CONOCOPHILLIPS
Form 10-K
February 21, 2017
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2016

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

[x] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)

OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended **December 31, 2016**

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)

OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ________________ to ________________

Commission file number: **001-32395**

ConocoPhillips

(Exact name of registrant as specified in its charter)

Delaware	**01-0562944**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*

600 North Dairy Ashford

Houston, TX 77079

(Address of principal executive offices) (Zip Code)

Registrant s telephone number, including area code: **281-293-1000**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	**Name of each exchange on which registered**
Common Stock, $.01 Par Value	New York Stock Exchange
6.65% Debentures due July 15, 2018	New York Stock Exchange
7% Debentures due 2029	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

[x] Yes [ ] No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

[ ] Yes [x] No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

[x] Yes [ ] No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

[x] Yes [ ] No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer [x] Accelerated filer [ ] Non-accelerated filer [ ] Smaller reporting company [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).
[ ] Yes [x] No

The aggregate market value of common stock held by non-affiliates of the registrant on June 30, 2016, the last business day of the registrant s most recently completed second fiscal quarter, based on the closing price on that date of $43.60, was $54.0 billion.

The registrant had 1,235,832,469 shares of common stock outstanding at January 31, 2017.

Documents incorporated by reference:

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 16, 2017 (Part III)

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PART I

Unless otherwise indicated, the company, we, our, us and ConocoPhillips are used in this report to refer to the businesses of ConocoPhillips and its consolidated subsidiaries. Items 1 and 2 Business and Properties, contain forward-looking statements including, without limitation, statements relating to our plans, strategies, objectives, expectations and intentions that are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. The words anticipate, estimate, believe, budget, continue, could, intend, may, pl predict, seek, should, will, would, expect, objective, projection, forecast, goal, guidance, outl similar expressions identify forward-looking statements. The company does not undertake to update, revise or correct any forward-looking information unless required to do so under the federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with the company s disclosures under the heading CAUTIONARY STATEMENT FOR THE PURPOSES OF THE SAFE HARBOR PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995, beginning on page 72.

Items 1 and 2. BUSINESS AND PROPERTIES

CORPORATE STRUCTURE

ConocoPhillips is the world s largest independent exploration and production (E&P) company, based on proved reserves and production of liquids and natural gas. ConocoPhillips was incorporated in the state of Delaware on November 16, 2001, in connection with, and in anticipation of, the merger between Conoco Inc. and Phillips Petroleum Company. The merger between Conoco and Phillips was consummated on August 30, 2002.

In April 2012, the ConocoPhillips Board of Directors approved the separation of our downstream business into an independent, publicly traded energy company, Phillips 66. Each ConocoPhillips stockholder received one share of Phillips 66 stock for every two shares of ConocoPhillips stock held at the close of business on the record date of April 16, 2012. The separation was completed on April 30, 2012, and activities related to Phillips 66 have been treated as discontinued operations for all periods prior to the separation.

In 2012, we agreed to sell our interest in the North Caspian Sea Production Sharing Agreement (Kashagan) and our Nigeria and Algeria businesses (collectively, the Disposition Group). We sold our Nigeria business in the third quarter of 2014, and we sold Kashagan and our Algeria business in the fourth quarter of 2013. Results for the Disposition Group have been reported as discontinued operations in the applicable periods presented. For additional information on the sale of our Nigeria business, see Note 3 Discontinued Operations, in the Notes to Consolidated Financial Statements.

Headquartered in Houston, Texas, we have operations and activities in 17 countries. Our key focus areas include safely operating producing assets, executing major developments and exploring for new resources in promising areas. Our portfolio includes resource-rich North American tight oil and oil sands assets; lower-risk conventional assets in North America, Europe, Asia and Australia; several liquefied natural gas (LNG) developments; and an inventory of global conventional and unconventional exploration prospects.

At December 31, 2016, ConocoPhillips employed approximately 13,300 people worldwide.

In November 2016, we announced our planned $5 billion to $8 billion asset disposition program, primarily associated with North American natural gas assets, over the next two years. For additional information on asset sales, see the Outlook section of Management s Discussion and Analysis of Financial Condition and Results of Operations, and Note 6 Assets Held for Sale or Sold, in the Notes to Consolidated Financial Statements.

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SEGMENT AND GEOGRAPHIC INFORMATION

For operating segment and geographic information, see Note 24 Segment Disclosures and Related Information, in the Notes to Consolidated Financial Statements, which is incorporated herein by reference.

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and natural gas liquids on a worldwide basis. At December 31, 2016, our operations were producing in the United States, Norway, the United Kingdom, Canada, Australia, Timor-Leste, Indonesia, China, Malaysia, Qatar and Libya.

The information listed below appears in the Oil and Gas Operations disclosures following the Notes to Consolidated Financial Statements and is incorporated herein by reference:

- Proved worldwide crude oil, natural gas liquids, natural gas and bitumen reserves.
- Net production of crude oil, natural gas liquids, natural gas and bitumen.
- Average sales prices of crude oil, natural gas liquids, natural gas and bitumen.
- Average production costs per barrel of oil equivalent (BOE).
- Net wells completed, wells in progress and productive wells.
- Developed and undeveloped acreage.

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The following table is a summary of the proved reserves information included in the Oil and Gas Operations disclosures following the Notes to Consolidated Financial Statements. Approximately 81 percent of our proved reserves are located in politically stable countries that belong to the Organization for Economic Cooperation and Development. Natural gas reserves are converted to BOE based on a 6:1 ratio: six thousand cubic feet (MCF) of natural gas converts to one BOE. See Management s Discussion and Analysis of Financial Condition and Results of Operations for a discussion of factors that will enhance the understanding of the following summary reserves table.

	Millions of Barrels of Oil Equivalent		
Net Proved Reserves at December 31	**2016**	2015	2014
Crude oil			
Consolidated operations	**2,047**	2,270	2,605
Equity affiliates	**88**	93	103
Total Crude Oil	**2,135**	2,363	2,708
Natural gas liquids			
Consolidated operations	**457**	508	662
Equity affiliates	**47**	50	53
Total Natural Gas Liquids	**504**	558	715
Natural gas			
Consolidated operations	**1,807**	1,988	2,543
Equity affiliates	**730**	878	874
Total Natural Gas	**2,537**	2,866	3,417
Bitumen			
Consolidated operations	**159**	687	598
Equity affiliates	**1,089**	1,706	1,468
Total Bitumen	**1,248**	2,393	2,066
Total consolidated operations	**4,470**	5,453	6,408
Total equity affiliates	**1,954**	2,727	2,498
Total company	**6,424**	8,180	8,906

Total production, including Libya, of 1,569 thousand barrels of oil equivalent per day (MBOED) decreased 1 percent in 2016 compared with 2015. The decrease in total average production primarily resulted from normal field decline and the loss of 72 MBOED mainly attributable to the 2015 dispositions of several non-core assets in the Lower 48, western Canada and the sale of our interest in the Polar Lights Company in Russia. The decrease in production was partly offset by additional production from major developments, including tight oil plays in the Lower 48; APLNG in

Australia; the Western North Slope in Alaska; the Kebabangan gas field in Malaysia; and the Greater Ekofisk Area in Norway. Improved drilling and well performance in Canada, Norway, the Lower 48, and China, as well as lower unplanned downtime in the Lower 48 also partly offset the decrease in production. Assets sold in 2016 produced 27 MBOED and 36 MBOED in 2016 and 2015, respectively.

Our worldwide annual average realized price was $28.35 per BOE in 2016, a decrease of 17 percent compared with $34.34 per BOE in 2015, which reflected lower average realized prices across all commodities. Our worldwide annual average crude oil price decreased 15 percent in 2016, from $48.26 per barrel in 2015 to $40.86 per barrel in 2016. Additionally, our worldwide annual average natural gas liquids prices decreased 6 percent, from $17.79 per barrel in 2015 to $16.68 per barrel in 2016. Our worldwide annual average natural gas price decreased 24 percent, from $3.96 per MCF in 2015 to $3.00 per MCF in 2016. Average annual bitumen prices also decreased 18 percent, from $18.72 per barrel in 2015 to $15.27 per barrel in 2016.

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ALASKA

The Alaska segment primarily explores for, produces, transports and markets crude oil, natural gas liquids, natural gas and LNG. We are the largest crude oil producer in Alaska and have major ownership interests in two of North America s largest oil fields located on Alaska s North Slope: Prudhoe Bay and Kuparuk. We also have a significant operating interest in the Alpine Field, located on the Western North Slope. Additionally, we are one of Alaska s largest owners of state, federal and fee exploration leases, with approximately 0.5 million net undeveloped acres at year-end 2016. Following the impairment of our Chukchi Sea leases in the fourth quarter of 2015, we surrendered 0.3 million acres in the Chukchi Sea in May 2016. In 2016, Alaska operations contributed 19 percent of our worldwide liquids production and less than 1 percent of our natural gas production.

				2016	
	Interest	Operator	Liquids MBD*	Natural Gas MMCFD**	Total MBOED
Average Daily Net Production					
Greater Prudhoe Area	36.1%	BP	88	9	90
Greater Kuparuk Area	52.2 55.5	ConocoPhillips	50	-	50
Western North Slope	78.0	ConocoPhillips	37	1	37
Cook Inlet Area	33.3-100.0	ConocoPhillips	-	15	2
Total Alaska			175	25	179

**Thousands of barrels per day.*

***Millions of cubic feet per day.*

Greater Prudhoe Area

The Greater Prudhoe Area includes the Prudhoe Bay Field and five satellite fields, as well as the Greater Point McIntyre Area fields. Prudhoe Bay, the largest oil field on Alaska s North Slope, is the site of a large waterflood and enhanced oil recovery operation, as well as a gas plant which processes natural gas to recover natural gas liquids before reinjection into the reservoir. Prudhoe Bay s satellites are Aurora, Borealis, Polaris, Midnight Sun and Orion, while the Point McIntyre, Niakuk, Raven, Lisburne and North Prudhoe Bay State fields are part of the Greater Point McIntyre Area.

Greater Kuparuk Area

We operate the Greater Kuparuk Area, which consists of the Kuparuk Field and four satellite fields: Tarn, Tabasco, Meltwater and West Sak. Kuparuk is located 40 miles west of Prudhoe Bay. Field installations include three central production facilities which separate oil, natural gas and water, as well as a separate seawater treatment plant. Development drilling at Kuparuk consists of rotary-drilled wells and horizontal multi-laterals from existing well bores utilizing coiled-tubing drilling.

Drill Site 2S, in the southwestern area of the Kuparuk Field, was sanctioned in October 2014. First oil was achieved in October 2015, and completion of the first phase of the project was achieved in 2016.

The 1H Northeast West Sak (NEWS) oil development targeting the West Sak reservoir in the Kuparuk River Unit, was sanctioned in March 2015. First production is anticipated in 2018.

Western North Slope

On the Western North Slope, we operate the Colville River Unit, which includes the Alpine Field and three satellite fields: Nanuq, Fiord and Qannik. Alpine is located 34 miles west of Kuparuk. In October 2015, first oil was achieved at Alpine West CD5, a new drill site which extends the Alpine reservoir west into the National Petroleum Reserve-Alaska (NPR-A). During the year, we approved drilling an additional 18 wells, bringing CD5 up to its full permit capacity.

The Greater Mooses Tooth Unit, the first unit established entirely within the NPR-A, was formed in 2008. In 2017, we began construction in the unit, which is currently planned to have two drill sites; Greater Mooses Tooth #1 and #2, with expected first oil in 2018 and 2020, respectively.

Cook Inlet Area

We have a 100 percent interest and are the operator of the Kenai LNG Facility in the Cook Inlet Area. The Kenai LNG Facility includes a 1.6 million-tons-per-year capacity plant, as well as docking and loading facilities for LNG tankers. LNG from the plant has historically been transported and sold to utility companies in Japan. In February 2016, our export license was renewed for an additional two years. However, there was no LNG export program in 2016 due to market conditions. We are currently marketing this facility.

In April and October 2016, we sold our interests in the Beluga River Unit natural gas field and the North Cook Inlet Unit, respectively, both in the Cook Inlet Area. The full-year 2016 production from the assets sold was 2 MBOED.

Point Thomson

We own a 4.9 percent interest in the Point Thomson Unit, which is located approximately 60 miles east of Prudhoe Bay. An Initial Production System (IPS) was brought online in April 2016, and achieved full production of 400 BOED net of condensate in December.

Alaska North Slope Gas

In 2016, we, along with affiliates of Exxon Mobil Corporation, BP p.l.c. and Alaska Gasline Development Corporation (AGDC), a state-owned corporation (collectively, the AKLNG co-venturers), completed preliminary front-end engineering and design (pre-FEED) technical work for a potential LNG project which would liquefy and export natural gas from Alaska s North Slope and deliver it to market. In September 2016, we, along with the affiliates of ExxonMobil and BP, indicated our intention not to progress into the next phase of the project due to changes in the economic environment. Given AGDC s intention to continue efforts to advance a North Slope Gas project, the AKLNG co-venturers executed certain agreements to enhance AGDC s ability to do so. We remain supportive of AGDC s efforts to progress a project.

Exploration

In 2016, we drilled three exploration wells in the NPR-A. Two of these wells, Tinmiaq 2 and 6, form the Willow discovery, which is located in the northeast portion of the NPR-A. The third exploration well was recorded to dry hole expense in the fourth quarter of 2016. Appraisal of the Willow discovery commenced in January 2017 with the acquisition of 3-D seismic. In a follow-up to the Willow discovery, we were successful in December s state and federal lease sales on the Western North Slope, where we were the high bidder on 139 tracts for a total of 737,252 gross acres.

Transportation

We transport the petroleum liquids produced on the North Slope to south central Alaska through an 800-mile pipeline that is part of Trans-Alaska Pipeline System (TAPS). We have a 29.1 percent ownership interest in TAPS, and we also have ownership interests in the Alpine, Kuparuk and Oliktok pipelines on the North Slope.

Our wholly-owned subsidiary, Polar Tankers, Inc., manages the marine transportation of our North Slope production, using five company-owned, double-hulled tankers, and charters third-party vessels as necessary. The tankers deliver oil from Valdez, Alaska, primarily to refineries on the west coast of the United States.

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LOWER 48

The Lower 48 segment consists of operations located in the U.S. Lower 48 states and the Gulf of Mexico. The Lower 48 business is organized within three regions covering the Gulf Coast, Mid-Continent and Rockies. As a result of tight oil opportunities, we have directed our investments toward certain shorter cycle time, low cost-of-supply plays. In July 2015, we announced our plan to reduce future deepwater exploration spending. We have subsequently terminated our Gulf of Mexico deepwater drillship contracts. We hold 12.4 million net onshore and offshore acres in the Lower 48. In 2016, the Lower 48 contributed 30 percent of our worldwide liquids production and 32 percent of our natural gas production.

				2016	
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Eagle Ford	Various%	Various	129	193	161
Gulf of Mexico	Various	Various	15	13	17
Gulf Coast Other	Various	Various	5	18	8
Total Gulf Coast			149	224	186
Permian	Various	Various	42	130	64
Barnett	Various	Various	5	36	11
Anadarko Basin	Various	Various	5	102	22
Total Mid-Continent			52	268	97
Bakken	Various	Various	53	50	61
Wyoming/Uinta	Various	Various	-	89	15
Niobrara	Various	Various	2	4	3
San Juan	Various	Various	27	584	124
Total Rockies			82	727	203
Total U.S. Lower 48			283	1,219	486

Onshore

We hold 12.3 million net acres of onshore conventional and unconventional acreage in the Lower 48, the majority of which is either held by production or owned by the company. Our unconventional holdings total approximately 2.6 million net acres in the following areas:

900,000 net acres in the San Juan Basin, located in northwestern New Mexico and southwestern Colorado.

620,000 net acres in the Bakken, located in North Dakota and eastern Montana.
213,000 net acres in the Eagle Ford, located in South Texas.
104,000 net acres in the Niobrara, located in northeastern Colorado.
123,500 net acres in the Permian, located in West Texas and southeastern New Mexico.
68,000 net acres in the Barnett, located in north central Texas.
591,000 net acres in other unconventional exploration plays.

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The majority of our 2016 onshore production originated from the Eagle Ford, San Juan, Permian and Bakken. Onshore activities in 2016 were centered mostly on continued development of emerging and existing assets, with an emphasis on areas with low cost of supply, particularly in growing unconventional plays. The 2016 drilling activity levels declined relative to 2015 due to reduced capital spending in the low commodity price environment. Our major focus areas in 2016 included the following:

- Eagle Ford The Eagle Ford scaled down full-field development in 2016. We operated three rigs on average in 2016, resulting in 69 operated wells drilled and 80 operated wells brought online. Production decreased 7 percent in 2016 compared with 2015, and reached a net peak of 176 MBOED, compared with 190 MBOED in 2015.
- Bakken We operated two rigs on average throughout the year in the Bakken. We continued our pad drilling efficiency, drilling 34 operated wells during the year and bringing 37 operated wells online. We achieved net peak production of 72 MBOED in 2016, compared with 80 MBOED in 2015.
- San Juan Basin The San Juan Basin includes significant conventional gas production, which yields approximately 20 percent natural gas liquids, as well as the majority of our U.S. coalbed methane (CBM) production. We hold approximately 1.3 million net acres of oil and gas leases by production in San Juan, including approximately 900,000 net unconventional acres of lease rights.
- Permian Basin The Permian Basin is an area where we are leveraging our conventional legacy position by utilizing new technology to improve the ultimate recovery and value from these fields. This technology should also identify new, unconventional plays across the region. We hold approximately 1.0 million net acres in the Permian, which includes 123,500 net unconventional acres. The Permian Basin produced 64 MBOED in 2016, which includes 15 MBOED of unconventional production.

In 2015, we completed the sale of certain non-core assets in East Texas and North Louisiana and South Texas. Production from the assets sold was 33 MBOED, approximately 6 percent of the total Lower 48 segment production in 2015. In the second quarter of 2016, we completed the sale of certain non-core assets in the Delaware basin. The full-year 2016 production from the assets sold was 1 MBOED.

Gulf of Mexico

At year-end 2016, our portfolio of producing properties in the Gulf of Mexico primarily consisted of one operated field and three fields operated by co-venturers, including:

- 75 percent operated working interest in the Magnolia Field in Garden Banks Blocks 783 and 784.
- 15.9 percent nonoperated working interest in the unitized Ursa Field located in the Mississippi Canyon Area.
- 15.9 percent nonoperated working interest in the Princess Field, a northern subsalt extension of the Ursa Field.
- 12.4 percent nonoperated working interest in the unitized K2 Field, comprised of seven blocks in the Green Canyon Area.

Exploration

Conventional Exploration

At December 31, 2016, we held approximately 73,000 net acres in the deepwater Gulf of Mexico.

We own a 30 percent nonoperated working interest in the Shenandoah discovery, which was announced in 2009, and had a net book value of $286 million at December 31, 2016. Appraisal drilling continued in 2016 with the fifth Shenandoah well reaching total depth in the third quarter. In February 2017, the sixth Shenandoah well, Shenandoah WR52-3, reached total depth. Drilling of a sidetrack well from Shenandoah WR52-3 also commenced in February.

As part of our continued phased exit from deepwater exploration, in 2016, we decided not to pursue further development of the nonoperated Gibson and Tiber wells, collectively known as the Tigris project. Accordingly, we recorded dry hole expenses for previously suspended Gibson and Tiber wells, and impairment charges for the applicable leaseholds.

We recorded dry hole and associated leasehold impairment expense in the first quarter of 2016 for the Melmar exploration well.

Unconventional Exploration

In 2016, we drilled a total of five operated unconventional wells, primarily in the Eagle Ford. Our onshore focus areas include the Permian in the Delaware Basin and the Niobrara in the Denver-Julesburg Basin, as well as several emerging plays. We continue to assess and appraise these and other unconventional opportunities.

Facilities

Freeport LNG Terminal

In July 2013, we agreed with Freeport LNG Development, L.P. to terminate our long-term agreement to use 0.9 billion cubic feet per day of regasification capacity at Freeport s 1.5 billion cubic-feet-per-day LNG receiving terminal in Quintana, Texas. The termination agreement conditions were satisfied in 2014. Our terminal regasification capacity was reduced to zero on July 1, 2016. For additional information, see Note 7 Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements.

Golden Pass LNG Terminal

We have a 12.4 percent ownership interest in the Golden Pass LNG Terminal and affiliated Golden Pass Pipeline, with a combined net book value of approximately $260 million at December 31, 2016. It is located adjacent to the Sabine-Neches Industrial Ship Channel northwest of Sabine Pass, Texas. The terminal became commercially operational in May 2011. We hold terminal and pipeline capacity for the receipt, storage and regasification of the LNG purchased from Qatar Liquefied Gas Company Limited (3) (QG3) and the transportation of regasified LNG to interconnect with major interstate natural gas pipelines. Utilization of the terminal has been and is expected to be limited, as market conditions currently favor the flow of LNG to European and Asian markets. As a result, we are evaluating opportunities to optimize the value of the terminal facilities.

Greater Northern Iron Ore Properties Trust

We held the reversionary interest in the Greater Northern Iron Ore Properties trust (the Trust), a grantor trust that owns mineral and surface interests in the Mesabi Iron Range in northeastern Minnesota and certain other personal property. Pursuant to the terms of the Trust Agreement, the Trust terminated on April 6, 2015. On November 3, 2016, the end of the wind-down period, documents memorializing our ownership of certain Trust property, including all the Trust s mineral properties and active leases, were delivered to us. The $144 million fair value of the Trust s net assets transferred to us and a gain of $88 million were both recorded in the fourth quarter of 2016. On December 8, 2016, we closed on a sale of the Trust s and certain other assets for net proceeds of $148 million. For additional information, see Note 6 Assets Held for Sale or Sold, in the Notes to Consolidated Financial Statements.

Other

San Juan Gas Plant We operate and own a 50 percent interest in the San Juan Gas Plant, a 550 million cubic-feet-per-day capacity natural gas processing plant in Bloomfield, New Mexico.
Lost Cabin Gas Plant We operate and own a 46 percent interest in the Lost Cabin Gas Plant, a 312 million cubic-feet-per-day capacity natural gas processing facility in Lysite, Wyoming.
Helena Condensate Processing Facility We operate and own the Helena Condensate Processing Facility, a 90,000 barrel-per-day condensate processing plant located in Kenedy, Texas.

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Sugarloaf Condensate Processing Facility We operate and own an 87.5 percent interest in the Sugarloaf Condensate Processing Facility, a 30,000 barrel-per-day condensate processing plant located near Pawnee, Texas.

Bordovsky Condensate Processing Facility We operate and own the Bordovsky Condensate Processing Facility, a 15,000 barrel-per-day condensate processing plant located in Kenedy, Texas.

CANADA

Our Canadian operations mainly consist of natural gas fields in western Canada and oil sands developments in the Athabasca Region of northeastern Alberta. In 2016, operations in Canada contributed 23 percent of our worldwide liquids production and 14 percent of our natural gas production.

			2016			
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Bitumen MBD	Total MBOED
Average Daily Net Production						
Western Canada	Various%	Various	30	524	-	117
Surmont	50.0	ConocoPhillips	-	-	35	35
Foster Creek	50.0	Cenovus	-	-	70	70
Christina Lake	50.0	Cenovus	-	-	78	78
Total Canada			30	524	183	300

Western Canada

Our operations in western Canada extend across Alberta and British Columbia. We operate or have ownership interests in approximately 30 natural gas processing plants in the region, and, as of December 31, 2016, held leasehold rights in 3.1 million net acres in western Canada. Our investments in 2016 were focused mainly on opportunities in the following three core development areas:

Deep Basin We hold leasehold rights in 1.3 million net acres in the Deep Basin, located in northwest Alberta and northeast British Columbia. In 2016, Deep Basin achieved average net production of 46 MBOED, and we drilled eight horizontal wells.

Kaybob-Edson We hold leasehold rights in 0.7 million net acres in the Kaybob-Edson Area, located south of the Deep Basin in west central Alberta. Net production for Kaybob-Edson averaged 37 MBOED in 2016, and we drilled 15 horizontal wells.

Clearwater We hold leasehold rights in 0.8 million net acres in the Clearwater area, located in west central Alberta, south of Kaybob-Edson. In 2016, average net production for Clearwater was 34 MBOED.

Oil Sands

Our bitumen resources in Canada are produced via an enhanced thermal oil recovery method called steam-assisted gravity drainage (SAGD), whereby steam is injected into the reservoir, effectively liquefying the heavy bitumen, which is recovered and pumped to the surface for further processing. We hold approximately 0.9 million net acres of land in the Athabasca Region of northeastern Alberta.

Surmont The Surmont oil sands leases are located approximately 35 miles south of Fort McMurray, Alberta. Surmont is a 50/50 joint venture with Total S.A. The Surmont 2 project achieved first production in 2015, and production continued to ramp up in 2016. Net production at Surmont increased 21 MBOED in 2016.

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FCCL FCCL Partnership, a Canadian upstream general partnership, is a 50/50 business venture with Cenovus Energy Inc. FCCL s assets are operated by Cenovus and include the Foster Creek, Christina Lake and Narrows Lake SAGD bitumen developments. FCCL continues to progress development plans for each of these assets.

¡ *Foster Creek*

Foster Creek is located approximately 200 miles northeast of Edmonton, Alberta. With the achievement of first production at Phase G in 2016, there are seven producing phases at Foster Creek, Phases A through G. Net production at Foster Creek increased approximately 5 MBOED in 2016.

¡ *Christina Lake*

Christina Lake is located approximately 75 miles south of Fort McMurray, Alberta. Christina Lake Phase F achieved first production in 2016. There are now six producing phases at Christina Lake. Construction on Phase G, which has a design capacity of 50 MBOED gross, will resume in 2017 after being deferred since 2014. First production from Phase G is expected in the second half of 2019. Net production at Christina Lake increased approximately 6 MBOED in 2016.

¡ *Narrows Lake*

Narrows Lake Phase A, was sanctioned in late 2012 and is expected to have 45 MBOED of gross design production capacity. Construction has been deferred, however, we expect to progress engineering activity in 2017.

Exploration

We hold exploration acreage in four areas of Canada: onshore western Canada, offshore eastern Canada, the Mackenzie Delta/Beaufort Sea Region and the Arctic Islands. Our primary exploration focus is on unconventional plays in western Canada.

Conventional Exploration

During 2014, we entered into a farm-in agreement to acquire a 30 percent nonoperated interest in six exploration licenses covering approximately five million gross acres in the deepwater Shelburne Basin, offshore Nova Scotia. In 2016, we recorded dry hole expenses associated with two wells in the Shelburne Basin, and an impairment charge for the undeveloped leasehold costs. Other related costs have been accrued.

In August 2016, we sold our Newfoundland Partnership, which held a 30 percent nonoperated interest in the exploration license in the Flemish Pass Basin, offshore Newfoundland.

Unconventional Exploration

We hold approximately 0.7 million net acres in the emerging Montney, Muskwa, Duvernay and Canol unconventional plays in Alberta, northeastern British Columbia and the Northwest Territories. During 2016, we completed a lease swap for unproved lands in the Blueberry area and continued to drill exploration and appraisal wells in the Montney play, which extends from British Columbia into Alberta. Full-year 2016 production from the assets swapped was 5 MBOED. For additional information, see Note 6 Assets Held for Sale or Sold, in the Notes to Consolidated Financial Statements.

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EUROPE AND NORTH AFRICA

The Europe and North Africa segment consists of operations and exploration activities in Norway, the United Kingdom and Libya. In 2016, operations in Europe and North Africa contributed 14 percent of our worldwide liquids production and 12 percent of natural gas production.

Norway

			2016		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Greater Ekofisk Area	35.1%	ConocoPhillips	54	48	62
Alvheim	20.0	Aker BP	11	10	13
Heidrun	24.0	Statoil	15	15	17
Other	Various	Statoil	16	81	29
Total Norway			96	154	121

The Greater Ekofisk Area is located approximately 200 miles offshore Stavanger, Norway, in the North Sea, and comprises three producing fields: Ekofisk, Eldfisk and Embla. Crude oil is exported to Teesside, England, and the natural gas is exported to Emden, Germany. Ekofisk South achieved first production in 2013, while Eldfisk II achieved startup in January 2015. Continued development drilling in the Greater Ekofisk Area will contribute additional production over the coming years, as additional wells come online.

The Alvheim development is located in the northern part of the North Sea and consists of a floating production, storage and offloading (FPSO) vessel and subsea installations. Produced crude oil is exported via shuttle tankers, and natural gas is transported to the Scottish Area Gas Evacuation (SAGE) terminal at St. Fergus, Scotland, through the SAGE pipeline.

The Heidrun Field is located in the Norwegian Sea. Produced crude oil is stored in a floating storage unit and exported via shuttle tankers. Part of the natural gas is currently injected into the reservoir for optimization of crude oil production, some gas is exported to the Continent via gas processing terminals in Norway, while the remainder is exported for use as feedstock in a methanol plant in Norway, in which we own an 18 percent interest.

We also have varying ownership interests in five other producing fields in the Norway sector of the North Sea and in the Norwegian Sea, as well as the Aasta Hansteen development. The operator is targeting first gas for Aasta Hansteen by late 2018.

Exploration

We participated in two nonoperated exploration wells in the Oseberg and Alvheim areas. Both wells were discoveries and are currently undergoing evaluation. We were awarded three licenses in 2016, including the PL845 and PL782SB, both with interests of 40 percent, and PL859, which has a 15 percent interest.

Transportation

We own a 35.1 percent interest in the Norpipe Oil Pipeline System, a 220-mile pipeline which carries crude oil from Ekofisk to a crude oil stabilization and natural gas liquids processing facility in Teesside, England.

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United Kingdom

				2016	
				Natural	
	Interest	Operator	Liquids MBD	Gas MMCFD	Total MBOED
Average Daily Net Production					
Britannia	58.7%	ConocoPhillips	4	77	17
Britannia Satellites	26.3 83.5*	ConocoPhillips	12	72	24
J-Area	32.5 36.5	ConocoPhillips	10	60	20
Southern North Sea	Various	ConocoPhillips	-	49	8
East Irish Sea	100.0	HRL	-	42	7
Other	Various	Various	5	5	6
Total United Kingdom			31	305	82

** Includes the Chevron-operated Alder field, ConocoPhillips equity 26.3%.*

Britannia is one of the largest natural gas and condensate fields in the North Sea. We assumed operatorship of Britannia in August 2015, following the acquisition of third party equity in Britannia Operator Limited, which is now wholly owned by ConocoPhillips. Condensate is delivered through the Forties Pipeline to an oil stabilization and processing plant near the Grangemouth Refinery in Scotland, while natural gas is transported through Britannia s line to St. Fergus, Scotland. The Britannia satellite fields, Callanish, Brodgar, Enochdhu and Alder, produce via subsea manifolds and pipelines linked to the Britannia platform. Project startups for the Brodgar H3 susbsea well, and Enochdhu, a single well tie back to Callanish, were achieved in 2015. First gas was achieved from Alder, a single well tie back to Britannia, in the fourth quarter of 2016.

The J-Area consists of the Judy/Joanne, Jade and Jasmine fields, located in the U.K. Central North Sea. The Jasmine Field is a high-pressure, high-temperature gas condensate reservoir located approximately six miles west of the Judy Platform. The development includes a 24-slot wellhead platform with a bridge-linked accommodation and utilities platform, a six-mile, 16-inch multi-phase pipeline bundle, and a riser and processing platform bridge-linked to the existing Judy Platform.

We have various ownership interests in several producing gas fields in the Rotliegendes and Carboniferous areas of the Southern North Sea. Decommissioning activity in the Southern North Sea is ongoing, with final production from the Viking transportation system and associated satellites achieved in early 2016. Our interests in the East Irish Sea include the Millom, Dalton and Calder fields, which are operated on our behalf by a third party.

We own a 24 percent interest in the Clair Field, located in the Atlantic Margin. Clair Ridge is the second phase of development for the Clair Field and is comprised of a 36-slot drilling and production facility with a bridge-linked accommodation and utilities platform. The new facilities will tie into existing oil and gas export pipelines to the Shetland Islands. Initial production for Clair Ridge is targeted for 2018.

Exploration

In 2016, we recorded dry hole expense for the fully-owned Temple Wood well in the Greater Britannia Area, which was permanently plugged and abandoned.

Transportation

We operate the Teesside oil and Theddlethorpe gas terminals in which we have 29.3 percent and 50 percent ownership interests, respectively. We also have a 100 percent ownership interest in the Rivers Gas Terminal, operated by a third party.

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Greenland

Exploration

In the first quarter of 2016, we completed the process to assign our participating interest in the nonoperated Avinngaq license. Additionally, our operated Qamut license expired on December 31, 2016. Our work program in Greenland is complete, pending certain approvals.

Libya

			2016		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Waha Concession	16.3%	Waha Oil Co.	2	1	2
Total Libya			2	1	2

The Waha Concession consists of multiple concessions and encompasses nearly 13 million gross acres in the Sirte Basin. Our production operations in Libya and related oil exports were interrupted in mid-2013, as a result of the shutdown of the Es Sider crude oil export terminal at the end of July 2013. The Es Sider Terminal briefly reopened in the third quarter of 2014 and production and liftings resumed temporarily; however, further disruptions occurred in December 2014, and production was shut in again. Production resumed in Libya in October 2016, with three crude liftings from Es Sider in January 2017. We expect a gradual ramp-up in activity.

ASIA PACIFIC AND MIDDLE EAST

The Asia Pacific and Middle East segment has exploration and production operations in China, Indonesia, Malaysia and Australia; producing operations in Qatar and Timor-Leste; and exploration activities in Brunei. In 2016, operations in the Asia Pacific and Middle East segment contributed 14 percent of our worldwide liquids production and 42 percent of natural gas production.

Australia and Timor Sea

			2016		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED

Average Daily Net Production					
Australia Pacific LNG	37.5%	ConocoPhillips/ Origin Energy	-	531	89
Bayu-Undan	56.9	ConocoPhillips	13	254	55
Athena/Perseus	50.0	ExxonMobil	-	35	6
Total Australia and Timor Sea			13	820	150

Australia Pacific LNG

Australia Pacific LNG Pty Ltd (APLNG), our joint venture with Origin Energy Limited and China Petrochemical Corporation (Sinopec), is focused on producing CBM from the Bowen and Surat basins in Queensland, Australia, and converting the coalbed methane into LNG. Natural gas is sold to domestic customers, while LNG is exported. Origin operates APLNG s upstream production and pipeline system, and we operate the downstream LNG facility, located on Curtis Island near Gladstone, Queensland, as well as the LNG export sales business.

Two fully subscribed 4.5 million tonnes-per-year LNG trains have been completed. Approximately 3,900 net wells are ultimately envisioned to supply both the domestic gas market and the LNG sales contracts. The wells are supported by gathering systems, central gas processing and compression stations, water treatment facilities, and an export pipeline connecting the gas fields to the LNG facilities. The first APLNG Train 1 cargo sailed in January 2016, and LNG sales continued throughout the year. Train 1 LNG is being sold to Sinopec under a 20-year sales agreement for up to 4.3 million metric tonnes of LNG per year. APLNG Train 2 achieved first production in the third quarter of 2016. The LNG from Train 2 is being sold to Sinopec under a 20-year sales agreement for an additional 3.3 million metric tonnes of LNG per year through 2035, and Japan-based Kansai Electric Power Co., Inc. under a 20-year sales agreement for approximately 1 million metric tonnes of LNG per year.

APLNG has an $8.5 billion project finance facility, of which $8.5 billion had been drawn from the facility at December 31, 2016. In connection with the execution of the project financing, we provided a completion guarantee for our pro-rata share of the project finance facility until the project achieves financial completion. In October 2016, we reached financial completion for Train 1, which reduced our associated guarantee by 60 percent. For additional information, see Note 4 Variable Interest Entities (VIEs), Note 7 Investments, Loans and Long-Term Receivables, and Note 12 Guarantees, in the Notes to Consolidated Financial Statements.

