferred	**262**	881	549	**83**	229	(46)	**4**	5	(3)
Total income tax expense	**185**	662	535	**559**	525	349	**101**	81	59
Net income	**(704)**	2,059	1,712	**1,586**	1,594	1,052	**287**	229	162
Cash flows from (used in) operating activities	**224**	2,519	1,690	**1,686**	1,666	1,453	**383**	250	198
Capital and exploration expenditures (c)	**3,135**	4,974	7,755	**340**	572	187	**52**	26	9
Property, plant and equipment									
Cost	**45,171**	42,142	38,819	**7,596**	7,460	7,146	**857**	798	771
Accumulated depreciation and depletion	**(11,016)**	(10,103)	(10,749)	**(4,584)**	(4,459)	(4,347)	**(616)**	(601)	(586)
Net property, plant and equipment (d)	**34,155**	32,039	28,070	**3,012**	3,001	2,799	**241**	197	185
Total assets	**36,971**	34,421	30,553	**5,574**	5,823	5,732	**394**	372	397

	Corporate and Other			Eliminations			Consolidated		
millions of dollars	**2015**	2014	2013	**2015**	2014	2013	**2015**	2014	2013
Revenues and other income									
Operating revenues (a)	**-**	-	-	**-**	-	-	**26,756**	36,231	32,722
Intersegment sales	**-**	-	-	**(3,739)**	(5,827)	(6,322)	**-**	-	-
Investment and other income	**6**	3	3	**-**	-	-	**132**	735	207
	6	3	3	**(3,739)**	(5,827)	(6,322)	**26,888**	36,966	32,929
Expenses									
Exploration	**-**	-	-	**-**	-	-	**73**	67	123
Purchases of crude oil and products	**-**	-	-	**(3,735)**	(5,821)	(6,316)	**15,284**	22,479	20,155
Production and manufacturing (b)	**-**	-	-	**-**	-	(6)	**5,434**	5,662	5,288
Selling and general	**50**	121	125	**(4)**	(6)	-	**1,117**	1,075	1,082
Federal excise tax	**-**	-	-	**-**	-	-	**1,568**	1,562	1,423
Depreciation and depletion (b)	**13**	11	10	**-**	-	-	**1,450**	1,096	1,110
Financing costs (note 12)	**34**	-	-	**-**	-	-	**39**	4	11
Total expenses	**97**	132	135	**(3,739)**	(5,827)	(6,322)	**24,965**	31,945	29,192
Income before income taxes	**(91)**	(129)	(132)	**-**	-	-	**1,923**	5,021	3,737
Income taxes (note 3)									
Current	**(45)**	(47)	(18)	**-**	-	-	**451**	106	425
Deferred	**1**	15	(16)	**-**	-	-	**350**	1,130	484
Total income tax expense	**(44)**	(32)	(34)	**-**	-	-	**801**	1,236	909
Net income	**(47)**	(97)	(98)	**-**	-	-	**1,122**	3,785	2,828
Cash flows from (used in) operating activities	**(124)**	(30)	(49)	**(2)**	-	-	**2,167**	4,405	3,292
Capital and exploration expenditures (c)	**68**	82	69	**-**	-	-	**3,595**	5,654	8,020
Property, plant and equipment									
Cost	**579**	511	429	**-**	-	-	**54,203**	50,911	47,165
Accumulated depreciation and depletion	**(188)**	(174)	(163)	**-**	-	-	**(16,404)**	(15,337)	(15,845)
Net property, plant and equipment (d)	**391**	337	266	**-**	-	-	**37,799**	35,574	31,320
Total assets	**579**	565	581	**(348)**	(351)	(45)	**43,170**	40,830	37,218

(a) Includes export sales to the United States of $4,157 million (2014 - $5,940 million, 2013 - $5,217 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 2015, amounts incurred associated with decommissioning, environmental and employee-related costs totaled $98 million (2014 - $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 $3,719 million (2014 - $12,535 million).

