

# 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 business model involving exploration for, and production of, crude oil and natural gas and manufacture, trade, transport and sale of crude oil, natural gas, petroleum products, petrochemicals and a variety of specialty products.

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 depend on supply and demand and may be volatile on a short-term basis, Imperial's investment decisions are grounded on fundamentals reflected in its long-term business outlook, and use 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. Volumes are based on individual field production profiles, which are also updated annually. Price ranges for crude oil, natural gas, refined products and chemical products are based on corporate plan assumptions developed annually and are utilized for investment evaluation purposes. Major investment opportunities are evaluated over a range of potential market conditions. Once major 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

The "Long-term business outlook" is based on Exxon Mobil Corporation's 2018 *Outlook for Energy*, which is used to help inform the company's long-term business strategies and investment plans. By 2040, the world's population is projected at around 9.2 billion people, or about 1.7 billion more people than in 2016. Coincident with this population increase, the company expects worldwide economic growth to average close to 3 percent per year, with economic output nearly doubling by 2040. As economies and populations grow, and as living standards improve for billions of people, the need for energy is expected to continue to rise. Even with significant efficiency gains, global energy demand is projected to rise by about 25 percent from 2016 to 2040. This increase in energy demand is expected to be driven by developing countries (i.e., those that are not member nations of the Organization for Economic Co-operation and Development (OECD)). Canada is expected to see flat to modest local energy demand growth through to 2040 and will continue to be a large supplier of energy exports to help meet rising global energy needs.

As expanding prosperity helps drive global energy demand higher, increasing use of energy efficient technologies and practices, as well as lower emission fuels 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's economy through 2040, affecting energy requirements for power generation, transportation, industrial applications, and residential and commercial needs.

Global electricity demand is expected to increase approximately 60 percent from 2016 to 2040, with developing countries likely to account for about 85 percent of the increase. Consistent with this projection, power generation is expected to remain the largest and fastest growing major segment of global primary energy demand, supported by a wide variety of energy sources. The share of coal fired generation is likely to decline substantially and approach 25 percent of the world's electricity by 2040, versus nearly 40 percent in 2016, in part as a result of policies to improve air quality, as well as reduce greenhouse gas emissions to address the risks of climate change. From 2016 to 2040, the amount of electricity supplied using natural gas, nuclear power, and renewables is likely to approximately double, and account for about 95 percent of the growth in electricity supplies. Electricity from wind and solar is likely to increase about 400 percent, helping total renewables (including other sources, i.e., hydropower) to account for about half of the increase in electricity supplies worldwide through 2040. Total renewables will likely reach nearly 35 percent of global electricity supplies by 2040. Natural gas and nuclear are also expected to increase shares over the period to 2040, reaching about 25 percent and 12 percent respectively of global electricity supplies by 2040. Supplies of electricity by energy type will reflect significant differences across regions, reflecting a wide range of factors including the cost and availability of various energy types.

Energy for global transportation – including cars, trucks, ships, trains and airplanes – is expected to increase by about 30 percent from 2016 to 2040. Transportation energy demand is likely to account for approximately 60 percent of the growth in liquid fuels demand worldwide over this period. Liquid fuels demand for light duty vehicles is expected to remain relatively flat to 2040 as the impact of better fuel economy and significant growth in electric cars, led by China, Europe, and the United States, work to offset growth in the worldwide car fleet of about 75 percent. By 2040, light-duty vehicles are expected to account for about 20 percent of global liquid fuels demand. During the same time period, nearly all the world's transportation fleets are likely to continue to run on liquid fuels, which are widely available and offer practical advantages in providing a large quantity of energy in small volumes.

Liquid fuels provide the largest share of global energy supplies today due to their broad based availability, affordability, ease of transportation, storage and fitness as a practical solution to meet a wide variety of needs. By 2040, global demand for liquid fuels is projected to grow to approximately 118 million barrels per day, an increase of about 20 percent from 2016. The non-OECD share of global liquid fuels demand is expected to increase to about 65 percent by 2040, as liquid fuels demand in the OECD is likely to decline by close to 10 percent. Much of the global liquid fuels demand today is met by crude production from traditional conventional sources; these supplies will remain important and significant development activity is expected to offset much of the natural declines from these fields. At the same time, a variety of emerging supply sources – including tight oil, deep water oil, oil sands, natural gas liquids and biofuels – are expected to grow to help meet rising demand. The world's resource base is sufficient to meet projected demand through 2040 as technological advances continue to expand the availability of economic supply options. However, timely investments will remain critical to meeting global needs with reliable and affordable supplies.

Natural gas is a versatile and practical fuel for a wide variety of applications and it is expected to grow the most of any primary energy type from 2016 to 2040, meeting more than 35 percent of global energy demand growth. Global natural gas demand is expected to rise nearly 40 percent from 2016 to 2040, with about 45 percent of that increase in the Asia Pacific region. Significant growth in supplies of unconventional gas – the natural gas found in shale and other tight rock formations – will help meet these needs. In total, about 55 percent of the growth in natural gas supplies is expected to be from unconventional sources. However, it is expected conventionally produced natural gas is likely to remain the cornerstone of global supply, meeting about two-thirds of worldwide demand in 2040. Liquefied natural gas (LNG) trade will expand significantly, meeting about one-third of the increase in demand growth, with much of this supply expected to help meet rising demand in Asia Pacific.