Bayu-Undan

The Bayu-Undan gas condensate field is located in the Timor Sea Joint Petroleum Development Area between Timor-Leste and Australia. We also operate and own a 56.9 percent interest in the associated Darwin LNG Facility, located at Wickham Point, Darwin.

The Bayu-Undan natural gas recycle facility processes wet gas; separates, stores and offloads condensate, propane and butane; and re-injects dry gas back into the reservoir. In addition, a 310-mile natural gas pipeline connects the facility to the 3.5 million tonnes-per-year capacity Darwin LNG Facility. Produced natural gas is piped to the Darwin LNG Plant, where it is converted into LNG before being transported to international markets. In 2016, we sold 168 billion gross cubic feet of LNG primarily to utility customers in Japan.

The Bayu-Undan Phase Three Development consists of two standalone, subsea horizontal wells tied back to the existing drilling, production and processing platform. The first subsea horizontal well was tied back to the existing drilling, production and processing platform, and commenced production in 2015, while the second well was suspended due to insufficient deliverability to the platform. A continuation of the Bayu-Undan Phase Three Development is being evaluated with the front-end engineering and design phase approaching completion. The current premise is that drilling of one subsea and two platform wells will commence in 2018, pending internal, joint venture and regulatory approval.

ConocoPhillips served a Notice of Arbitration on the Timor-Leste Minister of Finance in October 2012 for outstanding disputes related to a series of tax assessments. The arbitration hearing was conducted in Singapore in June 2014 under the United Nations Commission on International Trade Laws (UNCITRAL) arbitration rules, pursuant to the terms of the Tax Stability Agreement with the Timor-Leste government. We reached a settlement with the Timor-Leste government on these disputes in 2016.

Athena/Perseus

The Athena production license (WA-17-L) is located offshore Western Australia and contains part of the Perseus Field, which straddles the boundary with WA-1-L, an adjoining license area. Natural gas is produced from these licenses.

Greater Sunrise

We have a 30 percent interest in the Greater Sunrise gas and condensate field located in the Timor Sea. In April 2016, the Timor-Leste Government initiated conciliation under the United Nations Convention of the Law of the Sea (UNCLOS) in an attempt to negotiate permanent maritime boundaries. The conciliation is on-going between the governments of Timor-Leste and Australia.

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The UNCLOS conciliation does not directly impact our underlying interests in Sunrise; however, we and the Sunrise co-venturers are unable to commit to further commercial and technical work activities due to the uncertainty created by the lack of government alignment. Accordingly, current activities are restricted to compliance and social investment, as well as maintaining relationships and development options for Sunrise.

Exploration

Conventional Exploration

We operate three exploration permits in the Browse Basin, offshore northwest Australia, in which we own a 40 percent interest in permits WA-315-P, WA-398-P and TP 28, of the Greater Poseidon Area. The TP 28 Western Australia State exploration permit was granted for five years from January 2017, with a 40 percent working interest and was excised from the existing permits as agreed between state and federal regulators. Phase I of the Browse Basin drilling campaign in 2009/2010 resulted in three discoveries in the Greater Poseidon Area: Poseidon-1, Poseidon-2 and Kronos-1. Phase II of the drilling campaign resulted in five additional discoveries: Boreas-1, Zephyros-1, Proteus-1 SD2, Poseidon-North-1 and Pharos-1. All wells have been completed, plugged and abandoned.

We operate two retention leases in the Bonaparte Basin, offshore northern Australia, where we own a 37.5 percent interest in leases NT/RL5 and NT/RL6, containing the Barossa and Caldita discoveries. A new 3-D seismic survey was completed over the Barossa and Caldita Field area between August and October 2016. Drilling of the next appraisal well, Barossa-5, commenced in January 2017. Drilling of a subsequent well, Barossa-6, may follow dependent on the results of Barossa-5.

Indonesia

				2016	
				Natural	
			Liquids	Gas	Total
	Interest	Operator	MBD	MMCFD	MBOED
Average Daily Net Production					
South Natuna Sea Block B	40.0%	ConocoPhillips	8	65	19
South Sumatra	45.0 54.0	ConocoPhillips	2	328	57
Total Indonesia			10	393	76

We operate three production sharing contracts (PSCs) in Indonesia: The Corridor Block and South Jambi B, both located in South Sumatra, and Kualakurun in Central Kalimantan. Currently there is production from the Corridor Block. In 2016, we sold our 40 percent working interest in the offshore South Natuna Sea Block B PSC, which had 3 producing oil fields, and 16 natural gas fields in various stages of development. Full-year 2016 production from South Natuna Sea Block B was 19 MBOED.

South Sumatra

The Corridor PSC consists of five oil fields and seven natural gas fields in various stages of development. Natural gas is supplied from the Grissik and Suban gas processing plants to the Duri steamflood in central Sumatra and to markets in Singapore, Batam and West Java. Production from the South Jambi B PSC has reached depletion and field development has been suspended.

Exploration

During 2016, we relinquished our 80 percent interest in the Warim Block PSC. We have a 60 percent working interest in the Kualakurun PSC, located in Central Kalimantan, which was signed in May 2015. This block has an area of approximately 2 million gross acres.

Transportation

We are a 35 percent owner of a consortium company that has a 40 percent ownership in PT Transportasi Gas Indonesia, which owns and operates the Grissik to Duri and Grissik to Singapore natural gas pipelines.

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China

	Interest	Operator	Liquids MBD	2016 Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Penglai	49.0%	CNOOC	32	1	32
Panyu	24.5	CNOOC	9	-	9
Total China			41	1	41

The Penglai 19-3, 19-9 and 25-6 fields are located in Bohai Bay Block 11/05. Production from the Phase 1 development of the Penglai 19-3 Field began in 2002. Phase 2 included six additional wellhead platforms and an FPSO vessel, and was fully operational by 2009.

As part of further development of the Penglai 19-9 Field, a new wellhead platform, which adds up to 62 wells, is progressing according to schedule, with two wells completed and brought online in December 2016.

We sanctioned the Penglai 19-3/19-9 Phase 3 Project in December 2015. This project will consist of three new wellhead platforms and a central processing platform. First oil from Phase 3 is expected in 2018.

The Panyu development, located in Block 15/34 in the South China Sea, is comprised of three oil fields: Panyu 4-2, Panyu 5-1 and Panyu 11-6. The production period for Panyu 4-2 and 5-1 will expire in 2018, and the production period for Panyu 11-6 will expire in 2022.

Exploration

In 2016, we participated in a successful appraisal well in the Penglai fields, which will support future development plans.

Malaysia

	Interest	Operator	Liquids MBD	2016 Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Siakap North-Petai	21.0%	Murphy	3	2	3
Gumusut	29.0	Shell	36	-	36

KBB	30.0	KPOC	1	45	9
Total Malaysia			40	47	48

We own interests in six PSCs in Malaysia. Three are located off the eastern Malaysian state of Sabah: Block G, Block J and the Kebabangan Cluster (KBBC). Three other blocks, deepwater Block 3E, Block SK313 and Block WL4-00 are located off the eastern Malaysian state of Sarawak.

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Block G

We have a 21 percent interest in the unitized Siakap North-Petai oil field, which began producing in the first quarter of 2014 and reached its estimated net annual peak production of 5 MBOED in 2015.

First production from Malikai was achieved in December 2016, with estimated net annual peak production of 18 MBOED expected in 2019. The Limbayong-1 well was drilled in 2002 and resulted in a gas discovery. The Limbayong-2 appraisal well was drilled in 2013 and resulted in an oil discovery. Development options are being evaluated. We own a 35 percent interest in the Malikai, Limbayong and Pisagan discoveries.

Block J

First production for Gumusut occurred from an early production system in 2012. Production from a permanent, semi-submersible floating production vessel was achieved in October 2014, with net annual peak production of 36 MBOED reached in 2016. Unitization of the Gumusut Field with Brunei was recorded in 2014 and reduced our ownership interest from 33 percent to an initial 29 percent. A final ownership split is expected to be agreed in 2017. Gumusut Phase 2 infill drilling is planned to start in 2018.

KBBC

We own a 30 percent interest in the KBBC PSC. Development of the KBB gas field commenced in 2011, and first production was achieved in November 2014. Estimated net annual peak production of 26 MBOED is expected in 2018. Development options for the Kamunsu East gas field are being evaluated.

Exploration

We own a 50 percent operated interest in deepwater Block 3E, which encompasses approximately 480,000 gross acres offshore Sarawak. Seismic processing was completed in 2015. The Langsat-1 exploration well was spud in February 2017.

In the fourth quarter of 2016, we entered into a farm-in agreement to acquire a 50 percent interest in Block SK 313, a 1.4 million gross-acre exploration block, effective January 2017. Following completion of the Sadok-1 exploration well in January 2017, we assumed operatorship of the block from PETRONAS.

We were awarded Block WL4-00, which encompasses approximately 629,000 gross acres, in January 2017. We have a 50 percent operated interest in this block which includes the Salam-1 oil discovery. A new 3-D seismic survey is planned for 2017 with drilling of an appraisal well expected in 2018.

Brunei

Exploration

We have a 6.25 percent working interest in the deepwater Block CA-2 PSC, which has an exploration period through December 2018. Exploration has been ongoing since September 2011, with natural gas discovered at the Kelidang NE-1 and Keratau-1 wells in 2013 and at the Keratau SW-1 well in 2015. Evaluation of the results is ongoing.

Myanmar

Exploration

In 2014, we were awarded deepwater Block AD-10 in the 2013 Myanmar offshore oil and gas bidding round. We signed the PSC in the second quarter of 2015. In 2016, we assigned our participating interest to the operator.

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Qatar

			2016		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
QG3	30.0%	Qatargas Operating Company Limited	22	368	84
Total Qatar			22	368	84

QG3 is an integrated development jointly owned by Qatar Petroleum (68.5 percent), ConocoPhillips (30 percent) and Mitsui & Co., Ltd. (1.5 percent). QG3 consists of upstream natural gas production facilities, which produce approximately 1.4 billion gross cubic feet per day of natural gas from Qatar s North Field over a 25 year life, in addition to a 7.8 million gross tonnes-per-year LNG facility. LNG is shipped in leased LNG carriers destined for sale globally.

QG3 executed the development of the onshore and offshore assets as a single integrated development with Qatargas 4 (QG4), a joint venture between Qatar Petroleum and Royal Dutch Shell plc. This included the joint development of offshore facilities situated in a common offshore block in the North Field, as well as the construction of two identical LNG process trains and associated gas treating facilities for both the QG3 and QG4 joint ventures. Production from the LNG trains and associated facilities is combined and shared.

OTHER INTERNATIONAL

The Other International segment includes exploration activities in Colombia and Chile. In 2016, we sold ConocoPhillips Senegal B.V., the entity that held our 35 percent interest in three exploration blocks offshore Senegal.

Angola

Exploration

Our 50 percent operated interest in Block 36 and our 30 percent operated interest in Block 37, both of which are located in Angola s subsalt play trend, expired on December 31, 2016. In February 2017, we reached a settlement agreement on our contract for the Athena drilling rig, initially secured for our four-well commitment program in Angola. As a result of the cancellation, we will recognize a before-tax charge of $43 million net in the first quarter of 2017.

Senegal

Exploration

On October 28, 2016, we sold ConocoPhillips Senegal B.V., the entity that held our 35 percent interest in three exploration blocks offshore Senegal. See Note 6 Assets Held for Sale or Sold, in the Notes to Consolidated Financial Statements, for information regarding our asset dispositions.

Colombia

Unconventional Exploration

We have an 80 percent operated interest in the Middle Magdalena Basin Block VMM-3. The block extends over approximately 67,000 net acres and contains the Picoplata-1 well, which completed drilling in 2015. Production tests and appraisal of the area are ongoing.

We hold 70 percent nonoperated interests in the deep rights in the Santa Isabel Block in the Middle Magdalena Basin, which covers approximately 71,000 net acres. The relinquishment of the Santa Isabel Block was accepted and the parties are in the process of documenting such relinquishment.

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The exploration and production contract for the VMM27 Block, in the Middle Magdalena Basin, where we held a 30 percent nonoperated interest, has been fully terminated. We also hold a 30 percent nonoperated interest in the VMM28 Block, in the Middle Magdalena Basin, where we are in the process of terminating with the relevant parties and the regulatory agency.

Chile

Exploration

In June 2016, we entered into an agreement with Empresa Nacional Del Petroleo (ENAP) to acquire an additional 44 percent participating interest in the onshore Coiron Block located in the Magallanes Basin in southern Chile where we already had 5 percent participation. Assignment of the additional participating interest to ConocoPhillips was approved by the Chilean Ministry of Energy and the Controller General of Chile. ENAP holds the remaining 51 percent participating interest and will continue to be the operator.

In 2016, two exploration wells were successfully drilled, logged and cored. In 2017, we will continue to explore and appraise the Coiron Block.

Venezuela

In October 2014, we filed for arbitration under the rules of the International Chamber of Commerce (ICC) against Petroleos de Venezuela (PDVSA), the Venezuela state oil company, for contractual compensation related to the Petrozuata and Hamaca heavy crude oil projects. The ICC arbitration is a separate and independent legal action from the investment treaty arbitration against the government of Venezuela, which is currently proceeding before an arbitral tribunal under the World Bank s International Centre for Settlement for Investment Disputes (ICSID). The ICSID Tribunal is determining the damages owed to ConocoPhillips as a result of Venezuela s unlawful expropriation of ConocoPhillips significant oil investments in the Petrozuata and Hamaca heavy crude oil projects and the offshore Corocoro development project in June 2007. In October 2016, ConocoPhillips brought fraudulent transfer actions in the U.S. District Court of Delaware against PDVSA, alleging that PDVSA has taken actions to improperly expatriate assets from the United States to Venezuela in an effort to avoid judgment creditors. For additional information, see Note 13 Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

Ecuador

In December 2012, an ICSID Tribunal issued a decision on liability in favor of Burlington Resources, Inc., a wholly owned subsidiary of ConocoPhillips, finding that Ecuador s seizure of Blocks 7 and 21 was an unlawful expropriation in violation of the Ecuador-U.S. Bilateral Investment Treaty. In February 2017, the tribunal unanimously awarded Burlington $380 million for Ecuador s unlawful expropriation and breach of the U.S.-Ecuador bilateral investment treaty. The tribunal also issued a separate decision finding Ecuador to be entitled to $42 million for limited environmental and infrastructure impacts associated with the operations of Burlington and its co-venturer. Ecuador recently filed a request for annulment of this decision with ICSID. The schedule for the annulment process has not yet been set. For additional information, see Note 13 Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

Discontinued Operations

See Note 3 Discontinued Operations, in the Notes to Consolidated Financial Statements, for information regarding our discontinued operations.

OTHER

Marketing Activities

Our Commercial organization manages our worldwide commodity portfolio, which mainly includes natural gas, crude oil, bitumen, natural gas liquids and LNG. Marketing activities are performed through offices in the United States, Canada, Europe and Asia. In marketing our production, we attempt to minimize flow disruptions, maximize realized prices and manage credit-risk exposure. Commodity sales are generally made at prevailing market prices at the time of sale. We also purchase and sell third-party volumes to better position the company to satisfy customer demand while fully utilizing transportation and storage capacity.

Natural Gas

Our natural gas production, along with third-party purchased gas, is primarily marketed in the United States, Canada, Europe and Asia. Our natural gas is sold to a diverse client portfolio which includes local distribution companies; gas and power utilities; large industrials; independent, integrated or state-owned oil and gas companies; as well as marketing companies. To reduce our market exposure and credit risk, we also transport natural gas via firm and interruptible transportation agreements to major market hubs.

Crude Oil, Bitumen and Natural Gas Liquids

Our crude oil, bitumen and natural gas liquids revenues are derived from production in the United States, Canada, Australia, Asia, Africa and Europe. These commodities are primarily sold under contracts with prices based on market indices, adjusted for location, quality and transportation.

LNG

LNG marketing efforts are focused on equity LNG production facilities located in Australia and Qatar. LNG is primarily sold under long-term contracts with prices based on market indices.

Energy Partnerships

Marine Well Containment Company

We are a founding member of the Marine Well Containment Company (MWCC), a non-profit organization formed in 2010, which provides well containment equipment and technology in the deepwater U.S. Gulf of Mexico. MWCC s containment system meets the U.S. Bureau of Safety and Environmental Enforcement requirements for a subsea well containment system that can respond to a deepwater well control incident in the U.S. Gulf of Mexico. For additional information, see Note 4 Variable Interest Entities (VIEs), in the Notes to Consolidated Financial Statements.

Subsea Well Response Project

In 2011, we, along with several leading oil and gas companies, launched the Subsea Well Response Project (SWRP), a non-profit organization based in Stavanger, Norway, which was created to enhance the industry s capability to respond to international subsea well control incidents. Through collaboration with Oil Spill Response Limited, a non-profit organization in the United Kingdom, subsea well intervention equipment is available for the industry to use in the event of a subsea well incident. This complements the work being undertaken in the United States by MWCC.

Oil Spill Response Removal Organizations (OSROs)

We maintain memberships in several OSROs across the globe as a key element of our preparedness program in addition to internal response resources. Many of the OSROs are not-for-profit cooperatives owned by the member companies wherein we may actively participate as a member of the board of directors, steering committee, work group or other supporting role. Globally, our primary OSRO is Oil Spill Response Ltd. based in the U.K., with facilities in several other countries and the ability to respond anywhere in the world. In North America, our primary OSROs include the Marine Spill Response Corporation for the continental U.S. and Alaska Clean Seas and Ship Escort/Response Vessel System for the Alaska North Slope and Prince William Sound, respectively. Internationally, we maintain memberships in various regional OSROs including the Norwegian Clean Seas Association for Operating Companies, Australian Marine Oil Spill Center and Petroleum Industry of Malaysia Mutual Aid Group.

Technology

We have several technology programs that improve our ability to develop unconventional reservoirs, produce heavy oil economically with fewer emissions, improve the efficiency of our company s exploration program, increase recoveries from our legacy fields, and implement sustainability measures.

Our Optimized Cascade® LNG liquefaction technology business continues to be successful with the demand for new LNG plants. The technology has been licensed for use in 25 LNG trains around the world, with feasibility studies ongoing for additional trains.

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RESERVES

We have not filed any information with any other federal authority or agency with respect to our estimated total proved reserves at December 31, 2016. No difference exists between our estimated total proved reserves for year-end 2015 and year-end 2014, which are shown in this filing, and estimates of these reserves shown in a filing with another federal agency in 2016.

DELIVERY COMMITMENTS

We sell crude oil and natural gas from our producing operations under a variety of contractual arrangements, some of which specify the delivery of a fixed and determinable quantity. Our Commercial organization also enters into natural gas sales contracts where the source of the natural gas used to fulfill the contract can be the spot market or a combination of our reserves and the spot market. Worldwide, we are contractually committed to deliver approximately 2.0 trillion cubic feet of natural gas, including approximately 363 billion cubic feet related to the noncontrolling interests of consolidated subsidiaries, and 180 million barrels of crude oil in the future. These contracts have various expiration dates through the year 2027. We expect to fulfill the majority of these delivery commitments with proved developed reserves. In addition, we anticipate using proved undeveloped reserves and spot market purchases to fulfill any remaining commitments. See the disclosure on Proved Undeveloped Reserves in the Oil and Gas Operations section following the Notes to Consolidated Financial Statements, for information on the development of proved undeveloped reserves.

COMPETITION

We compete with private, public and state-owned companies in all facets of the E&P business. Some of our competitors are larger and have greater resources. Each of our segments is highly competitive, with no single competitor, or small group of competitors, dominating.

We compete with numerous other companies in the industry, including state-owned companies, to locate and obtain new sources of supply and to produce oil, bitumen, natural gas liquids and natural gas in an efficient, cost-effective manner. Based on statistics published in the September 5, 2016, issue of the *Oil and Gas Journal*, we were the third-largest U.S.-based oil and gas company in worldwide liquids and natural gas production and reserves in 2015. We deliver our production into the worldwide commodity markets. Principal methods of competing include geological, geophysical and engineering research and technology; experience and expertise; economic analysis in connection with portfolio management; and safely operating oil and gas producing properties.

GENERAL

At the end of 2016, we held a total of 714 active patents in 49 countries worldwide, including 286 active U.S. patents. During 2016, we received 37 patents in the United States and 66 foreign patents. Our products and processes generated licensing revenues of $128 million in 2016. The overall profitability of any business segment is not dependent on any single patent, trademark, license, franchise or concession.

Company-sponsored research and development activities charged against earnings were $116 million, $222 million and $263 million in 2016, 2015 and 2014, respectively.

Health, Safety and Environment

Our Health, Safety and Environment (HSE) organization provides tools and support to our business units and staff groups to help them ensure world class health, safety and environmental performance. The framework through which we safely manage our operations, the HSE Management System Standard, emphasizes process safety, risk management, emergency preparedness and environmental performance, with an intense focus on process and occupational safety. In support of the goal of zero incidents, HSE milestones and criteria are established annually to drive strong safety performance.

Progress toward these milestones and criteria are measured and reported. HSE audits are conducted on business functions periodically, and improvement actions are established and tracked to completion. We also have detailed processes in place to address sustainable development in our economic, environmental and social performance. Our processes, related tools and requirements focus on water, biodiversity and climate change, as well as social and stakeholder issues.

The environmental information contained in Management s Discussion and Analysis of Financial Condition and Results of Operations on pages 63 through 66 under the captions Environmental and Climate Change is incorporated herein by reference. It includes information on expensed and capitalized environmental costs for 2016 and those expected for 2017 and 2018.

Website Access to SEC Reports

Our internet website address is *www.conocophillips.com*. Information contained on our internet website is not part of this report on Form 10-K.

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available on our website, free of charge, as soon as reasonably practicable after such reports are filed with, or furnished to, the U.S. Securities and Exchange Commission (SEC). Alternatively, you may access these reports at the SEC s website at *www.sec.gov*.

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Item 1A. RISK FACTORS

You should carefully consider the following risk factors in addition to the other information included in this Annual Report on Form 10-K. Each of these risk factors could adversely affect our business, operating results and financial condition, as well as adversely affect the value of an investment in our common stock.

Our operating results, our future rate of growth and the carrying value of our assets are exposed to the effects of changing commodity prices.

Prices for crude oil, bitumen, natural gas, natural gas liquids and LNG can fluctuate widely. Globally, prices for crude oil, bitumen, natural gas, natural gas liquids and LNG have experienced significant declines from their historic levels during 2013 and 2014, with excess of supply relative to global demand leading to global inventory builds. Total average annual prices in 2016 for Brent crude oil, WTI crude oil, Henry Hub natural gas and our realized natural gas liquids all decreased by more than 5 percent when compared with 2015. In the fourth quarter of 2016, Brent crude oil, WTI crude oil, Henry Hub natural gas and our realized natural gas liquids prices all increased, compared with the same period of 2015. Given volatility in commodity price drivers and the business environment, price trends may not continue or reverse themselves.

Our revenues, operating results and future rate of growth are highly dependent on the prices we receive for our crude oil, bitumen, natural gas, natural gas liquids and LNG. The factors influencing these prices are beyond our control. Lower crude oil, bitumen, natural gas, natural gas liquids and LNG prices may have a material adverse effect on our revenues, operating income, cash flows and liquidity and on the amount of dividends we elect to declare and pay on our common stock. Lower prices may also limit the amount of reserves we can produce economically, adversely affecting our ability to maintain our reserve replacement ratio and accelerating the reduction in our existing reserve levels as we continue production from upstream fields.

Significant reductions in crude oil, bitumen, natural gas, natural gas liquids and LNG prices could also require us to reduce our capital expenditures or impair the carrying value of our assets. In the past two years, we recognized several impairments, which are described in Note 9 Impairments and the APLNG section of Note 7 Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements. If commodity prices remain low relative to their historic levels, and as we continue to optimize our investments and exercise capital flexibility, it is reasonably likely we will incur future impairments to long-lived assets used in operations, investments in nonconsolidated entities accounted for under the equity method and unproved properties. Although it is not reasonably practicable to quantify the impact of any future impairments at this time, our results of operations could be adversely affected as a result.

Our ability to declare and pay dividends is subject to certain considerations.

Dividends are authorized and determined by our Board of Directors in its sole discretion and depend upon a number of factors, including:

- Cash available for distribution.
- Our results of operations and anticipated future results of operations.
- Our financial condition, especially in relation to the anticipated future capital needs of our properties.
- The level of reserves we establish for future capital expenditures.
- The level of distributions paid by comparable companies.
- Our operating expenses.

Other factors our Board of Directors deems relevant.

We expect to continue to pay quarterly distributions to our stockholders; however, we bear all expenses incurred by our operations, and our funds generated by operations, after deducting these expenses, may not be sufficient to cover desired levels of distributions to our stockholders. Any downward revision in our distribution could have a material adverse effect on the market price of our common stock.

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We may need additional capital in the future, and it may not be available on acceptable terms.

We have historically relied primarily upon cash generated by our operations to fund our operations and strategy, however we have also relied from time to time on access to the debt and equity capital markets for funding. There can be no assurance that additional debt or equity financing will be available in the future on acceptable terms, or at all. Our ability to obtain additional financing will be subject to a number of factors, including market conditions, our operating performance, investor sentiment and our ability to incur additional debt in compliance with agreements governing our then-outstanding debt. If we are unable to generate sufficient funds from operations or raise additional capital, our growth could be impeded.

In addition, we are regularly evaluated by the major rating agencies based on a number of factors, including our financial strength and conditions affecting the oil and gas industry generally. Due to the significant decline in prices for crude oil, bitumen, natural gas, natural gas liquids and LNG, and the expectation that these prices could remain depressed in the near future, the major ratings agencies conducted a review of the oil and gas industry and downgraded our debt ratings and those of several companies operating in the industry. Any downgrade in our credit rating, could increase the cost associated with any additional indebtedness we incur.

Our business may be adversely affected by deterioration in the credit quality of, or defaults under our contracts with, third parties with whom we do business.

The operation of our business requires us to engage in transactions with numerous counterparties operating in a variety of industries, including other companies operating in the oil and gas industry. These counterparties may default on their obligations to us as a result of operational failures or a lack of liquidity, or for other reasons, including bankruptcy. Market speculation about the credit quality of these counterparties, or their ability to continue performing on their existing obligations, may also exacerbate any operational difficulties or liquidity issues they are experiencing, particularly as it relates to other companies in the oil and gas industry as a result of the recent significant declines in commodity prices. Any default by any of our counterparties may result in our inability to perform obligations under agreements we have made with third parties or may otherwise adversely affect our business or results of operations. In addition, our rights against any of our counterparties as a result of a default may not be adequate to compensate us for the resulting harm caused or may not be enforceable at all in some circumstances.

Unless we successfully add to our existing proved reserves, our future crude oil, bitumen, natural gas and natural gas liquids production will decline, resulting in an adverse impact to our business.

The rate of production from upstream fields generally declines as reserves are depleted. Except to the extent that we conduct successful exploration and development activities, or, through engineering studies, optimize production performance or identify additional or secondary recovery reserves, our proved reserves will decline materially as we produce crude oil, bitumen, natural gas and natural gas liquids. Accordingly, to the extent we are unsuccessful in replacing the crude oil, bitumen, natural gas and natural gas liquids we produce with good prospects for future production, our business will experience reduced cash flows and results of operations. Any cash conservation efforts we may undertake as a result of commodity price declines may further limit our ability to replace depleted reserves.

The exploration and production of oil and gas is a highly competitive industry.

The exploration and production of crude oil, bitumen, natural gas and natural gas liquids is a highly competitive business. We compete with private, public and state-owned companies in all facets of the exploration and production business, including to locate and obtain new sources of supply and to produce oil, bitumen, natural gas and natural gas liquids in an efficient, cost-effective manner. Some of our competitors are larger and have greater resources than we do or may be willing to incur a higher level of risk than we are willing to incur to obtain potential sources of supply. If we are not successful in our competition for new reserves, our financial condition and results of operations may be adversely affected.

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Any material change in the factors and assumptions underlying our estimates of crude oil, bitumen, natural gas and natural gas liquids reserves could impair the quantity and value of those reserves.

Our proved reserve information included in this annual report has been derived from engineering estimates prepared by our personnel. Reserve estimation is a process that involves estimating volumes to be recovered from underground accumulations of crude oil, bitumen, natural gas and natural gas liquids that cannot be directly measured. As a result, different petroleum engineers, each using industry-accepted geologic and engineering practices and scientific methods, may produce different estimates of reserves and future net cash flows based on the same available data. Any significant future price changes could have a material effect on the quantity and present value of our proved reserves. Any material changes in the factors and assumptions underlying our estimates of these items could result in a material negative impact to the volume of reserves reported or could cause us to incur impairment expenses on property associated with the production of those reserves. Future reserve revisions could also result from changes in, among other things, governmental regulation. In addition to changes in the quantity and value of our proved reserves, the amount of crude oil, bitumen, natural gas and natural gas liquids that can be obtained from any proved reserve may ultimately be different from those estimated prior to extraction.

We expect to continue to incur substantial capital expenditures and operating costs as a result of our compliance with existing and future environmental laws and regulations. Likewise, future environmental laws and regulations, such as limitations on greenhouse gas emissions, may impact or limit our current business plans and reduce demand for our products.

Our businesses are subject to numerous laws and regulations relating to the protection of the environment. These laws and regulations continue to increase in both number and complexity and affect our operations with respect to, among other things:

- The discharge of pollutants into the environment.
- Emissions into the atmosphere, such as nitrogen oxides, sulfur dioxide, mercury and greenhouse gas emissions.
- Carbon taxes.
- The handling, use, storage, transportation, disposal and cleanup of hazardous materials and hazardous and nonhazardous wastes.
- The dismantlement, abandonment and restoration of our properties and facilities at the end of their useful lives.
- Exploration and production activities in certain areas, such as offshore environments, arctic fields, oil sands reservoirs and tight oil plays.

We have incurred and will continue to incur substantial capital, operating and maintenance, and remediation expenditures as a result of these laws and regulations. To the extent these expenditures, as with all costs, are not ultimately reflected in the prices of our products and services, our business, financial condition, results of operations and cash flows in future periods could be materially adversely affected.

Although our business operations are designed and operated to accommodate expected climatic conditions, to the extent there are significant changes in the Earth s climate, such as more severe or frequent weather conditions in the markets we serve or the areas where our assets reside, we could incur increased expenses, our operations could be materially impacted, and demand for our products could fall. Demand for our products may also be adversely affected by conservation plans and efforts undertaken in response to global climate change, including plans developed in connection with the Paris climate conference in December 2015. Many governments also provide, or may in the future provide, tax advantages and other subsidies to support the use and development of alternative energy technologies. Our operations and the demand for our products could be materially impacted by the development and adoption of these technologies.

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Domestic and worldwide political and economic developments could damage our operations and materially reduce our profitability and cash flows.

Actions of the U.S., state, local and foreign governments, through tax and other legislation, executive order and commercial restrictions, could reduce our operating profitability both in the United States and abroad. In certain locations, governments have imposed or proposed restrictions on our operations; special taxes or tax assessments; and payment transparency regulations that could require us to disclose competitively sensitive information or might cause us to violate non-disclosure laws of other countries. U.S. federal, state and local legislative and regulatory agencies initiatives regarding the hydraulic fracturing process could result in operating restrictions or delays in the completion of our oil and gas wells.

The U.S. government can also prevent or restrict us from doing business in foreign countries. These restrictions and those of foreign governments have in the past limited our ability to operate in, or gain access to, opportunities in various countries. Actions by host governments have affected operations significantly in the past, such as the expropriation of our oil assets by the Venezuelan government, and may continue to do so in the future. Changes in domestic and international regulations may affect our ability to obtain or maintain permits, including those necessary for drilling and development of wells or for construction of LNG terminals or regasification facilities in various locations.

Local political and economic factors in international markets could have a material adverse effect on us. Approximately 58 percent of our hydrocarbon production was derived from production outside the United States in 2016, and 55 percent of our proved reserves, as of December 31, 2016, was located outside the United States. We are subject to risks associated with operations in international markets, including changes in foreign governmental policies relating to crude oil, natural gas, bitumen, natural gas liquids or LNG pricing and taxation, other political, economic or diplomatic developments, changing political conditions and international monetary fluctuations. In particular, some countries where we operate lack well-developed legal systems or have not adopted clear legal and regulatory frameworks for oil and gas exploration and production. This lack of legal certainty exposes our operations to increased risks, including increased difficulty in enforcing our agreements in those jurisdictions and increased risks of adverse actions by local government authorities, such as expropriations.

Changes in governmental regulations may impose price controls and limitations on production of crude oil, bitumen, natural gas and natural gas liquids.

Our operations are subject to extensive governmental regulations. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of crude oil, bitumen, natural gas and natural gas liquids wells below actual production capacity. Because legal requirements are frequently changed and subject to interpretation, we cannot predict the effect of these requirements.

Our investments in joint ventures decrease our ability to manage risk.

We conduct many of our operations through joint ventures in which we may share control with our joint venture partners. There is a risk our joint venture participants may at any time have economic, business or legal interests or goals that are inconsistent with those of the joint venture or us, or our joint venture partners may be unable to meet their economic or other obligations and we may be required to fulfill those obligations alone. Failure by us, or an entity in which we have a joint venture interest, to adequately manage the risks associated with any acquisitions or joint ventures could have a material adverse effect on the financial condition or results of operations of our joint ventures and, in turn, our business and operations.

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We may not be able to successfully complete any disposition we elect to pursue.

From time to time, we may seek to divest portions of our business or investments that are not important to our ongoing strategic objectives. Any dispositions we undertake may involve numerous risks and uncertainties, any of which could adversely affect our results of operations or financial condition. In particular, we may not be able to successfully complete any disposition on a timeline or on terms acceptable to us, if at all, whether due to market conditions, regulatory challenges or other concerns. In addition, the reinvestment of capital from disposition proceeds may not ultimately yield investment returns in line with our internal or external expectations. Any dispositions we pursue may also result in disruption to other parts of our business, including through the diversion of resources and management attention from our ongoing business and other strategic matters, or through the disruption of relationships with our employees and key vendors. Further, in connection with any disposition, we may enter into transition services agreements or undertake indemnity or other obligations that may result in additional expenses for us.

We do not insure against all potential losses; therefore, we could be harmed by unexpected liabilities and increased costs.

We maintain insurance against many, but not all, potential losses or liabilities arising from operating risks. As such, our insurance coverage may not be sufficient to fully cover us against potential losses arising from such risks. Uninsured losses and liabilities arising from operating risks could reduce the funds available to us for capital, exploration and investment spending and could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our operations present hazards and risks that require significant and continuous oversight.

The scope and nature of our operations present a variety of significant hazards and risks, including operational hazards and risks such as explosions, fires, crude oil spills, severe weather, geological events, labor disputes, terrorist attacks, sabotage, civil unrest or cyber attacks. Our operations may also be adversely affected by unavailability, interruptions or accidents involving services or infrastructure required to develop, produce, process or transport our production, such as contract labor, drilling rigs, pipelines, railcars, tankers, barges or other infrastructure. Our operations are subject to the additional hazards of pollution, releases of toxic gas and other environmental hazards and risks. Activities in deepwater areas may pose incrementally greater risks because of complex subsurface conditions such as higher reservoir pressures, water depths and metocean conditions. All such hazards could result in loss of human life, significant property and equipment damage, environmental pollution, impairment of operations, substantial losses to us and damage to our reputation. Further, our business and operations may be disrupted if we do not respond, or are perceived not to respond, in an appropriate manner to any of these hazards and risks or any other major crisis or if we are unable to efficiently restore or replace affected operational components and capacity.