3. Income taxes

millions of dollars	**2015**	2014	2013
Current income tax expense (a)	**451**	106	425
Deferred income tax expense (a) (b)	**350**	1,130	484
Total income tax expense (a) (c)	**801**	1,236	909
Statutory corporate tax rate (percent)	**27.2**	25.5	25.4
Increase/(decrease) resulting from:			
Enacted tax rate change (a)	**16.1**	-	-
Other	**(1.6)**	(0.9)	(1.1)
Effective income tax rate	**41.7**	24.6	24.3

(a) On June 30, 2015 the Alberta government enacted a 2 percent increase in the provincial tax rate, from 10 percent to 12 percent.
(b) 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 and 2013.
(c) Cash outflow from income taxes, plus investment credits earned, was $202 million in 2015 (2014 – $811 million, 2013 – $911 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	**2015**	2014	2013
Depreciation and amortization	**4,677**	3,777	2,949
Successful drilling and land acquisitions	**922**	827	815
Pension and benefits	**(396)**	(438)	(376)
Asset retirement obligation	**(406)**	(304)	(287)
Capitalized interest	**104**	82	69
Other	**(710)**	(103)	(99)
Net long-term deferred income tax liabilities	**4,191**	3,841	3,071
LIFO inventory valuation	**(112)**	(201)	(450)
Other	**(160)**	(113)	(109)
Net current deferred income tax assets	**(272)**	(314)	(559)
Net current deferred income tax liabilities	**41**	-	-
Valuation allowance	**-**	-	-
Net deferred income tax liabilities	**3,960**	3,527	2,512

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	**2015**	2014	2013
Balance as at January 1	**151**	151	143
Additions based on current year's tax position	**-**	4	10
Additions for prior years' tax positions	**10**	-	2
Reductions for prior years' tax positions	**(29)**	(4)	(4)
Reductions due to lapse of the statute of limitations	**-**	-	-
Balance as at December 31	**132**	151	151

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 2015, 2014 and 2013 changes in unrecognized tax benefits did not have a material effect on the company's net income or cash flow. The company's tax filings from 2008 to 2015 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 2016. 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	
	2015	2014	**2015**	2014
Assumptions used to determine benefit obligations at December 31 (percent)				
Discount rate	**4.00**	3.75	**4.00**	3.75
Long-term rate of compensation increase	**4.50**	4.50	**4.50**	4.50

millions of dollars				
Change in projected benefit obligation				
Projected benefit obligation at January 1	**7,970**	6,870	**634**	503
Current service cost	**211**	152	**15**	9
Interest cost	**307**	322	**25**	26
Actuarial loss/(gain)	**114**	1,083	**(2)**	123
Amendments	**-**	-	**-**	-
Benefits paid (a)	**(455)**	(457)	**(30)**	(27)
Projected benefit obligation at December 31	**8,147**	7,970	**642**	634
Accumulated benefit obligation at December 31	**7,506**	7,292		

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 2016 and subsequent years.

	Pension benefits		Other post-retirement benefits	
millions of dollars	**2015**	2014	**2015**	2014
Change in plan assets				
Fair value at January 1	**6,807**	5,872		
Actual return/(loss) on plan assets	**592**	923		
Company contributions	**225**	362		
Benefits paid (b)	**(364)**	(350)		
Fair value at December 31	**7,260**	6,807		
Plan assets in excess of/(less than) projected benefit obligation at December 31				
Funded plans	**(300)**	(589)		
Unfunded plans	**(587)**	(574)	**(642)**	(634)
Total (c)	**(887)**	(1,163)	**(642)**	(634)

(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 2015	2014	Other post-retirement benefits 2015	2014
Amounts recorded in the consolidated balance sheet consist of:				
Current liabilities	**(30)**	(29)	**(29)**	(29)
Other long-term obligations	**(857)**	(1,134)	**(613)**	(605)
Total recorded	**(887)**	(1,163)	**(642)**	(634)
Amounts recorded in accumulated other comprehensive income consist of:				
Net actuarial loss/(gain)	**2,382**	2,666	**164**	180
Prior service cost	**23**	39	**-**	-
Total recorded in accumulated other comprehensive income, before tax	**2,405**	2,705	**164**	180

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 2015 long-term expected return of 5.75 percent used in the calculations of pension expense compares to an actual rate of return of 6.60 percent and 8.30 percent over the last 10- and 20-year periods ending December 31, 2015.