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 2020 to 2025 timeframe. The share of natural gas is expected to reach 25 percent by 2040, while the share of coal falls to about 20 percent. Nuclear power is projected to grow significantly, as many nations are likely to expand nuclear capacity to address rising electricity needs, as well as energy security and environmental issues. Total renewable energy is likely to exceed 15 percent of total global energy by 2040, with biomass, hydro and geothermal contributing a combined share of more than 10 percent. Total energy supplied from wind, solar and biofuels is expected to increase rapidly, growing nearly 250 percent from 2016 to 2040, when they will approach about 5 percent of the world's 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 investments to develop and supply resources to meet global demand through 2040 will be significant - even if demand remains flat. This reflects a fundamental aspect of the oil and natural gas business, in that, as the International Energy Agency (IEA) notes in its *World Energy Outlook in 2018*, a "key understanding driver for new investment is declining output from existing fields". According to the IEA's New Policies Scenario, the investment required to meet oil and natural gas supply requirements worldwide over the period 2018 to 2040 will be about US\$21 trillion (measured in 2017 dollars) or approximately US\$900 billion per year on average.

International accords and underlying regional and national regulations covering greenhouse gas emissions continue to evolve with uncertain timing and outcome, making it difficult to predict their business impact. Imperial's estimates of potential costs related to greenhouse gas emissions align with applicable provincial and federal regulations. Additionally, Imperial uses ExxonMobil's *Outlook for Energy* as a foundation for estimating energy supply and demand requirements from various energy sources and uses, and the *Outlook for Energy* takes into account policies established to reduce energy related greenhouse gas emissions. The climate accord reached at the Conference of the Parties (COP 21) in Paris set many new goals, and many related policies are still emerging. The *Outlook for Energy* reflects an environment with increasingly stringent climate policies and is consistent with the aggregation of Nationally Determined Contributions which were submitted by signatories to the United Nations Framework Convention on Climate Change (UNFCCC) 2015 Paris Agreement. The *Outlook for Energy* seeks to identify potential impacts of climate related policies, which often target specific sectors. It estimates potential impacts of these climate related policies on consumer energy demand by using various assumptions and tools – including, depending on the sector, application of a proxy cost of carbon or assessment of targeted policies (i.e., automotive fuel economy standards). As people and nations look for ways to reduce risks of global climate change, they will continue to need practical solutions that do not jeopardize the affordability or reliability of the energy they need.

Practical solutions to the world's energy and climate challenges will benefit from market competition, well informed, well designed and transparent policy approaches that carefully weigh costs and benefits. Such policies are likely to help manage the risks of climate change while also enabling societies to pursue other high priority goals around the world – including clean air and water, access to reliable, affordable energy, and economic progress for all people. All practical and economically viable energy sources, both conventional and unconventional, will need to be pursued to continue meeting global energy demand, recognizing the scale and variety of worldwide energy needs, as well as the importance of expanding access to modern energy to promote better standards of living for billions of people.

The information provided in the "Long-term business outlook" includes internal estimates and forecasts based upon ExxonMobil's 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 North American markets. Imperial's Upstream business strategies guide the company's exploration, development, production, research and gas marketing activities. These strategies include maximizing asset reliability, accelerating development and application of high impact technologies, maximizing value by capturing new business opportunities and managing the existing portfolio, as well as pursuing sustainable improvements in organizational efficiency and effectiveness. These strategies are underpinned by a relentless focus on operations integrity, commitment to innovative technologies, disciplined approach to investing and cost management, 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 long-term growth. As future development projects bring new production online, Imperial expects growth from oil sands in-situ and mining, as well as unconventional resources, with the largest growth potential related to in-situ. Actual volumes will vary from year to year due to the factors described in Item 1A. "Risk factors".

The industry experienced challenges throughout 2018 with the volatility in crude differentials in the western Canadian market. Prices for most of the company's crude oil sold are referenced to Western Canada Select (WCS) and West Texas Intermediate (WTI) oil markets. While WTI crude oil prices improved in 2018, abundant crude oil supply and limited pipeline takeaway capacity caused the average price of WCS to decrease slightly versus 2017. The WTI / WCS differential widened significantly during the fourth quarter of 2018 to average approximately US\$40 per barrel, compared to around US\$12 per barrel in the same period of 2017. In December 2018 the Government of Alberta introduced temporary mandatory production curtailment regulations, which took effect on January 1, 2019. Following the announcement to impose production limits on large producers in Alberta, the WTI / WCS differential narrowed. The duration and impact of these regulations is uncertain. Imperial believes prices over the long-term will be driven by market supply and demand, with the demand side largely being a function of general economic activities, levels of prosperity, technology advances, consumer preference and government policies. On the supply side, prices may be significantly impacted by political events, logistics constraints, the actions of OPEC, governments and other factors. To manage the risks associated with price, Imperial evaluates annual plans and all major investments across a range of price scenarios.

### **Downstream**

Imperial's Downstream serves predominantly Canadian markets with refining, logistics and marketing assets. Imperial's Downstream business strategies competitively position the company across a range of market conditions. These strategies include targeting industry leading performance in reliability, safety and operations integrity, as well as 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 quality, valued and differentiated products and services to customers.