Our technologies, systems and networks may be subject to cybersecurity breaches. Although we have experienced occasional, actual or attempted breaches of our cybersecurity, none of these breaches has had a material effect on our business, operations or reputation. If our systems for protecting against cybersecurity risks prove to be insufficient, we could be adversely affected by having our business systems compromised, our proprietary information altered, lost or stolen, or our business operations disrupted. As cyber attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information systems and related infrastructure security vulnerabilities.

Item 1B. UNRESOLVED STAFF COMMENTS

None.

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Item 3. LEGAL PROCEEDINGS

The following is a description of reportable legal proceedings, including those involving governmental authorities under federal, state and local laws regulating the discharge of materials into the environment for this reporting period. The following proceedings include those matters that arose during the fourth quarter of 2016, as well as matters previously reported in our 2015 Form 10-K and our first-, second- and third-quarter 2016 Form 10-Qs that were not resolved prior to the fourth quarter of 2016. Material developments to the previously reported matters have been included in the descriptions below. While it is not possible to accurately predict the final outcome of these pending proceedings, if any one or more of such proceedings were to be decided adversely to ConocoPhillips, we expect there would be no material effect on our consolidated financial position. Nevertheless, such proceedings are reported pursuant to SEC regulations.

On April 30, 2012, the separation of our downstream business was completed, creating two independent energy companies: ConocoPhillips and Phillips 66. In connection with the separation, we entered into an Indemnification and Release Agreement, which provides for cross-indemnities between Phillips 66 and us and established procedures for handling claims subject to indemnification and related matters, such as legal proceedings. We have included matters where we remain or have subsequently become a party to a proceeding relating to Phillips 66, in accordance with SEC regulations. We do not expect any of those matters to result in a net claim against us.

New Matters ConocoPhillips

A Judgment and Consent Decree was entered on December 7, 2016, by the South Central Judicial District Court in Burleigh County, North Dakota against Burlington Resources Oil & Gas Company LP and ConocoPhillips Company resolving alleged violations of the state s air pollution control laws. The North Dakota Department of Health was the Plaintiff in this matter. The Consent Decree requires the companies to implement a specified program to inspect and repair as necessary its facilities in North Dakota and to pay a penalty of approximately $220,000.

Matters Previously Reported Phillips 66

In October 2007, we received a Complaint from the U.S. Environmental Protection Agency (EPA) alleging violations of the Clean Water Act related to a 2006 oil spill at the Bayway Refinery and proposing a penalty of $156,000. Phillips 66 resolved this matter with the EPA in December 2016 with a settlement payment of $35,500.

In May 2012, the Illinois Attorney General s office filed and notified ConocoPhillips of a complaint with respect to operations at the Phillips 66 WRB Wood River Refinery alleging violations of the Illinois groundwater standards and a third-party s hazardous waste permit. The complaint seeks as relief remediation of area groundwater; compliance with the hazardous waste permit; enhanced pipeline and tank integrity measures; additional spill reporting; and yet-to-be specified amounts for fines and penalties.

New Matters Phillips 66

In October 2016, after Phillips 66 received a Notice of Intent to Sue from the Sierra Club, Phillips 66 entered into a voluntary settlement with the Illinois Environmental Protection Agency for alleged violations of wastewater requirements at the Wood River Refinery occurring in part prior to the separation. The settlement involves certain capital projects and payment of $125,000. The settlement has been filed with the Court for final approval and the Sierra Club has sought to intervene in the case to oppose the settlement. A court hearing is scheduled for March 2017.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

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EXECUTIVE OFFICERS OF THE REGISTRANT

Name	Position Held	Age*
Janet L. Carrig	Senior Vice President, Legal, General Counsel and Corporate Secretary	59
Ellen R. DeSanctis	Vice President, Investor Relations and Communications	60
Matt J. Fox	Executive Vice President, Strategy, Exploration and Technology	56
Alan J. Hirshberg	Executive Vice President, Production, Drilling and Projects	55
Ryan M. Lance	Chairman of the Board of Directors and Chief Executive Officer	54
Andrew D. Lundquist	Senior Vice President, Government Affairs	56
James D. McMorran	Vice President, Human Resources, Real Estate and Facilities Services	59
Glenda M. Schwarz	Vice President and Controller	51
Don E. Wallette, Jr.	Executive Vice President, Finance, Commercial and Chief Financial Officer	58

**On February 15, 2017.*

There are no family relationships among any of the officers named above. Each officer of the company is elected by the Board of Directors at its first meeting after the Annual Meeting of Stockholders and thereafter as appropriate. Each officer of the company holds office from the date of election until the first meeting of the directors held after the next Annual Meeting of Stockholders or until a successor is elected. The date of the next annual meeting is May 16, 2017. Set forth below is information about the executive officers.

Janet L. Carrig was appointed Senior Vice President, Legal, General Counsel and Corporate Secretary in 2007.

Ellen R. DeSanctis was appointed Vice President, Investor Relations and Communications in May 2012. She was previously employed by Petrohawk Energy Corp. and served as Senior Vice President, Corporate Communications since 2010. Prior to that she was employed by Rosetta Resources Inc. and served as Executive Vice President of Strategy and Development from 2008 to 2010.

Matt J. Fox was appointed as Executive Vice President, Strategy, Exploration and Technology in April 2016. He previously served as the Executive Vice President, Exploration and Production, from 2012 to 2016. Prior to that, he was employed by Nexen, Inc. and served as Executive Vice President, International since 2010.

Alan J. Hirshberg was appointed Executive Vice President, Production, Drilling and Projects in April 2016. He previously served as Executive Vice President, Technology and Projects, from 2012 to 2016. Prior to that, he served as Senior Vice President, Planning and Strategy since 2010.

Ryan M. Lance was appointed Chairman of the Board of Directors and Chief Executive Officer in May 2012, having previously served as Senior Vice President, Exploration and Production International since May 2009.

Andrew D. Lundquist was appointed Senior Vice President, Government Affairs in 2013. Prior to that, he served as managing partner of BlueWater Strategies LLC, since 2002.

James D. McMorran was appointed Vice President, Human Resources, Real Estate and Facilities Services in August 2015. Prior to that, he served as Manager, Compensation and Benefits, since 2004.

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Glenda M. Schwarz was appointed Vice President and Controller in 2009.

Don E. Wallette, Jr. was appointed Executive Vice President, Finance, Commercial and Chief Financial Officer in April 2016. He previously served as Executive Vice President, Commercial, Business Development and Corporate Planning from 2012 to 2016. Prior to that, he served as President, Asia Pacific since 2010 and President, Russia/Caspian from 2006 to 2010.

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PART II

Item 5. MARKET FOR REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Quarterly Common Stock Prices and Cash Dividends Per Share

ConocoPhillips common stock is traded on the New York Stock Exchange, under the symbol COP.

		Stock Price		
		High	Low	Dividends
2016				
First	**$**	**47.77**	**31.05**	**0.25**
Second		**49.35**	**38.19**	**0.25**
Third		**44.42**	**38.80**	**0.25**
Fourth		**53.17**	**40.37**	**0.25**
2015				
First	$	70.11	60.57	0.73
Second		69.72	60.86	0.73
Third		61.51	41.10	0.74
Fourth		57.24	44.56	0.74

Closing Stock Price at December 31, 2016	$	50.14
Closing Stock Price at January 31, 2017	$	48.76
Number of Stockholders of Record at January 31, 2017*		49,845

**In determining the number of stockholders, we consider clearing agencies and security position listings as one stockholder for each agency listing.*

The declaration of dividends is subject to the discretion of our Board of Directors, and may be affected by various factors, including our future earnings, financial condition, capital requirements, levels of indebtedness, credit ratings and other considerations our Board of Directors deems relevant. Our Board of Directors has adopted a quarterly dividend declaration policy providing that the declaration of any dividends will be determined quarterly by the Board of Directors taking into account such factors as our business model, prevailing business conditions and our financial results and capital requirements, without a predetermined annual net income payout ratio.

On February 4, 2016, we announced that our Board of Directors approved a reduction in the quarterly dividend to $0.25 per share, compared with the previous quarterly dividend of $0.74 per share.

On January 31, 2017, we announced that our Board of Directors approved an increase in the quarterly dividend to $0.265 per share, compared with the previous quarterly dividend of $0.25 per share.

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Issuer Purchases of Equity Securities

				Millions of Dollars
Period	Total Number of Shares Purchased*	Average Price Paid Per Share	Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
October 1-31, 2016	-	$ -	-	$ -
November 1-30, 2016	695,393	45.30	695,393	2,969
December 1-31, 2016	1,883,705	50.16	1,883,705	2,874
Total fourth-quarter 2016	2,579,098	$ 48.85	2,579,098	

**There were no repurchases of common stock from company employees in connection with the company s broad-based employee incentive plans.*

On November 10, 2016, we announced plans to purchase up to $3 billion of our common stock over the next three years. Repurchase of shares began in November and totaled 2,579,098 shares at a cost of $126 million, through December 31, 2016. Acquisitions for the share repurchase program are made at management s discretion, at prevailing prices, subject to market conditions and other factors. Repurchases may be increased, decreased or discontinued at any time without prior notice. Shares of stock repurchased under the plan are held as treasury shares.

Stock Performance Graph

The following graph shows the cumulative total shareholder return (TSR) for ConocoPhillips common stock in each of the five years from December 31, 2011, to December 31, 2016. The graph also compares the cumulative total returns for the same five-year period with the S&P 500 Index, the performance peer group used in the prior fiscal year (the Prior Peer Group) and a new performance peer group for the current fiscal year (the New Peer Group). The Prior Peer Group consisted of BP, Chevron, ExxonMobil, Royal Dutch Shell, Total, Anadarko, Apache, BG Group plc, Devon and Occidental, weighted according to the respective peer s stock market capitalization at the beginning of each annual period. The New Peer Group excludes BG Group plc due to its acquisition by Royal Dutch Shell in 2016 and includes Marathon Oil Corporation. The Prior Peer Group is presented for purposes of comparison. The comparison assumes $100 was invested on December 31, 2011, in ConocoPhillips stock, the S&P 500 Index, the Prior Peer Group and New Peer Group and assumes that all dividends were reinvested. The spinoff of Phillips 66 in 2012 is treated as a special dividend for the purposes of calculating TSR for ConocoPhillips. The market value of the distributed shares on the spinoff date was deemed reinvested in shares of ConocoPhillips common stock.

**Prior Peer Group: BP; Chevron; ExxonMobil; Royal Dutch Shell; Total; Anadarko; Apache; BG Group plc; Devon; Occidental.*

***New Peer Group: BP; Chevron; ExxonMobil; Royal Dutch Shell; Total; Anadarko; Apache; Marathon Oil Corporation; Devon; Occidental.*

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Item 6. SELECTED FINANCIAL DATA

	Millions of Dollars Except Per Share Amounts				
	2016	2015	2014	2013	2012
Sales and other operating revenues	**$ 23,693**	29,564	52,524	54,413	57,967
Income (loss) from continuing operations	**(3,559)**	(4,371)	5,807	8,037	7,481
Per common share					
Basic	**(2.91)**	(3.58)	4.63	6.47	5.95
Diluted	**(2.91)**	(3.58)	4.60	6.43	5.91
Income from discontinued operations	**-**	-	1,131	1,178	1,017
Net income (loss)	**(3,559)**	(4,371)	6,938	9,215	8,498
Net income (loss) attributable to ConocoPhillips	**(3,615)**	(4,428)	6,869	9,156	8,428
Per common share					
Basic	**(2.91)**	(3.58)	5.54	7.43	6.77
Diluted	**(2.91)**	(3.58)	5.51	7.38	6.72
Total assets	**89,772**	97,484	116,539	118,057	117,144
Long-term debt	**26,186**	23,453	22,383	21,073	20,770
Joint venture acquisition obligation long-term	**-**	-	-	-	2,810
Cash dividends declared per common share	**1.00**	2.94	2.84	2.70	2.64

Net income (loss) and Net income (loss) attributable to ConocoPhillips from 2012 to 2014 includes income from discontinued operations as a result of the separation of the downstream business, the sale of our interest in Kashagan, and the sales of our Algeria and Nigeria businesses. These factors impact the comparability of this information. For additional information on the sale of our Nigeria business, see Note 3 Discontinued Operations, in the Notes to Consolidated Financial Statements.

See Management s Discussion and Analysis of Financial Condition and Results of Operations and the Notes to Consolidated Financial Statements for a discussion of factors that will enhance an understanding of this data.

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Item 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management s Discussion and Analysis is the company s analysis of its financial performance and of significant trends that may affect future performance. It should be read in conjunction with the financial statements and notes, and supplemental oil and gas disclosures included elsewhere in this report. It contains forward-looking statements including, without limitation, statements relating to the company s plans, strategies, objectives, expectations and intentions that are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. The words anticipate, estimate, believe, budget, continue, could, intend, may, plan, potential should, will, would, expect, objective, projection, forecast, goal, guidance, outlook, effort, ta expressions identify forward-looking statements. The company does not undertake to update, revise or correct any of the forward-looking information unless required to do so under the federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with the company s disclosures under the heading: CAUTIONARY STATEMENT FOR THE PURPOSES OF THE SAFE HARBOR PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995, beginning on page 72.

Due to discontinued operations reporting, we believe income (loss) from continuing operations is more representative of ConocoPhillips earnings than overall net income (loss) attributable to ConocoPhillips. The terms earnings and loss as used in Management s Discussion and Analysis refer to income (loss) from continuing operations. For additional information, see Note 3 *Discontinued Operations, in the Notes to Consolidated Financial Statements.*

BUSINESS ENVIRONMENT AND EXECUTIVE OVERVIEW

ConocoPhillips is the world s largest independent exploration and production (E&P) company, based on proved reserves and production of liquids and natural gas. Headquartered in Houston, Texas, we have operations and activities in 17 countries. Our diverse portfolio primarily includes resource-rich North American unconventional assets and oil sands assets in Canada; lower-risk conventional assets in North America, Europe, Asia and Australia; several liquefied natural gas (LNG) developments; and an inventory of global conventional and unconventional exploration prospects. At December 31, 2016, we employed approximately 13,300 people worldwide and had total assets of $90 billion. Our stock is listed on the New York Stock Exchange under the symbol COP.

Overview

The energy landscape remained challenged throughout 2016. Global production oversupply caused continued weakness in commodity prices in 2016 following a year of weak prices in 2015. Ongoing uncertainty around the timing and trajectory of a price recovery, coupled with tightening credit capacity across the industry, caused us to take actions early in the year to mitigate the impacts of possible prolonged weak prices. We reduced our quarterly dividend by 66 percent, to $0.25 per share, issued $3.0 billion of long-term debt, obtained a $1.6 billion three-year term loan, reduced capital expenditures and production and operating expenses, and further streamlined our portfolio.

Our capital expenditures in 2016 were $4.9 billion, a 52 percent reduction compared with 2015 and a 72 percent reduction compared with 2014. Production and operating expenses in 2016 were $5.7 billion, down 19 percent compared with 2015 and down 36 percent compared with 2014.

We also progressed our efforts to high-grade our portfolio. In 2016, we generated $1.3 billion from the disposition of certain non-core assets in our portfolio, including the offshore South Natuna Sea Block B in Indonesia and ConocoPhillips Senegal B.V., the entity that held our interest in three exploration blocks offshore Senegal. The full-year 2016 production impact of completed dispositions was 27 thousand barrels of oil equivalent per day (MBOED).

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During 2016, we expanded our value proposition to position the company for long-term success in light of our view that commodity prices, specifically oil prices, are likely to remain lower and be more volatile in the future. Our value proposition principles, namely to maintain a strong balance sheet, grow our dividend and pursue disciplined growth, remain essentially unchanged. However, we took steps to improve our competitiveness and resilience by establishing clear priorities for allocating future cash flows.

In order, these priorities are: invest capital at a level that maintains flat production volumes and pays our existing dividend; grow our existing dividend; reduce debt to a level we believe is sufficient to maintain a strong investment grade rating through price cycles; repurchase shares; and invest capital to grow absolute production. We outlined a 2017 to 2019 operating plan that achieves these priorities at Brent prices at or above $50 per barrel with asset sales of $5 billion to $8 billion.

We believe we have taken prudent actions to position the company for success in an environment of price uncertainty and ongoing volatility, while accomplishing significant milestones in a challenged business environment throughout 2016.

Key Operating and Financial Summary

Significant items during 2016 included the following:

- Achieved full-year production excluding Libya of 1,567 MBOED; 3 percent production growth adjusted for downtime and dispositions.
- Capital expenditures of $4.9 billion, a more than 50 percent reduction compared with 2015.
- Reduced production and operating expenses by 19 percent year over year.
- Achieved project startups at APLNG Train 2 in Australia, Foster Creek Phase G and Christina Lake Phase F in Canada, Alder in Europe, Malikai in Malaysia, and Bohai wellhead platform J in China.
- Significant discovery at Willow prospect in Alaska.
- Generated proceeds of $1.3 billion from asset dispositions.
- Announced preliminary year-end proved reserves of 6.4 billion BOE.
- Initiated $3 billion share buyback program in mid-November.

Business Environment

Global oil market conditions in 2016 were challenging as the excess of supply relative to global demand led to another year of global inventory builds. Global oil prices experienced elevated levels of volatility throughout 2016 with first quarter Brent crude oil prices reaching a 10-year quarterly average low of $33.89 per barrel. Prices recovered slightly in the second and third quarters of 2016 as production growth slowed while demand continued to increase. In the fourth quarter, prices continued to trend higher, with Brent crude oil averaging $49.46 per barrel, as OPEC members and key non-OPEC producers agreed to cut production in 2017.

The energy industry has periodically experienced this type of extreme volatility due to fluctuating supply-and-demand conditions. Commodity prices are the most significant factor impacting our profitability and related reinvestment of operating cash flows into our business. Among other dynamics that could influence world energy markets and commodity prices are global economic health, supply disruptions or fears thereof caused by civil unrest or military conflicts, actions taken by OPEC, environmental laws, tax regulations, governmental policies and weather-related disruptions. North America s energy landscape has been transformed from resource scarcity to an abundance of supply, primarily due to advances in technology responsible for the rapid growth of tight oil production, successful exploration and rising production from the Canadian oil sands. Our strategy is to create value through price cycles by delivering on the financial and operational priorities that underpin our value proposition.

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Financial Priorities

The financial priorities we believe will drive our success through the price cycles include:

- Control costs and expenses. Controlling operating and overhead costs, without compromising safety and environmental stewardship, is a high priority. We monitor these costs using various methodologies that are reported to senior management monthly, on both an absolute-dollar basis and a per-unit basis. Managing operating and overhead costs is critical to maintaining a competitive position in our industry, particularly in a low commodity price environment. The ability to control our operating and overhead costs impacts our ability to deliver strong cash from operations.

- Maintain a strong balance sheet. We believe financial strength is critical in a cyclical business such as ours. In early 2016, ongoing uncertainty around the timing of a price recovery, coupled with tightening credit capacity across the industry, caused us to take actions to preserve our balance sheet strength and mitigate the impacts of possible weak prices in 2016 and 2017. During the first quarter of 2016, we reduced our quarterly dividend and issued additional debt to secure liquidity. Realized commodity prices improved subsequent to the first quarter of 2016, and we paid down approximately $2.3 billion of debt during the second half of the year. In November 2016, we announced our plan to reduce debt to $20 billion by year-end 2019. We expect to retire outstanding debt as it matures and exercise flexibility in paying down our term loan, which is due in 2019.

- Return capital to shareholders. In 2016, we paid dividends on our common stock of $1.3 billion. We believe in delivering value to our shareholders through the price cycles. As a result, we have set a priority to increase our dividend rate annually and purchase up to $3 billion of our common stock over the next three years. We began repurchasing shares in November 2016, and in January 2017, we announced a 6 percent increase to our quarterly dividend, from $0.25 per share to $0.265 per share.

- Focus on financial returns. This is a core aspect of our value proposition. Our goal is to achieve strong financial returns by controlling our costs, high-grading our portfolio, shifting our production mix, and exercising capital discipline.

Operational Priorities

The operational priorities we must manage well to be successful include:

- Maintain capital discipline. We participate in a commodity price-driven and capital-intensive industry, with varying lead times from when an investment decision is made to the time an asset is operational and generates cash flow. As a result, we must invest significant capital dollars to explore for new oil and gas fields, develop newly discovered fields, maintain existing fields, and construct pipelines and LNG facilities. Given our view of greater price volatility, we have shifted our capital allocation to focus on value-preserving, shorter cycle time and low cost-of-supply unconventional programs in our resource base. Our cash allocation priorities call for the investment of sufficient capital to maintain production and pay the existing dividend. Additional allocations of capital toward absolute growth will be dependent on satisfaction of other financial priorities. We use a disciplined approach, focused on value maximization, to set our capital plans.

In November 2016, we announced a 2017 capital budget of $5 billion.

Optimize our portfolio. We continue to optimize our asset portfolio by focusing on low cost-of-supply assets which strategically fit our development plans. In the third quarter of 2015, we announced plans to reduce future capital spending in our deepwater exploration program. Subsequently, in 2016, we sold our interests in several exploration areas, including offshore Senegal, and terminated our final Gulf of Mexico deepwater drillship contract. Additionally, during the year, we sold our 40 percent working interest in the offshore South Natuna Sea Block B Production Sharing Contract (PSC) in Indonesia and our 30 percent interest in an exploration license offshore Newfoundland. We generated approximately $1.3 billion in proceeds from non-core asset dispositions in 2016.

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In November 2016, we announced our plan to divest between $5 billion and $8 billion of assets, primarily associated with North American natural gas, over the next two years. Proceeds from the sale of assets will be directed toward the achievement of our financial priorities. We will continue to evaluate our assets to determine whether they fit our strategic direction and will optimize the portfolio as necessary, directing our capital investments to areas that align with our objectives.

Maintain a relentless focus on safety and environmental stewardship. Safety and environmental stewardship, including the operating integrity of our assets, remain our highest priorities, and we are committed to protecting the health and safety of everyone who has a role in our operations and the communities in which we operate. We strive to conduct our business with respect and care for both the local and global environment and systematically manage risk to drive sustainable business growth. Our sustainability efforts in 2016 focused on updating action plans for climate change, biodiversity, water and human rights, as well as revamping public reporting to be more informative, searchable and responsive to common questions. We are committed to building a learning organization using human performance principles as we relentlessly pursue improved Health, Safety and Environment (HSE) and operational performance.

Add to our proved reserve base. We primarily add to our proved reserve base in two ways:

- Successful exploration, exploitation and development of new and existing fields.
- Application of new technologies and processes to improve recovery from existing fields.

Proved reserve estimates require economic production based on historical 12-month, first-of-month, average prices and current costs. Therefore, our proved reserves generally decrease as prices decline and increase as prices rise. Additionally, as we continue cash conservation efforts, our reserve replacement efforts could be delayed thus limiting our ability to replace depleted reserves. Low commodity prices and reduced capital expenditures in 2016 adversely affected our reported year-end proved reserves. In 2016, our reserve replacement was negative 194 percent. In the five years ended December 31, 2016, our reserve replacement was 35 percent. We expect our proved reserves to increase if prices rise.

Access to additional resources may become increasingly difficult as commodity prices can make projects uneconomic or unattractive. In addition, prohibition of direct investment in some nations, national fiscal terms, political instability, competition from national oil companies, and lack of access to high-potential areas due to environmental or other regulation may negatively impact our ability to increase our reserve base. As such, the timing and level at which we add to our reserve base may, or may not, allow us to replace our production over subsequent years.

Apply technical capability. We leverage our knowledge and technology to create value and safely deliver on our plans. Technical strength is part of our heritage, and we are evolving our technical approach to optimally apply best practices. Companywide, we continue to evaluate potential solutions to leverage knowledge of technological successes across our operations. Such innovations enable us to economically convert additional resources to reserves, achieve greater operating efficiencies and reduce our environmental impact.

Develop and retain a talented work force. We strive to attract, train, develop and retain individuals with the knowledge and skills to implement our business strategy and who support our values and ethics. To this end, we offer university internships across multiple disciplines to attract the best talent and, as needed, recruit experienced hires to maintain a broad range of skills and experience. We promote continued learning, development and technical training through structured development programs designed to enhance the technical and functional skills of our employees.

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Other Factors Affecting Profitability

Other significant factors that can affect our profitability include:

Commodity prices. Our earnings and operating cash flows generally correlate with industry price levels for crude oil and natural gas, the prices of which are subject to factors external to the company and over which we have no control. The following graph depicts the average benchmark prices for West Texas Intermediate (WTI) crude oil, Dated Brent crude oil and U.S. Henry Hub natural gas:

Brent crude oil prices averaged $49.46 per barrel in the fourth quarter of 2016, an increase of 13 percent compared with $43.67 per barrel in the fourth quarter of 2015. Similarly, WTI crude oil prices increased 17 percent from $42.10 per barrel in the fourth quarter of 2015 to $49.18 per barrel in the same period of 2016.

Despite the fourth quarter increase, crude oil prices were under pressure throughout 2016 due to a continued global production increase that outpaced demand growth, leading to a large observed rise in global inventory. The average Brent crude oil price decreased 17 percent, from $52.46 per barrel in 2015 to $43.69 per barrel in 2016.

Henry Hub natural gas prices averaged $2.98 per million British thermal units (MMBTU) in the fourth quarter of 2016, an increase of 31 percent compared with $2.27 per MMBTU in the fourth quarter of 2015. Natural gas prices increased in the fourth quarter due to growth in demand, coupled with declining production.

On average, Henry Hub natural gas prices decreased 8 percent from $2.67 per MMBTU in 2015 to $2.46 per MMBTU in 2016, mainly due to strong production levels and a warmer-than expected winter reducing demand below expectations. In 2016, U.S. underground gas storage inventories reached their highest levels in five years.

Our realized natural gas liquids prices averaged $21.82 per barrel in the fourth quarter of 2016, an increase of 33 percent compared with $16.42 per barrel in the same quarter of 2015.

Similar to natural gas and crude oil, our natural gas liquids prices also declined on average in 2016. Our average realized natural gas liquids prices decreased 6 percent, from $17.79 per barrel in 2015 to $16.68 per barrel in 2016, as the expansion in tight oil production boosted supplies of natural gas liquids, resulting in continued downward pressure on natural gas liquids prices in the United States.

Declining global crude oil prices resulted in the Western Canada Select benchmark price experiencing a 17 percent decline, from $35.21 per barrel in 2015 to $29.36 per barrel in 2016. Consequently, our realized bitumen price experienced a decrease relative to 2015 price levels. Our realized bitumen price was $15.27 per barrel in 2016, a decrease of 18 percent compared with $18.72 per barrel in the same period of 2015.

Our worldwide annual average realized price was $28.35 per barrel of oil equivalent (BOE) in 2016, a decrease of 17 percent compared with $34.34 per BOE in 2015. The reduction in the prices reflects lower average realized prices across all commodities.

In recent years, the use of hydraulic fracturing and horizontal drilling in tight oil formations has led to increased industry actual and forecasted crude oil and natural gas production in the United States. Although providing significant short- and long-term growth opportunities for our company, the increased abundance of crude oil and natural gas due to development of tight oil plays could also have adverse financial implications to us, including: an extended period of low commodity prices; production curtailments; delay of plans to develop areas such as unconventional fields or Alaska North Slope natural gas fields; and underutilization of LNG regasification facilities. Should one or more of these events occur, our revenues would be reduced and additional asset impairments might be possible.

Impairments. As mentioned above, we participate in a capital-intensive industry. At times, our properties, plants and equipment and investments become impaired when, for example, commodity prices decline significantly for long periods of time, our reserve estimates are revised downward, or a decision to dispose of an asset leads to a write-down to its fair value. We may also invest large amounts of money in exploration which, if exploratory drilling proves unsuccessful, could lead to a material impairment of leasehold values. In 2016, we recorded before-tax impairments of $139 million for proved properties and $466 million for unproved properties. As we optimize our assets in the future, it is reasonably possible we may incur future losses upon sale or impairment charges to long-lived assets used in operations, investments in nonconsolidated entities accounted for under the equity method, and unproved properties. For additional information on our impairments in 2016, 2015 and 2014, see Note 9 Impairments, in the Notes to Consolidated Financial Statements.

Effective tax rate. Our operations are located in countries with different tax rates and fiscal structures. Accordingly, even in a stable commodity price and fiscal/regulatory environment, our overall effective tax rate can vary significantly between periods based on the mix of before-tax earnings within our global operations.

Fiscal and regulatory environment. Our operations can be affected by changing economic, regulatory and political environments in the various countries in which we operate, including the United States. Civil unrest or strained relationships with governments may impact our operations or investments. These changing environments have generally negatively impacted our results of operations, and further changes to government fiscal take could have a negative impact on future operations. Our production operations in Libya and related oil exports were suspended or significantly curtailed from July 2013 to October 2016 due to the closure of the Es Sider crude oil export terminal, and they were also suspended in 2011 during Libya s period of civil unrest. In 2016, the United Kingdom government enacted tax legislation which reduced our U.K. corporate tax rate by 10 percent. Our assets in Venezuela and Ecuador were expropriated in 2007 and

2009, respectively. Our management carefully considers these events when evaluating projects or determining the level of activity in such countries.

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Outlook

Full-year 2017 production is expected to be 1,540 to 1,570 MBOED. This results in flat to 2 percent growth compared with full-year 2016 production of 1,540 MBOED when adjusted for 2016 dispositions of 27 MBOED. First-quarter 2017 production is expected to be 1,540 to 1,580 MBOED. Production guidance for 2017 excludes Libya and the impact of future dispositions.

Marketing Activities

In line with our strategic objectives, we are currently marketing certain non-core assets primarily associated with North American natural gas. We expect to generate $5 billion to $8 billion in proceeds over the next two years from asset sales.

Operating Segments

We manage our operations through six operating segments, which are primarily defined by geographic region: Alaska, Lower 48, Canada, Europe and North Africa, Asia Pacific and Middle East, and Other International.

Corporate and Other represents costs not directly associated with an operating segment, such as most interest expense, corporate overhead, certain technology activities, as well as licensing revenues received.

Our key performance indicators, shown in the statistical tables provided at the beginning of the operating segment sections that follow, reflect results from our continuing operations, including commodity prices and production.

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RESULTS OF OPERATIONS

Consolidated Results

A summary of the company s income (loss) from continuing operations by business segment follows:

	Millions of Dollars		
Years Ended December 31	**2016**	2015	2014
Alaska	**$ 319**	4	2,041
Lower 48	**(2,257)**	(1,932)	(22)
Canada	**(935)**	(1,044)	940
Europe and North Africa	**394**	409	814
Asia Pacific and Middle East	**265**	(406)	3,008
Other International	**(16)**	(593)	(100)
Corporate and Other	**(1,329)**	(809)	(874)
Income (loss) from continuing operations	**$ (3,559)**	(4,371)	5,807

2016 vs. 2015

Losses for ConocoPhillips decreased 19 percent in 2016. The decrease was mainly due to:

- Lower exploration expenses. Exploration expenses decreased mainly due to reduced leasehold impairment expense and dry hole costs.
- Lower proved property and equity investment impairments, including the absence of a $1.5 billion before- and after-tax impairment of our equity investment in Australia Pacific LNG Pty Ltd (APLNG) in 2015.
- Lower production and operating expenses.
- A $161 million net deferred tax benefit resulting from a reduction in the U.K. tax rate, which was enacted in September 2016 and effective January 1, 2016.
- The absence of a $129 million deferred tax charge from increased corporate tax rates in Canada in 2015.

The decrease in losses was partly offset by:

- Lower commodity prices.
- The absence of a $555 million net deferred tax benefit resulting from a change in the U.K. tax rate in 2015.
- Lower crude oil, natural gas liquids, and gas sales volumes.
- Lower equity earnings, primarily driven by increased depreciation, depletion and amortization (DD&A) expense, as well as a 2016 deferred tax charge of $174 million resulting from the change of the tax functional currency for APLNG to U.S. dollar.
- Higher interest and debt expense.

Lower gain on dispositions, mainly due to the absence of a $368 million after-tax gain on the disposition of certain properties in our Lower 48 segment.

2015 vs. 2014

Earnings for ConocoPhillips decreased 175 percent in 2015. The decrease was mainly due to lower commodity prices.

In addition, earnings were negatively impacted by:

- Higher proved property and equity investment impairments, including a $1.5 billion before- and after-tax impairment of our equity investment in APLNG.
- Higher exploration expenses. Exploration expenses increased mainly as a result of higher unproved property impairments, dry hole costs and other exploration expenses. The increase included after-tax unproved property impairments of $368 million for our Alaska Chukchi Sea leasehold and capitalized interest, $310 million for our Angola Block 36 and 37 PSCs, $154 million for multiple Gulf of Mexico leases, and $100 million for various Gila Prospect blocks. Additional after-tax dry hole costs and other expenses resulted from a $185 million charge for several properties in Canada, $140 million for two dry holes in Angola, $111 million for a dry hole in the Gila Prospect in deepwater Gulf of Mexico, and $246 million related to the termination of our drilling contract with Ensco.
- Higher DD&A, mainly from increased production and commodity price-driven reserve revisions.
- Higher restructuring charges and pension settlement expense.

These reductions to earnings were partly offset by higher sales volumes, lower production taxes due to reduced commodity prices, lower operating expenses, a $555 million net deferred tax benefit resulting from a change in the U.K. tax rate in the first quarter of 2015, the absence of a $540 million after-tax loss resulting from the Freeport LNG termination agreement, gain on sale of assets, and higher licensing revenue.

Income Statement Analysis

2016 vs. 2015

Sales and other operating revenues decreased 20 percent in 2016, mainly as a result of lower prices across all commodities. Additionally, sales and other operating revenues decreased due to lower natural gas, crude oil and natural gas liquids sales volumes, mainly from dispositions and field decline, partly offset by increased bitumen sales volumes.

Equity in earnings of affiliates decreased 92 percent in 2016. The decrease was primarily due to lower commodity prices, increased DD&A mainly from Trains 1 and 2 being placed in service at APLNG, and a 2016 deferred tax charge of $174 million resulting from a tax functional currency change. The decrease in earnings was partly offset by higher sales volumes at APLNG and FCCL Partnership, as well as lower production taxes at Qatar Liquefied Gas Company Limited (3) (QG3).

Gain on dispositions decreased 39 percent in 2016. The decrease resulted from the absence of a $583 million before-tax gain in 2015 from the sales of producing properties in East Texas and North Louisiana, South Texas, and a certain pipeline and gathering assets in South Texas, as well as a $26 million before-tax loss on the sale of our interest in the Block B PSC in Indonesia in 2016. The decrease was partly offset by the absence of a $149 million before-tax loss on the disposition of non-core assets in western Canada in the fourth quarter of 2015; and gains on the 2016 dispositions of ConocoPhillips Senegal B.V., the entity that held our interests in three exploration blocks offshore Senegal, the Alaska Beluga River Unit natural gas field, and non-core assets in the Lower 48. For additional information on gains on dispositions, see Note 6 Assets Held for Sale or Sold, in the Notes to Consolidated Financial

Statements.

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Other income increased 104 percent in 2016, mainly due to a gain of $88 million from our receipt of mineral properties and active leases from the Greater Northern Iron Ore Properties Trust in the fourth quarter of 2016. Other income was further increased $76 million before-tax for a damage claim settlement in our Lower 48 segment.

Purchased commodities decreased 20 percent in 2016, mainly due to lower natural gas prices.

Production and operating expenses decreased 19 percent in 2016, mainly due to lower operating expense activity, reduced headcount and dispositions of non-core assets, as well as favorable foreign currency impacts.

Selling, general and administrative (SG&A) expenses decreased 24 percent in 2016, primarily due to reduced restructuring expenses, lower headcount and reduced activity. The decrease was partly offset by increases from market impacts on certain compensation programs.

Exploration expenses decreased 54 percent in 2016, primarily as a result of lower leasehold impairment expense, dry hole costs, and other exploration expenses.