	Pension benefits 2015	2014	2013	Other post-retirement benefits 2015	2014	2013
Assumptions used to determine net periodic benefit cost for years ended December 31 (percent)						
Discount rate	**3.75**	4.75	3.75	**3.75**	4.75	3.75
Long-term rate of return on funded assets	**5.75**	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	**211**	152	181	**15**	9	11
Interest cost	**307**	322	281	**25**	26	21
Expected return on plan assets	**(392)**	(369)	(331)	**-**	-	-
Amortization of prior service cost	**16**	23	23	**-**	-	-
Amortization of actuarial loss/(gain)	**198**	166	243	**14**	7	10
Net periodic benefit cost	**340**	294	397	**54**	42	42
Changes in amounts recorded in accumulated other comprehensive income						
Net actuarial loss/(gain)	**(86)**	529	(664)	**(2)**	123	(50)
Amortization of net actuarial (loss)/gain included in net periodic benefit cost	**(198)**	(166)	(243)	**(14)**	(7)	(10)
Amortization of prior service cost included in net periodic benefit cost	**(16)**	(23)	(23)	**-**	-	-
Total recorded in other comprehensive income	**(300)**	340	(930)	**(16)**	116	(60)
Total recorded in net periodic benefit cost and other comprehensive income, before tax	**40**	634	(533)	**38**	158	(18)

Costs for defined contribution plans, primarily the employee savings plan, were $43 million in 2015 (2014 - $40 million, 2013 - $37 million).

Notes to consolidated financial statements (continued)

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

millions of dollars	Total pension and other post-retirement benefits **2015**	2014	2013
(Charge)/credit to other comprehensive income, before tax	**316**	(456)	990
Deferred income tax (charge)/credit (note 17)	**(85)**	118	(256)
(Charge)/credit to other comprehensive income, after tax	**231**	(338)	734

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 5 percent are invested in venture capital partnerships that pursue a strategy of investment in U.S. and international early stage ventures.

The 2015 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, 2015, using:				
millions of dollars	Total	Level 1	Level 2		Level 3	
Asset class						
Equity securities						
Canadian	469		469	(a)		
Non-Canadian	2,267		2,267	(a)		
Debt securities - Canadian						
Corporate	984		984	(b)		
Government	3,251		3,251	(b)		
Asset backed	4		4	(b)		
Equities – Venture capital	272				272	(c)
Cash	13	13				
Total plan assets at fair value	7,260	13	6,975		272	

(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.

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	Venture capital
Fair value at January 1, 2015	211
Net realized gains/(losses)	(34)
Net unrealized gains/(losses)	95
Net purchases/(sales)	-
Fair value at December 31, 2015	272

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	Level 1	Level 2		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.

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

Notes to consolidated financial statements (continued)

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

	Pension benefits	
millions of dollars	**2015**	2014
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	**587**	574
Accumulated benefit obligation	**560**	542

Estimated 2016 amortization from accumulated other comprehensive income

millions of dollars	Pension benefits	Other post-retirement benefits
Net actuarial loss/(gain) (a)	164	11
Prior service cost (b)	9	-

(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
2016	405	29
2017	415	30
2018	425	31
2019	435	31
2020	440	32
2021 - 2025	2,225	170

In 2016, the company expects to make cash contributions of about $166 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	(65)	65
Discount rate:		
Effect on net benefit cost, before tax	(95)	125
Effect on benefit obligation	(1,060)	1,350
Rate of pay increases:		
Effect on net benefit cost, before tax	50	(45)
Effect on benefit obligation	195	(165)

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	7	(5)
Effect on benefit obligation	75	(60)

5. Other long-term obligations

millions of dollars	**2015**	2014
Employee retirement benefits (a) (note 4)	**1,470**	1,739
Asset retirement obligations and other environmental liabilities (b)	**1,628**	1,325
Share-based incentive compensation liabilities (note 7)	**134**	154
Other obligations (note 16)	**365**	347
Total other long-term obligations	**3,597**	3,565

(a) Total recorded employee retirement benefit obligations also include $59 million in current liabilities (2014 – $58 million).
(b) Total asset retirement obligations and other environmental liabilities also include $116 million in current liabilities (2014 – $143 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	**2015**	2014
Balance as at January 1	**1,292**	1,237
Additions	**250**	184
Reductions due to property sales	**(12)**	(153)
Accretion	**84**	105
Settlement	**(43)**	(81)
Balance as at December 31	**1,571**	1,292

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.