Imperial owns and operates three refineries in Canada, with aggregate distillation capacity of 423,000 barrels per day. 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 the market prices for the range of products produced (primarily gasoline, heating oil, diesel oil, jet fuel, fuel oil and asphalt). 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 the global and regional marketplaces and are influenced by many factors, including global and regional supply / demand balances, inventory levels, industry refinery operations, import / export balances, currency fluctuations, seasonal demand, weather and political climate.

In 2018, Imperial's margins strengthened, benefitting from widening crude differentials and strong product prices.

As described in more detail in Item 1A. "Risk factors", proposed carbon policy and other climate related regulations, as well as continued biofuels mandates, could have negative impacts on the downstream business. Imperial's integration across the value chain, from refining to marketing, enhances overall value across the fuels business.

Imperial supplies petroleum products to the motoring public through Esso and Mobil-branded sites and independent marketers. At the end of 2018, there were about 2,200 sites operating under a branded wholesaler model whereby Imperial supplies fuel to independent third parties who own and operate sites in alignment with Esso and Mobil brand standards. The Mobil fuels brand was launched in Canada in 2017 with the conversion of more than 200 existing unbranded third party sites completed by the end of 2018.

### **Chemical**

North America continued to benefit from abundant supplies of natural gas and gas liquids, providing both low cost energy and feedstock for steam crackers, and a favourable margin environment for integrated chemical producers. Imperial sustained a competitive advantage through continued operational excellence, investment and cost discipline. In 2018, the company continued to capture value from 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 Canadian dollars	2018	2017	2016
Net income (loss)	<b>2,314</b>	490	2,165

#### 2018

Net income in 2018 was \$2,314 million, or \$2.86 per share on a diluted basis, an increase of \$1,824 million compared to net income of \$490 million or \$0.58 per share in 2017. The prior year results included upstream non-cash impairment charges of \$566 million.

#### 2017

Net income in 2017 was \$490 million, or \$0.58 per share on a diluted basis, reflecting impairment charges of \$289 million (\$0.35 per share) associated with the Horn River development and \$277 million (\$0.33 per share) associated with the Mackenzie gas project. This compares with net income of \$2,165 million or \$2.55 per share in 2016, which included a gain of \$1.7 billion (\$2.01 per share) from the sale of retail sites.

### Upstream

millions of Canadian dollars	2018	2017	2016
Net income (loss)	<b>(138)</b>	(706)	(661)

#### 2018

Upstream recorded a net loss of \$138 million in 2018, compared to a net loss of \$706 million in 2017. Improved results reflect the absence of impairment charges of \$566 million, higher Kearl volumes of about \$210 million, lower royalties of about \$80 million and favourable foreign exchange effects of about \$50 million. These items were partially offset by higher operating costs of about \$200 million, lower Cold Lake volumes of about \$170 million and lower Canadian crude oil realizations of about \$60 million.

#### 2017

Upstream recorded a net loss of \$706 million in 2017, reflecting impairment charges of \$289 million associated with the Horn River development and \$277 million associated with the Mackenzie gas project. Excluding these impairment charges, the net loss of \$140 million compares to a net loss of \$661 million in 2016. Results benefitted from higher Canadian crude oil realizations of about \$1,190 million and higher Kearl volumes of about \$60 million. Results were negatively impacted by higher royalties of about \$250 million, lower Syncrude and Norman Wells volumes of about \$190 million, higher operating expenses mainly associated with Syncrude and Kearl of about \$150 million, higher energy costs of about \$80 million and the impact of a stronger Canadian currency of about \$60 million.

## Average realizations

Canadian dollars	2018	2017	2016
Bitumen (per barrel)	<b>37.56</b>	39.13	26.52
Synthetic oil (per barrel)	<b>70.66</b>	67.58	57.12
Conventional crude oil (per barrel)	<b>41.84</b>	53.51	32.93
Natural gas liquids (per barrel)	<b>38.66</b>	31.46	15.58
Natural gas (per thousand cubic feet)	<b>2.43</b>	2.58	2.41

### 2018

WTI averaged US\$65.03 per barrel in 2018, up from US\$50.85 per barrel in 2017. WCS averaged US\$38.71 per barrel and US\$38.95 per barrel for the same periods. The WTI / WCS differential widened to average approximately US\$26 per barrel in 2018, from around US\$12 per barrel in 2017. The Canadian dollar averaged US\$0.77 in 2018, unchanged from 2017.

Imperial's average Canadian dollar realizations for bitumen declined generally in line with WCS, adjusted for changes in the exchange rate and transportation costs. Bitumen realizations averaged \$37.56 per barrel in 2018, a decrease of \$1.57 per barrel from 2017. The company's average Canadian dollar realizations for synthetic crude increased by \$3.08 per barrel to average \$70.66 per barrel in 2018, however the widening of the western Canadian light crude differential relative to WTI during the fourth quarter of 2018 negatively impacted synthetic crude realizations.

### 2017

WTI averaged US\$50.85 per barrel in 2017, up from US\$43.44 per barrel in the prior year. WCS averaged US\$38.95 per barrel and US\$29.49 per barrel respectively for the same periods. The WTI / WCS differential narrowed to approximately US\$12 per barrel in 2017, from around US\$14 per barrel in 2016. The Canadian dollar averaged US\$0.77 in 2017, an increase of about US\$0.02 from 2016.