Leasehold impairment expense was reduced, mainly due to the absence of 2015 before-tax charges of $575 million for our Chukchi Sea leasehold and capitalized interest; $493 million for Angola Blocks 36 and 37; and $447 million for certain Gulf of Mexico leases, partly offset by 2016 impairments of our Melmar, Gibson, Tiber and other Gulf of Mexico leaseholds.

Dry hole costs were reduced due to the absence of before-tax charges of $1,141 million in 2015, mainly from wells in deepwater Gulf of Mexico, Horn River and Northwest Territories in Canada, Angola Blocks 36 and 37, and Malaysia. The reduction in costs was partly offset by before-tax charges in 2016, including $434 million from several wells in deepwater Gulf of Mexico and $256 million for two wells in Nova Scotia.

Other exploration expenses were reduced mainly due to the absence of a $335 million before-tax charge in 2015 related to the termination of our Ensco Gulf of Mexico deepwater drillship contract, partly offset by before-tax rig cancellation charges and third-party costs of $146 million for our final Gulf of Mexico deepwater drillship contract in 2016.

For additional information on leasehold impairments and other exploration expenses, see Note 8 Suspended Wells and Other Exploration Expenses, and Note 9 Impairments, in the Notes to Consolidated Financial Statements.

Impairments decreased 94 percent in 2016. For additional information, see Note 9 Impairments, in the Notes to Consolidated Financial Statements.

Taxes other than income taxes decreased 18 percent in 2016, primarily as a result of lower production taxes, mainly in our Alaska and Lower 48 segments, given reduced commodity prices and the absence of the impact of a transportation cost ruling by the Federal Energy Regulatory Commission in the fourth quarter of 2015 in Alaska. Taxes other than income taxes were additionally decreased due to lower property taxes in 2016 in our Alaska and Lower 48 segments.

Interest and debt expense increased 35 percent in 2016, primarily due to lower capitalized interest on projects and increased debt.

See Note 19 Income Taxes, in the Notes to Consolidated Financial Statements, for information regarding our income tax provision (benefit) and effective tax rate.

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2015 vs. 2014

Sales and other operating revenues decreased 44 percent in 2015, mainly as a result of lower prices across all commodities. Lower prices were partly offset by higher crude oil and LNG sales volumes.

Equity in earnings of affiliates decreased 74 percent in 2015. The decrease was primarily due to lower earnings from FCCL and QG3, given lower commodity prices, partly offset by higher volumes and lower operational costs.

Gain on dispositions increased by $493 million in 2015. The increase resulted from a $583 million gain from the sales of producing properties in East Texas and North Louisiana, South Texas, and a certain pipeline and gathering assets in South Texas. Gains realized were partly offset by a net loss from the disposition of non-core assets in western Canada. For additional information on gains on dispositions, see Note 6 Assets Held for Sale or Sold, in the Notes to Consolidated Financial Statements.

Other income decreased 66 percent in 2015, mainly due to the absence of 2014 income related to the resolution of a contingent liability in the Other International segment and a legal arbitration settlement in Asia Pacific and Middle East.

Purchased commodities decreased 44 percent in 2015, largely as a result of lower natural gas prices and the absence of a $130 million loss in the Lower 48 related to transportation and storage capacity agreements recognized in 2014.

Production and operating expenses decreased 21 percent in 2015, largely due to lower operating expense activity, including reduced turnarounds at our Bayu-Undan Field and Darwin LNG facility, favorable foreign exchange-related impacts, and the absence of an $849 million charge resulting from the Freeport LNG termination agreement in 2014. The decrease in expense was partially offset by restructuring expenses of $206 million in 2015.

SG&A expenses increased 30 percent in 2015, primarily due to $407 million in restructuring and pension settlement expenses, partially offset by lower staff and compensation plan costs.

Exploration expenses increased 105 percent in 2015, mainly as a result of higher unproved property impairments, primarily in Alaska, Angola and the Lower 48. Higher dry hole and other exploration costs, including a $253 million before-tax expense for wells charged to dry hole in Canada, a $383 million expense related to the termination of our Gulf of Mexico deepwater drillship contract, and a $176 million charge for two wells charged to dry hole in the Gila prospect in the deepwater Gulf of Mexico, also contributed to the increase in exploration expenses. For additional information on leasehold impairments and other exploration expenses, see Note 8 Suspended Wells and Other Exploration Expenses and Note 9 Impairments, in the Notes to Consolidated Financial Statements.

DD&A increased 9 percent in 2015. The increase was mainly associated with higher production volumes in the Lower 48 and Asia Pacific and Middle East and commodity price-related reserve revisions, partly offset by reserve additions in the Lower 48.

Impairments increased 162 percent in 2015. For additional information, see Note 9 Impairments, in the Notes to Consolidated Financial Statements.

Taxes other than income taxes decreased 57 percent in 2015, mainly due to lower production taxes from reduced commodity prices in the Lower 48, Alaska and Asia Pacific and Middle East.

Interest and debt expense increased 42 percent in 2015, primarily due to lower capitalized interest on projects and increased average debt levels in 2015.

See Note 19 Income Taxes, in the Notes to Consolidated Financial Statements, for information regarding our income tax provision (benefit) and effective tax rate.

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Summary Operating Statistics

		2016	2015	2014
Average Net Production				
Crude oil (MBD)*		**598**	605	595
Natural gas liquids (MBD)		**145**	156	159
Bitumen (MBD)		**183**	151	129
Natural gas (MMCFD)**		**3,857**	4,060	3,943
Total Production (MBOED)***		**1,569**	1,589	1,540
		Dollars Per Unit		
Average Sales Prices				
Crude oil (per barrel)	$	**40.86**	48.26	92.80
Natural gas liquids (per barrel)		**16.68**	17.79	38.99
Bitumen (per barrel)		**15.27**	18.72	55.13
Natural gas (per thousand cubic feet)		**3.00**	3.96	6.57
		Millions of Dollars		
Worldwide Exploration Expenses				
General and administrative; geological and geophysical, lease rental, and other	$	**731**	1,127	879
Leasehold impairment		**466**	1,924	562
Dry holes		**718**	1,141	604
	$	**1,915**	4,192	2,045

Excludes discontinued operations.

* *Thousands of barrels per day.*
** *Millions of cubic feet per day. Represents quantities available for sale and excludes gas equivalent of natural gas liquids included above.*
*** *Thousands of barrels of oil equivalent per day.*

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and natural gas liquids on a worldwide basis. At December 31, 2016, our operations were producing in the United States, Norway, the United Kingdom, Canada, Australia, Timor-Leste, Indonesia, China, Malaysia, Qatar and Libya.

Total production, including Libya, of 1,569 MBOED decreased 1 percent in 2016 compared with 2015. The decrease in total average production primarily resulted from normal field decline and the loss of 72 MBOED mainly attributable to the 2015 dispositions of several non-core assets in the Lower 48, western Canada and the sale of our interest in the Polar Lights Company in Russia. The decrease in production was partly offset by additional production from major developments, including tight oil plays in the Lower 48; APLNG in Australia; the Western North Slope in Alaska; the Kebabangan gas field in Malaysia; and the Greater Ekofisk Area in Norway. Improved drilling and well performance in Canada, Norway, the Lower 48, and China, as well as lower unplanned downtime in the Lower 48 also partly offset the decrease in production. Adjusted for downtime and dispositions of 66 MBOED, our production, excluding Libya, increased by 44 MBOED, or 3 percent, compared with 2015. Assets sold in 2016 produced 27 MBOED and 36 MBOED in 2016 and 2015, respectively.

In 2015, average production from continuing operations, including Libya, increased 3 percent compared with 2014, while average liquids production increased 4 percent. The increase in total average production in 2015 primarily resulted from additional production from major developments, including tight oil plays in the Lower 48; Gumusut in Malaysia; APLNG in Australia; Greater Britannia projects and the J-Area in the U.K.; and the ramp-up of Foster Creek Phase F in Canada. Improved well performance, mostly in the Lower 48, western Canada and Norway, and lower turnaround activity also contributed to higher production in 2015. These increases were largely offset by normal field decline. Adjusted for downtime and dispositions of 13 MBOED, our production from continuing operations, excluding Libya, increased by 70 MBOED, or 5 percent, compared with 2014. Full-year 2015 production from assets sold or under agreement was 64 MBOED.

Alaska

		2016	2015	2014
Income from Continuing Operations (millions of dollars)	$	**319**	4	2,041
Average Net Production				
Crude oil (MBD)		**163**	158	162
Natural gas liquids (MBD)		**12**	13	13
Natural gas (MMCFD)		**25**	42	49
Total Production (MBOED)		**179**	178	183
Average Sales Prices				
Crude oil (per barrel)	$	**41.93**	51.61	97.68
Natural gas (per thousand cubic feet)		**5.22**	4.33	5.42

The Alaska segment primarily explores for, produces, transports and markets crude oil, natural gas liquids, natural gas and LNG. In 2016, Alaska contributed 19 percent of our worldwide liquids production and less than 1 percent of our natural gas production.

2016 vs. 2015

Alaska reported earnings of $319 million in 2016, compared with earnings of $4 million in 2015. The increase in earnings was mainly due to:

- Lower exploration expenses, primarily due to the absence of the 2015 impairment charge for our Chukchi Sea leasehold and capitalized interest. For additional information on our impairments, see Note 9 Impairments, in the Notes to Consolidated Financial Statements.
- Reduced production and operating expense, mainly from lower maintenance costs and general and administrative expenses.
- Enhanced oil recovery tax credits.
- Higher crude oil sales volumes, partly offset by the absence of LNG sales volumes.
- A $57 million after-tax impact for the recognition of state deferred tax assets.
- A $36 million after-tax gain on the sale of our interest in the Alaska Beluga River Unit natural gas field.

The increase in earnings was partly offset by lower crude oil prices and higher DD&A expense, mainly due to capital additions.

Average production increased 1 percent in 2016 compared with 2015, primarily due to new production from the Alpine CD5 drill site and strong well performance in the Greater Prudhoe Area. The production increase was partly offset by normal field decline.

2015 vs. 2014

Alaska reported earnings of $4 million in 2015, compared with earnings of $2,041 million in 2014, mainly due to lower commodity prices and a $368 million after-tax charge in the fourth quarter of 2015 for the impairment of our Chukchi Sea leasehold and capitalized interest. The earnings decrease was partly offset by reduced production taxes resulting from lower commodity prices.

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Average production decreased 3 percent in 2015 compared with 2014, primarily due to normal field decline, partly offset by lower planned downtime activity and new production from the Western North Slope, Greater Prudhoe and Greater Kuparuk areas.

Lower 48

		2016	2015	2014
Loss from Continuing Operations (millions of dollars)	$	**(2,257)**	(1,932)	(22)
Average Net Production				
Crude oil (MBD)		**195**	206	188
Natural gas liquids (MBD)		**88**	94	97
Natural gas (MMCFD)		**1,219**	1,472	1,491
Total Production (MBOED)		**486**	545	533
Average Sales Prices				
Crude oil (per barrel)	$	**37.49**	42.62	84.18
Natural gas liquids (per barrel)		**14.34**	14.01	30.74
Natural gas (per thousand cubic feet)		**2.20**	2.43	4.29

The Lower 48 segment consists of operations located in the U.S. Lower 48 states and exploration activities in the Gulf of Mexico. During 2016, the Lower 48 contributed 30 percent of our worldwide liquids production and 32 percent of our natural gas production.

2016 vs. 2015

Lower 48 reported a loss of $2,257 million after-tax in 2016, compared with a loss of $1,932 million after-tax in 2015. The increase in losses was primarily due to:

- The absence of a $368 million after-tax gain on the disposition of certain properties in South Texas, East Texas and North Louisiana.
- Lower crude oil and natural gas prices.
- Lower sales volumes across all commodities due to dispositions and field decline.
- Higher proved property impairments, including a $49 million after-tax impairment associated with changes to development plans for Eagle Ford infrastructure.

The increase in losses was partly offset by:

- Lower production and operating expenses, mainly due to reduced activity and cost efficiencies.

Lower exploration expenses, mainly due to:

- Reduced other exploration costs, mainly due to the absence of a $216 million after-tax charge related to the termination of our Gulf of Mexico deepwater drillship contract with Ensco in 2015, partly offset by 2016 rig cancellation and related third party costs of $95 million after-tax for our final Gulf of Mexico deepwater drillship contract.
- Lower general and administrative, and geological and geophysical expenses.
- Lower leasehold impairment expense, including the absence of 2015 after-tax charges of $154 million for certain leases in the Gulf of Mexico and $100 million for various blocks in the Gila Prospect. The decrease in leasehold impairment was partly offset by 2016 after-tax charges of $132 million for our Gibson and Tiber leaseholds and $62 million for the Melmar Prospect, all in the Gulf of Mexico.

- Lower exploration expenses were partly offset by slightly increased dry hole costs in 2016, including after-tax charges in deepwater Gulf of Mexico of $162 million for our Gibson and Tiber wells and $83 million associated with our Melmar well. Dry hole costs in 2016 were partly offset by the absence of a $111 million after-tax charge in 2015 associated with two wells in the Gila Prospect in the deepwater Gulf of Mexico.

An $88 million gain associated with our receipt of Greater Northern Iron Ore Properties Trust assets in the fourth quarter of 2016.
A $48 million after-tax benefit from a damage claim settlement.
A $38 million after-tax gain from the disposition of non-core assets and lease exchanges.
Lower DD&A, mainly due to 2016 reserve additions and reduced volumes, partly offset by price-related reserve revisions.

Our average realized prices in the Lower 48 have historically correlated with WTI prices; however, beginning in the second half of 2013, our Lower 48 crude differential versus WTI began to widen. Our 2016 average realized crude oil price of $37.49 per barrel was 13 percent less than WTI of $43.20 per barrel. The differential is driven primarily by local market dynamics in the Gulf Coast, Bakken and the Permian Basin, and may remain relatively wide in the near term.

Total average production decreased 11 percent in 2016 compared with 2015. The decrease was mainly attributable to normal field decline and the 2015 disposition of non-core properties in East Texas and North Louisiana, as well as South Texas. The reduction was partly offset by new production and well performance, primarily from Eagle Ford, Bakken and the Permian Basin, as well as lower unplanned downtime.

2015 vs. 2014

Lower 48 reported a loss of $1,932 million after-tax in 2015, compared with a loss of $22 million after-tax in 2014. The decrease in earnings was primarily due to:

Lower crude oil, natural gas and natural gas liquids prices.
Higher DD&A, mostly due to increased crude oil production.
Higher exploration expenses, mainly due to:

- Increased impairment expense in 2015, including after-tax charges of $154 million for certain leases in the Gulf of Mexico and $100 million for various blocks in the Gila Prospect, where we ceased further activity.
- A $246 million after-tax charge to exploration expense related to the termination of our Gulf of Mexico deepwater drillship contract with Ensco.
- Higher dry hole costs, including $111 million after-tax, associated with two wells in the Gila Prospect in the deepwater Gulf of Mexico.

These decreases were partly offset by the absence of a $545 million after-tax charge resulting from the Freeport LNG termination agreement in 2014; a $368 million after-tax gain on the disposition of certain properties in South Texas, East Texas and North Louisiana; higher volumes; lower production taxes; and the absence of a $151 million after-tax impairment charge resulting from reduced volume forecasts on proved properties and the associated undeveloped leasehold costs.

Total average production increased 2 percent in 2015 compared with 2014, while average crude oil production increased 10 percent across the same period. The increase was mainly attributable to new production, primarily from Eagle Ford, Bakken and the Permian Basin, partially offset by normal field decline.

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Canada

		2016	2015	2014
Income (Loss) from Continuing Operations (millions of dollars)	$	**(935)**	(1,044)	940
Average Net Production				
Crude oil (MBD)		**7**	12	13
Natural gas liquids (MBD)		**23**	26	23
Bitumen (MBD)				
Consolidated operations		**35**	13	12
Equity affiliates		**148**	138	117
Total bitumen		**183**	151	129
Natural gas (MMCFD)		**524**	715	711
Total Production (MBOED)		**300**	308	284
Average Sales Prices				
Crude oil (per barrel)	$	**35.25**	39.52	77.87
Natural gas liquids (per barrel)		**14.82**	17.02	46.23
Bitumen (dollars per barrel)				
Consolidated operations		**12.91**	20.13	60.03
Equity affiliates		**15.80**	18.58	54.62
Total bitumen		**15.27**	18.72	55.13
Natural gas (per thousand cubic feet)		**1.49**	1.91	4.13

Our Canadian operations mainly consist of natural gas fields in western Canada and oil sands developments in the Athabasca Region of northeastern Alberta. In 2016, Canada contributed 23 percent of our worldwide liquids production and 14 percent of our worldwide natural gas production.

2016 vs. 2015

Canada operations reported a loss of $935 million in 2016, a decrease in loss of $109 million compared with 2015. The decrease in loss was primarily due to:

- The absence of a $136 million impact of a 2 percent increase in Alberta corporate tax rates on deferred taxes in 2015.
- Lower production and operating expenses, mainly due to reduced headcount and the disposition of non-core assets in western Canada.

Lower exploration expenses, mainly due to:

- Reduced leasehold impairment expense, including the absence of an impairment charge for undeveloped leasehold in the Duvernay, Thornbury, Saleski and Crow Lake areas. The reduction in leasehold impairment expense was partly offset by a $23 million after-tax charge in the fourth quarter of 2016 primarily due to decisions to discontinue further testing on undeveloped leaseholds.
- Lower general and administrative, and geological and geophysical expenses.
- Lower dry hole costs, mainly due to the absence of 2015 charges associated with our Horn River, Northwest Territories, Thornbury and Saleski properties, partly offset by dry hole costs in 2016, including total after-tax charges in offshore Nova Scotia of $187 million for our Cheshire and Monterey Jack wells.

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Higher gains on dispositions, including the absence of a $103 million net after-tax loss on the disposition of non-core assets in western Canada in 2015.

The decrease in loss was partly offset by lower commodity prices; higher DD&A expense, mainly from price-related reserve revisions; and a $42 million after-tax impairment charge related to certain developed properties in central Alberta, which were classified as held for sale, being written down to fair value less costs to sell.

Total average production decreased 3 percent in 2016 compared with 2015, while bitumen production increased 21 percent over the same periods. The decrease in total production was mainly attributable to the disposition of non-core assets in western Canada and normal field decline. The production decrease was partly offset by strong well performance in western Canada, Surmont and FCCL. Surmont has fully recovered from the forest fire impacts.

2015 vs. 2014

Canada operations reported a loss of $1,044 million in 2015, a reduction in earnings of $1,984 million compared with 2014. The decrease in earnings was primarily due to:

Lower bitumen and natural gas prices.

Higher exploration expenses, mainly due to:

- Higher dry hole costs, including an after-tax charge of $185 million associated with our Horn River, Northwest Territories, Thornbury and Saleski properties.
- An after-tax impairment charge of $75 million for undeveloped leaseholds in the Duvernay, Thornbury, Saleski and Crow Lake areas.

A 2 percent increase in Alberta corporate tax rates on deferred taxes.

A $103 million net after-tax loss realized on the disposition of non-core assets in western Canada.

The earnings decrease was partly offset by higher bitumen production volumes; lower operating expenses and DD&A, both primarily from favorable foreign currency impacts; and the absence of the $109 million after-tax impairment of undeveloped leasehold costs associated with the offshore Amauligak discovery, Arctic Islands and other Beaufort properties in 2014.

Total average production increased 8 percent in 2015 compared with 2014, while bitumen production increased 17 percent over the same periods. The increases in total production were mainly attributable to strong well performance in western Canada, lower royalty impacts, strong plant performance at Foster Creek and Christina Lake and the continued ramp-up of production from Foster Creek Phase F. These increases were partly offset by normal field decline and increased unplanned downtime, including the precautionary shut down of Foster Creek for nearby forest fires in the second quarter of 2015.

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Europe and North Africa

		2016	2015	2014
Income from Continuing Operations (millions of dollars)	$	**394**	409	814
Average Net Production				
Crude oil (MBD)		**122**	120	134
Natural gas liquids (MBD)		**7**	7	8
Natural gas (MMCFD)		**460**	476	464
Total Production (MBOED)		**205**	207	219
Average Sales Prices				
Crude oil (dollars per barrel)	$	**43.66**	52.75	98.98
Natural gas liquids (per barrel)		**22.62**	27.56	52.65
Natural gas (per thousand cubic feet)		**4.71**	7.14	9.28

The Europe and North Africa segment consists of operations principally located in the Norwegian and U.K. sectors of the North Sea, the Norwegian Sea, and Libya. In 2016, our Europe and North Africa operations contributed 14 percent of our worldwide liquids production and 12 percent of our natural gas production.

2016 vs. 2015

Earnings for Europe and North Africa operations of $394 million decreased 4 percent in 2016. The decrease in earnings was primarily due to the absence of a $555 million net deferred tax benefit as a result of a change in the U.K. tax rate, effective at the beginning of 2015; lower crude oil and natural gas prices; lower sales volumes; and the absence of a 2015 after-tax gain of $49 million on the sale of our 1.9 percent interest in Norwegian Continental Shelf Gas Transportation (Gassled).

The decrease in earnings was partly offset by:

- Lower property impairments, including the absence of 2015 after-tax charges of $317 million in the U.K. due to lower crude oil and natural gas prices, and a $180 million credit to impairment in 2016 due to decreased asset retirement obligation estimates on fields that are nearing the end of life and were impaired in prior years. The reduction in property impairments was partly offset by a $59 million after-tax charge associated with our Calder Field and Rivers terminal in the U.K. For additional information on our impairments, see Note 9 Impairments, in the Notes to Consolidated Financial Statements.
- Lower DD&A expense in the U.K. driven by reduced rate, as a result of completed depreciation on the Brodgar H3 tie-back well in 2015, and lower volumes.
- A $161 million net deferred tax benefit resulting from a reduction in the U.K. tax rate, which was enacted in September 2016 and effective January 1, 2016.

Reduced operating expenses across the segment.

Average production decreased 1 percent in 2016, compared with 2015. The decrease in production was mainly due to normal field decline, partly offset by improved drilling and well performance in Norway and new production from the Greater Ekofisk and Greater Britannia areas. Libya production remained largely shut in, as the Es Sider crude oil export terminal closure continued throughout the third quarter of 2016. Production resumed in Libya in October 2016, with three crude liftings from Es Sider in January 2017. We expect a gradual ramp-up in activity.

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2015 vs. 2014

Earnings for Europe and North Africa operations decreased 50 percent in 2015. The decrease in earnings was primarily due to lower crude oil and natural gas prices. Earnings further decreased due to higher property impairments in the U.K., given lower natural gas prices and increases to asset retirement obligations. The earnings decrease was partly offset by a $555 million net deferred tax benefit as a result of a change in the U.K. tax rate, effective at the beginning of 2015, and an after-tax gain of $49 million on the sale of our 1.9 percent interest in Norwegian Continental Shelf Gas Transportation (Gassled).

For additional information on the impairments, see Note 9 Impairments, in the Notes to Consolidated Financial Statements.

Average production decreased 5 percent in 2015, compared with 2014. The decrease in production was mostly due to normal field decline and lower volumes from Libya, partly offset by the new production from the Greater Britannia Area, the J-Area and the Greater Ekofisk Area, as well as improved well performance in Norway.

The Es Sider Terminal in Libya remained shut in throughout 2015 as a result of civil unrest.

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Asia Pacific and Middle East

		2016	2015	2014
Income (Loss) from Continuing Operations (millions of dollars)	$	**265**	(406)	3,008
Average Net Production				
Crude oil (MBD)				
Consolidated operations		**97**	91	79
Equity affiliates		**14**	14	15
Total crude oil		**111**	105	94
Natural gas liquids (MBD)				
Consolidated operations		**7**	9	10
Equity affiliates		**8**	7	8
Total natural gas liquids		**15**	16	18
Natural gas (MMCFD)				
Consolidated operations		**730**	717	723
Equity affiliates		**899**	638	505
Total natural gas		**1,629**	1,355	1,228
Total Production (MBOED)		**399**	347	317
Average Sales Prices				
Crude oil (dollars per barrel)				
Consolidated operations	$	**42.23**	49.70	95.32
Equity affiliates		**44.11**	53.12	99.01
Total crude oil		**42.47**	50.16	95.92
Natural gas liquids (dollars per barrel)				
Consolidated operations		**29.00**	37.78	69.36
Equity affiliates		**31.13**	35.79	67.20
Total natural gas liquids		**30.11**	36.88	68.46
Natural gas (dollars per thousand cubic feet)				
Consolidated operations		**4.31**	6.23	9.80
Equity affiliates		**2.97**	4.83	9.79
Total natural gas		**3.57**	5.58	9.80

The Asia Pacific and Middle East segment has operations in China, Indonesia, Malaysia, Australia, Timor-Leste and Qatar, as well as exploration activities in Brunei. During 2016, Asia Pacific and Middle East contributed 14 percent of our worldwide liquids production and 42 percent of our natural gas production.

2016 vs. 2015

Asia Pacific and Middle East reported earnings of $265 million in 2016, compared with a loss of $406 million in 2015. The earnings increase was mainly due to:

- The absence of a $1,502 million before- and after-tax charge for the impairment of our APLNG investment in 2015. For additional information on our APLNG impairment, see the APLNG section of Note 7 Investments, Loans and Long-Term Receivables in the Notes to Consolidated Financial Statements.
- Higher LNG sales volumes.

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- Lower production taxes.
- Reduced feedstock costs at Darwin LNG.
- Lower operating expenses, mainly due to lower general and administrative spend, maintenance costs and transportation expenses across the segment.
- Lower exploration expenses, mainly due to lower dry hole costs, as well as the absence of a $41 million after-tax charge in 2015 for the impairment of our relinquished Palangkaraya PSC, and reduced exploration general and administrative expense.

The earnings increase was partly offset by lower prices across all commodities; lower equity earnings from APLNG, mainly as a result of higher DD&A expense from APLNG Trains 1 and 2 coming online; and a third-quarter 2016 deferred tax charge of $174 million resulting from APLNG s tax functional currency change.

Average production increased 15 percent in 2016, compared with 2015. The production increase in 2016 was mainly attributable to new production from the ramp-up of APLNG in Australia and the Kebabangan gas field in Malaysia, improved drilling and well performance in China and Malaysia, and increased recoveries from production sharing contracts in Indonesia. The production increase was partially offset by normal field decline across the segment.

2015 vs. 2014

Asia Pacific and Middle East reported a loss of $406 million in 2015, compared with income of $3,008 million in 2014. The decrease in earnings was mainly due to lower prices across all commodities. Earnings in 2015 were further decreased by a $1,502 million before- and after-tax charge for the impairment of our APLNG investment, higher DD&A expense from increased volumes, primarily in Malaysia, and a $41 million after-tax charge for the impairment of our relinquished Palangkaraya PSC. The earnings decrease was partially offset by lower production taxes, increased volumes, as well as lower feedstock costs and reduced turnarounds at our Bayu-Undan Field and Darwin LNG facility.

Average production increased 9 percent in 2015, compared with 2014. The production increase was mainly attributable to new production from Gumusut, in Malaysia, which came online in the fourth quarter of 2014; the ramp-up of APLNG production due to additional gas processing facilities online; and infill drilling in China. Production increases were partly offset by normal field decline.

Other International

		2016	2015	2014
Loss from Continuing Operations (millions of dollars)	$	**(16)**	(593)	(100)
Average Net Production				
Crude oil (MBD)				
Equity affiliates		**-**	4	4
Total Production (MBOED)		**-**	4	4
Average Sales Prices				

Crude oil (dollars per barrel)			
Equity affiliates	**-**	37.21	64.14

The Other International segment includes exploration activities in Colombia and Chile.

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2016 vs. 2015

Other International operations reported a loss of $16 million in 2016, compared with a loss of $593 million in 2015. The decrease in losses was primarily due to the absence of after-tax charges in 2015 of $235 million, $75 million and $32 million net for property impairments on our Angola Block 36, Angola Block 37 and Poland leasehold, respectively. Additionally, losses decreased due to the absence of the 2015 after-tax dry hole expenses offshore Angola of $81 million for the Omosi-1 well and $59 million for the Vali-1 well, combined with a $138 million gain on the disposition of ConocoPhillips Senegal B.V., the entity that held our interest in three exploration blocks offshore Senegal.

2015 vs. 2014

Other International operations reported a loss of $593 million in 2015, compared with a loss of $100 million in 2014. The decrease in earnings was primarily due to after-tax charges of $235 million, $75 million and $32 million net for property impairments on our Angola Block 36, Angola Block 37 and Poland leasehold, respectively. Earnings were also reduced due to increased dry hole expenses for the Omosi-1 and Vali-1 wells offshore Angola and the absence of other income of $154 million after-tax associated with the favorable resolution of a contingent liability. The reduction in earnings was partly offset by the absence of the $136 million after-tax charge in 2014 for the Kamoxi-1 exploration well, located offshore Angola; and a $53 million after-tax gain from the disposition of our interest in the Polar Lights Company.

For additional information on the impairments, see Note 9 Impairments, in the Notes to Consolidated Financial Statements.

Average production was flat in 2015 compared with 2014.

Corporate and Other

		Millions of Dollars		
		2016	2015	2014
Income (Loss) from Continuing Operations				
Net interest	$	**(980)**	(518)	(502)
Corporate general and administrative expenses		**(289)**	(246)	(194)
Technology		**50**	122	(93)
Other		**(110)**	(167)	(85)
	$	**(1,329)**	(809)	(874)

2016 vs. 2015

Net interest consists of interest and financing expense, net of interest income and capitalized interest, as well as premiums incurred on the early retirement of debt. Net interest increased 89 percent in 2016 compared with 2015, primarily as a result of the absence of the 2015 impacts from the fair market value of apportioning interest expense in the United States, lower capitalized interest on projects, and increased debt.

Corporate general and administrative expenses increased 17 percent in 2016, mainly due to increases from market impacts on certain compensation programs, partly offset by lower staff expenses.

Technology includes our investment in new technologies or businesses, as well as licensing revenues received. Activities are focused on tight oil reservoirs, heavy oil and oil sands, as well as LNG. Earnings from Technology were $50 million in 2016, compared with $122 million in 2015. The decrease in earnings primarily resulted from lower licensing revenues, partly offset by reduced technology program spend.

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The category Other includes certain foreign currency transaction gains and losses, environmental costs associated with sites no longer in operation, and other costs not directly associated with an operating segment. Other expenses decreased 34 percent in 2016, mainly due to lower restructuring costs and favorable foreign currency impacts, partly offset by the absence of a 2015 tax benefit.

2015 vs. 2014

Net interest increased 3 percent in 2015 compared with 2014, primarily as a result of lower capitalized interest on projects completed or sold and increased debt. The 2015 net interest expense increase was largely offset by a $148 million net tax benefit for electing the fair market value method of apportioning interest expense in the United States for prior years.

Corporate general and administrative expenses increased 27 percent in 2015, mainly due to $143 million in after-tax pension settlement expense, partially offset by lower staff and compensation plan costs.

Earnings from Technology were $122 million in 2015, compared with a loss of $93 million in 2014. The increase in earnings primarily resulted from higher licensing revenues.

Other expenses increased by $82 million in 2015, mainly due to $142 million after-tax in restructuring charges and foreign currency translation impacts, partially offset by lower environmental expenses.

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CAPITAL RESOURCES AND LIQUIDITY

Financial Indicators

		Millions of Dollars Except as Indicated		
		2016	2015	2014
Net cash provided by continuing operating activities	$	**4,403**	7,572	16,412
Net cash provided by discontinued operations		**-**	-	157
Cash and cash equivalents		**3,610**	2,368	5,062
Short-term debt		**1,089**	1,427	182
Total debt		**27,275**	24,880	22,565
Total equity		**35,226**	40,082	52,273
Percent of total debt to capital*		**44 %**	38	30
Percent of floating-rate debt to total debt		**9 %**	7	5

**Capital includes total debt and total equity.*

To meet our short- and long-term liquidity requirements, we look to a variety of funding sources, including cash generated from operating activities. In addition, during 2016 we received $1,286 million in proceeds from asset sales and issued $4,594 million of new debt consisting of a three-year term loan and fixed rate notes. The primary uses of our available cash were $4,869 million to support our ongoing capital expenditures and investments program; $2,251 million to repay debt; $1,253 million to pay dividends on our common stock; and $126 million to repurchase common stock. During 2016, cash and cash equivalents increased by $1,242 million, to $3,610 million.

In addition to cash flows from operating activities and proceeds from asset sales, we rely on our commercial paper and credit facility programs and our shelf registration statement to support our short- and long-term liquidity requirements. We believe current cash balances and cash generated by operations, together with access to external sources of funds as described below in the Significant Sources of Capital section, will be sufficient to meet our funding requirements in the near and long term, including our capital spending program, dividend payments and required debt payments.

Significant Sources of Capital

Operating Activities

During 2016, cash provided by operating activities was $4,403 million, a 42 percent decrease from 2015. The decrease was primarily due to lower prices across all commodities. Cash flows from operating activities were positively impacted by the $585 million and $642 million tax refunds received from the Internal Revenue Service during 2016 and 2015, respectively.

While the stability of our cash flows from operating activities benefits from geographic diversity, our short- and long-term operating cash flows are highly dependent upon prices for crude oil, bitumen, natural gas, LNG and natural gas liquids. Prices and margins in our industry have historically been volatile and are driven by market conditions over which we have no control. Absent other mitigating factors, as these prices and margins fluctuate, we would expect a corresponding change in our operating cash flows.

The level of absolute production volumes, as well as product and location mix, impacts our cash flows. Our 2016 production averaged 1,569 MBOED. Full-year 2017 production is expected to be 1,540 to 1,570 MBOED, which results in flat to 2 percent growth compared with full-year 2016 production, excluding Libya, of 1,540 MBOED when adjusted for 2016 dispositions of 27 MBOED. Production guidance for 2017 excludes Libya and the impact of future dispositions. Future production is subject to numerous uncertainties, including, among others, the volatile crude oil and natural gas price environment, which may impact investment decisions; the effects of price changes on production sharing and variable-royalty contracts; acquisition and disposition of fields; field production decline rates; new technologies; operating efficiencies;

timing of startups and major turnarounds; political instability; weather-related disruptions; and the addition of proved reserves through exploratory success and their timely and cost-effective development. While we actively manage these factors, production levels can cause variability in cash flows, although generally this variability has not been as significant as that caused by commodity prices.

To maintain or grow our production volumes, we must continue to add to our proved reserve base. Our total reserve replacement in 2016 was negative 194 percent. Over the five-year period ended December 31, 2016, our reserve replacement was 35 percent (including 11 percent from consolidated operations) reflecting the impact of lower prices and asset dispositions. The total reserve replacement amount above is based on the sum of our net additions (revisions, improved recovery, purchases, extensions and discoveries, and sales) divided by our production, as shown in our reserve table disclosures. For additional information about our 2017 capital budget, see the 2017 Capital Budget section within Capital Resources and Liquidity and for additional information on proved reserves, including both developed and undeveloped reserves, see the Oil and Gas Operations section of this report.

As discussed in the Critical Accounting Estimates section, engineering estimates of proved reserves are imprecise; therefore, each year reserves may be revised upward or downward due to the impact of changes in commodity prices or as more technical data becomes available on reservoirs. In 2016 and 2015, revisions decreased reserves, while in 2014, revisions increased reserves. It is not possible to reliably predict how revisions will impact reserve quantities in the future.