Notes to consolidated financial statements (continued)

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

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

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

The following table summarizes information about these units for the year ended December 31, 2015:

	Restricted stock units	Deferred share units
Outstanding at January 1, 2015	**8,377,485**	**107,199**
Granted	**884,080**	**14,170**
Exercised	**(1,710,721)**	**-**
Forfeited and cancelled	**(46,351)**	**-**
Outstanding at December 31, 2015	**7,504,493**	**121,369**

In 2015, the compensation expense charged against income for these programs was $35 million (2014 - $90 million, 2013 - $92 million). Income tax benefit recognized in income related to compensation expense for the year was $13 million (2014 - $31 million, 2013 - $33 million). Cash payments of $78 million were made for these programs in 2015 (2014 - $94 million, 2013 - $88 million).

As of December 31, 2015, there was $141 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 3.4 years. All units under the deferred share programs have vested as of December 31, 2015.

8. Investment and other income

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

millions of dollars	**2015**	2014	2013
Proceeds from asset sales	**142**	851	160
Book value of assets sold	**45**	155	10
Gain/(loss) on asset sales, before tax (a) (b)	**97**	696	150
Gain/(loss) on asset sales, after tax (a) (b)	**79**	526	120

(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.

On February 10, 2016, the company entered into an agreement which will result in the sale and transition of its general aviation business to a branded wholesaler operating model for approximately US$135 million, having an approximate book value of US$16 million. The sale is subject to final closing adjustments, foreign exchange and other closing conditions. The transaction will be subject to a review by Canada's Competition Bureau and the sale is expected to close late 2016.

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	2016	2017	2018	2019	2020	After 2020	Total
Unconditional purchase obligations (a)	**100**	**87**	**88**	**101**	**106**	**154**	**636**

(a) Undiscounted obligations of $636 million mainly pertain to pipeline throughput agreements. Total payments under unconditional purchase obligations were $125 million (2014 - $112 million, 2013 - $95 million). The present value of these commitments, excluding imputed interest of $108 million, totaled $528 million.

10. Common shares

thousands of shares	**As at Dec. 31 2015**	As at Dec. 31 2014
Authorized	**1,100,000**	1,100,000

From 1995 through 2015 the company purchased shares under twenty 12-month normal course issuer bid share repurchase programs, as well as an auction tender. Cumulative purchases to date under these programs totaled 906,544 thousand shares and $15,708 million. ExxonMobil's participation in these programs maintained its ownership interest in Imperial at 69.6 percent. On June 22, 2015, 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, 2013	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
Issued under employee share-based awards	**1**	**-**
Purchases at stated value	**(1)**	**-**
Balance as at December 31, 2015	**847,599**	**1,566**

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

	2015	2014	2013
Net income per common share – basic			
Net income (millions of dollars)	**1,122**	3,785	2,828
Weighted average number of common shares outstanding (millions of shares)	**847.6**	847.6	847.6
Net income per common share (dollars)	**1.32**	4.47	3.34
Net income per common share - diluted			
Net income (millions of dollars)	**1,122**	3,785	2,828
Weighted average number of common shares outstanding (millions of shares)	**847.6**	847.6	847.6
Effect of employee share-based awards (millions of shares)	**3.0**	3.0	3.0
Weighted average number of common shares outstanding, assuming dilution (millions of shares)	**850.6**	850.6	850.6
Net income per common share (dollars)	**1.32**	4.45	3.32

Notes to consolidated financial statements (continued)

11. Miscellaneous financial information

In 2015, net income included an after-tax loss of $39 million (2014 – $29 million gain, 2013 – $24 million gain) attributable to the effect of changes in last-in, first-out (LIFO) inventories and a non-cash charge of $59 million associated with the carrying value of inventory exceeding the current market value. The replacement cost of inventories was estimated to exceed their LIFO carrying values at December 31, 2015 by $427 million (2014 – $857 million). Inventories of crude oil and products at year-end consisted of the following:

millions of dollars	**2015**	2014
Crude oil	**690**	650
Petroleum products	**443**	409
Chemical products	**51**	53
Natural gas and other	**6**	9
Total inventories of crude oil and products	**1,190**	1,121

Net research and development costs charged to expenses in 2015 were $149 million (2014 – $128 million, 2013 – $154 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 $378 million at December 31, 2015 (2014 – $408 million).