Imperial's average Canadian dollar realizations for bitumen and synthetic crudes increased generally in line with the North American benchmarks, adjusted for changes in the exchange rate and transportation costs. Bitumen realizations averaged \$39.13 per barrel for 2017, an increase of \$12.61 per barrel versus 2016. Synthetic crude realizations averaged \$67.58 per barrel, an increase of \$10.46 per barrel from 2016.

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

thousands of barrels per day	2018		2017		2016	
	gross	net	gross	net	gross	net
Bitumen	293	255	288	255	281	256
Synthetic oil (b)	62	60	62	57	68	67
Conventional crude oil	5	5	4	3	14	12
Total crude oil production	360	320	354	315	363	335
NGLs available for sale	1	2	1	1	1	1
Total crude oil and NGL production	361	322	355	316	364	336
Bitumen sales, including diluent (c)	406		381		374	
NGL sales	6		6		5	

**Natural gas - production and production available for sale (a)**

millions of cubic feet per day	2018		2017		2016	
	gross	net	gross	net	gross	net
Production (d) (e)	129	126	120	114	129	122
Production available for sale (f)		94		80		87

- (a) Volume per day metrics are 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 crude bitumen to facilitate transportation to market by pipeline and rail.
- (d) Gross production of natural gas includes amounts used for internal consumption with the exception of the amounts re-injected.
- (e) 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.
- (f) Includes sales of the company's share of net production and excludes amounts used for internal consumption.

**2018**

Gross production of Cold Lake bitumen averaged 147,000 barrels per day in 2018, compared to 162,000 barrels per day in 2017. Lower volumes were primarily due to production timing associated with steam management and planned maintenance.

Gross production of Kearl bitumen averaged 206,000 barrels per day in 2018 (146,000 barrels Imperial's share) up from 178,000 barrels per day (126,000 barrels Imperial's share) in 2017. Increased 2018 production reflects improved operational reliability associated with ore preparation, enhanced piping durability and feed management.

During 2018, the company's share of gross production from Syncrude averaged 62,000 barrels per day, unchanged from 2017.

**2017**

Gross production of Cold Lake bitumen averaged 162,000 barrels per day in 2017, up from 161,000 barrels per day in 2016.

Gross production of Kearl bitumen averaged 178,000 barrels per day in 2017 (126,000 barrels Imperial's share) up from 169,000 barrels per day (120,000 barrels Imperial's share) in 2016. Increased 2017 production reflects improved reliability associated with the mining and ore preparation operations.

During 2017, the company's share of gross production from Syncrude averaged 62,000 barrels per day, compared to 68,000 barrels per day in 2016. Syncrude 2017 production was impacted by the March 2017 fire at the Syncrude Mildred Lake upgrader and planned maintenance. In 2016, production was impacted by the Alberta wildfires and planned maintenance.

## Downstream

millions of Canadian dollars	2018	2017	2016
Net income (loss)	<b>2,366</b>	1,040	2,754

### 2018

Downstream net income was \$2,366 million, an increase of \$1,326 million versus the prior year. Higher earnings primarily reflect stronger margins of about \$1,530 million, partially offset by the absence of a \$151 million gain on the sale of a surplus property in 2017.

### 2017

Downstream net income was \$1,040 million, compared to \$2,754 million in 2016, which included a \$1,841 million gain from the sale of company-owned retail sites and the general aviation business. Excluding the impact of the 2016 asset sales, earnings increased by \$127 million reflecting higher refining margins of about \$340 million, lower marketing expenses of about \$160 million, mainly associated with the retail divestment, and a gain of \$151 million from the sale of a surplus property. These factors were partially offset by lower marketing margins of about \$330 million, mainly associated with the impact of the retail divestment, and higher maintenance activity of about \$130 million.

## Refinery utilization

thousands of barrels per day (a)	2018	2017	2016
Total refinery throughput (b)	<b>392</b>	383	362
Refinery capacity at December 31	<b>423</b>	423	423
Utilization of total refinery capacity (percent)	<b>93</b>	91	86

## Sales

thousands of barrels per day (a)	2018	2017	2016
Gasolines	<b>255</b>	257	261
Heating, diesel and jet fuels	<b>183</b>	177	170
Heavy fuel oils (c)	<b>26</b>	18	16
Lube oils and other products	<b>40</b>	40	37
Net petroleum product sales (c)	<b>504</b>	492	484

(a) Volume per day metrics are calculated by dividing the volume for the period by the number of calendar days in the period.

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

(c) In 2018 and 2017, carbon black product sales are reported under Net petroleum product sales – Heavy fuel oils; in 2016, they were reported under Total petrochemical sales – Polymers and basic chemicals.

### 2018

Refinery throughput averaged 392,000 barrels per day in 2018, up from 383,000 barrels per day in 2017. Capacity utilization increased to 93 percent from 91 percent in 2017. Petroleum product sales were 504,000 barrels per day in 2018, up from 492,000 barrels per day in 2017. Sales growth continues to be driven by optimization across the full downstream value chain, and the expansion of Imperial's logistics capabilities.

### 2017

Refinery throughput averaged 383,000 barrels per day in 2017, up from 362,000 barrels per day in 2016. Capacity utilization increased to 91 percent from 86 percent in 2016, reflecting reduced turnaround maintenance activity. Petroleum product sales were 492,000 barrels per day in 2017, up from 484,000 barrels per day in 2016. Sales growth continues to be driven by optimization across the full downstream value chain.