Investing Activities

Proceeds from asset sales in 2016 were $1.3 billion, primarily from the sales of ConocoPhillips Senegal B.V., the entity that held our 35 percent interest in three exploration blocks offshore Senegal; our 40 percent interest in South Natuna Sea Block B in Indonesia; our interest in the Alaska Beluga River Unit natural gas field in the Cook Inlet; and certain mineral and non-mineral fee lands in northeastern Minnesota. This compares with proceeds of $2.0 billion in 2015, primarily from the sales of certain western Canadian properties; producing properties in East Texas and North Louisiana and in South Texas; a certain pipeline and gathering assets in South Texas; and our 50 percent equity method investment in the Russian joint venture, Polar Lights Company. For additional information, see Note 6 Assets Held for Sale or Sold in the Notes to Consolidated Financial Statements, and the Outlook section within Management s Discussion and Analysis.

Commercial Paper and Credit Facilities

On March 28, 2016, we reduced our revolving credit facility, expiring in June 2019, from $7.0 billion to $6.75 billion. Our revolving credit facility may be used for direct bank borrowings, the issuance of letters of credit totaling up to $500 million, or as support for our commercial paper programs. The revolving credit facility is broadly syndicated among financial institutions and does not contain any material adverse change provisions or any covenants requiring maintenance of specified financial ratios or credit ratings. The facility agreement contains a cross-default provision relating to the failure to pay principal or interest on other debt obligations of $200 million or more by ConocoPhillips or any of its consolidated subsidiaries.

Credit facility borrowings may bear interest at a margin above rates offered by certain designated banks in the London interbank market or at a margin above the overnight federal funds rate or prime rates offered by certain designated banks in the United States. The agreement calls for commitment fees on available, but unused, amounts. The agreement also contains early termination rights if our current directors or their approved successors cease to be a majority of the Board of Directors.

Our primary funding source for short-term working capital needs is the ConocoPhillips $6.25 billion commercial paper program. Commercial paper maturities are generally limited to 90 days. We also have the ConocoPhillips Qatar Funding Ltd. $500 million commercial paper program, which is used to fund commitments relating to QG3. At both December 31, 2016 and 2015, we had no direct borrowings or letters of credit issued under the revolving credit facility. Under the ConocoPhillips Qatar Funding Ltd. commercial paper programs, no commercial paper was outstanding at December 31, 2016, compared with $803 million at December 31, 2015. Since we had no commercial paper outstanding and had issued no letters of credit, we had access to $6.75 billion in borrowing capacity under our revolving credit facility at December 31, 2016.

Due to the significant decline in commodity prices during 2015, and the expectation these prices could remain depressed in the near future, the major ratings agencies conducted a review of the oil and gas industry. As a result of this review, our credit ratings, along with several other companies in the oil and gas industry, were downgraded. In the first quarter of 2016, Moody s Investors Service downgraded our senior long-term debt ratings to Baa2 from A2, with a negative outlook and our short-term commercial paper ratings to Prime 2 from Prime 1 and Fitch downgraded our long-term debt ratings to A- from A with a negative outlook and our short-term commercial paper ratings to F2 from F1. In the second quarter of 2016, Standard and Poor s downgraded our senior long-term debt ratings to A- from A, with a negative outlook and our short-term commercial paper ratings to A-2 from A-1. We do not have any ratings triggers on any of our corporate debt that would cause an automatic default, and thereby impact our access to liquidity, in the event of a further downgrade of our credit rating. If our credit rating were downgraded further, it could increase the cost of corporate debt available to us and restrict our access to commercial paper. If our credit rating were to deteriorate to a level prohibiting us from accessing the commercial paper market, we would still be able to access funds under our revolving credit facility.

Certain of our project-related contracts, commercial contracts and derivative instruments contain provisions requiring us to post collateral. Many of these contracts and instruments permit us to post either cash or letters of credit as collateral. At December 31, 2016 and December 31, 2015, we had direct bank letters of credit of $304 million and $340 million, respectively, which secured performance obligations related to various purchase commitments incident to the ordinary conduct of business. In the event of further credit ratings downgrades, we may be required to post additional letters of credit.

Shelf Registration

We have a universal shelf registration statement on file with the U.S. Securities and Exchange Commission (SEC) under which we, as a well-known seasoned issuer, have the ability to issue and sell an indeterminate amount of various types of debt and equity securities.

Off-Balance Sheet Arrangements

As part of our normal ongoing business operations and consistent with normal industry practice, we enter into numerous agreements with other parties to pursue business opportunities, which share costs and apportion risks among the parties as governed by the agreements.

For information about guarantees, see Note 12 Guarantees, in the Notes to Consolidated Financial Statements, which is incorporated herein by reference.

Capital Requirements

For information about our capital expenditures and investments, see the Capital Expenditures section.

Our debt balance at December 31, 2016, was $27.3 billion, an increase of $2.4 billion from the balance at December 31, 2015, primarily as a result of obtaining a $1.6 billion three-year term loan and the issuance of $3.0 billion in new fixed rate notes, both in March 2016, partly offset by the retirement in October 2016 of the $1,250 million of 5.625% Notes at maturity, the $803 million repayment of outstanding commercial paper, and early repayment of $150 million of our term loan. Our short-term debt balance at December 31, 2016, decreased $338 million compared with December 31, 2015, primarily as a result of the timing of scheduled maturities. For more information, see Note 11 Debt, in the Notes to Consolidated Financial Statements.

To preserve our balance sheet strength and provide financial flexibility through the recent downturn, in the first quarter of 2016, we announced a reduction in the quarterly dividend to $0.25 per share. The dividend was paid March 1, 2016, to stockholders of record at the close of business on February 16, 2016. In July 2016, we announced a dividend of $0.25 per share. The dividend was paid September 1, 2016, to stockholders of record at the close of business on July 25, 2016. In October 2016, we announced a dividend of $0.25 per share. The dividend was paid December 1, 2016, to stockholders of record at the close of business on October 17, 2016.

Additionally, on January 31, 2017, we announced an increase to our quarterly dividend of 6 percent, from $0.25 per share to $0.265 per share. The dividend will be paid March 1, 2017, to stockholders of record at the close of business on February 14, 2017.

On November 10, 2016, we announced plans to purchase up to $3 billion of our common stock over the next three years. Repurchase of shares began in November and totaled 2,579,098 shares at a cost of $126 million, through December 31, 2016.

Contractual Obligations

The following table summarizes our aggregate contractual fixed and variable obligations as of December 31, 2016:

		Millions of Dollars				
		Payments Due by Period				
		Total	Up to 1 Year	Years 2 3	Years 4 5	After 5 Years
Debt obligations (a)	$	26,423	1,005	5,542	3,689	16,187
Capital lease obligations (b)		852	84	136	139	493
Total debt		27,275	1,089	5,678	3,828	16,680
Interest on debt and other obligations		15,765	1,318	2,371	1,964	10,112
Operating lease obligations (c)		1,626	277	410	504	435
Purchase obligations (d)		22,791	15,581	2,259	1,304	3,647
Other long-term liabilities						
Pension and postretirement benefit contributions (e)		1,628	430	635	563	
Asset retirement obligations (f)		8,405	202	546	697	6,960
Accrued environmental costs (g)		247	25	46	42	134
Unrecognized tax benefits (h)		42	42	(h)	(h)	(h)
Total	$	77,779	18,964	11,945	8,902	37,968

(a) Includes $248 million of net unamortized premiums, discounts and debt issuance costs. See Note 11 Debt, in the Notes to Consolidated Financial Statements, for additional information.

(b) Capital lease obligations are presented on a discounted basis.

(c) Operating lease obligations are presented on an undiscounted basis.

(d) Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms, presented on an undiscounted basis. Does not include purchase commitments for jointly owned fields and facilities where we are not the operator.

The majority of the purchase obligations are market-based contracts related to our commodity business. Product purchase commitments with third parties totaled $4,673 million.

Purchase obligations of $6,232 million are related to agreements to access and utilize the capacity of third-party equipment and facilities, including pipelines and LNG and product terminals, to transport, process, treat and store commodities. The remainder is primarily our net share of purchase commitments for materials and services for jointly owned fields and facilities where we are the operator.

(e) Represents contributions to qualified and nonqualified pension and postretirement benefit plans for the years 2017 through 2021. For additional information related to expected benefit payments subsequent to 2021, see Note 18 Employee Benefit Plans, in the Notes to Consolidated Financial Statements.

(f) Represents estimated discounted costs to retire and remove long-lived assets at the end of their operations.

(g) Represents estimated costs for accrued environmental expenditures presented on a discounted basis for costs acquired in various business combinations and an undiscounted basis for all other accrued environmental costs.

(h) Excludes unrecognized tax benefits of $341 million because the ultimate disposition and timing of any payments to be made with regard to such amounts are not reasonably estimable. Although unrecognized tax benefits are not a contractual obligation, they are presented in this table because they represent potential demands on our liquidity.

Capital Expenditures

	Millions of Dollars		
	2016	2015	2014
Alaska	$ **883**	1,352	1,564
Lower 48	**1,262**	3,765	6,054
Canada	**698**	1,255	2,340
Europe and North Africa	**1,020**	1,573	2,540
Asia Pacific and Middle East	**838**	1,812	3,877
Other International	**104**	173	520
Corporate and Other	**64**	120	190
Capital expenditures and investments from continuing operations	**4,869**	10,050	17,085
Discontinued operations in Nigeria	**-**	-	59
Capital Program	$ **4,869**	10,050	17,144

Our capital expenditures and investments from continuing operations for the three-year period ended December 31, 2016, totaled $32 billion. The 2016 expenditures supported key exploration and developments, primarily:

- Oil and natural gas development and exploration activities in the Lower 48, including Eagle Ford, Bakken, and the Permian Basin.
- In Europe, development activities in the Clair Ridge, Greater Ekofisk, Aasta Hansteen, and Greater Britannia areas, and exploration and appraisal activities in the North Sea.

Alaska activities related to development in the Greater Kuparuk Area, Greater Prudhoe Area and the Western North Slope, and exploration activities in the National Petroleum Reserve-Alaska.
Major project expenditures associated with the APLNG joint venture in Australia.
Oil sands development in Canada.
Exploration and appraisal drilling in deepwater Gulf of Mexico.
Exploration activities in offshore Nova Scotia and appraisal activities in western Canada.
Continued development in China, Malaysia and Indonesia, and exploration and appraisal activity in Senegal and Chile.

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2017 CAPITAL BUDGET

In 2016, given our view of greater price volatility, we announced a plan for allocating cash across the business which sets annual capital at a level that maintains flat production volumes. Our 2017 capital budget of $5 billion reaffirms this strategy. We have shifted our capital allocation to focus on value-preserving, shorter cycle time and low cost-of-supply unconventional programs in our resource base.

We are planning to allocate approximately:

- 46 percent of our 2017 capital expenditures budget to development drilling programs. These funds will focus predominantly on the Lower 48 unconventionals including the Eagle Ford and Bakken, as well as development drilling in Norway, Alaska and Canada.
- 26 percent of our 2017 capital expenditures budget to major projects. These funds will focus on major projects in Alaska, China, Europe and Malaysia, as well as APLNG in Australia.
- 15 percent of our 2017 capital expenditures budget to maintain base production and corporate expenditures.
- 13 percent of our 2017 capital expenditures budget to exploration and appraisal activity. These funds will primarily target the Permian and Niobrara, Colombia, Chile, Australia and Canada.

For information on proved undeveloped reserves and the associated costs to develop these reserves, see the Oil and Gas Operations section.

Contingencies

A number of lawsuits involving a variety of claims arising in the ordinary course of business have been filed against ConocoPhillips. We also may be required to remove or mitigate the effects on the environment of the placement, storage, disposal or release of certain chemical, mineral and petroleum substances at various active and inactive sites. We regularly assess the need for accounting recognition or disclosure of these contingencies. In the case of all known contingencies (other than those related to income taxes), we accrue a liability when the loss is probable and the amount is reasonably estimable. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not reduce these liabilities for potential insurance or third-party recoveries. If applicable, we accrue receivables for probable insurance or other third-party recoveries. With respect to income tax related contingencies, we use a cumulative probability-weighted loss accrual in cases where sustaining a tax position is less than certain.

Based on currently available information, we believe it is remote that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on our consolidated financial statements. For information on other contingencies, see Critical Accounting Estimates and Note 13 Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

Legal and Tax Matters

We are subject to various lawsuits and claims including but not limited to matters involving oil and gas royalty and severance tax payments, gas measurement and valuation methods, contract disputes, environmental damages, personal injury, and property damage. Our primary exposures for such matters relate to alleged royalty and tax underpayments on certain federal, state and privately owned properties and claims of alleged environmental contamination from historic operations. We will continue to defend ourselves vigorously in these matters.

Our legal organization applies its knowledge, experience and professional judgment to the specific characteristics of our cases, employing a litigation management process to manage and monitor the legal proceedings against us. Our process facilitates the early evaluation and quantification of potential exposures in individual cases. This process also enables us to track those cases that have been scheduled for trial and/or mediation. Based on professional judgment and experience in using these litigation management tools and available information about current developments in all our cases, our legal organization regularly assesses the

adequacy of current accruals and determines if adjustment of existing accruals, or establishment of new accruals, is required. See Note 19 Income Taxes, in the Notes to Consolidated Financial Statements, for additional information about income tax-related contingencies.

Environmental

We are subject to the same numerous international, federal, state and local environmental laws and regulations as other companies in our industry. The most significant of these environmental laws and regulations include, among others, the:

- U.S. Federal Clean Air Act, which governs air emissions.
- U.S. Federal Clean Water Act, which governs discharges to water bodies.
- European Union Regulation for Registration, Evaluation, Authorization and Restriction of Chemicals (REACH).
- U.S. Federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), which imposes liability on generators, transporters and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur.
- U.S. Federal Resource Conservation and Recovery Act (RCRA), which governs the treatment, storage and disposal of solid waste.
- U.S. Federal Oil Pollution Act of 1990 (OPA90), under which owners and operators of onshore facilities and pipelines, lessees or permittees of an area in which an offshore facility is located, and owners and operators of vessels are liable for removal costs and damages that result from a discharge of oil into navigable waters of the United States.
- U.S. Federal Emergency Planning and Community Right-to-Know Act (EPCRA), which requires facilities to report toxic chemical inventories with local emergency planning committees and response departments.
- U.S. Federal Safe Drinking Water Act, which governs the disposal of wastewater in underground injection wells.
- U.S. Department of the Interior regulations, which relate to offshore oil and gas operations in U.S. waters and impose liability for the cost of pollution cleanup resulting from operations, as well as potential liability for pollution damages.
- European Union Trading Directive resulting in European Emissions Trading Scheme.

These laws and their implementing regulations set limits on emissions and, in the case of discharges to water, establish water quality limits. They also, in most cases, require permits in association with new or modified operations. These permits can require an applicant to collect substantial information in connection with the application process, which can be expensive and time consuming. In addition, there can be delays associated with notice and comment periods and the agency s processing of the application. Many of the delays associated with the permitting process are beyond the control of the applicant.

Many states and foreign countries where we operate also have, or are developing, similar environmental laws and regulations governing these same types of activities. While similar, in some cases these regulations may impose additional, or more stringent, requirements that can add to the cost and difficulty of marketing or transporting products across state and international borders.

The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor easily determinable as new standards, such as air emission standards, water quality standards and stricter fuel regulations, continue to evolve. However, environmental laws and regulations, including those that may arise to address concerns about global climate change, are expected to continue to have an increasing impact on our operations in the United States and in other countries in which we operate. Notable areas of potential impacts include air emission compliance and remediation obligations in the United States and Canada.

An example is the use of hydraulic fracturing, an essential completion technique that facilitates production of oil and natural gas otherwise trapped in lower permeability rock formations. A range of local, state, federal or national laws and regulations currently govern hydraulic fracturing operations, with hydraulic fracturing currently prohibited in some jurisdictions.

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Although hydraulic fracturing has been conducted for many decades, a number of new laws, regulations and permitting requirements are under consideration by the U.S. Environmental Protection Agency (EPA), the U.S. Department of the Interior, and others which could result in increased costs, operating restrictions, operational delays and/or limit the ability to develop oil and natural gas resources. Governmental restrictions on hydraulic fracturing could impact the overall profitability or viability of certain of our oil and natural gas investments. We have adopted operating principles that incorporate established industry standards designed to meet or exceed government requirements. Our practices continually evolve as technology improves and regulations change.

We also are subject to certain laws and regulations relating to environmental remediation obligations associated with current and past operations. Such laws and regulations include CERCLA and RCRA and their state equivalents. Longer-term expenditures are subject to considerable uncertainty and may fluctuate significantly.

We occasionally receive requests for information or notices of potential liability from the EPA and state environmental agencies alleging we are a potentially responsible party under CERCLA or an equivalent state statute. On occasion, we also have been made a party to cost recovery litigation by those agencies or by private parties. These requests, notices and lawsuits assert potential liability for remediation costs at various sites that typically are not owned by us, but allegedly contain wastes attributable to our past operations. As of December 31, 2016, there were 14 sites around the United States in which we were identified as a potentially responsible party under CERCLA and comparable state laws.

For most Superfund sites, our potential liability will be significantly less than the total site remediation costs because the percentage of waste attributable to us, versus that attributable to all other potentially responsible parties, is relatively low. Although liability of those potentially responsible is generally joint and several for federal sites and frequently so for state sites, other potentially responsible parties at sites where we are a party typically have had the financial strength to meet their obligations, and where they have not, or where potentially responsible parties could not be located, our share of liability has not increased materially. Many of the sites at which we are potentially responsible are still under investigation by the EPA or the state agencies concerned. Prior to actual cleanup, those potentially responsible normally assess site conditions, apportion responsibility and determine the appropriate remediation. In some instances, we may have no liability or attain a settlement of liability. Actual cleanup costs generally occur after the parties obtain EPA or equivalent state agency approval. There are relatively few sites where we are a major participant, and given the timing and amounts of anticipated expenditures, neither the cost of remediation at those sites nor such costs at all CERCLA sites, in the aggregate, is expected to have a material adverse effect on our competitive or financial condition.

Expensed environmental costs were $435 million in 2016 and are expected to be about $470 million per year in 2017 and 2018. Capitalized environmental costs were $192 million in 2016 and are expected to be about $275 million per year in 2017 and 2018.

Accrued liabilities for remediation activities are not reduced for potential recoveries from insurers or other third parties and are not discounted (except those assumed in a purchase business combination, which we do record on a discounted basis).

Many of these liabilities result from CERCLA, RCRA and similar state or international laws that require us to undertake certain investigative and remedial activities at sites where we conduct, or once conducted, operations or at sites where ConocoPhillips-generated waste was disposed. The accrual also includes a number of sites we identified that may require environmental remediation, but which are not currently the subject of CERCLA, RCRA or other agency enforcement activities. If applicable, we accrue receivables for probable insurance or other third-party recoveries. In the future, we may incur significant costs under both CERCLA and RCRA.

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Remediation activities vary substantially in duration and cost from site to site, depending on the mix of unique site characteristics, evolving remediation technologies, diverse regulatory agencies and enforcement policies, and the presence or absence of potentially liable third parties. Therefore, it is difficult to develop reasonable estimates of future site remediation costs.

At December 31, 2016, our balance sheet included total accrued environmental costs of $247 million, compared with $258 million at December 31, 2015, for remediation activities in the U.S. and Canada. We expect to incur a substantial amount of these expenditures within the next 30 years.

Notwithstanding any of the foregoing, and as with other companies engaged in similar businesses, environmental costs and liabilities are inherent concerns in our operations and products, and there can be no assurance that material costs and liabilities will not be incurred. However, we currently do not expect any material adverse effect upon our results of operations or financial position as a result of compliance with current environmental laws and regulations.

Climate Change

There has been a broad range of proposed or promulgated state, national and international laws focusing on greenhouse gas (GHG) reduction. These proposed or promulgated laws apply or could apply in countries where we have interests or may have interests in the future. Laws in this field continue to evolve, and while it is not possible to accurately estimate either a timetable for implementation or our future compliance costs relating to implementation, such laws, if enacted, could have a material impact on our results of operations and financial condition. Examples of legislation or precursors for possible regulation that do or could affect our operations include:

- European Emissions Trading Scheme (ETS), the program through which many of the European Union (EU) member states are implementing the Kyoto Protocol. Our cost of compliance with the EU ETS in 2016 was approximately $1.4 million (net share before-tax).
- The Alberta Specified Gas Emitter regulations require any existing facility with emissions equal to or greater than 100,000 metric tonnes of carbon dioxide or equivalent per year to reduce its net emissions intensity from its baseline. The reduction requirement increased from 12 percent in 2015, to 15 percent in 2016 and will increase again to 20 percent in 2017. We also incur a carbon tax for emissions from fossil fuel combustion in our British Columbia operations. The total cost of compliance with these regulations in 2016 was approximately $8 million.
- The U.S. Supreme Court decision in Massachusetts v. EPA, 549 U.S. 497, 127 S.Ct. 1438 (2007), confirming that the EPA has the authority to regulate carbon dioxide as an air pollutant under the Federal Clean Air Act.
- The U.S. EPA s announcement on March 29, 2010 (published as Interpretation of Regulations that Determine Pollutants Covered by Clean Air Act Permitting Programs, 75 Fed. Reg. 17004 (April 2, 2010)), and the EPA s and U.S. Department of Transportation s joint promulgation of a Final Rule on April 1, 2010, that triggers regulation of GHGs under the Clean Air Act, may trigger more climate-based claims for damages, and may result in longer agency review time for development projects.
- The U.S. EPA s announcement on January 14, 2015, outlining a series of steps it plans to take to address methane and smog-forming volatile organic compound emissions from the oil and gas industry. The former U.S. administration established a goal of reducing the 2012 levels in methane emissions from the oil and gas industry by 40 to 45 percent by 2025.
- Carbon taxes in certain jurisdictions. Our cost of compliance with Norwegian carbon tax legislation in 2016 was approximately $28 million (net share before-tax).

The agreement reached in Paris in December 2015 at the 21st Conference of the Parties to the United Nations Framework on Climate Change, setting out a new process for achieving global emission reductions.

In the United States, some additional form of regulation may be forthcoming in the future at the federal and state levels with respect to GHG emissions. Such regulation could take any of several forms that may result in the creation of additional costs in the form of taxes, the restriction of output, investments of capital to maintain compliance with laws and regulations, or required acquisition or trading of emission allowances.

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We are working to continuously improve operational and energy efficiency through resource and energy conservation throughout our operations.

Compliance with changes in laws and regulations that create a GHG emission trading scheme or GHG reduction policies could significantly increase our costs, reduce demand for fossil energy derived products, impact the cost and availability of capital and increase our exposure to litigation. Such laws and regulations could also increase demand for less carbon intensive energy sources, including natural gas. The ultimate impact on our financial performance, either positive or negative, will depend on a number of factors, including but not limited to:

- Whether and to what extent legislation or regulation is enacted.
- The timing of the introduction of such legislation or regulation.
- The nature of the legislation (such as a cap and trade system or a tax on emissions) or regulation.
- The price placed on GHG emissions (either by the market or through a tax).
- The GHG reductions required.
- The price and availability of offsets.
- The amount and allocation of allowances.
- Technological and scientific developments leading to new products or services.
- Any potential significant physical effects of climate change (such as increased severe weather events, changes in sea levels and changes in temperature).
- Whether, and the extent to which, increased compliance costs are ultimately reflected in the prices of our products and services.

The company has responded by putting in place a corporate Climate Change Action Plan, together with individual business unit climate change management plans in order to undertake actions in four major areas:

- Equipping the company for a low emission world, for example by integrating GHG forecasting and reporting into company procedures; utilizing GHG pricing in planning economics; developing systems to handle GHG market transactions.
- Reducing GHG emissions In 2015, the company reduced or avoided GHG emissions by approximately 566,000 metric tonnes by carrying out a range of programs across a number of business units.
- Evaluating business opportunities such as the creation of offsets and allowances, the use of low carbon energy and the development of low carbon technologies.
- Engaging externally The company is a sponsor of MIT s Joint Program on the Science and Policy of Global Change; constructively engages in the development of climate change legislation and regulation; and discloses our progress and performance through the Carbon Disclosure Project and the Dow Jones Sustainability Index.

The company uses an estimated market cost of GHG emissions in the range of $9 to $43 per tonne depending on the timing and country or region to evaluate future opportunities.

Other

We have deferred tax assets related to certain accrued liabilities, loss carryforwards and credit carryforwards. Valuation allowances have been established to reduce these deferred tax assets to an amount that will, more likely than not, be realized. Based on our historical taxable income, our expectations for the future, and available tax-planning strategies, management expects the net deferred tax assets will be realized as offsets to reversing deferred tax liabilities and as offsets to the tax consequences of future taxable income.

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NEW ACCOUNTING STANDARDS

In February 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2016-02, Leases (ASU No. 2016-02), which establishes comprehensive accounting and financial reporting requirements for leasing arrangements. This ASU supersedes the existing requirements in FASB Accounting Standards Codification (ASC) Topic 840, Leases, and requires lessees to recognize substantially all lease assets and lease liabilities on the balance sheet. The provisions of ASU No. 2016-02 also modify the definition of a lease and outline requirements for recognition, measurement, presentation, and disclosure of leasing arrangements by both lessees and lessors. The ASU is effective for interim and annual periods beginning after December 15, 2018, and early adoption of the standard is permitted. Entities are required to adopt the ASU using a modified retrospective approach, subject to certain optional practical expedients, and apply the provisions of ASU No. 2016-02 to leasing arrangements existing at or entered into after the earliest comparative period presented in the financial statements. While we continue to evaluate the ASU, we expect the adoption of the ASU to have a material impact on our consolidated financial statements and disclosures. For additional information, see Note 25 New Accounting Standards, in the Notes to Consolidated Financial Statements.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in conformity with generally accepted accounting principles requires management to select appropriate accounting policies and to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. See Note 1 Accounting Policies, in the Notes to Consolidated Financial Statements, for descriptions of our major accounting policies. Certain of these accounting policies involve judgments and uncertainties to such an extent there is a reasonable likelihood materially different amounts would have been reported under different conditions, or if different assumptions had been used. These critical accounting estimates are discussed with the Audit and Finance Committee of the Board of Directors at least annually. We believe the following discussions of critical accounting estimates, along with the discussions of contingencies and of deferred tax asset valuation allowances in this report, address all important accounting areas where the nature of accounting estimates or assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change.

Oil and Gas Accounting

Accounting for oil and gas exploratory activity is subject to special accounting rules unique to the oil and gas industry. The acquisition of geological and geophysical seismic information, prior to the discovery of proved reserves, is expensed as incurred, similar to accounting for research and development costs. However, leasehold acquisition costs and exploratory well costs are capitalized on the balance sheet pending determination of whether proved oil and gas reserves have been discovered on the prospect.

Property Acquisition Costs

For individually significant leaseholds, management periodically assesses for impairment based on exploration and drilling efforts to date. For relatively small individual leasehold acquisition costs, management exercises judgment and determines a percentage probability that the prospect ultimately will fail to find proved oil and gas reserves and pools that leasehold information with others in the geographic area. For prospects in areas with limited, or no, previous exploratory drilling, the percentage probability of ultimate failure is normally judged to be quite high. This judgmental percentage is multiplied by the leasehold acquisition cost, and that product is divided by the contractual period of the leasehold to determine a periodic leasehold impairment charge that is reported in exploration expense.

This judgmental probability percentage is reassessed and adjusted throughout the contractual period of the leasehold based on favorable or unfavorable exploratory activity on the leasehold or on adjacent leaseholds, and leasehold impairment amortization expense is adjusted prospectively. At year-end 2016, the book value of the pools of property acquisition costs, that individually are relatively small and thus subject to the above-described periodic leasehold impairment calculation, was $404 million and the accumulated impairment reserve was $197 million.

The weighted-average judgmental percentage probability of ultimate failure was approximately 69 percent, and the weighted-average amortization period was approximately two years. If that judgmental percentage were to be raised by 5 percent across all calculations, before-tax leasehold impairment expense in 2017 would increase by approximately $5 million. At year-end 2016, the remaining $3,659 million of net capitalized unproved property costs consisted primarily of individually significant leaseholds, mineral rights held in perpetuity by title ownership, exploratory wells currently being drilled, suspended exploratory wells, and capitalized interest. Of this amount, approximately $2.5 billion is concentrated in nine major development areas, the majority of which are not expected to move to proved properties in 2017. Management periodically assesses individually significant leaseholds for impairment based on the results of exploration and drilling efforts and the outlook for commercialization.

Exploratory Costs

For exploratory wells, drilling costs are temporarily capitalized, or suspended, on the balance sheet, pending a determination of whether potentially economic oil and gas reserves have been discovered by the drilling effort to justify development.

If exploratory wells encounter potentially economic quantities of oil and gas, the well costs remain capitalized on the balance sheet as long as sufficient progress assessing the reserves and the economic and operating viability of the project is being made. The accounting notion of sufficient progress is a judgmental area, but the accounting rules do prohibit continued capitalization of suspended well costs on the expectation future market conditions will improve or new technologies will be found that would make the development economically profitable. Often, the ability to move into the development phase and record proved reserves is dependent on obtaining permits and government or co-venturer approvals, the timing of which is ultimately beyond our control. Exploratory well costs remain suspended as long as we are actively pursuing such approvals and permits, and believe they will be obtained. Once all required approvals and permits have been obtained, the projects are moved into the development phase, and the oil and gas reserves are designated as proved reserves. For complex exploratory discoveries, it is not unusual to have exploratory wells remain suspended on the balance sheet for several years while we perform additional appraisal drilling and seismic work on the potential oil and gas field or while we seek government or co-venturer approval of development plans or seek environmental permitting. Once a determination is made the well did not encounter potentially economic oil and gas quantities, the well costs are expensed as a dry hole and reported in exploration expense.

Management reviews suspended well balances quarterly, continuously monitors the results of the additional appraisal drilling and seismic work, and expenses the suspended well costs as a dry hole when it determines the potential field does not warrant further investment in the near term. Criteria utilized in making this determination include evaluation of the reservoir characteristics and hydrocarbon properties, expected development costs, ability to apply existing technology to produce the reserves, fiscal terms, regulations or contract negotiations, and our expected return on investment.

At year-end 2016, total suspended well costs were $1,063 million, compared with $1,260 million at year-end 2015. For additional information on suspended wells, including an aging analysis, see Note 8 Suspended Wells and Other Exploration Expenses, in the Notes to Consolidated Financial Statements.

Proved Reserves

Engineering estimates of the quantities of proved reserves are inherently imprecise and represent only approximate amounts because of the judgments involved in developing such information. Reserve estimates are based on geological and engineering assessments of in-place hydrocarbon volumes, the production plan, historical extraction recovery and processing yield factors, installed plant operating capacity and approved operating limits. The reliability of these estimates at any point in time depends on both the quality and quantity of the technical and economic data and the efficiency of extracting and processing the hydrocarbons.

Despite the inherent imprecision in these engineering estimates, accounting rules require disclosure of proved reserve estimates due to the importance of these estimates to better understand the perceived value and future cash flows of a company s operations. There are several authoritative guidelines regarding the engineering criteria that must be met before estimated reserves can be designated as proved.

Our geosciences and reservoir engineering organization has policies and procedures in place consistent with these authoritative guidelines. We have trained and experienced internal engineering personnel who estimate our proved reserves held by consolidated companies, as well as our share of equity affiliates.

Proved reserve estimates are adjusted annually in the fourth quarter and during the year if significant changes occur, and take into account recent production and subsurface information about each field. Also, as required by current authoritative guidelines, the estimated future date when an asset will be permanently shut down for economic reasons is based on 12-month average prices and current costs. This estimated date when production will end affects the amount of estimated reserves. Therefore, as prices and cost levels change from year to year, the estimate of proved reserves also changes. Generally, our proved reserves decrease as prices decline and increase as prices rise.

Our proved reserves include estimated quantities related to production sharing contracts, reported under the economic interest method, as well as variable-royalty regimes, and are subject to fluctuations in commodity prices; recoverable operating expenses; and capital costs. If costs remain stable, reserve quantities attributable to recovery of costs will change inversely to changes in commodity prices. We would expect reserves from these contracts to decrease when product prices rise and increase when prices decline.

The estimation of proved developed reserves also is important to the income statement because the proved developed reserve estimate for a field serves as the denominator in the unit-of-production calculation of the DD&A of the capitalized costs for that asset. At year-end 2016, the net book value of productive properties, plants and equipment (PP&E) subject to a unit-of-production calculation was approximately $60 billion and the DD&A recorded on these assets in 2016 was approximately $8.6 billion. The estimated proved developed reserves for our consolidated operations were 4.0 billion BOE at the end of 2015 and 3.7 billion BOE at the end of 2016. If the estimates of proved reserves used in the unit-of-production calculations had been lower by 10 percent across all calculations, before-tax DD&A in 2016 would have increased by an estimated $955 million.

Impairments

Long-lived assets used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in future cash flows expected to be generated by an asset group and annually in the fourth quarter following updates to corporate planning assumptions. If there is an indication the carrying amount of an asset may not be recovered, the asset is monitored by management through an established process where changes to significant assumptions such as prices, volumes and future development plans are reviewed. If, upon review, the sum of the undiscounted before-tax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value. Individual assets are grouped for impairment purposes based on a judgmental assessment of the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets generally on a field-by-field basis for exploration and production assets. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is typically determined based on the present values of expected future cash flows using discount rates believed to be consistent with those used by principal market participants, or based on a multiple of operating cash flow validated with historical market transactions of similar assets where possible. The expected future cash flows used for impairment reviews and related fair value calculations are based on judgmental assessments of future production volumes, commodity prices, operating costs and capital decisions, considering all available information at the date of review. Differing assumptions could affect the timing and the amount of an impairment in any period. See Note 9 Impairments, in the Notes to Consolidated Financial Statements, for additional information.

Investments in nonconsolidated entities accounted for under the equity method are reviewed for impairment when there is evidence of a loss in value and annually following updates to corporate planning assumptions. Such evidence of a loss in value might include our inability to recover the carrying amount, the lack of sustained earnings capacity which would justify the current investment amount, or a current fair value less than the investment s carrying amount. When it is determined such a loss in value is other than temporary, an impairment charge is recognized for the difference between the investment s carrying value and its estimated fair value.

When determining whether a decline in value is other than temporary, management considers factors such as the length of time and extent of the decline, the investee s financial condition and near-term prospects, and our ability and intention to retain our investment for a period that will be sufficient to allow for any anticipated recovery in the market value of the investment. Since quoted market prices are usually not available, the fair value is typically based on the present value of expected future cash flows using discount rates believed to be consistent with those used by principal market participants, plus market analysis of comparable assets owned by the investee, if appropriate. Differing assumptions could affect the timing and the amount of an impairment of an investment in any period. See the APLNG section of Note 7 Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements, for additional information.

Asset Retirement Obligations and Environmental Costs

Under various contracts, permits and regulations, we have material legal obligations to remove tangible equipment and restore the land or seabed at the end of operations at operational sites. Our largest asset removal obligations involve plugging and abandonment of wells, removal and disposal of offshore oil and gas platforms around the world, as well as oil and gas production facilities and pipelines in Alaska. The fair values of obligations for dismantling and removing these facilities are recorded as a liability and an increase to PP&E at the time of installation of the asset based on estimated discounted costs. Estimating future asset removal costs is difficult. Most of these removal obligations are many years, or decades, in the future and the contracts and regulations often have vague descriptions of what removal practices and criteria must be met when the removal event actually occurs. Asset removal technologies and costs, regulatory and other compliance considerations, expenditure timing, and other inputs into valuation of the obligation, including discount and inflation rates, are also subject to change.

Normally, changes in asset removal obligations are reflected in the income statement as increases or decreases to DD&A over the remaining life of the assets. However, for assets at or nearing the end of their operations, as well as previously sold assets for which we retained the asset removal obligation, an increase in the asset removal obligation can result in an immediate charge to earnings, because any increase in PP&E due to the increased obligation would immediately be subject to impairment, due to the low fair value of these properties.