12. Financing costs and additional notes and loans payable information

millions of dollars	**2015**	2014	2013
Debt-related interest	**102**	82	69
Capitalized interest	**(68)**	(82)	(69)
Net interest expense	**34**	-	-
Other interest	**5**	4	11
Total financing costs (a)	**39**	4	11

(a) Cash interest payments in 2015 were $74 million (2014 – $82 million, 2013 – $69 million). The weighted average interest rate on short-term borrowings in 2015 was 0.8 percent (2014 – 1.1 percent).

As at December 31, 2015, 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 2015, the company extended the maturity date of its existing $500 million 364-day short-term unsecured committed bank credit facility to March 2016. The company has not drawn on the facility.

13. Leased facilities

At December 31, 2015, the company held non-cancelable operating leases covering office buildings, rail cars, service stations and other properties with minimum undiscounted lease commitments totaling $455 million as indicated in the following table:

	Payments due by period						
millions of dollars	2016	2017	2018	2019	2020	After 2020	Total
Lease payments under minimum commitments (a)	**185**	**129**	**71**	**29**	**8**	**33**	**455**

(a) Net rental cost under cancelable and non-cancelable operating leases incurred in 2015 was $311 million (2014 – $315 million, 2013 – $287 million). Related rental income was not material.

14. Long-term debt

millions of dollars	**As at Dec. 31 2015**	As at Dec. 31 2014
Long-term debt (a)	**5,952**	4,746
Capital leases (b)	**612**	167
Total long-term debt	**6,564**	4,913

(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 $7.75 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 1.0 percent in 2015.

(b) Capital leases are primarily associated with transportation facilities and services agreements. The average imputed rate was 5.8 percent in 2015 (2014 – 7.0 percent). Total capitalized lease obligations also include $28 million in current liabilities (2014 - $22 million). Principal payments on capital leases of approximately $25 million per year are due in each of the next four years after December 31, 2016.

During 2015, the company increased its long-term debt by $1,206 million by drawing on an existing facility with an affiliated company of Exxon Mobil Corporation. The increased debt was used to finance normal operations and capital projects.

In July 2015, the company increased the capacity of its existing floating rate loan facility with an affiliated company of ExxonMobil from $6.25 billion to $7.75 billion. All terms and conditions of the agreement remained unchanged.

In 2015, the company entered into a long-term capital lease related to the Woodland pipeline for approximately $480 million. A commitment related to this obligation was previously reported as a firm capital commitment in the company's 2014 Form 10-K.

In the third quarter of 2015, the company extended the maturity date of its existing $500 million long-term bank credit facility to August 2017. The company has not drawn on the facility.

Subsequent to December 31, 2015 and up to February 10, 2016, the company increased its total debt by $328 million by drawing on an existing facility. The increased debt was used to supplement normal operations and capital projects.

Notes to consolidated financial statements (continued)

15. Accounting for suspended exploratory well costs

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

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

Change in capitalized suspended exploratory well costs:

millions of dollars	**2015**	2014	2013
Balance as at January 1	**167**	173	167
Additions pending the determination of proved reserves	**-**	5	12
Charged to expense	**-**	-	-
Reclassification to wells, facilities and equipment based on the determination of proved reserves	**-**	(11)	(6)
Balance as at December 31	**167**	167	173

Period end capitalized suspended exploratory well costs:

millions of dollars	**2015**	2014	2013
Capitalized for a period of one year or less	**-**	-	6
Capitalized for a period of between one and five years	**167**	167	167
Capitalized for a period of greater than one year	**167**	167	167
Total	**167**	167	173

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.