## Chemical

millions of Canadian dollars	2018	2017	2016
Net income (loss)	275	235	187

## Sales

thousands of tonnes	2018	2017	2016
Polymers and basic chemicals (a)	602	564	697
Intermediate and others	205	210	211
Total petrochemical sales (a)	807	774	908

(a) In 2018 and 2017, carbon black product sales are reported under Net petroleum product sales – Heavy fuel oils; in 2016, they were reported under Total petrochemical sales – Polymers and basic chemicals.

### 2018

Chemical net income was \$275 million, an increase of \$40 million versus the prior year, reflecting higher margins and volumes.

### 2017

Chemical net income was \$235 million, up from \$187 million in 2016, mainly due to stronger margins.

## Corporate and other

millions of Canadian dollars	2018	2017	2016
Net income (loss)	(189)	(79)	(115)

### 2018

For 2018, Corporate and other expenses were \$189 million, compared to \$79 million in 2017. As part of the implementation of the Financial Accounting Standards Board's update, Compensation – Retirement Benefits (Topic 715): *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*, beginning January 1, 2018, Corporate and other includes all non-service pension and postretirement benefit expenses. Prior to 2018, the majority of these costs were allocated to the operating segments.

### 2017

For 2017, Corporate and other costs were \$79 million, versus \$115 million in 2016, mainly due to lower share-based compensation charges.

## Liquidity and capital resources

### Sources and uses of cash

millions of Canadian dollars	2018	2017	2016
Cash provided by (used in)			
Operating activities	3,922	2,763	2,015
Investing activities	(1,559)	(781)	1,947
Financing activities	(2,570)	(1,178)	(3,774)
Increase (decrease) in cash and cash equivalents	(207)	804	188
Cash and cash equivalents at end of year	988	1,195	391

The company issues long-term debt from time to time and maintains a commercial paper program. However, internally generated funds cover the majority of its financial requirements. Cash that may be temporarily 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.

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 completed at least once every three years depending on funding status. The most recent valuation of the company's registered retirement plans was completed as at December 31, 2016. The company contributed \$203 million to the registered retirement plans in 2018. 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

2018

Cash flow generated from operating activities was \$3,922 million in 2018, up from \$2,763 million in 2017, primarily reflecting higher earnings, partially offset by unfavourable working capital effects.

2017

Cash flow generated from operating activities was \$2,763 million in 2017, compared with \$2,015 million in 2016, reflecting higher earnings, excluding the impact of asset sales and impairment charges, partially offset by the absence of favourable working capital effects.

### Cash flow from investing activities

2018

Investing activities used net cash of \$1,559 million in 2018, compared with \$781 million used in 2017, reflecting higher additions to property, plant and equipment, and lower proceeds from asset sales.

2017

Investing activities used net cash of \$781 million in 2017, compared with cash generated from investing activities of \$1,947 million in 2016, reflecting lower proceeds from asset sales.

## Cash flow from financing activities

2018

Cash used in financing activities was \$2,570 million in 2018, compared with \$1,178 million used in 2017.

At the end of 2018, total debt outstanding was \$5,180 million, compared with \$5,207 million at the end of 2017.

In November 2018, the company extended the maturity date of its existing \$250 million committed long-term line of credit to November 2020. The company has not drawn on the facility.

In December 2018, the company extended the maturity date of its existing \$250 million committed short-term line of credit to December 2019. The company has not drawn on the facility.

During 2018, the company, under its share purchase program, purchased about 48.7 million shares for \$1,971 million, including shares purchased from Exxon Mobil Corporation.

Dividends paid in 2018 were \$572 million. The per share dividend paid in 2018 was \$0.70, up from \$0.62 in 2017.

2017

Cash used in financing activities was \$1,178 million in 2017, compared with \$3,774 million in 2016, mainly reflecting the absence of debt repayments, partially offset by share purchases under the company's share purchase program.

At the end of 2017, total debt outstanding was \$5,207 million, compared with \$5,234 million at the end of 2016.

In November 2017, the company extended the maturity date of its existing \$250 million committed long-term line of credit to November 2019. The company has not drawn on the facility.

In December 2017, the company extended the maturity date of its existing \$250 million committed short-term line of credit to December 2018. The company has not drawn on the facility.

During 2017 the company purchased about 16.4 million shares for \$627 million, including shares purchased from Exxon Mobil Corporation.

Dividends paid in 2017 were \$524 million. The per share dividend paid in 2017 was \$0.62, up from \$0.58 in 2016.

## Financial strength

	<b>2018</b>	2017	2016
Total debt as a percentage of capital (a)	<b>18</b>	18	17

(a) Current and long-term debt (page 63) and the company's share of equity company debt, divided by debt and shareholders' equity (page 63).

Debt represented 18 percent of the company's capital structure at the end of 2018.

Debt-related interest incurred in 2018, before capitalization of interest, was \$133 million, compared with \$103 million in 2017. The average effective interest rate on the company's debt was 2.5 percent in 2018, compared with 2.0 percent in 2017.

The company's financial strength represents a competitive advantage of strategic importance providing it the opportunity to readily access capital markets under 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.