In addition to asset removal obligations, under the above or similar contracts, permits and regulations, we have certain environmental-related projects. These are primarily related to remediation activities required by Canada and various states within the United States at exploration and production sites. Future environmental remediation costs are difficult to estimate because they are subject to change due to such factors as the uncertain magnitude of cleanup costs, the unknown time and extent of such remedial actions that may be required, and the determination of our liability in proportion to that of other responsible parties. See Note 10 Asset Retirement Obligations and Accrued Environmental Costs, in the Notes to Consolidated Financial Statements, for additional information.

Projected Benefit Obligations

Determination of the projected benefit obligations for our defined benefit pension and postretirement plans are important to the recorded amounts for such obligations on the balance sheet and to the amount of benefit expense in the income statement. The actuarial determination of projected benefit obligations and company contribution requirements involves judgment about uncertain future events, including estimated retirement dates, salary levels at retirement, mortality rates, lump-sum election rates, rates of return on plan assets, future health care cost-trend rates, and rates of utilization of health care services by retirees. Due to the specialized nature of these calculations, we engage outside actuarial firms to assist in the determination of these projected benefit obligations and company contribution requirements. For Employee Retirement Income Security Act-governed pension plans, the actuary exercises fiduciary care on behalf of plan participants in the determination of the judgmental assumptions used in determining required company contributions into the plans. Due to differing objectives and requirements between financial accounting rules and the pension plan funding regulations promulgated by governmental agencies, the actuarial methods and assumptions for the two purposes differ in certain important respects. Ultimately, we will be required to fund all vested benefits under pension and postretirement benefit plans not funded by plan assets or investment returns, but the judgmental assumptions used in the actuarial calculations significantly affect periodic financial statements and funding patterns over time. Projected benefit obligations are particularly sensitive to the discount rate assumption. A 1 percent decrease in the discount rate assumption would increase projected benefit obligations by $1,100 million. Benefit expense is particularly sensitive to the discount rate and return on plan assets assumptions. A 1 percent decrease in the discount rate assumption would increase annual benefit expense by $90 million, while a 1 percent decrease in the return on plan assets assumption would increase annual benefit expense by $50 million. In determining the discount rate, we use yields on high-quality fixed income investments matched to the estimated benefit cash flows of our plans. We are also exposed to the possibility that lump sum retirement benefits taken from pension plans during the year could exceed the total of service and interest components of annual pension expense and trigger accelerated recognition of a portion of unrecognized net actuarial losses and gains. These benefit payments are based on decisions by plan participants and are therefore difficult to predict. In the event there is a significant reduction in the expected years of future service of present employees or elimination for a significant number of employees the accrual of defined benefits for some or all of their future services, we could recognize a curtailment gain or loss. See Note 18 Employee Benefit Plans, in the Notes to Consolidated Financial Statements, for additional information.

Contingencies

A number of claims and lawsuits are made against the company arising in the ordinary course of business. Management exercises judgment related to accounting and disclosure of these claims which includes losses, damages, and underpayments associated with environmental remediation, tax, contracts, and other legal disputes. As we learn new facts concerning contingencies, we reassess our position both with respect to amounts recognized and disclosed considering changes to the probability of additional losses and potential exposure. However, actual losses can and do vary from estimates for a variety of reasons including legal, arbitration, or other third party decisions; settlement discussions; evaluation of scope of damages; interpretation of regulatory or contractual terms; expected timing of future actions; and proportion of liability shared with other responsible parties. Estimated future costs related to contingencies are subject to change as events evolve and as additional information becomes available during the administrative and litigation processes. For additional information on contingent liabilities, see the Contingencies section within Capital Resources and Liquidity.

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CAUTIONARY STATEMENT FOR THE PURPOSES OF THE SAFE HARBOR PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included or incorporated by reference in this report, including, without limitation, statements regarding our future financial position, business strategy, budgets, projected revenues, projected costs and plans, and objectives of management for future operations, are forward-looking statements. Examples of forward-looking statements contained in this report include our expected production growth and outlook on the business environment generally, our expected capital budget and capital expenditures, and discussions concerning future dividends. You can often identify our forward-looking statements by the words anticipate, estimate, believe, budget, continue, could, intend, m potential, predict, seek, should, will, would, expect, objective, projection, forecast, goal, guic target and similar expressions.

We based the forward-looking statements on our current expectations, estimates and projections about ourselves and the industries in which we operate in general. We caution you these statements are not guarantees of future performance as they involve assumptions that, while made in good faith, may prove to be incorrect, and involve risks and uncertainties we cannot predict. In addition, we based many of these forward-looking statements on assumptions about future events that may prove to be inaccurate. Accordingly, our actual outcomes and results may differ materially from what we have expressed or forecast in the forward-looking statements. Any differences could result from a variety of factors, including, but not limited to, the following:

- Fluctuations in crude oil, bitumen, natural gas, LNG and natural gas liquids prices, including a prolonged decline in these prices relative to historical or future expected levels.
- The impact of recent, significant declines in prices for crude oil, bitumen, natural gas, LNG and natural gas liquids, which may result in recognition of impairment costs on our long-lived assets, leaseholds and nonconsolidated equity investments.
- Potential failures or delays in achieving expected reserve or production levels from existing and future oil and gas developments, including due to operating hazards, drilling risks and the inherent uncertainties in predicting reserves and reservoir performance.
- Inability to maintain reserves replacement rates consistent with prior periods, whether as a result of the recent, significant declines in commodity prices or otherwise.
- Unsuccessful exploratory drilling activities or the inability to obtain access to exploratory acreage.
- Unexpected changes in costs or technical requirements for constructing, modifying or operating exploration and production facilities.
- Legislative and regulatory initiatives addressing environmental concerns, including initiatives addressing the impact of global climate change or further regulating hydraulic fracturing, methane emissions, flaring or water disposal.
- Lack of, or disruptions in, adequate and reliable transportation for our crude oil, bitumen, natural gas, LNG and natural gas liquids.
- Inability to timely obtain or maintain permits, including those necessary for drilling and/or development, construction of LNG terminals or regasification facilities; failure to comply with applicable laws and regulations; or inability to make capital expenditures required to maintain compliance with any necessary permits or applicable laws or regulations.
- Failure to complete definitive agreements and feasibility studies for, and to timely complete construction of, announced and future exploration and production and LNG development.

Potential disruption or interruption of our operations due to accidents, extraordinary weather events, civil unrest, political events, war, terrorism, cyber attacks or infrastructure constraints or disruptions.
Changes in international monetary conditions and exchange controls, including changes in foreign currency exchange rates.
Reduced demand for our products or the use of competing energy products, including alternative energy sources.

- Substantial investment in and development of alternative energy sources, including as a result of existing or future environmental rules and regulations.
- Liability for remedial actions, including removal and reclamation obligations, under environmental regulations.
- Liability resulting from litigation.
- General domestic and international economic and political developments, including armed hostilities; expropriation of assets; changes in governmental policies relating to crude oil, bitumen, natural gas, LNG and natural gas liquids pricing, regulation or taxation; and other political, economic or diplomatic developments.
- Volatility in the commodity futures markets.
- Changes in tax and other laws, regulations (including alternative energy mandates), or royalty rules applicable to our business.
- Competition in the oil and gas exploration and production industry.
- Any limitations on our access to capital or increase in our cost of capital related to illiquidity or uncertainty in the domestic or international financial markets.
- Our inability to execute asset dispositions or delays in the completion of any asset dispositions we elect to pursue.
- Our inability to obtain economical financing for development, construction or modification of facilities and general corporate purposes.
- The operation and financing of our joint ventures.
- The ability of our customers and other contractual counterparties to satisfy their obligations to us.
- Our inability to realize anticipated cost savings and expenditure reductions.
- The factors generally described in Item 1A Risk Factors in this report.

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Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Financial Instrument Market Risk

We and certain of our subsidiaries hold and issue derivative contracts and financial instruments that expose our cash flows or earnings to changes in commodity prices, foreign currency exchange rates or interest rates. We may use financial and commodity-based derivative contracts to manage the risks produced by changes in the prices of natural gas, crude oil and related products; fluctuations in interest rates and foreign currency exchange rates; or to capture market opportunities.

Our use of derivative instruments is governed by an Authority Limitations document approved by our Board of Directors that prohibits the use of highly leveraged derivatives or derivative instruments without sufficient liquidity. The Authority Limitations document also establishes the Value at Risk (VaR) limits for the company, and compliance with these limits is monitored daily. The Executive Vice President of Finance, Commercial, and Chief Financial Officer, who reports to the Chief Executive Officer, monitors commodity price risk and risks resulting from foreign currency exchange rates and interest rates. The Commercial organization manages our commercial marketing, optimizes our commodity flows and positions, and monitors risks.

Commodity Price Risk

Our Commercial organization uses futures, forwards, swaps and options in various markets to accomplish the following objectives:

- Meet customer needs. Consistent with our policy to generally remain exposed to market prices, we use swap contracts to convert fixed-price sales contracts, which are often requested by natural gas consumers, to floating market prices.
- Enable us to use market knowledge to capture opportunities such as moving physical commodities to more profitable locations and storing commodities to capture seasonal or time premiums. We may use derivatives to optimize these activities.

We use a VaR model to estimate the loss in fair value that could potentially result on a single day from the effect of adverse changes in market conditions on the derivative financial instruments and derivative commodity instruments we hold or issue, including commodity purchases and sales contracts recorded on the balance sheet at December 31, 2016, as derivative instruments. Using Monte Carlo simulation, a 95 percent confidence level and a one-day holding period, the VaR for those instruments issued or held for trading purposes or held for purposes other than trading at December 31, 2016 and 2015, was immaterial to our consolidated cash flows and net income attributable to ConocoPhillips.

Interest Rate Risk

The following table provides information about our financial instruments that are sensitive to changes in U.S. interest rates. The debt portion of the table presents principal cash flows and related weighted-average interest rates by expected maturity dates. Weighted-average variable rates are based on effective rates at the reporting date. The carrying amount of our floating-rate debt approximates its fair value. The fair value of the fixed-rate financial instruments is estimated based on quoted market prices.

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	Millions of Dollars Except as Indicated			
	Debt			
Expected Maturity Date	Fixed Rate Maturity	Average Interest Rate	Floating Rate Maturity	Average Interest Rate
Year-End 2016				
2017	**$ 1,001**	**1.06 %**	**$ -**	**- %**
2018	**1,570**	**3.63**	**250**	**1.24**
2019	**2,250**	**5.75**	**1,450**	**2.31**
2020	**1,500**	**4.73**	**-**	**-**
2021	**2,150**	**4.08**	**-**	**-**
Remaining years	**15,221**	**5.77**	**783**	**1.43**
Total	**$ 23,692**		**$ 2,483**	
Fair value	**$ 26,824**		**$ 2,483**	
Year-End 2015				
2016	$ 1,250	5.63 %	$ 108	0.35 %
2017	1,024	1.03	-	-
2018	1,547	3.68	250	0.69
2019	2,250	5.75	695	0.35
2020	1,500	4.73	-	-
Remaining years	14,371	5.72	783	0.81
Total	$ 21,942		$ 1,836	
Fair value	$ 22,949		$ 1,836	

Foreign Currency Exchange Risk

We have foreign currency exchange rate risk resulting from international operations. We do not comprehensively hedge the exposure to currency exchange rate changes although we may choose to selectively hedge certain foreign currency exchange rate exposures, such as firm commitments for capital projects or local currency tax payments, dividends and cash returns from net investments in foreign affiliates to be remitted within the coming year.

At December 31, 2016 and 2015, we held foreign currency exchange forwards hedging cross-border commercial activity and foreign currency exchange swaps for purposes of mitigating our cash-related exposures. Although these forwards and swaps hedge exposures to fluctuations in exchange rates, we elected not to utilize hedge accounting. As a result, the change in the fair value of these foreign currency exchange derivatives is recorded directly in earnings. Since the gain or loss on the swaps is offset by the gain or loss from remeasuring the related cash balances, and since our aggregate position in the forwards was not material, there would be no material impact to our income from an adverse hypothetical 10 percent change in the December 31, 2016, or 2015, exchange rates. The notional and fair market values of these positions at December 31, 2016 and 2015, were as follows:

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		In Millions			
Foreign Currency Exchange Derivatives		Notional*		Fair Market Value**	
		2016	2015	**2016**	2015
Sell U.S. dollar, buy British pound	USD	**-**	200	$ **-**	(3)
Sell U.S. dollar, buy Canadian dollar	USD	**13**	-	**-**	-
Sell U.S. dollar, buy Norwegian krone	USD	**-**	147	**-**	(2)
Buy U.S. dollar, sell Canadian dollar	USD	**-**	20	**-**	2
Buy U.S. dollar, sell British pound	USD	**25**	-	**-**	-
Buy British pound, sell Canadian dollar	GBP	**1,069**	564	**(168)**	44
Buy British pound, sell Euro	GBP	**-**	3	**-**	(1)
Sell British pound, buy Norwegian krone	GBP	**51**	-	**1**	-

**Denominated in U.S. dollars (USD) and British pound (GBP).*

***Denominated in U.S. dollars.*

For additional information about our use of derivative instruments, see Note 14 Derivative and Financial Instruments, in the Notes to Consolidated Financial Statements.

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Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CONOCOPHILLIPS

INDEX TO FINANCIAL STATEMENTS

Report of Management

Management prepared, and is responsible for, the consolidated financial statements and the other information appearing in this annual report. The consolidated financial statements present fairly the company s financial position, results of operations and cash flows in conformity with accounting principles generally accepted in the United States. In preparing its consolidated financial statements, the company includes amounts that are based on estimates and judgments management believes are reasonable under the circumstances. The company s financial statements have been audited by Ernst & Young LLP, an independent registered public accounting firm appointed by the Audit and Finance Committee of the Board of Directors and ratified by stockholders. Management has made available to Ernst & Young LLP all of the company s financial records and related data, as well as the minutes of stockholders and directors meetings.

Assessment of Internal Control Over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. ConocoPhillips internal control system was designed to provide reasonable assurance to the company s management and directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Management assessed the effectiveness of the company s internal control over financial reporting as of December 31, 2016. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control Integrated Framework (2013)*. Based on our assessment, we believe the company s internal control over financial reporting was effective as of December 31, 2016.

Ernst & Young LLP has issued an audit report on the company s internal control over financial reporting as of December 31, 2016, and their report is included herein.

/s/ Ryan M. Lance	/s/ Don E. Wallette, Jr.
Ryan M. Lance Chairman and	**Don E. Wallette, Jr.** Executive Vice President, Finance,
Chief Executive Officer	Commercial and Chief Financial Officer

February 21, 2017

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders

ConocoPhillips

We have audited the accompanying consolidated balance sheets of ConocoPhillips as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2016. Our audits also included the related condensed consolidating financial information listed in the Index at Item 8 and financial statement schedule listed in Item 15(a). These financial statements, condensed consolidating financial information, and schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements, condensed consolidating financial information, and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of ConocoPhillips at December 31, 2016 and 2015, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2016, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related condensed consolidating financial information and financial statement schedule, when considered in relation to the basic financial statements taken as a whole, present fairly in all material respects the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), ConocoPhillips internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 21, 2017, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas

February 21, 2017

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders

ConocoPhillips

We have audited ConocoPhillips internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). ConocoPhillips management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included under the heading Assessment of Internal Control Over Financial Reporting in the accompanying Report of Management. Our responsibility is to express an opinion on the Company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate.

In our opinion, ConocoPhillips maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2016 consolidated financial statements of ConocoPhillips and our report dated February 21, 2017, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas

February 21, 2017

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Consolidated Income Statement **ConocoPhillips**

Years Ended December 31

	Millions of Dollars		
	2016	2015	2014
Revenues and Other Income			
Sales and other operating revenues	$ **23,693**	29,564	52,524
Equity in earnings of affiliates	**52**	655	2,529
Gain on dispositions	**360**	591	98
Other income	**255**	125	366
Total Revenues and Other Income	**24,360**	30,935	55,517
Costs and Expenses			
Purchased commodities	**9,994**	12,426	22,099
Production and operating expenses	**5,667**	7,016	8,909
Selling, general and administrative expenses	**723**	953	735
Exploration expenses	**1,915**	4,192	2,045
Depreciation, depletion and amortization	**9,062**	9,113	8,329
Impairments	**139**	2,245	856
Taxes other than income taxes	**739**	901	2,088
Accretion on discounted liabilities	**425**	483	484
Interest and debt expense	**1,245**	920	648
Foreign currency transaction gains	**(19)**	(75)	(66)
Total Costs and Expenses	**29,890**	38,174	46,127
Income (loss) from continuing operations before income taxes	**(5,530)**	(7,239)	9,390
Income tax provision (benefit)	**(1,971)**	(2,868)	3,583
Income (Loss) From Continuing Operations	**(3,559)**	(4,371)	5,807
Income from discontinued operations*	**-**	-	1,131
Net income (loss)	**(3,559)**	(4,371)	6,938
Less: net income attributable to noncontrolling interests	**(56)**	(57)	(69)
Net Income (Loss) Attributable to ConocoPhillips	$ **(3,615)**	(4,428)	6,869
Amounts Attributable to ConocoPhillips Common Shareholders:			
Income (loss) from continuing operations	$ **(3,615)**	(4,428)	5,738
Income from discontinued operations*	**-**	-	1,131

Net Income (Loss)	**$**	**(3,615)**	(4,428)	6,869
Net Income (Loss) Attributable to ConocoPhillips Per Share of Common Stock *(dollars)*				
Basic				
Continuing operations	**$**	**(2.91)**	(3.58)	4.63
Discontinued operations		**-**	-	0.91
Net Income (Loss) Attributable to ConocoPhillips Per Share of Common Stock	**$**	**(2.91)**	(3.58)	5.54
Diluted				
Continuing operations	**$**	**(2.91)**	(3.58)	4.60
Discontinued operations		**-**	-	0.91
Net Income (Loss) Attributable to ConocoPhillips Per Share of Common Stock	**$**	**(2.91)**	(3.58)	5.51
Dividends Paid Per Share of Common Stock *(dollars)*	**$**	**1.00**	2.94	2.84
Average Common Shares Outstanding *(in thousands)*				
Basic		**1,245,440**	1,241,919	1,237,325
Diluted		**1,245,440**	1,241,919	1,245,863
**Net of provision for income taxes on discontinued operations of:*	*$*	-	-	*16*

See Notes to Consolidated Financial Statements.

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Consolidated Statement of Comprehensive Income **ConocoPhillips**
Years Ended December 31

		Millions of Dollars		
		2016	2015	2014
Net Income (Loss)	$	**(3,559)**	(4,371)	6,938
Other comprehensive income (loss)				
Defined benefit plans				
Prior service credit (cost) arising during the period		**23**	301	(3)
Reclassification adjustment for amortization of prior service credit included in net income		**(35)**	(19)	(6)
Net change		**(12)**	282	(9)
Net actuarial gain (loss) arising during the period		**(481)**	592	(840)
Reclassification adjustment for amortization of net actuarial losses included in net income		**309**	403	131
Net change		**(172)**	995	(709)
Nonsponsored plans*		**2**	1	-
Income taxes on defined benefit plans		**78**	(460)	281
Defined benefit plans, net of tax		**(104)**	818	(437)
Foreign currency translation adjustments		**153**	(5,199)	(3,539)
Reclassification adjustment for gain included in net income		**5**	-	-
Income taxes on foreign currency translation adjustments		**-**	36	72
Foreign currency translation adjustments, net of tax		**158**	(5,163)	(3,467)
Other Comprehensive Income (Loss), Net of Tax		**54**	(4,345)	(3,904)
Comprehensive Income (Loss)		**(3,505)**	(8,716)	3,034
Less: comprehensive income attributable to noncontrolling interests		**(56)**	(57)	(69)
Comprehensive Income (Loss) Attributable to ConocoPhillips	$	**(3,561)**	(8,773)	2,965

**Plans for which ConocoPhillips is not the primary obligor primarily those administered by equity affiliates.*
See Notes to Consolidated Financial Statements.

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Consolidated Balance Sheet **ConocoPhillips**

At December 31		Millions of Dollars	
		2016	2015
Assets			
Cash and cash equivalents	$	**3,610**	2,368
Short-term investments		**50**	-
Accounts and notes receivable (net of allowance of $5 million in 2016 and $7 million in 2015)		**3,249**	4,314
Accounts and notes receivable related parties		**165**	200
Inventories		**1,018**	1,124
Prepaid expenses and other current assets		**517**	783
Total Current Assets		**8,609**	8,789
Investments and long-term receivables		**21,091**	20,490
Loans and advances related parties		**581**	696
Net properties, plants and equipment (net of accumulated depreciation, depletion and amortization of $73,075 million in 2016 and $70,413 million in 2015)		**58,331**	66,446
Other assets		**1,160**	1,063
Total Assets	$	**89,772**	97,484
Liabilities			
Accounts payable	$	**3,631**	4,895
Accounts payable related parties		**22**	38
Short-term debt		**1,089**	1,427
Accrued income and other taxes		**484**	499
Employee benefit obligations		**689**	887
Other accruals		**994**	1,510
Total Current Liabilities		**6,909**	9,256
Long-term debt		**26,186**	23,453
Asset retirement obligations and accrued environmental costs		**8,425**	9,580
Deferred income taxes		**8,949**	10,999
Employee benefit obligations		**2,552**	2,286
Other liabilities and deferred credits		**1,525**	1,828
Total Liabilities		**54,546**	57,402
Equity			
Common stock (2,500,000,000 shares authorized at $.01 par value)			

Issued (2016 1,782,079,107 shares; 2015 1,778,226,388 shares)			
Par value		**18**	18
Capital in excess of par		**46,507**	46,357
Treasury stock (at cost: 2016 544,809,771 shares; 2015 542,230,673 shares)		**(36,906)**	(36,780)
Accumulated other comprehensive loss		**(6,193)**	(6,247)
Retained earnings		**31,548**	36,414
Total Common Stockholders Equity		**34,974**	39,762
Noncontrolling interests		**252**	320
Total Equity		**35,226**	40,082
Total Liabilities and Equity	**$**	**89,772**	97,484

See Notes to Consolidated Financial Statements.

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Consolidated Statement of Cash Flows **ConocoPhillips**

Years Ended December 31		Millions of Dollars	
	2016	2015	2014
Cash Flows From Operating Activities			
Net income (loss)	$ **(3,559)**	(4,371)	6,938
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depreciation, depletion and amortization	**9,062**	9,113	8,329
Impairments	**139**	2,245	856
Dry hole costs and leasehold impairments	**1,184**	3,065	1,166
Accretion on discounted liabilities	**425**	483	484
Deferred taxes	**(2,221)**	(2,772)	709
Undistributed equity earnings	**299**	101	77
Gain on dispositions	**(360)**	(591)	(98)
Income from discontinued operations	**-**	-	(1,131)
Other	**(85)**	321	(233)
Working capital adjustments			
Decrease in accounts and notes receivable	**820**	1,810	1,227
Decrease (increase) in inventories	**44**	166	(193)
Decrease (increase) in prepaid expenses and other current assets	**105**	239	(190)
Decrease in accounts payable	**(524)**	(1,647)	(963)
Decrease in taxes and other accruals	**(926)**	(590)	(566)
Net cash provided by continuing operating activities	**4,403**	7,572	16,412
Net cash provided by discontinued operations	**-**	-	157
Net Cash Provided by Operating Activities	**4,403**	7,572	16,569
Cash Flows From Investing Activities			
Capital expenditures and investments	**(4,869)**	(10,050)	(17,085)
Working capital changes associated with investing activities	**(331)**	(968)	180
Proceeds from asset dispositions	**1,286**	1,952	1,603
Net sales (purchases) of short-term investments	**(51)**	-	253
Collection of advances/loans related parties	**108**	105	603
Other	**(2)**	306	(446)
Net cash used in continuing investing activities	**(3,859)**	(8,655)	(14,892)
Net cash used in discontinued operations	**-**	-	(73)
Net Cash Used in Investing Activities	**(3,859)**	(8,655)	(14,965)

Cash Flows From Financing Activities			
Issuance of debt	**4,594**	2,498	2,994
Repayment of debt	**(2,251)**	(103)	(2,014)
Issuance of company common stock	**(63)**	(82)	35
Repurchase of company common stock	**(126)**	-	-
Dividends paid	**(1,253)**	(3,664)	(3,525)
Other	**(137)**	(78)	(64)
Net Cash Provided by (Used in) Financing Activities	**764**	(1,429)	(2,574)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**(66)**	(182)	(214)
Net Change in Cash and Cash Equivalents	**1,242**	(2,694)	(1,184)
Cash and cash equivalents at beginning of period	**2,368**	5,062	6,246
Cash and Cash Equivalents at End of Period	**$ 3,610**	2,368	5,062

See Notes to Consolidated Financial Statements.

Consolidated Statement of Changes in Equity **ConocoPhillips**

	Millions of Dollars							
	Attributable to ConocoPhillips							
	Common Stock							
		Par Value	Capital in Excess of Par	Treasury Stock	Accum. Other Comprehensive Income (Loss)	Retained Earnings	Non-Controlling Interests	Total
December 31, 2013	$	18	45,690	(36,780)	2,002	41,160	402	52,492
Net income						6,869	69	6,938
Other comprehensive loss					(3,904)			(3,904)
Dividends paid						(3,525)		(3,525)
Distributions to noncontrolling interests and other							(109)	(109)
Distributed under benefit plans			381					381
December 31, 2014	$	18	46,071	(36,780)	(1,902)	44,504	362	52,273
Net income (loss)						(4,428)	57	(4,371)
Other comprehensive loss					(4,345)			(4,345)
Dividends paid						(3,664)		(3,664)
Distributions to noncontrolling interests and other							(100)	(100)
Distributed under benefit plans			286					286
Other						2	1	3
December 31, 2015	$	18	46,357	(36,780)	(6,247)	36,414	320	40,082
Net income (loss)						**(3,615)**	**56**	**(3,559)**
Other comprehensive income					**54**			**54**
Dividends paid						**(1,253)**		**(1,253)**
Repurchase of company common stock				**(126)**				**(126)**
Distributions to noncontrolling interests and other							**(124)**	**(124)**
Distributed under benefit plans			**150**					**150**
Other						**2**		**2**
December 31, 2016	**$**	**18**	**46,507**	**(36,906)**	**(6,193)**	**31,548**	**252**	**35,226**

See Notes to Consolidated Financial Statements.

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Notes to Consolidated Financial Statements **ConocoPhillips**

Note 1 Accounting Policies

Consolidation Principles and Investments Our consolidated financial statements include the accounts of majority-owned, controlled subsidiaries and variable interest entities where we are the primary beneficiary. The equity method is used to account for investments in affiliates in which we have the ability to exert significant influence over the affiliates operating and financial policies. When we do not have the ability to exert significant influence, the investment is either classified as available-for-sale if fair value is readily determinable, or the cost method is used if fair value is not readily determinable. Undivided interests in oil and gas joint ventures, pipelines, natural gas plants and terminals are consolidated on a proportionate basis. Other securities and investments are generally carried at cost.

We manage our operations through six operating segments, defined by geographic region: Alaska, Lower 48, Canada, Europe and North Africa, Asia Pacific and Middle East, and Other International. For additional information, see Note 24 Segment Disclosures and Related Information. Unless indicated otherwise, the information in the Notes to the Consolidated Financial Statements relates to our continuing operations.

Foreign Currency Translation Adjustments resulting from the process of translating foreign functional currency financial statements into U.S. dollars are included in accumulated other comprehensive income in common stockholders equity. Foreign currency transaction gains and losses are included in current earnings. Most of our foreign operations use their local currency as the functional currency.

Use of Estimates The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosures of contingent assets and liabilities. Actual results could differ from these estimates.

Revenue Recognition Revenues associated with sales of crude oil, bitumen, natural gas, liquefied natural gas (LNG), natural gas liquids and other items are recognized when title passes to the customer, which is when the risk of ownership passes to the purchaser and physical delivery of goods occurs, either immediately or within a fixed delivery schedule that is reasonable and customary in the industry.

Revenues associated with producing properties in which we have an interest with other producers are recognized based on the actual volumes we sold during the period. Any differences between volumes sold and entitlement volumes, based on our net working interest, which are deemed to be nonrecoverable through remaining production, are recognized as accounts receivable or accounts payable, as appropriate. Cumulative differences between volumes sold and entitlement volumes are generally not significant.

Revenues associated with transactions commonly called buy/sell contracts, in which the purchase and sale of inventory with the same counterparty are entered into in contemplation of one another, are combined and reported net (i.e., on the same income statement line).

Shipping and Handling Costs We include shipping and handling costs in production and operating expenses for production activities. Transportation costs related to marketing activities are recorded in purchased commodities. Freight costs billed to customers are recorded as a component of revenue.

Cash Equivalents Cash equivalents are highly liquid, short-term investments that are readily convertible to known amounts of cash and have original maturities of 90 days or less from their date of purchase. They are carried at cost plus accrued interest, which approximates fair value.

Short-Term Investments Investments in bank time deposits and marketable securities (commercial paper and government obligations) with original maturities of greater than 90 days but less than one year are classified as short-term investments.

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Inventories We have several valuation methods for our various types of inventories and consistently use the following methods for each type of inventory. Commodity-related inventories are valued at the lower of cost or market in the aggregate, primarily on the last-in, first-out (LIFO) basis. Any necessary lower-of-cost-or-market write-downs at year end are recorded as permanent adjustments to the LIFO cost basis. LIFO is used to better match current inventory costs with current revenues. Costs include both direct and indirect expenditures incurred in bringing an item or product to its existing condition and location, but not unusual/nonrecurring costs or research and development costs. Materials, supplies and other miscellaneous inventories, such as tubular goods and well equipment, are valued using various methods, including the weighted-average-cost method, and the first-in, first-out (FIFO) method, consistent with industry practice.

Fair Value Measurements Assets and liabilities measured at fair value and required to be categorized within the fair value hierarchy are categorized into one of three different levels depending on the observability of the inputs employed in the measurement. Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Level 2 inputs are observable inputs other than quoted prices included within Level 1 for the asset or liability, either directly or indirectly through market-corroborated inputs. Level 3 inputs are unobservable inputs for the asset or liability reflecting significant modifications to observable related market data or our assumptions about pricing by market participants.

Derivative Instruments Derivative instruments are recorded on the balance sheet at fair value. If the right of offset exists and certain other criteria are met, derivative assets and liabilities with the same counterparty are netted on the balance sheet and the collateral payable or receivable is netted against derivative assets and derivative liabilities, respectively.

Recognition and classification of the gain or loss that results from recording and adjusting a derivative to fair value depends on the purpose for issuing or holding the derivative. Gains and losses from derivatives not accounted for as hedges are recognized immediately in earnings. For derivative instruments that are designated and qualify as a fair value hedge, the gains or losses from adjusting the derivative to its fair value will be immediately recognized in earnings and, to the extent the hedge is effective, offset the concurrent recognition of changes in the fair value of the hedged item.

Oil and Gas Exploration and Development Oil and gas exploration and development costs are accounted for using the successful efforts method of accounting.

Property Acquisition Costs Oil and gas leasehold acquisition costs are capitalized and included in the balance sheet caption properties, plants and equipment (PP&E). Leasehold impairment is recognized based on exploratory experience and management s judgment. Upon achievement of all conditions necessary for reserves to be classified as proved, the associated leasehold costs are reclassified to proved properties.

Exploratory Costs Geological and geophysical costs and the costs of carrying and retaining undeveloped properties are expensed as incurred. Exploratory well costs are capitalized, or suspended, on the balance sheet pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. If exploratory wells encounter potentially economic quantities of oil and gas, the well costs remain capitalized on the balance sheet as long as sufficient progress assessing the reserves and the economic and operating viability of the project is being made. For complex exploratory discoveries, it is not unusual to have exploratory wells remain suspended on the balance sheet for several years while we perform additional appraisal drilling and seismic work on the potential oil and gas field or while we seek government or co-venturer approval of development plans or seek environmental permitting. Once all required approvals and permits have been obtained, the projects are moved into the development phase, and the oil and gas resources are designated as proved reserves.

Management reviews suspended well balances quarterly, continuously monitors the results of the additional appraisal drilling and seismic work, and expenses the suspended well costs as dry holes when it judges the potential field does not warrant further investment in the near term. See Note 8 Suspended Wells and Other Exploration Expenses, for additional information on suspended wells.

Development Costs Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized.

Depletion and Amortization Leasehold costs of producing properties are depleted using the unit-of-production method based on estimated proved oil and gas reserves. Amortization of intangible development costs is based on the unit-of-production method using estimated proved developed oil and gas reserves.

Capitalized Interest Interest from external borrowings is capitalized on major projects with an expected construction period of one year or longer. Capitalized interest is added to the cost of the underlying asset and is amortized over the useful lives of the assets in the same manner as the underlying assets.

Depreciation and Amortization Depreciation and amortization of PP&E on producing hydrocarbon properties and certain pipeline assets (those which are expected to have a declining utilization pattern), are determined by the unit-of-production method. Depreciation and amortization of all other PP&E are determined by either the individual-unit-straight-line method or the group-straight-line method (for those individual units that are highly integrated with other units).

Impairment of Properties, Plants and Equipment PP&E used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group and annually in the fourth quarter following updates to corporate planning assumptions. If there is an indication the carrying amount of an asset may not be recovered, the asset is monitored by management through an established process where changes to significant assumptions such as prices, volumes and future development plans are reviewed. If, upon review, the sum of the undiscounted before-tax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value through additional amortization or depreciation provisions and reported as impairments in the periods in which the determination of the impairment is made. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets generally on a field-by-field basis for exploration and production assets. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is typically determined based on the present values of expected future cash flows using discount rates believed to be consistent with those used by principal market participants or based on a multiple of operating cash flow validated with historical market transactions of similar assets where possible. Long-lived assets committed by management for disposal within one year are accounted for at the lower of amortized cost or fair value, less cost to sell, with fair value determined using a binding negotiated price, if available, or present value of expected future cash flows as previously described.

The expected future cash flows used for impairment reviews and related fair value calculations are based on estimated future production volumes, prices and costs, considering all available evidence at the date of review. The impairment review includes cash flows from proved developed and undeveloped reserves, including any development expenditures necessary to achieve that production. Additionally, when probable and possible reserves exist, an appropriate risk-adjusted amount of these reserves may be included in the impairment calculation.

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Impairment of Investments in Nonconsolidated Entities Investments in nonconsolidated entities are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value has occurred and annually following updates to corporate planning assumptions. When such a condition is judgmentally determined to be other than temporary, the carrying value of the investment is written down to fair value. The fair value of the impaired investment is based on quoted market prices, if available, or upon the present value of expected future cash flows using discount rates believed to be consistent with those used by principal market participants, plus market analysis of comparable assets owned by the investee, if appropriate.

Maintenance and Repairs Costs of maintenance and repairs, which are not significant improvements, are expensed when incurred.

Property Dispositions When complete units of depreciable property are sold, the asset cost and related accumulated depreciation are eliminated, with any gain or loss reflected in the Gain on dispositions line of our consolidated income statement. When less than complete units of depreciable property are disposed of or retired, the difference between asset cost and salvage value is charged or credited to accumulated depreciation.

Asset Retirement Obligations and Environmental Costs The fair value of legal obligations to retire and remove long-lived assets are recorded in the period in which the obligation is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, we capitalize this cost by increasing the carrying amount of the related PP&E. If, in subsequent periods, our estimate of this liability changes, we will record an adjustment to both the liability and PP&E. Over time the liability is increased for the change in its present value, and the capitalized cost in PP&E is depreciated over the useful life of the related asset. For additional information, see Note 10 Asset Retirement Obligations and Accrued Environmental Costs.

Environmental expenditures are expensed or capitalized, depending upon their future economic benefit. Expenditures relating to an existing condition caused by past operations, and those having no future economic benefit, are expensed. Liabilities for environmental expenditures are recorded on an undiscounted basis (unless acquired in a purchase business combination, which we record on a discounted basis) when environmental assessments or cleanups are probable and the costs can be reasonably estimated. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is probable and estimable.