	2015	2014	2013
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

Exploration activity on the Horn River project with suspended well costs has been completed and further development options are being evaluated.

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, 2015, the company had outstanding long-term loans of $5,952 million (2014 – $4,746 million) and short-term loans of $75 million (2014 – $75 million) from ExxonMobil (see note 14, long-term debt, on page A47 and note 12, financing costs and additional notes and loans payable information, on page A46 for further details).

As at December 31, 2015, the company had outstanding obligations of $187 million (2014 - $123 million) due to a rail loading joint venture, in which the company has a 50% ownership interest, for financing the capital expenditure programs and capital requirements.

Notes to consolidated financial statements (continued)

17. Other comprehensive income information

Changes in accumulated other comprehensive income:

millions of dollars	**2015**	2014	2013
Balance as at January 1	**(2,059)**	(1,721)	(2,455)
Post-retirement benefits liability adjustment:			
Current period change excluding amounts reclassified from accumulated other comprehensive income	**64**	(483)	529
Amounts reclassified from accumulated other comprehensive income	**167**	145	205
Balance as at December 31	**(1,828)**	(2,059)	(1,721)

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

millions of dollars	**2015**	2014	2013
Amortization of post-retirement benefits liability adjustment included in net periodic benefit cost (a)	**(228)**	(196)	(276)

(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	**2015**	2014	2013
Post-retirement benefits adjustments:			
Post-retirement benefits liability adjustment (excluding amortization)	**24**	(169)	185
Amortization of post-retirement benefits liability adjustment included in net periodic benefit cost	**61**	51	71
Total	**85**	(118)	256

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 and U.S. Financial Accounting Standards Board 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	**2015**	2014	2013
Sales to customers (a)	**2,483**	2,921	2,282
Intersegment sales (a) (b)	**1,855**	3,862	3,905
	4,338	6,783	6,187
Production expenses	**3,727**	3,860	3,392
Exploration expenses	**73**	67	123
Depreciation and depletion	**1,102**	789	586
Income taxes	**174**	513	512
Results of operations	**(738)**	1,554	1,574

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	**2015**	2014	2013
Property costs (c)			
Proved	**-**	-	34
Unproved	**-**	-	2,013
Exploration costs	**76**	74	124
Development costs	**3,035**	4,710	5,847
Total costs incurred in property acquisitions, exploration and development activities	**3,111**	4,784	8,018

(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	**2015**	2014
Property costs (a)		
Proved	**2,172**	2,202
Unproved	**2,542**	2,575
Producing assets	**35,769**	25,126
Incomplete construction	**2,862**	11,171
Total capitalized cost	**43,345**	41,074
Accumulated depreciation and depletion	**(10,975)**	(10,084)
Net capitalized costs	**32,370**	30,990

(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 U.S. Financial Accounting Standards Board, 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	**2015**	2014	2013
Future cash flows	**168,482**	292,376	231,873
Future production costs	**(122,188)**	(127,070)	(92,926)
Future development costs	**(36,048)**	(39,814)	(32,126)
Future income taxes	**(3,333)**	(27,853)	(23,707)
Future net cash flows	**6,913**	97,639	83,114
Annual discount of 10 percent for estimated timing of cash flows	**(3,683)**	(66,582)	(58,204)
Discounted future cash flows	**3,230**	31,057	24,910

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

Balance at beginning of year	**31,057**	24,910	24,836
Changes resulting from:			
Sales and transfers of oil and gas produced, net of production costs	**(1,134)**	(3,282)	(3,026)
Net changes in prices, development costs and production costs	**(37,945)**	655	(17,683)
Extensions, discoveries, additions and improved recovery, less related costs	**29**	(374)	31
Development costs incurred during the year	**2,250**	4,414	5,500
Revisions of previous quantity estimates	**972**	4,907	12,321
Accretion of discount	**1,683**	1,634	1,703
Net change in income taxes	**6,318**	(1,807)	1,228
Net change	**(27,827)**	6,147	74
Balance at end of year	**3,230**	31,057	24,910