## Commitments

The following table shows the company's commitments outstanding at December 31, 2018. It combines data from the Consolidated balance sheet and from individual notes to the consolidated financial statements, where appropriate.

millions of Canadian dollars	Note reference	Payment due by period				Total
		2019	2020 to 2021	2022 to 2023	2024 and beyond	
Long-term debt (a)	15	-	4,478	26	474	4,978
- Due in one year		27				27
Operating leases (b)	14	130	125	24	12	291
Firm capital commitments (c)		645	91	-	-	736
Pension and other postretirement obligations (d)	5	267	114	115	754	1,250
Asset retirement obligations (e)	6	71	81	57	1,208	1,417
Other long-term purchase agreements (f)		814	1,575	1,695	8,637	12,721

- (a) Long-term debt includes a loan from an affiliated company of ExxonMobil of \$4,447 million and capital lease obligations of \$558 million, \$27 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, covers primarily storage tanks, rail cars and marine vessels.
- (c) Firm capital commitments represent legally-binding payment obligations to third parties where agreements specifying all significant terms have been executed for the construction and purchase of fixed assets and other permanent investments. In certain cases where the company executes contracts requiring commitments to a work scope, those commitments have been included to the extent that the amounts and timing of payments can be reliably estimated. Firm capital commitments related to capital projects are shown on an undiscounted basis. In 2018 the company entered into approximately \$300 million in firm capital commitments mainly associated with the Aspen in-situ project.
- (d) The amount by which the benefit obligations exceeded the fair value of fund assets for pension and other postretirement plans at year end. The payments by period include expected contributions to funded pension plans in 2019 and estimated benefit payments for unfunded plans in all years.
- (e) Asset retirement obligations represent the fair value of legal obligations associated with site restoration on the retirement of assets with determinable useful lives.
- (f) Other long-term purchase agreements are non-cancelable, or cancelable only under certain conditions and long-term commitments other than unconditional purchase obligations. They include primarily transportation services agreements, raw material supply and community benefits agreements.

Unrecognized tax benefits totaling \$36 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 4 to the financial statements on page 75.

### Litigation and other contingencies

As discussed in note 10 to the consolidated financial statements on page 85, 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.

Additionally, as discussed in note 10, Imperial was contingently liable at December 31, 2018, for guarantees relating to performance under contracts. These guarantees do not have a material 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 Canadian dollars	2018	2017
Upstream (a)	991	416
Downstream	383	200
Chemical	25	17
Other	28	38
Total	1,427	671

(a) Exploration expenses included.

Total capital and exploration expenditures were \$1,427 million in 2018, an increase of \$756 million from 2017.

For the Upstream segment, capital and exploration expenditures were \$991 million in 2018, compared with \$416 million in 2017. Investments were primarily related to growth activities including further development of unconventional assets, investment in supplemental crushing capacity at Kearn, and progressing the Aspen in-situ project.

For the Downstream segment, capital expenditures were \$383 million in 2018, compared with \$200 million in 2017. In 2018, investments were primarily in support of enhancing the company's distribution network as well as refinery projects to improve reliability, feedstock flexibility, energy efficiency and environmental performance.

Total capital and exploration expenditures are expected to range between \$2.3 billion to \$2.4 billion in 2019. Planned increases in spending versus 2018 are largely driven by the Aspen in-situ project, drilling and other Upstream projects. 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.

Imperial's earnings are influenced by North American crude oil benchmark prices as well as changes in the differentials between these benchmarks and western Canadian prices for light and heavy crude oil. Imperial's integrated business model reduces the company's risk from changes in commodity prices. For instance, when light and heavy differentials between North American crude benchmarks and western Canadian prices widen together, Imperial is able to mitigate the impact of these widening differentials through integration with Downstream investments in refineries, pipeline commitments and the Edmonton rail terminal. As a result, the negative exposure to these widening differentials in the Upstream is more than offset by the benefit of lower feedstock costs in the Downstream.

At this time, Imperial is a net consumer of natural gas, used in Imperial's Upstream operation and refineries. A decrease in the value of natural gas reduces Imperial's operating expenses, thereby increasing Imperial's earnings.

In the competitive downstream and chemical environments, earnings are primarily determined by margin capture rather than absolute price levels on products sold. Refining margins are a function of the difference between what a refiner pays for its raw materials (primarily crude oil) and the market prices for the range of products produced. These prices in turn depend on global and regional supply / demand balances, inventory levels, refinery operations, import / export balances and weather.

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.

Imperial is exposed to changes in interest rates, primarily on its debt which carries floating interest rates. The impact of a quarter percent change in interest rates affecting Imperial's debt would not be material to earnings, cash flow or fair value. Imperial has access to significant sources of long-term and short-term liquidity. Internally generated funds are expected to cover the majority of financial requirements, supplemented by long-term and short-term debt as needed.

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, which shows the estimated annual effect, under current conditions, on the company's after-tax net income. For any given period, the extent of actual benefit or detriment will be dependent on the price movements of individual types of crude oil and products, production and sales volumes, transportation capacity, costs and egress methods, and other factors. Accordingly, changes in benchmark prices for crude oil and crude oil differentials, and other factors listed in the table following, only provide broad indicators of changes in the earnings experienced in any particular period.

