

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

Overview

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

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

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

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

Business environment and risk assessment

Long-term business outlook

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

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

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

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

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greenhouse gas emissions. Nuclear power and renewables, led by hydropower and wind, are expected to grow significantly over the period.

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

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

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

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

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

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

Upstream

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

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

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

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

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

Downstream

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

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

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

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

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

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

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

Chemical

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

Results of operations

Consolidated

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

2014

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

2013

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

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

Upstream

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

2014

Upstream net income in 2014 was \$2,059 million, \$347 million higher than 2013. Earnings in 2014 included a gain of \$478 million from the divestment of conventional upstream producing assets, whereas 2013 included a \$73 million gain for the sale of non-operating assets. Earnings also increased due to the impacts of a weaker Canadian dollar of about \$280 million and higher liquids volumes of about \$100 million, reflecting the incremental contribution from Kearn 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 Kearn production, as well as higher energy and other operating costs of about \$130 million, and the impact of lower crude oil realizations of about \$50 million.

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2013

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

Average realizations

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

2014

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

2013

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

Crude oil and NGLs - production and sales (a)

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

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

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

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

2014

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

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

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

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

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

2013

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

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

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

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

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

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Downstream

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

2014

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

2013

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

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

Refinery utilization

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

Sales

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

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

(b) Crude oil and feedstocks sent directly to atmospheric distillation units.

(c) Refinery operations at the Dartmouth refinery were discontinued on September 16, 2013. Capacity utilization is calculated based on the number of days the refineries were operated as a refinery in 2013.

2014

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

2013

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

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

Chemical

millions of dollars	2014	2013	2012
Net income	229	162	165

Sales

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

2014

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

2013

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

Corporate and Other

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

2014

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

2013

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

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Liquidity and capital resources

Sources and uses of cash

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

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

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

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

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

Cash flow from operating activities

2014

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

2013

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

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Cash flow used in investing activities

2014

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

2013

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

Cash flow from financing activities

2014

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

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

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

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

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

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

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

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

2013

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

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

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

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

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

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Financial percentages and ratios

	2014	2013	2012
Total debt as a percentage of capital (a)	23	24	9
Interest coverage ratio – earnings basis (b)	61	55	239
(a) Current and long-term debt (page 53) and the company's share of equity company debt, divided by debt and shareholders' equity (page 53).			
(b) Net income (page 51), debt-related interest before capitalization, including the company's share of equity company interest, and income taxes (page 51), divided by debt-related interest before capitalization, including the company's share of equity company interest.			

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

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

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

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

Commitments

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

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

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

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

Unrecognized tax benefits totalling \$151 million have not been included in the company's commitments table because the company does not expect there will be any cash impact from the final settlements as sufficient funds have been deposited with the Canada Revenue Agency. Further details on the unrecognized tax benefits can be found in note 3 to the financial statements on page 61.

Litigation and other contingencies

As discussed in note 9 to the consolidated financial statements on page 70, a variety of claims have been made against Imperial and its subsidiaries. Based on a consideration of all relevant facts and circumstances, the company does not believe the ultimate outcome of any currently pending lawsuits against the company will have a material adverse effect on the company's operations, financial condition, or financial statements taken as a whole. There are no events or uncertainties beyond those already included in reported financial information that would indicate a material change in future operating results or financial condition.

Capital and exploration expenditures

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

(a) Exploration expenses included.

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

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

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

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

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

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

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

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

Market risks and other uncertainties

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

Earnings sensitivities (a)

millions of dollars, after tax

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Risk management

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

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

Critical accounting estimates

The company's financial statements have been prepared in accordance with United States generally accepted accounting principles (GAAP). GAAP requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. The company's accounting and financial reporting fairly reflect its straightforward business model. Imperial does not use financing structures for the purpose of altering accounting outcomes or removing debt from the balance sheet. The company's significant accounting policies are summarized in note 1 to the consolidated financial statements on page 56.

Oil and gas reserves

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

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

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

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

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

Impact of oil and gas reserves on depreciation

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

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

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

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

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

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

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

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

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

Pension benefits

The company's pension plan is managed in compliance with the requirements of governmental authorities and meets funding levels as determined by independent third-party actuaries. Pension accounting requires explicit assumptions regarding, among others, the discount rate for the benefit obligations, the expected rate of return on plan assets and the long-term rate of future compensation increases. All pension assumptions are reviewed annually by senior management. These assumptions are adjusted only as appropriate to reflect long-term changes in market rates and outlook. The long-term expected rate of return on plan assets of 6.25 percent used in 2014 compares to actual returns of 6.90 percent and 8.80 percent achieved over the last 10- and 20-year periods ending December 31, 2014. If different assumptions are used, the expense and obligations could increase or decrease as a result. The company's potential exposure to changes in assumptions is summarized in note 4 to the consolidated financial statements on page 62. At Imperial, differences between actual returns on plan assets and the long-term expected returns are not recorded in pension expense in the year the differences occur. Such differences are deferred, along with other actuarial gains and losses, and are amortized into pension expense over the expected average remaining service life of employees. Employee benefit expense represented about one percent of total expenses in 2014.

Asset retirement obligations and other environmental liabilities

Legal obligations associated with site restoration on the retirement of assets with determinable useful lives are recognized when they are incurred, which is typically at the time the assets are installed. The obligations are initially measured at fair value and discounted to present value. Over time, the discounted asset retirement obligation amount will be accreted for the change in its present value, with this effect included in production and manufacturing expenses. As payments to settle the obligations occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed 25 years, the discount rate will be adjusted only as appropriate to reflect long-term changes in market rates and outlook. For 2014, the obligations were discounted

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

at six percent and the accretion expense was \$105 million, before tax, which was significantly less than one percent of total expenses in the year. There would be no material impact on the company's reported financial results if a different discount rate had been used.

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

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

Suspended exploratory well costs

The company continues capitalization of exploratory well costs when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project. Exploratory well costs not meeting these criteria are charged to expense. The facts and circumstances that support continued capitalization of suspended wells at year-end are disclosed in note 15 to the consolidated financial statements on page 74.

Tax contingencies

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

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

Recently issued accounting standards

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