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 2013	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
Revisions	**(10)**	**(28)**	**68**	**331**	**384**
Improved recovery	**-**	**-**	**-**	**-**	**-**
(Sale)/purchase of reserves in place	**1**	**11**	**-**	**-**	**3**
Discoveries and extensions	**2**	**18**	**-**	**-**	**5**
Production	**(5)**	**(45)**	**(21)**	**(90)**	**(124)**
End of year 2015	**34**	**583**	**581**	**3,515**	**4,227**
Net proved developed reserves included above, as of					
January 1, 2013	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
December 31, 2015	**23**	**283**	**581**	**3,063**	**3,714**
Net proved undeveloped reserves included above, as of					
January 1, 2013	1	115	-	2,298	2,318
December 31, 2013	7	310	-	1,450	1,509
December 31, 2014	10	327	-	1,639	1,704
December 31, 2015	**11**	**300**	**-**	**452**	**513**

(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 2013, 2014 and 2015. The definitions used are in accordance with the U.S. Securities and Exchange Commission's 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 re-evaluation 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 2015, upward revisions of proved developed bitumen reserves were associated with migration of the Kearl expansion project from proved undeveloped, and improved performance demonstrated at Kearl. As well, upward revisions to bitumen and synthetic oil were associated with lower royalty obligations driven by lower pricing.

When crude oil and natural gas prices are in the range seen in late 2015 and early 2016 for an extended period of time, under the SEC definition of proved reserves, certain quantities of oil and natural gas, such as oil sands operations, could temporarily not qualify as proved reserves. Amounts required to be de-booked as proved reserves on an SEC basis are subject to being re-booked as proved reserves at some point in the future when price levels recover. Under the terms of certain contractual arrangements or government royalty regimes, lower prices can also increase proved reserves attributable to the company. It is not expected that any temporary changes in reported proved reserves under SEC definitions would affect the operation of the underlying projects or alter the outlook for future production volumes.

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 fields, 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)

	2015 three months ended				2014 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	**6,229**	**7,155**	**7,301**	**6,203**	8,030	9,658	10,049	9,226
Total expenses	**6,100**	**6,518**	**6,705**	**5,642**	7,160	8,413	8,403	7,966
Income before income taxes	**129**	**637**	**596**	**561**	870	1,245	1,646	1,260
Income taxes	**27**	**158**	**476**	**140**	199	309	414	314
Net income	**102**	**479**	**120**	**421**	671	936	1,232	946
Segmented net income (millions of dollars)								
Upstream	**(289)**	**(52)**	**(174)**	**(189)**	218	532	857	452
Downstream	**352**	**454**	**215**	**565**	397	343	366	488
Chemical	**74**	**78**	**69**	**66**	63	66	57	43
Corporate and Other	**(35)**	**(1)**	**10**	**(21)**	(7)	(5)	(48)	(37)
Net income	**102**	**479**	**120**	**421**	671	936	1,232	946
Per-share information (dollars)								
Net earnings – basic	**0.12**	**0.56**	**0.14**	**0.50**	0.80	1.10	1.45	1.12
Net earnings – diluted	**0.12**	**0.56**	**0.14**	**0.50**	0.79	1.10	1.45	1.11
Dividends (declared quarterly)	**0.14**	**0.14**	**0.13**	**0.13**	0.13	0.13	0.13	0.13
Share prices (dollars) (b)								
Toronto Stock Exchange								
High	**46.27**	**49.40**	**55.37**	**52.06**	55.76	57.96	56.94	51.89
Low	**39.30**	**40.55**	**46.51**	**44.08**	45.52	52.05	50.36	44.99
Close	**45.08**	**42.28**	**48.25**	**50.55**	50.05	52.91	56.23	51.48
NYSE MKT (U.S. dollars) (b)								
High	**35.40**	**38.88**	**45.60**	**43.35**	49.55	54.09	53.10	47.08
Low	**28.66**	**30.35**	**37.94**	**35.69**	39.14	46.85	46.01	40.20
Close	**32.52**	**31.61**	**38.62**	**39.88**	43.03	47.22	52.63	46.55
Shares traded (thousands) (c)	**100,077**	**104,678**	**88,186**	**95,600**	113,657	69,107	78,236	87,465

(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.