## Earnings sensitivities (a)

millions of Canadian dollars, after tax

One dollar (U.S.) per barrel change in crude oil prices	+ (-)	<b>100</b>
One dollar (U.S.) per barrel change in light and heavy crude price differentials (b)	+ (-)	<b>40</b>
Ten cents per thousand cubic feet decrease (increase) in natural gas prices	+ (-)	<b>5</b>
One dollar (U.S.) per barrel change in refining 2-1-1 margins (c)	+ (-)	<b>140</b>
One cent (U.S.) per pound change in sales margins for polyethylene	+ (-)	<b>7</b>
One cent decrease (increase) in the value of the Canadian dollar versus the U.S. dollar	+ (-)	<b>100</b>

- (a) 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. These sensitivities have been updated to reflect current market conditions. They may not apply proportionately to larger fluctuations.
- (b) Light and heavy crude differentials represent the difference between WTI benchmark prices and western Canadian prices for light and heavy crudes.
- (c) The 2-1-1 crack spread is an indicator of the refining margin generated by converting two barrels of crude oil into one barrel of gasoline and one barrel of diesel.

The demand for crude oil, natural gas, petroleum products and petrochemical products are generally linked closely with economic growth. 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. Although price levels of crude oil and natural gas may rise and fall significantly over the short to medium term due to global economic conditions, political events, decisions by OPEC, governments 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 its major investments over a range of prices.

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 the company's 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. Where such intersegment sales take place, they are the result of efficiencies and competitive advantages from integrated business segments and refinery and chemical complexes. About 59 percent of the company's intersegment sales are crude oil produced by the Upstream and sold to the Downstream. Other intersegment sales include those between refineries and the chemical plant related to raw materials, feedstocks and finished products. All intersegment sales are at market based prices.

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.

### 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 exchange rates. Imperial uses derivative instruments to offset exposures associated with hydrocarbon prices that arise from existing assets, liabilities and forecasted transactions. The company's derivatives are not accounted for under hedge accounting. Credit risk associated with the company's derivative position is mitigated by several factors, including the use of derivative clearing exchanges and the quality of and financial limits placed on derivative counterparties. The company believes there are no material market or credit risks to the company's financial position, results of operations or liquidity as a result of the derivatives described in note 7 on page 83. The company maintains a system of controls that includes 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 (U.S. GAAP). U.S. 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 business model involving exploration for, and production of, crude oil and natural gas and manufacture, trade, transport and sale of crude oil, natural gas, petroleum products, petrochemicals and a variety of specialty products. 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 66.

### Oil and gas reserves

Evaluations of oil and natural 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.

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 qualified 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.

Oil and natural gas reserves include both proved and unproved reserves.

- Proved oil and natural gas reserves are determined in accordance with U.S. Securities and Exchange Commission (SEC) requirements. Proved reserves are those quantities of oil and natural gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible under existing economic and operating conditions and government regulations. Proved reserves are determined using the average of first-of-month oil and natural gas prices during the reporting year.

Proved reserves can be further subdivided into developed and undeveloped reserves. Proved developed reserves include amounts which are expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves include amounts expected to be recovered from new wells on undrilled proved acreage or from existing wells where a relatively major expenditure is required for completion. Proved undeveloped reserves are recognized only if a development plan has been adopted indicating that the reserves are scheduled to be drilled within five years, unless specific circumstances support a longer period of time.

The percentage of proved developed reserves was 89 percent of total proved reserves at year-end 2018, an increase from 71 percent in 2017. 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 natural gas prices.

- Unproved reserves are quantities of oil and natural gas 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.

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 the average of first-of-the-month 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.

At year-end 2016, downward revisions of proved developed and undeveloped bitumen reserves were a result of low prices. The entire 2.5 billion barrels of bitumen at Kearl and approximately 0.2 billion barrels of bitumen at Cold Lake no longer qualified as proved reserves under the U.S. Securities and Exchange Commission definition of proved reserves.

At year-end 2017, an additional 0.3 billion barrels of bitumen at Kearl and Cold Lake qualified as proved reserves resulting from improved prices in the year.

As a result of improved prices in 2018, an additional 2.3 billion barrels of bitumen at Kearl qualified as proved reserves at year-end 2018.

Under the terms of certain contractual arrangements or government royalty regimes, lower prices can also increase proved reserves attributable to Imperial. The company's operating decisions and its outlook for future production volumes are not impacted by proved reserves as disclosed under the U.S. Securities and Exchange Commission (SEC) definition.

### ***Unit-of-production depreciation***

The calculation of unit-of-production depreciation is a critical accounting estimate that measures the depreciation of upstream assets. Oil and natural gas reserve quantities are used as the basis to calculate unit-of-production depreciation rates for most upstream assets. Depreciation is calculated by taking the ratio of asset cost to total proved reserves or proved developed reserves applied to the actual cost of production. The volumes produced and asset cost are known, while proved reserves are based on estimates that are subject to some variability.

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 method is used. The straight-line method is used in limited situations where the expected life of the asset does not reasonably correlate with that of the underlying reserves. For example, certain assets used in the production of oil and natural gas have a shorter life than the reserves, and as such, the company uses straight-line depreciation to ensure the asset is fully depreciated by the end of its useful life.