Guarantees The fair value of a guarantee is determined and recorded as a liability at the time the guarantee is given. The initial liability is subsequently reduced as we are released from exposure under the guarantee. We amortize the guarantee liability over the relevant time period, if one exists, based on the facts and circumstances surrounding each type of guarantee. In cases where the guarantee term is indefinite, we reverse the liability when we have information indicating the liability is essentially relieved or amortize it over an appropriate time period as the fair value of our guarantee exposure declines over time. We amortize the guarantee liability to the related income statement line item based on the nature of the guarantee. When it becomes probable that we will have to perform on a guarantee, we accrue a separate liability if it is reasonably estimable, based on the facts and circumstances at that time. We reverse the fair value liability only when there is no further exposure under the guarantee.

Share-Based Compensation We recognize share-based compensation expense over the shorter of the service period (i.e., the stated period of time required to earn the award) or the period beginning at the start of the service period and ending when an employee first becomes eligible for retirement. We have elected to recognize expense on a straight-line basis over the service period for the entire award, whether the award was granted with ratable or cliff vesting.

Income Taxes Deferred income taxes are computed using the liability method and are provided on all temporary differences between the financial reporting basis and the tax basis of our assets and liabilities, except for deferred taxes on income and temporary differences related to the cumulative translation adjustment considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures.

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Allowable tax credits are applied currently as reductions of the provision for income taxes. Interest related to unrecognized tax benefits is reflected in interest and debt expense, and penalties related to unrecognized tax benefits are reflected in production and operating expenses.

Taxes Collected from Customers and Remitted to Governmental Authorities Sales and value-added taxes are recorded net.

Net Income (Loss) Per Share of Common Stock Basic net income (loss) per share of common stock is calculated based upon the daily weighted-average number of common shares outstanding during the year. Also, this calculation includes fully vested stock and unit awards that have not yet been issued as common stock, along with an adjustment to net income (loss) for dividend equivalents paid on unvested unit awards that are considered participating securities. Diluted net income per share of common stock includes unvested stock, unit or option awards granted under our compensation plans and vested but unexercised stock options, but only to the extent these instruments dilute net income per share, primarily under the treasury-stock method. Diluted net loss per share, which is calculated the same as basic net loss per share, does not assume conversion or exercise of securities that would have an antidilutive effect. Treasury stock is excluded from the daily weighted-average number of common shares outstanding in both calculations. The earnings per share impact of the participating securities is immaterial.

Note 2 Change in Accounting Principles

We adopted the provisions of Financial Accounting Standards Board (FASB) Accounting Standards Update (ASU) No. 2015-02, Amendments to the Consolidation Analysis, beginning January 1, 2016. The ASU amends existing requirements applicable to reporting entities that are required to evaluate whether certain legal entities, including variable interest entities (VIEs), should be consolidated. The adoption of this ASU did not have an impact on our consolidated financial statements and disclosures. See Note 4 Variable Interest Entities, for additional information on our significant VIEs.

Note 3 Discontinued Operations

On December 20, 2012, we entered into agreements with affiliates of Oando PLC to sell our Nigeria business, which was previously part of the Other International operating segment. On July 30, 2014, we completed the sale for $1,359 million, inclusive of $550 million deposits previously received. The deposits had been included in the Other accruals line on our consolidated balance sheet and in the Other line of cash flows from investing activities on our consolidated statement of cash flows. The deposits received included $435 million in 2012, $15 million in 2013, and $100 million in 2014. We recognized a before-tax gain of $1,052 million, which is included in the Income from discontinued operations line on our consolidated income statement.

Sales and other operating revenues and income from discontinued operations related to the Nigeria business during 2014 were as follows:

	Millions of Dollars
	2014

Sales and other operating revenues from discontinued operations	$	480
Income from discontinued operations before-tax	$	1,147
Income tax expense		16
Income from discontinued operations	$	1,131

Note 4 Variable Interest Entities (VIEs)

We hold variable interests in VIEs that have not been consolidated because we are not considered the primary beneficiary. Information on our significant VIEs follows:

Australia Pacific LNG Pty Ltd (APLNG)

APLNG is considered a VIE, as it has entered into certain contractual arrangements that provide it with additional forms of subordinated financial support. We are not the primary beneficiary of APLNG because we share with Origin Energy and China Petrochemical Corporation (Sinopec) the power to direct the key activities of APLNG that most significantly impact its economic performance, which involve activities related to the production and commercialization of coalbed methane, as well as LNG processing and export marketing. As a result, we do not consolidate APLNG, and it is accounted for as an equity method investment.

As of December 31, 2016, we have not provided any financial support to APLNG other than amounts previously contractually required. Unless we elect otherwise, we have no requirement to provide liquidity or purchase the assets of APLNG. See Note 7 Investments, Loans and Long-Term Receivables, and Note 12 Guarantees, for additional information.

Marine Well Containment Company, LLC (MWCC)

MWCC provides well containment equipment and technology and related services in the deepwater U.S. Gulf of Mexico. Its principal activities involve the development and maintenance of rapid-response hydrocarbon well containment systems that are deployable in the Gulf of Mexico on a call-out basis. We have a 10 percent ownership interest in MWCC, and it is accounted for as an equity method investment because MWCC is a limited liability company in which we are a Founding Member and exercise significant influence through our permanent seat on the ten member Executive Committee responsible for overseeing the affairs of MWCC. During the year ended December 31, 2016, MWCC executed a $154 million term loan financing arrangement with an external financial institution whose terms required the financing be secured by letters of credit provided by certain owners of MWCC, including ConocoPhillips. In connection with the financing transaction, we issued a letter of credit of $22 million which can be drawn upon in the event of a default by MWCC on its obligation to repay the proceeds of the term loan. The fair value of this letter of credit is immaterial and not recognized on our consolidated balance sheet. MWCC is considered a VIE, as it has entered into arrangements that provide it with additional forms of subordinated financial support. We are not the primary beneficiary and do not consolidate MWCC because we share the power to govern the business and operation of the company and to undertake certain obligations that most significantly impact its economic performance with nine other unaffiliated owners of MWCC.

At December 31, 2016, the book value of our equity method investment in MWCC was $148 million. We have not provided any financial support to MWCC other than amounts previously contractually required. Unless we elect otherwise, we have no requirement to provide liquidity or purchase the assets of MWCC.

Note 5 Inventories

Inventories at December 31 were:

Millions of Dollars

		2016	2015
Crude oil and natural gas	$	**418**	406
Materials and supplies		**600**	718
	$	**1,018**	1,124

Inventories valued on the LIFO basis totaled $269 million and $317 million at December 31, 2016 and 2015, respectively. The estimated excess of current replacement cost over LIFO cost of inventories was approximately $104 million and $6 million at December 31, 2016 and December 31, 2015, respectively. In 2016, liquidation of LIFO inventory values increased the net loss from continuing operations by $9 million.

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Note 6 Assets Held for Sale or Sold

Assets Sold

All gains or losses are reported before-tax and are included net in the Gain on dispositions line on our consolidated income statement.

2016

On April 22, 2016, we sold our interest in the Alaska Beluga River Unit natural gas field in the Cook Inlet for $134 million, net of settlement of gas imbalances and customary adjustments, and recognized a gain on disposition of $56 million. At the time of disposition, the net carrying value of our Beluga River Unit interest, which was included in the Alaska segment, was $78 million, consisting primarily of $100 million of PP&E and $19 million of asset retirement obligations (ARO).

On October 13, 2016, we completed an asset exchange with Bonavista Energy in which we gave up approximately 141,000 net acres of non-core developed properties in central Alberta in exchange for approximately 40,000 net acres of primarily undeveloped properties in northeast British Columbia. The fair value of the transaction was determined to be approximately $69 million and a before-tax impairment of $57 million was recognized in the third quarter of 2016 when the assets were considered held for sale, to reduce the carrying value to fair value. In the fourth quarter, a loss on disposition of approximately $1 million was recognized upon completion of the transaction. The divested properties were included in the Canada segment.

On October 28, 2016, we sold ConocoPhillips Senegal B.V., the entity that held our 35 percent interest in three exploration blocks offshore Senegal for $442 million and recognized a gain on disposition of $146 million. At the time of disposition, the carrying value of our interest was $286 million, which was primarily PP&E. Senegal results of operations were reported within our Other International segment.

On November 17, 2016, we completed the sale of our 40 percent interest in South Natuna Sea Block B for $225 million and recognized a loss on disposition of $26 million. Our interest in Block B was included in the Asia Pacific and Middle East segment. Previously, in the third quarter of 2016, we recognized a before-tax impairment of $42 million at the time it was considered held for sale to reduce the carrying value to fair value. At the time of the disposition, the carrying value of our interest was approximately $251 million, which included primarily $154 million of PP&E, $178 million of accounts receivable, $25 million of inventory, $54 million of deferred tax assets, $130 million of accounts payable and other accruals, and $38 million of employee benefit obligations.

On December 8, 2016, we completed the sale of certain mineral and non-mineral fee lands in northeastern Minnesota, which was included in the Lower 48 segment, for $148 million and recorded a gain on disposition of $4 million. The majority of the assets sold were acquired during the fourth quarter of 2016 as a result of ConocoPhillips holding a reversionary interest in the Greater Northern Iron Ore Properties Trust (the Trust), a grantor trust that owned mineral and surface interests in the Mesabi Iron Range in northeastern Minnesota and certain other personal property. Pursuant to the terms of the Trust Agreement, the Trust terminated on April 6, 2015 and in November 2016, upon completion of the wind-down period, documents memorializing ConocoPhillips ownership of certain Trust property, including all of the Trust s mineral properties and active leases, were delivered to us and we recognized the fair value of the net assets resulting in a gain of $88 million recorded in the Other income line on our consolidated income statement. At the time of the disposition, the carrying value of our interests, which included the assets obtained from the Trust, consisted of $144 million of PP&E.

2015

In November 2015, we sold a portion of our western Canadian properties located in British Columbia, Alberta, and Saskatchewan for $198 million and recognized a gain on disposition of $66 million. At the time of the disposition, the carrying value of our interest, which was included in the Canada segment, was $132 million, which included primarily $379 million of PP&E and $248 million of ARO.

In December 2015, we sold a portion of our western Canadian properties located in central Alberta for $130 million and recognized a loss on disposition of $235 million. At the time of the disposition, the carrying value of our interest, which was included in the Canada segment, was approximately $365 million, which included primarily $488 million of PP&E and $126 million of ARO.

Additionally, other December 2015 disposition transactions are summarized below.

We sold producing properties in East Texas and North Louisiana for $412 million and recognized a gain on disposition of $189 million. At the time of the disposition, the carrying value of our interest, which was included in the Lower 48 segment, was $223 million, which included $351 million of PP&E and $128 million of ARO.

We sold certain gas producing properties in South Texas for $358 million and recognized a gain on disposition of $201 million. At the time of the disposition, the carrying value of our interest, which was included in the Lower 48 segment, was $157 million, which included $369 million of PP&E and $212 million of ARO.

We sold certain pipeline and gathering assets in South Texas for $201 million and recognized a gain on disposition of $193 million. At the time of the disposition, the carrying value of our interest, which was included in the Lower 48 segment, was $8 million, which primarily included $24 million of PP&E and $18 million of ARO.

We also sold our 50 percent interest in the Russian joint venture, Polar Lights Company, for $98 million and recognized a gain on disposition of $58 million. At the time of the disposition, the carrying value of our equity method investment in Polar Lights Company, which was included in our Other International segment, was approximately $40 million.

2014

For information on the sale of our Nigeria business, which is included in the Income from discontinued operations line on our consolidated income statement, see Note 3 Discontinued Operations.

Note 7 Investments, Loans and Long-Term Receivables

Components of investments, loans and long-term receivables at December 31 were:

	Millions of Dollars	
	2016	2015
Equity investments	$ **20,364**	19,850

Loans and advances related parties		**581**	696
Long-term receivables		**631**	519
Other investments		**96**	121
	$	**21,672**	21,186

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Equity Investments

Affiliated companies in which we had a significant equity investment at December 31, 2016, included:

APLNG 37.5 percent owned joint venture with Origin Energy (37.5 percent) and Sinopec (25 percent) to develop coalbed methane production from the Bowen and Surat basins in Queensland, Australia, as well as process and export LNG.
FCCL Partnership 50 percent owned business venture with Cenovus Energy Inc. produces bitumen in the Athabasca oil sands in northeastern Alberta and sells the bitumen blend.
Qatar Liquefied Gas Company Limited (3) (QG3) 30 percent owned joint venture with affiliates of Qatar Petroleum (68.5 percent) and Mitsui & Co., Ltd. (1.5 percent) produces and liquefies natural gas from Qatar s North Field, as well as exports LNG.

Summarized 100 percent earnings information for equity method investments in affiliated companies, combined, was as follows:

	Millions of Dollars		
	2016	2015	2014
Revenues	$ **10,149**	11,003	19,243
Income before income taxes	**660**	1,866	6,746
Net income	**799**	1,801	6,630

Summarized 100 percent balance sheet information for equity method investments in affiliated companies, combined, was as follows:

	Millions of Dollars	
	2016	2015
Current assets	$ **3,578**	2,504
Noncurrent assets	**60,243**	58,431
Current liabilities	**2,352**	1,863
Noncurrent liabilities	**23,764**	24,820

Our share of income taxes incurred directly by an equity company is reported in equity in earnings of affiliates, and as such is not included in income taxes in our consolidated financial statements.

At December 31, 2016, retained earnings included $1,392 million related to the undistributed earnings of affiliated companies. Dividends received from affiliates were $398 million, $876 million and $2,648 million in 2016, 2015 and

2014, respectively.

APLNG

APLNG is focused on coalbed methane production from the Bowen and Surat basins in Queensland, Australia, and LNG processing and export sales. Our investment in APLNG gives us access to coalbed methane resources in Australia and enhances our LNG position. The majority of APLNG LNG is sold under two long-term sales and purchase agreements, supplemented with sales of additional LNG spot cargoes targeting the Asia Pacific markets. Origin Energy, an integrated Australian energy company, is the operator of APLNG s production and pipeline system, while we operate the LNG facility.

APLNG executed project financing agreements for an $8.5 billion project finance facility in 2012. The $8.5 billion project finance facility is composed of financing agreements executed by APLNG with the Export-Import Bank of the United States for approximately $2.9 billion, the Export-Import Bank of China for approximately $2.7 billion, and a syndicate of Australian and international commercial banks for approximately $2.9 billion. At December 31, 2016, $8.5 billion had been drawn from the facility.

In connection with the execution of the project financing, we provided a completion guarantee for our pro-rata share of the project finance facility until the project achieves financial completion. In October 2016, we reached financial completion for Train 1, which reduced our associated guarantee by 60 percent. See Note 12 Guarantees, for additional information.

APLNG is considered a VIE, as it has entered into certain contractual arrangements that provide it with additional forms of subordinated financial support. See Note 4 Variable Interest Entities (VIEs) for additional information.

On July 1, 2016, APLNG changed its tax functional currency from Australian dollar to U.S. dollar and translated all APLNG assets and liabilities into U.S. dollar, utilizing the exchange rate as of that date. As a result of this change, we recorded a reduction to our investment in APLNG for the deferred tax effect of $174 million in the Equity in earnings (losses) of affiliates line of our consolidated income statement.

During the fourth quarter of 2015, due to the outlook for crude oil and natural gas prices at that time, the estimated fair value of our investment in APLNG declined to an amount below book value. Accordingly, we recorded a noncash $1,502 million before- and after-tax impairment, in our fourth-quarter 2015 results.

During the third quarter of 2016, the outlook for crude oil prices weakened again, and as a result, the estimated fair value of our investment in APLNG declined to an amount below book value as of September 30, 2016. Based on a review of the facts and circumstances surrounding this decline in fair value, we concluded the impairment was not other than temporary under the guidance of FASB Accounting Standards Codification (ASC) Topic 323, Investments Equity Method and Joint Ventures.

During the fourth quarter of 2016, primarily due to the impact of accretion on discounted cash flows from the passage of time and strengthening of the U.S. dollar, the estimated fair value of our investment increased and is above book value as of December 31, 2016. The expected future cash flows used for the impairment review of our investment in APLNG are based on estimated future production, an outlook of future prices from a combination of exchanges (short-term) and pricing service companies (long-term), costs, a market outlook of foreign exchange rates provided by a third party, and a discount rate believed to be consistent with those used by principal market participants. Unfavorable changes in any of these assumptions could result in a reduction in future cash flows and could indicate impairment in the future. Subsequent to December 31, 2016, the outlook for crude prices and the U.S. dollar exchange rate relative to the Australian dollar has weakened. If these outlooks remain unchanged, we expect the estimated fair value of our investment in APLNG to be below book value at March 31, 2017.

At December 31, 2016, the book value of our equity method investment in APLNG was $10,089 million. The historical cost basis of our 37.5 percent share of net assets on the books of APLNG under U.S. generally accepted accounting principles was $8,348 million, resulting in a basis difference of $1,741 million on our books. The basis difference, which is substantially all associated with PP&E and subject to amortization, has been allocated on a relative fair value basis to individual exploration and production license areas owned by APLNG, some of which are not currently in production. Any future additional payments are expected to be allocated in a similar manner. Each exploration license area will periodically be reviewed for any indicators of potential impairment, which, if required, would result in acceleration of basis difference amortization. As the joint venture produces natural gas from each license, we amortize the basis difference allocated to that license using the unit-of-production method. Included in net income (loss) attributable to ConocoPhillips for 2016, 2015 and 2014 was after-tax expense of $92 million, $21 million and $24 million, respectively, representing the amortization of this basis difference on currently producing licenses.

FCCL

FCCL Partnership, a Canadian upstream 50/50 general partnership with Cenovus Energy Inc., produces bitumen in the Athabasca oil sands in northeastern Alberta and sells the bitumen blend. We account for our investment in FCCL under the equity method of accounting, with the operating results of our investment in FCCL converted to reflect the use of the successful efforts method of accounting for oil and gas exploration and development activities.

At December 31, 2016, the book value of our investment in FCCL was $8,784 million, net of a $1,706 million reduction due to cumulative foreign currency translation effects. FCCL s operating assets consist of the Foster Creek and Christina Lake steam-assisted gravity drainage bitumen projects, both located in the eastern flank of the Athabasca oil sands in northeastern Alberta. Cenovus is the operator and managing partner of FCCL.

We were obligated to contribute $7.5 billion, plus accrued interest, to FCCL over a 10-year period that began in 2007. In December 2013, we repaid the remaining balance of the obligation, which totaled $2,810 million. In the first quarter of 2014, we received a $1.3 billion distribution from FCCL, which is included in the Undistributed equity earnings line on our consolidated statement of cash flows.

QG3

QG3 is a joint venture that owns an integrated large-scale LNG project located in Qatar. We provided project financing, with a current outstanding balance of $696 million as described below under Loans and Long-Term Receivables. At December 31, 2016, the book value of our equity method investment in QG3, excluding the project financing, was $869 million. We have terminal and pipeline use agreements with Golden Pass LNG Terminal and affiliated Golden Pass Pipeline near Sabine Pass, Texas, in which we have a 12.4 percent interest, intended to provide us with terminal and pipeline capacity for the receipt, storage and regasification of LNG purchased from QG3. However, currently the LNG from QG3 is being sold to markets outside of the United States.

Loans and Long-Term Receivables

As part of our normal ongoing business operations and consistent with industry practice, we enter into numerous agreements with other parties to pursue business opportunities. Included in such activity are loans and long-term receivables to certain affiliated and non-affiliated companies. Loans are recorded when cash is transferred or seller financing is provided to the affiliated or non-affiliated company pursuant to a loan agreement. The loan balance will increase as interest is earned on the outstanding loan balance and will decrease as interest and principal payments are received. Interest is earned at the loan agreement s stated interest rate. Loans and long-term receivables are assessed for impairment when events indicate the loan balance may not be fully recovered.

Through November 2014, we had an agreement with Freeport LNG Development, L.P. (Freeport LNG) to participate in an LNG receiving terminal in Quintana, Texas. We had no ownership in Freeport LNG; however, we had a 50 percent interest in Freeport LNG GP, Inc. (Freeport GP), which serves as the general partner managing the venture. We had entered into a credit agreement with Freeport LNG, whereby we agreed to provide loan financing for the construction of the terminal. We also entered into a long-term agreement with Freeport LNG to use 0.9 billion cubic feet per day of regasification capacity, which would have expired in 2033. When the terminal became operational in June 2008, we began making payments under the terminal use agreement. Freeport LNG began making loan repayments in September 2008.

In July 2013, we reached an agreement with Freeport LNG to terminate our long-term agreement at the Freeport LNG Terminal, subject to Freeport LNG obtaining regulatory approval and project financing for an LNG liquefaction and export facility in Texas, in which we are not a participant. These conditions were satisfied in 2014, and we paid Freeport LNG a termination fee of $522 million. Freeport LNG repaid the outstanding $454 million ConocoPhillips loan used by Freeport LNG to partially fund the original construction of the terminal. The payment made to Freeport LNG to terminate our long-term agreement is included in the cash flows from operating activities section on our consolidated statement of cash flows, while the receipt of the funds from Freeport LNG to repay the outstanding loan is included in the cash flows from investing activities section in 2014. These transactions, plus miscellaneous items, including the disposal of our 50 percent interest in Freeport GP, resulted in a one-time net cash outflow of $63 million for us. In addition, we recognized an after-tax charge to earnings of $540 million in 2014, and our terminal regasification capacity was reduced to zero.

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At December 31, 2016, significant loans to affiliated companies include $696 million in project financing to QG3. We own a 30 percent interest in QG3, for which we use the equity method of accounting. The other participants in the project are affiliates of Qatar Petroleum and Mitsui. QG3 secured project financing of $4.0 billion in December 2005, consisting of $1.3 billion of loans from export credit agencies (ECA), $1.5 billion from commercial banks, and $1.2 billion from ConocoPhillips. The ConocoPhillips loan facilities have substantially the same terms as the ECA and commercial bank facilities. On December 15, 2011, QG3 achieved financial completion and all project loan facilities became nonrecourse to the project participants. Semi-annual repayments began in January 2011 and will extend through July 2022.

The long-term portion of these loans is included in the Loans and advances related parties line on our consolidated balance sheet, while the short-term portion is in Accounts and notes receivable related parties.

Note 8 Suspended Wells and Other Exploration Expenses

The following table reflects the net changes in suspended exploratory well costs during 2016, 2015 and 2014:

	Millions of Dollars		
	2016	2015	2014
Beginning balance at January 1	$ **1,260**	1,299	994
Additions pending the determination of proved reserves	**225**	331	478
Reclassifications to proved properties	**(27)**	(28)	(9)
Sales of suspended well investment	**(247)**	-	(57)
Charged to dry hole expense	**(148)**	(342)	(107)
Ending balance at December 31	$ **1,063**	1,260	1,299

The following table provides an aging of suspended well balances at December 31:

	Millions of Dollars		
	2016	2015	2014
Exploratory well costs capitalized for a period of one year or less	$ **132**	235	466
Exploratory well costs capitalized for a period greater than one year	**931**	1,025	833
Ending balance	$ **1,063**	1,260	1,299
Number of projects with exploratory well costs capitalized for a period greater than one year	**26**	28	30

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The following table provides a further aging of those exploratory well costs that have been capitalized for more than one year since the completion of drilling as of December 31, 2016:

	Millions of Dollars						
		Suspended Since					
	Total	2013	2015	2010	2012	2002	2009
Greater Poseidon Australia[2]	177		157		15		5
Shenandoah Lower 48[1]	161		118		-		43
Greater Clair UK[2]	131		120		11		-
Surmont 3 and beyond Canada[1]	107		55		29		23
NPRA Alaska[1]	93		70		-		23
Caldita/Barossa Australia[1]	77		-		-		77
Middle Magdalena Basin Colombia[1]	31		31		-		-
Limbayong Malaysia[1]	23		23		-		-
Alpine Satellite Alaska[2]	22		-		-		22
Bohai China[2]	19		19		-		-
Kamunsu East Malaysia[2]	19		19		-		-
NC 98 Libya[2]	15		11		-		4
Sunrise Australia[2]	13		-		-		13
Other of $10 million or less each[1][2]	43		25		3		15
Total	$ 931		648		58		225

(1)Additional appraisal wells planned.

(2)Appraisal drilling complete; costs being incurred to assess development.

In line with our July 2015 announcement of plans to reduce future deepwater exploration spending, we recognized before-tax cancellation costs of $335 million and wrote off $48 million of before-tax capitalized rig costs in relation to the termination of our Gulf of Mexico deepwater drillship contract with Ensco in the Lower 48 segment in the third quarter of 2015. In July 2016, we entered into an agreement to terminate our final Gulf of Mexico deepwater drillship contract. The drillship, used to drill our operated deepwater well inventory in the Gulf of Mexico through April 2016, was contracted on a shared, three-year term. Accordingly, we recorded before-tax rig cancellation charges and third party costs of $146 million in our Lower 48 segment in 2016. These charges are included in the Exploration expenses line on our consolidated income statement.

In February 2017, we reached a settlement agreement on our contract for the Athena drilling rig, initially secured for our four-well commitment program in Angola. As a result of the cancellation, we will recognize a before-tax charge of $43 million net in the first quarter of 2017.

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Note 9 Impairments

During 2016, 2015 and 2014, we recognized the following before-tax impairment charges:

	Millions of Dollars		
	2016	2015	2014
Alaska	**$ 1**	10	59
Lower 48	**149**	(2)	208
Canada	**88**	4	38
Europe and North Africa	**(160)**	724	541
Asia Pacific and Middle East	**44**	1,508	7
Corporate	**17**	1	3
	$ 139	2,245	856

2016

In Lower 48, we recorded impairments of $149 million primarily due to cancelled projects associated with plan of development changes for Eagle Ford infrastructure, as well as lower natural gas prices and increased asset retirement obligation estimates.

In Canada, we recorded impairments of $88 million mainly due to plan of development changes, as well as certain developed properties, which were classified as held for sale, being written down to fair value less costs to sell.

In Europe, we recorded a credit to impairment of $160 million, primarily in the United Kingdom, due to decreased asset retirement obligation estimates on fields that are nearing the end of life and were impaired in prior years, partly offset by asset impairments due to lower natural gas prices in the United Kingdom.

In Asia Pacific and Middle East, we recorded impairments of $44 million, mainly due to the write-down to fair value less costs to sell of our developed properties in Block B, offshore Indonesia, in the third quarter of 2016.

In Corporate, we recorded impairments of $17 million due to cancelled projects in our Houston and Bartlesville offices.

The charges discussed below, within this section, are included in the Exploration expenses line on our consolidated income statement and are not reflected in the table above.

Charges recorded in exploration expenses in 2016 were related to our decision announced in 2015 to reduce deepwater exploration spending.

In our Lower 48 segment, we recorded a $203 million before-tax impairment for the associated carrying value of our Gibson and Tiber undeveloped leaseholds in deepwater Gulf of Mexico. Additionally, we recorded a $95 million before-tax impairment for the associated carrying value of capitalized undeveloped leasehold costs of the Melmar prospect and a $79 million impairment, primarily as a result of changes in the estimated market value following the completion of marketing efforts.

In our Canada segment, we recorded before-tax unproved property impairments of $31 million, primarily due to decisions to discontinue further testing of undeveloped leaseholds.

2015

See the APLNG section of Note 7 Investments, Loans and Long-Term Receivables, for information on the impairment of our APLNG investment included within the Asia Pacific and Middle East segment.

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In Europe, we recorded impairments of $724 million, primarily in the United Kingdom as a result of lower natural gas prices and increases to asset retirement obligations.

The charges discussed below, within this section, are included in the Exploration expenses line on our consolidated income statement and are not reflected in the table above.

In our Other International segment, we decided not to pursue further evaluation of our Block 36 and Block 37 leases in Angola due to lack of commerciality of wells. Accordingly, we recorded impairments of $377 million and $116 million, respectively, for the associated carrying values of capitalized undeveloped leasehold costs.

In our Lower 48 segment, we decided not to conduct further activity on certain Gulf of Mexico leases, given our strategic plans to reduce deepwater exploration spending, and accordingly recorded impairments of $399 million for the associated carrying value of certain capitalized undeveloped leasehold costs.

In our Asia Pacific and Middle East segment, we decided to relinquish our Palangkaraya PSC in Indonesia. Accordingly, we recorded an impairment of $105 million for the associated carrying values of capitalized undeveloped leasehold cost.

In our Alaska segment, we recorded an impairment of $575 million for the associated carrying value of capitalized undeveloped leasehold cost in the Chukchi Sea in Alaska.

In our Canada segment, we recorded an impairment of $102 million for the Duvernay, Thornbury, Saleski and Crow Lake areas driven primarily by the lack of commerciality of wells.

2014

In Alaska, we recorded impairments of $59 million, primarily due to a cancelled project.

In our Lower 48 segment, we recorded impairments of $208 million, primarily as a result of reduced volume forecasts for an onshore field, as well as an LNG-related pipeline.

We recorded impairments of $38 million in our Canada segment, primarily due to reduced volume forecasts and lower natural gas prices.

In Europe, we recorded impairments of $541 million, mainly due to reduced volume forecasts, increases in the ARO and lower natural gas prices for properties in the United Kingdom which are nearing the end of their useful lives.

The charges discussed below, within this section, are included in the Exploration expenses line on our consolidated income statement and are not reflected in the table above.

In our Lower 48 segment, we recorded unproved property impairments of $239 million, primarily due to decisions to discontinue further testing of the undeveloped leaseholds.

Additionally, we decided not to pursue future development of the Amauligak discovery. Accordingly, we recorded a $145 million property impairment for the carrying value of capitalized undeveloped leasehold costs associated with our Amauligak, Arctic Islands and other Beaufort properties located offshore Canada.

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Note 10 Asset Retirement Obligations and Accrued Environmental Costs

Asset retirement obligations and accrued environmental costs at December 31 were:

	Millions of Dollars	
	2016	2015
Asset retirement obligations	**$ 8,405**	9,911
Accrued environmental costs	**247**	258
Total asset retirement obligations and accrued environmental costs	**8,652**	10,169
Asset retirement obligations and accrued environmental costs due within one year*	**(227)**	(589)
Long-term asset retirement obligations and accrued environmental costs	**$ 8,425**	9,580

**Classified as a current liability on the balance sheet under Other accruals.*

Asset Retirement Obligations

We record the fair value of a liability for an asset retirement obligation when it is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, we capitalize the associated asset retirement cost by increasing the carrying amount of the related PP&E. If, in subsequent periods, our estimate of this liability changes, we will record an adjustment to both the liability and PP&E. Over time, the liability increases for the change in its present value, while the capitalized cost depreciates over the useful life of the related asset.

We have numerous asset retirement obligations we are required to perform under law or contract once an asset is permanently taken out of service. Most of these obligations are not expected to be paid until several years, or decades, in the future and will be funded from general company resources at the time of removal. Our largest individual obligations involve plugging and abandonment of wells and removal and disposal of offshore oil and gas platforms around the world, as well as oil and gas production facilities and pipelines in Alaska.

During 2016 and 2015, our overall asset retirement obligation changed as follows:

	Millions of Dollars	
	2016	2015
Balance at January 1	**$ 9,911**	10,939
Accretion of discount	**420**	480
New obligations	**180**	135
Changes in estimates of existing obligations	**(1,197)**	267
Spending on existing obligations	**(314)**	(437)
Property dispositions	**(150)**	(726)

Foreign currency translation	**(464)**	(747)
Other	**19**	-
Balance at December 31	**$ 8,405**	9,911

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Accrued Environmental Costs

Total accrued environmental costs at December 31, 2016 and 2015, were $247 million and $258 million, respectively.

We had accrued environmental costs of $183 million and $184 million at December 31, 2016 and 2015, respectively, related to remediation activities in the United States and Canada. We had also accrued in Corporate and Other $51 million and $57 million of environmental costs associated with sites no longer in operation at December 31, 2016 and 2015, respectively. In addition, $13 million and $17 million were included at both December 31, 2016 and 2015, respectively, where the company has been named a potentially responsible party under the Federal Comprehensive Environmental Response, Compensation and Liability Act, or similar state laws. Accrued environmental liabilities are expected to be paid over periods extending up to 30 years.

Expected expenditures for environmental obligations acquired in various business combinations are discounted using a weighted-average 5 percent discount factor, resulting in an accrued balance for acquired environmental liabilities of $92 million at December 31, 2016. The expected future undiscounted payments related to the portion of the accrued environmental costs that have been discounted are: $9 million in 2017, $12 million in 2018, $8 million in 2019, $5 million in 2020, $4 million in 2021, and $110 million for all future years after 2021.

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Note 11 Debt

Long-term debt at December 31 was:

	Millions of Dollars	
	2016	2015
9.125% Debentures due 2021	$ **150**	150
8.20% Debentures due 2025	**150**	150
8.125% Notes due 2030	**600**	600
7.9% Debentures due 2047	**100**	100
7.8% Debentures due 2027	**300**	300
7.65% Debentures due 2023	**88**	88
7.40% Notes due 2031	**500**	500
7.375% Debentures due 2029	**92**	92
7.25% Notes due 2031	**500**	500
7.20% Notes due 2031	**575**	575
7% Debentures due 2029	**200**	200
6.95% Notes due 2029	**1,549**	1,549
6.875% Debentures due 2026	**67**	67
6.65% Debentures due 2018	**297**	297
6.50% Notes due 2039	**2,750**	2,750
6.00% Notes due 2020	**1,000**	1,000
5.951% Notes due 2037	**645**	645
5.95% Notes due 2036	**500**	500
5.95% Notes due 2046	**500**	-
5.90% Notes due 2032	**505**	505
5.90% Notes due 2038	**600**	600
5.75% Notes due 2019	**2,250**	2,250
5.625% Notes due 2016	**-**	1,250
5.20% Notes due 2018	**500**	500
4.95% Notes due 2026	**1,250**	-
4.30% Notes due 2044	**750**	750
4.20% Notes due 2021	**1,250**	-
4.15% Notes due 2034	**500**	500
3.35% Notes due 2024	**1,000**	1,000
3.35% Notes due 2025	**500**	500
2.875% Notes due 2021	**750**	750
2.4% Notes due 2022	**1,000**	1,000
2.2% Notes due 2020	**500**	500
1.5% Notes due 2018	**750**	750
1.05% Notes due 2017	**1,000**	1,000
Floating rate term loan due 2019 at 1.94% 2.31% during 2016	**1,450**	-
	250	250

Floating rate notes due 2018 at 0.69% 1.24% during 2016 and 0.61% 0.69% during 2015		
Floating rate notes due 2022 at 1.26% 1.81% during 2016 and 1.18% 1.26% during 2015	**500**	500
Commercial paper at 0.16% 0.80% during 2015	**-**	803
Industrial Development Bonds due 2016 through 2038 at 0.01% 0.91% during 2016 and 0.01% 0.13% during 2015	**18**	18
Marine Terminal Revenue Refunding Bonds due 2031 at 0.01% 0.95% during 2016 and 0.01% 0.14% during 2015	**265**	265
Other	**24**	24
Debt at face value	**26,175**	23,778
Capitalized leases	**852**	818
Net unamortized premiums, discounts and debt issuance costs	**248**	284
Total debt	**27,275**	24,880
Short-term debt	**(1,089)**	(1,427)
Long-term debt	**$ 26,186**	23,453

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Maturities of long-term borrowings, inclusive of net unamortized premiums and discounts, in 2017 through 2021 are: $1,089 million, $1,894 million, $3,784 million, $1,593 million and $2,235 million, respectively.