To the extent that proved reserves for a property are substantially de-booked and that property continues to produce such that the resulting depreciation charge does not result in an equitable allocation of cost over the expected life, assets will be depreciated using a unit-of-production method based on reserves determined at the most recent SEC price which results in a more meaningful quantity of proved reserves, appropriately adjusted for production and technical changes. This approach was applied in 2017 and 2018, with the corresponding effect on depreciation expense immaterial when compared to prior periods. In 2019, all properties have sufficient reserves at current SEC prices which will enable equitable allocation of cost over the economic lives of the Upstream assets. The effect of this approach compared to prior periods is anticipated to be immaterial.

### ***Impact of oil and gas reserves and prices and margins on testing for impairment***

The company tests assets or groups of assets for recoverability on an ongoing basis whenever events or changes in circumstances indicate the carrying amounts may not be recoverable. Among the events or changes in circumstances which could indicate that the carrying value of an asset or asset group may not be recoverable are the following:

- 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 the company's current and projected reserve volumes;
- A significant adverse change in legal factors or in the business climate that could affect the value, including a significant 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.

Asset valuation analyses performed as part of the company's asset management program and other profitability reviews assist Imperial in assessing whether events or changes in circumstances indicate the carrying amounts of any of its assets may not be recoverable.

In general, Imperial does not view temporarily low prices or margins as an indication of impairment. Management believes prices over the long-term must be sufficient to generate investments in energy supply to meet global demand. Although prices will occasionally drop significantly, industry prices over the long-term will continue to be driven by market supply and demand fundamentals. On the supply side, industry production from mature fields is declining. This is being offset by investments to generate production from new discoveries, field developments and technological and efficiency advancements. OPEC investment activities and production policies also have an impact on world oil supplies. The demand side is largely a function of general economic activities and levels of prosperity. Because the lifespans of the company's major assets are measured in decades, the value of these assets is predominantly based on long-term views of future commodity prices and production costs. During the lifespan of these major assets, the company expects that oil and gas prices will experience significant volatility, and consequently these assets will experience periods of higher earnings and periods of lower earnings, or even losses. In assessing whether the events or changes in circumstances indicate the carrying value of an asset may not be recoverable, the company considers recent periods of operating losses in the context of its longer-term view of prices. While near-term prices are subject to wide fluctuations, longer term price views are more stable and meaningful for purposes of assessing future cash flows.

When the industry experiences a prolonged and deep reduction in commodity prices, the market supply and demand conditions may result in changes to the company's long-term price or margin assumptions it uses for its capital investment decisions. To the extent those changes result in a significant reduction to its long-term oil prices or natural gas prices or margin ranges, the company may consider that situation, in conjunction with other events or changes in circumstances such as a history of operating losses, as an indicator of potential impairment for certain assets.

In the upstream, the standardized measure of discounted cash flows included in the "Supplemental information on oil and gas exploration and production activities" is required to use prices based on the yearly average of first-of-month prices. These prices represent discrete points in time and could be higher or lower than the company's long-term price assumptions which are used for impairment assessments. The company believes the standardized measure does not provide a reliable estimate of the expected future cash flows to be obtained from the development and production of its oil and gas properties or of the value of its oil and gas reserves and therefore does not consider it relevant in determining whether events or changes in circumstances indicate the need for an impairment assessment.

If events or changes in circumstances indicate that the carrying value of an asset may not be recoverable, the company estimates the future undiscounted cash flows of the affected properties to judge the recoverability of carrying amounts. In performing this assessment, 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. Cash flows used in recoverability assessments are based on the company's assumptions which are developed in the annual planning and budgeting process, and are consistent with the criteria management uses to evaluate investment opportunities. These evaluations make use of the company's assumptions of future capital allocations, crude oil and natural gas commodity prices, refining and chemical margins, volumes, costs, foreign currency exchange rates and inflation rates. Volumes are based on projected field and facility production profiles, throughput, or sales. Where unproved reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the evaluation. Cash flow estimates for impairment testing exclude the effects of derivative instruments.

An asset group is impaired if its estimated future undiscounted cash flows are less than the asset group's carrying value. Impairments are measured by the amount by which the carrying value exceeds fair value. Fair value is based on market prices if an active market exists for the asset group or discounted cash flows using a discount rate commensurate with the risk. Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs would be 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.

**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 5.0 percent used in 2018, compares to actual returns of 8.2 percent and 6.6 percent achieved over the last 10- and 20-year periods respectively, ending December 31, 2018. 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 5 to the consolidated financial statements starting on page 76. 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 1 percent of total expenses in 2018.

**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 2018, the obligations were discounted at 6 percent and the accretion expense was \$85 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 16 to the consolidated financial statements on page 89.

**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 4 to the consolidated financial statements starting on page 75.

**Recently issued accounting standards**

Effective January 1, 2019, Imperial adopted the Financial Accounting Standards Board's standard, *Leases (Topic 842)*, as amended. The standard requires all leases to be recorded on the balance sheet as a right of use asset and a lease liability. The company used a transition method that applies the new lease standard at January 1, 2019, and recognizes any cumulative effect adjustments to the opening balance of 2019 retained earnings. Imperial applied a policy election to exclude short-term leases from balance sheet recognition and also elected certain practical expedients at adoption. As permitted under these expedients the company did not reassess whether existing contracts are or contain leases, the lease classification for any existing leases, initial direct costs for any existing lease and whether existing land easements and rights of way, that were not previously accounted for as leases, are or contain a lease. At January 1, 2019, the operating lease liability and right of use asset is estimated to be in the range of \$300 million. The cumulative effect adjustment is expected to be de minimis.