In the first quarter of 2016, we reduced our revolving credit facility, expiring in June 2019, from $7.0 billion to $6.75 billion. Our revolving credit facility may be used for direct bank borrowings, for the issuance of letters of credit totaling up to $500 million, or as support for our commercial paper programs. The revolving credit facility is broadly syndicated among financial institutions and does not contain any material adverse change provisions or any covenants requiring maintenance of specified financial ratios or credit ratings. The facility agreement contains a cross-default provision relating to the failure to pay principal or interest on other debt obligations of $200 million or more by ConocoPhillips, or any of its consolidated subsidiaries.

Credit facility borrowings may bear interest at a margin above rates offered by certain designated banks in the London interbank market or at a margin above the overnight federal funds rate or prime rates offered by certain designated banks in the United States. The agreement calls for commitment fees on available, but unused, amounts. The agreement also contains early termination rights if our current directors or their approved successors cease to be a majority of the Board of Directors.

We have two commercial paper programs supported by our $6.75 billion revolving credit facility: the ConocoPhillips $6.25 billion program, primarily a funding source for short-term working capital needs, and the ConocoPhillips Qatar Funding Ltd. $500 million program, which is used to fund commitments relating to QG3. Commercial paper maturities are generally limited to 90 days.

At both December 31, 2016 and 2015, we had no direct outstanding borrowings under the revolving credit facility, with no letters of credit as of December 31, 2016 and 2015. Under the ConocoPhillips Qatar Funding Ltd. commercial paper program, no commercial paper was outstanding at December 31, 2016, compared with $803 million at December 31, 2015. Since we had no commercial paper outstanding and had issued no letters of credit, we had access to $6.75 billion in borrowing capacity under our revolving credit facility at December 31, 2016.

In March 2016, we issued notes consisting of:

- The $1,250 million of 4.20% Notes due 2021.
- The $1,250 million of 4.95% Notes due 2026.
- The $500 million of 5.95% Notes due 2046.

In addition, on March 18, 2016, we entered into a $1,600 million three-year senior unsecured term loan facility. In December 2016, an early repayment of $150 million reduced the loan to $1,450 million. We have the right at any time and from time to time to prepay the term loan, in whole or in part, without premium or penalty upon notice to the Administrative Agent. Borrowings will accrue interest at a base rate or, for certain Eurodollar borrowings, the London Interbank Offered Rate (LIBOR), in each case plus a margin that is set based on our corporate credit ratings. The applicable margin for loans bearing interest based on the base rate ranges from 0.50% to 1.00% and the applicable margin for loans bearing interest based on LIBOR ranges from 1.50% to 2.00%. Based on our current corporate credit ratings, the applicable margin for loans accruing interest at the base rate is 0.50% and the applicable margin for loans accruing interest at LIBOR is 1.50%.

The term loan facility contains customary covenants regarding, among other matters, material compliance with laws and restrictions against certain consolidations, mergers and asset sales and creation of certain liens on our assets and consolidated subsidiaries. The term loan facility also contains financial covenants including a total debt to capitalization ratio, excluding the impacts of certain noncash impairments and foreign currency translation adjustments as defined in the Term Loan Agreement, which may not exceed 65 percent. At December 31, 2016, we were in compliance with this covenant.

The term loan facility includes customary events of default (subject to specified cure periods, materiality qualifiers and exceptions), including the failure to pay any interest, principal or fees when due, the failure to perform or the violation of any covenant contained in the term loan facility, the making of materially inaccurate or false representations or warranties, a default on certain material indebtedness, insolvency or bankruptcy, a change of control and the occurrence of material Employee Retirement Income Security Act of 1974 (ERISA) events and certain judgments against us or our material subsidiaries.

The net proceeds of the notes and term loan will be used for general corporate purposes.

On October 17, 2016, the $1,250 million 5.625% Notes due 2016 were repaid at maturity.

At both December 31, 2016 and 2015, we had $283 million of certain variable rate demand bonds (VRDBs) outstanding with maturities ranging through 2035. The VRDBs are redeemable at the option of the bondholders on any business day. The VRDBs are included in the Long-term debt line on our consolidated balance sheet.

During 2013, a lease of a semi-submersible floating production system (FPS) commenced for the Gumusut development, located in Malaysia, in which we are a co-venturer. The FPS lease provides for an initial noncancelable term of 15 years, a subsequent 5-year cancelable term with no required lease payments, and an additional 5-year term with terms and conditions to be agreed at a later date. The lease has no ongoing purchase options or escalation clauses. Adjustments to provisional contingent rental payments may occur due to the finalization of actual commissioning costs. The lease does not impose any significant restrictions concerning dividends, debt or further leasing activities.

A capital lease asset and capital lease obligation were recognized for our proportionate interest in the FPS of $906 million, based on the present value of the future minimum lease payments using our before-tax incremental borrowing rate of 3.58 percent for debt with similar terms. Unitization of the Gumusut development with Brunei was recorded during the fourth quarter of 2015 and reduced our proportionate interest in the FPS from 33 percent to 29 percent. The net carrying value of the capital lease asset was approximately $540 million and $707 million as of December 31, 2016 and December 31, 2015, respectively. The capital lease asset is being depreciated over a period consistent with the estimated proved reserves of Gumusut using the unit-of-production method with the associated depreciation included in the Depreciation, depletion and amortization line on our consolidated income statement. As of December 31, 2016 and December 31, 2015, accumulated depreciation of the capital lease asset amounted to approximately $268 million and $122 million, respectively.

At December 31, 2016, future minimum payments due under capital leases were:

	Millions of Dollars
2017	$ 121
2018	102
2019	102
2020	103
2021	88
Remaining years	590
Total	1,106

Less: portion representing imputed interest		(254)
Capital lease obligations	$	852

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Note 12 Guarantees

At December 31, 2016, we were liable for certain contingent obligations under various contractual arrangements as described below. We recognize a liability, at inception, for the fair value of our obligation as a guarantor for newly issued or modified guarantees. Unless the carrying amount of the liability is noted below, we have not recognized a liability because the fair value of the obligation is immaterial. In addition, unless otherwise stated, we are not currently performing with any significance under the guarantee and expect future performance to be either immaterial or have only a remote chance of occurrence.

APLNG Guarantees

At December 31, 2016, we had outstanding multiple guarantees in connection with our 37.5 percent ownership interest in APLNG. The following is a description of the guarantees with values calculated utilizing December 2016 exchange rates:

We have guaranteed APLNG s performance with regard to a construction contract executed in connection with APLNG s issuance of the Train 1 and Train 2 Notices to Proceed. We estimate the remaining term of this guarantee is one year. Our maximum potential amount of future payments related to this guarantee is approximately $10 million and would become payable if APLNG cancels the applicable construction contract and does not perform with respect to the amounts owed to the contractor.

We have issued a construction completion guarantee related to the third-party project financing secured by APLNG. Our guarantee of the project financing will be released upon meeting certain completion tests with milestones which we estimate should occur in 2017. In October 2016, we reached financial completion for Train 1, releasing a portion of our guarantee. Our maximum exposure at December 31, 2016, is $1.3 billion based upon our pro-rata share of the facility used at that date, which could be payable if completion of the project is not achieved. At December 31, 2016, the carrying value of this guarantee is approximately $46 million.

During the third quarter of 2016, we issued a guarantee for our pro-rata portion of the funds in a project finance reserve account. We estimate the remaining term of this guarantee is 13 years. Our maximum exposure under this guarantee is approximately $60 million and may become payable if an enforcement action is commenced by the project finance lenders against APLNG. At December 31, 2016, the carrying value of this guarantee is approximately $9 million.

In conjunction with our original purchase of an ownership interest in APLNG from Origin Energy in October 2008, we agreed to reimburse Origin Energy for our share of the existing contingent liability arising under guarantees of an existing obligation of APLNG to deliver natural gas under several sales agreements with remaining terms of 1 to 25 years. Our maximum potential liability for future payments, or cost of volume delivery, under these guarantees is estimated to be $1.0 billion ($1.7 billion in the event of intentional or reckless breach) and would become payable if APLNG fails to meet its obligations under these agreements and the obligations cannot otherwise be mitigated. Future payments are considered unlikely, as the payments, or cost of volume delivery, would only be triggered if APLNG does not have enough natural gas to meet these sales commitments and if the co-venturers do not make necessary equity contributions into APLNG.

We have guaranteed the performance of APLNG with regard to certain other contracts executed in connection with the project s continued development. The guarantees have remaining terms of up to 29 years or the life of the venture. Our maximum potential amount of future payments related to these guarantees is approximately $160 million and would become payable if APLNG does not perform.

Other Guarantees

We have other guarantees with maximum future potential payment amounts totaling approximately $540 million, which consist primarily of a guarantee of the residual value of a leased office building, guarantees of the residual value of leased corporate aircraft, and a guarantee for our portion of a joint venture s project finance reserve accounts.

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These guarantees have remaining terms of up to six years and would become payable if, upon sale, certain asset values are lower than guaranteed amounts, business conditions decline at guaranteed entities, or as a result of nonperformance of contractual terms by guaranteed parties.

Indemnifications

Over the years, we have entered into agreements to sell ownership interests in certain corporations, joint ventures and assets that gave rise to qualifying indemnifications. These agreements include indemnifications for taxes, environmental liabilities, employee claims and litigation. The terms of these indemnifications vary greatly. The majority of these indemnifications are related to environmental issues, the term is generally indefinite and the maximum amount of future payments is generally unlimited. The carrying amount recorded for these indemnifications at December 31, 2016, was approximately $100 million. We amortize the indemnification liability over the relevant time period, if one exists, based on the facts and circumstances surrounding each type of indemnity. In cases where the indemnification term is indefinite, we will reverse the liability when we have information the liability is essentially relieved or amortize the liability over an appropriate time period as the fair value of our indemnification exposure declines. Although it is reasonably possible future payments may exceed amounts recorded, due to the nature of the indemnifications, it is not possible to make a reasonable estimate of the maximum potential amount of future payments. Included in the recorded carrying amount at December 31, 2016, were approximately $40 million of environmental accruals for known contamination that are included in the Asset retirement obligations and accrued environmental costs line on our consolidated balance sheet. For additional information about environmental liabilities, see Note 13 Contingencies and Commitments.

On April 30, 2012, the separation of our downstream business was completed, creating two independent energy companies: ConocoPhillips and Phillips 66. In connection with the separation, we entered into an Indemnification and Release Agreement, which provides for cross-indemnities between Phillips 66 and us and established procedures for handling claims subject to indemnification and related matters. We evaluated the impact of the indemnifications given and the Phillips 66 indemnifications received as of the separation date and concluded those fair values were immaterial.

On March 1, 2015, a supplier to one of the refineries included in Phillips 66 as part of the separation of our downstream business formally registered Phillips 66 as a party to the supply agreement, thereby triggering a guarantee we provided at the time of separation. Our maximum potential liability for future payments under this guarantee, which would become payable if Phillips 66 does not perform its contractual obligations under the supply agreement, is approximately $1.4 billion. At December 31, 2016, the carrying value of this guarantee is approximately $98 million and the remaining term is eight years. Because Phillips 66 has indemnified us for losses incurred under this guarantee, we have recorded an indemnification asset from Phillips 66 of approximately $98 million. The recorded indemnification asset amount represents the estimated fair value of the guarantee; however, if we are required to perform under the guarantee, we would expect to recover from Phillips 66 any amounts in excess of that value, provided Phillips 66 is a going concern.

Note 13 Contingencies and Commitments

A number of lawsuits involving a variety of claims arising in the ordinary course of business have been filed against ConocoPhillips. We also may be required to remove or mitigate the effects on the environment of the placement, storage, disposal or release of certain chemical, mineral and petroleum substances at various active and inactive sites. We regularly assess the need for accounting recognition or disclosure of these contingencies. In the case of all known contingencies (other than those related to income taxes), we accrue a liability when the loss is probable and the amount is reasonably estimable. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not reduce these liabilities for potential insurance or third-party recoveries. If applicable, we accrue receivables for probable insurance or other third-party recoveries. With respect to income tax-related contingencies, we use a cumulative probability-weighted loss accrual in cases where sustaining a tax position is less than certain. See Note 19 Income Taxes, for additional information about income tax-related contingencies.

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Based on currently available information, we believe it is remote that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on our consolidated financial statements. As we learn new facts concerning contingencies, we reassess our position both with respect to accrued liabilities and other potential exposures. Estimates particularly sensitive to future changes include contingent liabilities recorded for environmental remediation, tax and legal matters. Estimated future environmental remediation costs are subject to change due to such factors as the uncertain magnitude of cleanup costs, the unknown time and extent of such remedial actions that may be required, and the determination of our liability in proportion to that of other responsible parties. Estimated future costs related to tax and legal matters are subject to change as events evolve and as additional information becomes available during the administrative and litigation processes.

Environmental

We are subject to international, federal, state and local environmental laws and regulations. When we prepare our consolidated financial statements, we record accruals for environmental liabilities based on management s best estimates, using all information that is available at the time. We measure estimates and base liabilities on currently available facts, existing technology, and presently enacted laws and regulations, taking into account stakeholder and business considerations. When measuring environmental liabilities, we also consider our prior experience in remediation of contaminated sites, other companies cleanup experience, and data released by the U.S. Environmental Protection Agency (EPA) or other organizations. We consider unasserted claims in our determination of environmental liabilities, and we accrue them in the period they are both probable and reasonably estimable.

Although liability of those potentially responsible for environmental remediation costs is generally joint and several for federal sites and frequently so for other sites, we are usually only one of many companies cited at a particular site. Due to the joint and several liabilities, we could be responsible for all cleanup costs related to any site at which we have been designated as a potentially responsible party. We have been successful to date in sharing cleanup costs with other financially sound companies. Many of the sites at which we are potentially responsible are still under investigation by the EPA or the agency concerned. Prior to actual cleanup, those potentially responsible normally assess the site conditions, apportion responsibility and determine the appropriate remediation. In some instances, we may have no liability or may attain a settlement of liability. Where it appears that other potentially responsible parties may be financially unable to bear their proportional share, we consider this inability in estimating our potential liability, and we adjust our accruals accordingly. As a result of various acquisitions in the past, we assumed certain environmental obligations. Some of these environmental obligations are mitigated by indemnifications made by others for our benefit, and some of the indemnifications are subject to dollar limits and time limits.

We are currently participating in environmental assessments and cleanups at numerous federal Superfund and comparable state and international sites. After an assessment of environmental exposures for cleanup and other costs, we make accruals on an undiscounted basis (except those acquired in a purchase business combination, which we record on a discounted basis) for planned investigation and remediation activities for sites where it is probable future costs will be incurred and these costs can be reasonably estimated. We have not reduced these accruals for possible insurance recoveries. In the future, we may be involved in additional environmental assessments, cleanups and proceedings. See Note 10 Asset Retirement Obligations and Accrued Environmental Costs, for a summary of our accrued environmental liabilities.

Legal Proceedings

We are subject to various lawsuits and claims including but not limited to matters involving oil and gas royalty and severance tax payments, gas measurement and valuation methods, contract disputes, environmental damages, personal injury, and property damage. Our primary exposures for such matters relate to alleged royalty and tax underpayments on certain federal, state and privately owned properties and claims of alleged environmental contamination from historic operations. We will continue to defend ourselves vigorously in these matters.

Our legal organization applies its knowledge, experience and professional judgment to the specific characteristics of our cases, employing a litigation management process to manage and monitor the legal proceedings against us. Our process facilitates the early evaluation and quantification of potential exposures in individual cases. This process also enables us to track those cases that have been scheduled for trial and/or mediation. Based on professional judgment and experience in using these litigation management tools and available information about current developments in all our cases, our legal organization regularly assesses the adequacy of current accruals and determines if adjustment of existing accruals, or establishment of new accruals, is required.

Other Contingencies

We have contingent liabilities resulting from throughput agreements with pipeline and processing companies not associated with financing arrangements. Under these agreements, we may be required to provide any such company with additional funds through advances and penalties for fees related to throughput capacity not utilized. In addition, at December 31, 2016, we had performance obligations secured by letters of credit of $304 million (issued as direct bank letters of credit) related to various purchase commitments for materials, supplies, commercial activities and services incident to the ordinary conduct of business.

In 2007, we announced we had been unable to reach agreement with respect to our migration to an *empresa mixta* structure mandated by the Venezuelan government s Nationalization Decree. As a result, Venezuela s national oil company, Petróleos de Venezuela S.A. (PDVSA), or its affiliates, directly assumed control over ConocoPhillips interests in the Petrozuata and Hamaca heavy oil ventures and the offshore Corocoro development project. In response to this expropriation, we filed a request for international arbitration on November 2, 2007, with the World Bank s International Centre for Settlement of Investment Disputes (ICSID). An arbitration hearing was held before an ICSID tribunal during the summer of 2010. On September 3, 2013, an ICSID arbitration tribunal held that Venezuela unlawfully expropriated ConocoPhillips significant oil investments in June 2007. On January 17, 2017, the Tribunal reconfirmed the decision that the expropriation was unlawful. A separate arbitration phase is currently proceeding to determine the damages owed to ConocoPhillips for Venezuela s actions. Separate arbitrations for contractual compensation against PDVSA are also pending before an International Chamber of Commerce (ICC) arbitration tribunal. In addition, ConocoPhillips brought fraudulent transfer actions in the U.S. District Court of Delaware, alleging that PDVSA has taken actions to improperly expatriate assets from the United States to Venezuela in an effort to avoid judgment creditors.

In 2008, Burlington Resources, Inc., a wholly owned subsidiary of ConocoPhillips, initiated arbitration before ICSID against The Republic of Ecuador, as a result of the newly enacted Windfall Profits Tax Law and government-mandated renegotiation of our production sharing contracts. Despite a restraining order issued by the ICSID tribunal, Ecuador confiscated the crude oil production of Burlington and its co-venturer and sold the seized crude oil. In 2009, Ecuador took over operations in Blocks 7 and 21, fully expropriating our assets. In June 2010, the ICSID tribunal concluded it has jurisdiction to hear the expropriation claim. On April 24, 2012, Ecuador filed supplemental counterclaims asserting environmental damages, which we believe are not material. The ICSID tribunal issued a decision on liability on December 14, 2012, in favor of Burlington, finding that Ecuador s seizure of Blocks 7 and 21 was an unlawful expropriation in violation of the Ecuador-U.S. Bilateral Investment Treaty. An additional arbitration phase to determine the damages owed to ConocoPhillips for Ecuador s actions and to address Ecuador s counterclaims is complete. In February 2017, the tribunal unanimously awarded Burlington $380 million for Ecuador s unlawful expropriation and breach of the U.S.-Ecuador bilateral investment treaty. The tribunal also issued a separate decision finding Ecuador to be entitled to $42 million for limited environmental and infrastructure impacts associated with the operations of Burlington and its co-venturer. Ecuador recently filed a request for annulment of this decision with ICSID. The schedule for the annulment process has not yet been set.

In December 2016, ConocoPhillips Angola filed a notice of arbitration against Sonangol E.P. under the Block 36 Production Sharing Contract relating to disputes arising thereunder. The arbitration will be conducted under the United Nations Commission on International Trade Laws (UNCITRAL) rules using a three person tribunal.

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Long-Term Throughput Agreements and Take-or-Pay Agreements

We have certain throughput agreements and take-or-pay agreements in support of financing arrangements. The agreements typically provide for natural gas or crude oil transportation to be used in the ordinary course of the company s business. The aggregate amounts of estimated payments under these various agreements are: 2017 $24 million; 2018 $20 million; 2019 $7 million; 2020 $7 million; 2021 $7 million; and 2022 and after $75 million. Total payments under the agreements were $42 million in 2016, $27 million in 2015 and $127 million in 2014.

Note 14 Derivative and Financial Instruments

We use futures, forwards, swaps and options in various markets to meet our customer needs and capture market opportunities. Our commodity business primarily consists of natural gas, crude oil, bitumen, LNG and natural gas liquids.

Our derivative instruments are held at fair value on our consolidated balance sheet. Where these balances have the right of setoff, they are presented on a net basis. Related cash flows are recorded as operating activities on our consolidated statement of cash flows. On our consolidated income statement, realized and unrealized gains and losses are recognized either on a gross basis if directly related to our physical business or a net basis if held for trading. Gains and losses related to contracts that meet and are designated with the normal purchase normal sale exception are recognized upon settlement. We generally apply this exception to eligible crude contracts. We do not use hedge accounting for our commodity derivatives.

The following table presents the gross fair values of our commodity derivatives, excluding collateral, and the line items where they appear on our consolidated balance sheet:

		Millions of Dollars	
		2016	2015
Assets			
Prepaid expenses and other current assets	**$**	**268**	768
Other assets		**44**	60
Liabilities			
Other accruals		**300**	754
Other liabilities and deferred credits		**34**	46

The gains (losses) from commodity derivatives incurred, and the line items where they appear on our consolidated income statement were:

	Millions of Dollars		
	2016	2015	2014

Sales and other operating revenues	$ **(198)**	231	523
Other income	**(1)**	2	1
Purchased commodities	**161**	(201)	(458)

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The table below summarizes our material net exposures resulting from outstanding commodity derivative contracts:

	Open Position Long/(Short)	
	2016	2015
Commodity		
Natural gas and power (billions of cubic feet equivalent)		
Fixed price	**(31)**	(14)
Basis	**2**	(17)

Foreign Currency Exchange Derivatives

We have foreign currency exchange rate risk resulting from international operations. Our foreign currency exchange derivative activity primarily relates to managing our cash-related and foreign currency exchange rate exposures, such as firm commitments for capital programs or local currency tax payments, dividends, and cash returns from net investments in foreign affiliates. We do not elect hedge accounting on our foreign currency exchange derivatives.

The following table presents the gross fair values of our foreign currency exchange derivatives, excluding collateral, and the line items where they appear on our consolidated balance sheet:

	Millions of Dollars	
	2016	2015
Assets		
Prepaid expenses and other current assets	**$ 1**	47
Liabilities		
Other accruals	**168**	8

The (gains) losses from foreign currency exchange derivatives incurred, and the line item where they appear on our consolidated income statement were:

	Millions of Dollars		
	2016	2015	2014
Foreign currency transaction (gains) losses	**$ 247**	(33)	3

We had the following net notional position of outstanding foreign currency exchange derivatives:

		In Millions	
		Notional Currency	
		2016	2015
Foreign Currency Exchange Derivatives			
Sell U.S. dollar, buy other currencies*	USD	**13**	347
Buy U.S. dollar, sell other currencies**	USD	**25**	20
Buy British pound, sell other currencies***	GBP	**1,069**	567
Sell British pound, buy Norwegian krone	GBP	**51**	-

**Primarily Canadian dollar, Norwegian krone and British pound.*

***Primarily Canadian dollar and British pound.*

****Primarily Canadian dollar and Euro.*

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Financial Instruments

We have certain financial instruments on our consolidated balance sheet related to interest-bearing time deposits and commercial paper. These held-to-maturity financial instruments are included in Cash and cash equivalents on our consolidated balance sheet if the maturities at the time we made the investments were 90 days or less; otherwise, these investments are included in Short-term investments on our consolidated balance sheet.

		Millions of Dollars			
		Carrying Amount			
		Cash and Cash Equivalents		Short-Term Investments	
		2016	2015	**2016**	2015
Cash	$	**623**	528	**-**	-
Time deposits					
Remaining maturities from 1 to 90 days		**2,987**	1,840	**39**	-
Remaining maturities from 91 to 180 days		**-**	-	**11**	-
	$	**3,610**	2,368	**50**	-

Credit Risk

Financial instruments potentially exposed to concentrations of credit risk consist primarily of cash equivalents, short-term investments, over-the-counter (OTC) derivative contracts and trade receivables. Our cash equivalents and short-term investments are placed in high-quality commercial paper, money market funds, government debt securities and time deposits with major international banks and financial institutions.

The credit risk from our OTC derivative contracts, such as forwards and swaps, derives from the counterparty to the transaction. Individual counterparty exposure is managed within predetermined credit limits and includes the use of cash-call margins when appropriate, thereby reducing the risk of significant nonperformance. We also use futures, swaps and option contracts that have a negligible credit risk because these trades are cleared with an exchange clearinghouse and subject to mandatory margin requirements until settled; however, we are exposed to the credit risk of those exchange brokers for receivables arising from daily margin cash calls, as well as for cash deposited to meet initial margin requirements.

Our trade receivables result primarily from our petroleum operations and reflect a broad national and international customer base, which limits our exposure to concentrations of credit risk. The majority of these receivables have payment terms of 30 days or less, and we continually monitor this exposure and the creditworthiness of the counterparties. We do not generally require collateral to limit the exposure to loss; however, we will sometimes use letters of credit, prepayments and master netting arrangements to mitigate credit risk with counterparties that both buy from and sell to us, as these agreements permit the amounts owed by us or owed to others to be offset against amounts due to us.

Certain of our derivative instruments contain provisions that require us to post collateral if the derivative exposure exceeds a threshold amount. We have contracts with fixed threshold amounts and other contracts with variable threshold amounts that are contingent on our credit rating. The variable threshold amounts typically decline for lower credit ratings, while both the variable and fixed threshold amounts typically revert to zero if we fall below investment grade. Cash is the primary collateral in all contracts; however, many also permit us to post letters of credit as collateral, such as transactions administered through the New York Mercantile Exchange.

The aggregate fair value of all derivative instruments with such credit risk-related contingent features that were in a liability position on December 31, 2016 and December 31, 2015, was $42 million and $158 million, respectively. For these instruments, no collateral was posted as of December 31, 2016, and $2 million of collateral was posted as of December 31, 2015.

If our credit rating had been downgraded below investment grade on December 31, 2016, we would be required to post $42 million of additional collateral, either with cash or letters of credit.

Note 15 Fair Value Measurement

We carry a portion of our assets and liabilities at fair value that are measured at a reporting date using an exit price (i.e., the price that would be received to sell an asset or paid to transfer a liability) and disclosed according to the quality of valuation inputs under the following hierarchy:

Level 1: Quoted prices (unadjusted) in an active market for identical assets or liabilities.
Level 2: Inputs other than quoted prices that are directly or indirectly observable.
Level 3: Unobservable inputs that are significant to the fair value of assets or liabilities.

The classification of an asset or liability is based on the lowest level of input significant to its fair value. Those that are initially classified as Level 3 are subsequently reported as Level 2 when the fair value derived from unobservable inputs is inconsequential to the overall fair value, or if corroborated market data becomes available. Assets and liabilities initially reported as Level 2 are subsequently reported as Level 3 if corroborated market data is no longer available. Transfers occur at the end of the reporting period. There were no material transfers in or out of Level 1 during 2016 or 2015.

Recurring Fair Value Measurement

Financial assets and liabilities reported at fair value on a recurring basis primarily include commodity derivatives. Level 1 derivative assets and liabilities primarily represent exchange-traded futures and options that are valued using unadjusted prices available from the underlying exchange. Level 2 derivative assets and liabilities primarily represent OTC swaps, options and forward purchase and sale contracts that are valued using adjusted exchange prices, prices provided by brokers or pricing service companies that are all corroborated by market data. Level 3 derivative assets and liabilities consist of OTC swaps, options and forward purchase and sale contracts where a significant portion of fair value is calculated from underlying market data that is not readily available. The derived value uses industry standard methodologies that may consider the historical relationships among various commodities, modeled market prices, time value, volatility factors and other relevant economic measures. The use of these inputs results in management s best estimate of fair value. Level 3 activity was not material for all periods presented.

The following table summarizes the fair value hierarchy for gross financial assets and liabilities (i.e., unadjusted where the right of setoff exists for commodity derivatives accounted for at fair value on a recurring basis):

		Millions of Dollars							
		December 31, 2016				December 31, 2015			
		Level 1	**Level 2**	**Level 3**	**Total**	Level 1	Level 2	Level 3	Total
Assets									
Commodity derivatives	$	**194**	**96**	**22**	**312**	516	242	70	828
Total assets	$	**194**	**96**	**22**	**312**	516	242	70	828

Liabilities									
Commodity derivatives	**$**	**207**	**105**	**22**	**334**	515	273	12	800
Total liabilities	**$**	**207**	**105**	**22**	**334**	515	273	12	800

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The following table summarizes those commodity derivative balances subject to the right of setoff as presented on our consolidated balance sheet. We have elected to offset the recognized fair value amounts for multiple derivative instruments executed with the same counterparty in our financial statements when a legal right of offset exists.

	Millions of Dollars					
	Gross Amounts Recognized	Gross Amounts Offset	Net Amounts Presented	Cash Collateral	Gross Amounts without Right of Setoff	Net Amounts
December 31, 2016						
Assets	**$ 312**	**221**	**91**	**-**	**5**	**86**
Liabilities	**334**	**221**	**113**	**12**	**12**	**89**
December 31, 2015						
Assets	$ 828	600	228	-	8	220
Liabilities	800	600	200	1	11	188

At December 31, 2016 and December 31, 2015, we did not present any amounts gross on our consolidated balance sheet where we had the right of setoff.

Non-Recurring Fair Value Measurement

The following table summarizes the fair value hierarchy by major category for assets accounted for at fair value on a non-recurring basis:

	Millions of Dollars			
		Fair Value Measurements Using		
	Fair Value	Level 1 Inputs	Level 3 Inputs	Before-Tax Loss
Year ended December 31, 2016				
Net PP&E (held for use)				
March 31, 2016	**$ 217**	**-**	**217**	**129**
June 30, 2016	**23**	**-**	**23**	**53**
December 31, 2016	**13**	**-**	**13**	**29**
Net PP&E (held for sale)				
September 30, 2016	**217**	**217**	**-**	**99**
Cost and equity method investments				
December 31, 2016	**90**	**4**	**86**	**40**

Year ended December 31, 2015					
Net PP&E (held for use)					
March 31, 2015	$	-	-	-	9
June 30, 2015		42	-	42	70
September 30, 2015		-	-	-	7
December 31, 2015		440	-	440	595
Net PP&E (unproved property)					
September 30, 2015		104	-	104	240
Equity method investments					
December 31, 2015		10,210	-	10,210	1,507

Net PP&E (held for use)

Net PP&E held for use is comprised of various producing properties impaired to their individual fair values less costs to sell. The fair values were determined by internal discounted cash flow models using estimates of future production, prices from futures exchanges and pricing service companies, costs, and a discount rate believed to be consistent with those used by principal market participants.

Net PP&E (held for sale)

Net PP&E held for sale was written down to fair value, less costs to sell. The fair value of each asset was determined by its negotiated selling price.

Net PP&E (unproved property)

Net PP&E unproved property is comprised of unproved leaseholds impaired to our best estimate of sales value less costs to sell.

Equity Method Investments

Certain cost and equity method investments were determined to have fair values below their carrying amounts, and the impairments were considered to be other than temporary under the guidance of FASB ASC Topic 323. An investment using Level 1 inputs was written down to fair value, less costs to sell, determined by its negotiated selling price. Investments using Level 3 inputs had fair values determined primarily by internal discounted cash flow models using estimates of future production, prices from futures exchanges and pricing service companies, costs, and a discount factor believed to be consistent with those used by principal market participants. During 2015, this primarily included our investment in APLNG, which was written down to its fair value of $10,185 million, resulting in a charge of $1,502 million before-tax. For additional information on APLNG, see Note 7 Investments, Loans and Long-Term Receivables.

Reported Fair Values of Financial Instruments

We used the following methods and assumptions to estimate the fair value of financial instruments:

- Cash and cash equivalents and short-term investments: The carrying amount reported on the balance sheet approximates fair value.
- Accounts and notes receivable (including long-term and related parties): The carrying amount reported on the balance sheet approximates fair value. The valuation technique and methods used to estimate the fair value of the current portion of fixed-rate related party loans is consistent with Loans and advances related parties.
- Loans and advances related parties: The carrying amount of floating-rate loans approximates fair value. The fair value of fixed-rate loan activity is measured using market observable data and is categorized as Level 2 in the fair value hierarchy. See Note 7 Investments, Loans and Long-Term Receivables, for additional information.
- Accounts payable (including related parties) and floating-rate debt: The carrying amount of accounts payable and floating-rate debt reported on the balance sheet approximates fair value.

Fixed-rate debt: The estimated fair value of fixed-rate debt is measured using prices available from a pricing service that is corroborated by market data; therefore, these liabilities are categorized as Level 2 in the fair value hierarchy.

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The following table summarizes the net fair value of financial instruments (i.e., adjusted where the right of setoff exists for commodity derivatives):

	Millions of Dollars			
	Carrying Amount		Fair Value	
	2016	2015	**2016**	2015
Financial assets				
Commodity derivatives	$ **91**	228	**91**	228
Total loans and advances related parties	**701**	808	**701**	808
Financial liabilities				
Total debt, excluding capital leases	**26,423**	24,062	**29,307**	24,785
Commodity derivatives	**101**	199	**101**	199

Commodity derivatives

At December 31, 2016, commodity derivative assets and liabilities appear net with no obligations to return cash collateral and $12 million of rights to reclaim cash collateral, respectively. At December 31, 2015, commodity derivative assets and liabilities appear net with no obligations to return cash collateral and $1 million of rights to reclaim cash collateral, respectively.

Note 16 Equity

Common Stock

The changes in our shares of common stock, as categorized in the equity section of the balance sheet, were:

	Shares		
	2016	2015	2014
Issued			
Beginning of year	**1,778,226,388**	1,773,583,368	1,768,169,906
Distributed under benefit plans	**3,852,719**	4,643,020	5,413,462
End of year	**1,782,079,107**	1,778,226,388	1,773,583,368
Held in Treasury			
Beginning of year	**542,230,673**	542,230,673	542,230,673
Repurchase of common stock	**2,579,098**	-	-
End of year	**544,809,771**	542,230,673	542,230,673

Preferred Stock

We have authorized 500 million shares of preferred stock, par value $.01 per share, none of which was issued or outstanding at December 31, 2016 or 2015.

Noncontrolling Interests

At December 31, 2016 and 2015, we had $252 million and $320 million outstanding, respectively, of equity in less-than-wholly owned consolidated subsidiaries held by noncontrolling interest owners. For both periods, the amounts were related to the Darwin LNG and Bayu-Darwin Pipeline operating joint ventures we control.

Repurchase of Common Stock

On November 10, 2016, we announced plans to purchase up to $3 billion of our common stock over the next three years. Repurchase of shares began in November and totaled 2,579,098 shares at a cost of $126 million, through December 31, 2016.

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Note 17 Non-Mineral Leases

The company primarily leases drilling equipment and office buildings, as well as ocean transport vessels, tugboats, barges, corporate aircraft, computers and other facilities and equipment. Certain leases include escalation clauses for adjusting rental payments to reflect changes in price indices, as well as renewal options and/or options to purchase the leased property for the fair market value at the end of the lease term. There are no significant restrictions imposed on us by the leasing agreements with regard to dividends, asset dispositions or borrowing ability. For additional information on leased assets under capital leases, see Note 11 Debt.

At December 31, 2016, future minimum rental payments due under noncancelable leases were:

	Millions of Dollars
2017	$ 277
2018	238
2019	172
2020	390
2021	114
Remaining years	435
Total	1,626
Less: income from subleases	(15)
Net minimum operating lease payments	$ 1,611

Operating lease rental expense for the years ended December 31 was:

	Millions of Dollars		
	2016	2015	2014
Total rentals	**$ 537**	432	474
Less: sublease rentals	**(8)**	(9)	(10)
	$ 529	423	464

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Note 18 Employee Benefit Plans

Pension and Postretirement Plans

An analysis of the projected benefit obligations for our pension plans and accumulated benefit obligations for our postretirement health and life insurance plans follows:

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2016		2015		**2016**	2015
	U.S.	**Int l.**	U.S.	Int l.		
Change in Benefit Obligation						
Benefit obligation at January 1	$ **3,772**	**3,321**	4,387	3,984	**352**	716
Service cost	**108**	**76**	138	124	**2**	4
Interest cost	**133**	**120**	161	135	**13**	22
Plan participant contributions	**-**	**3**	-	5	**24**	21
Plan amendments	**-**	**-**	-	-	**(27)**	(303)
Actuarial (gain) loss	**247**	**466**	(212)	(442)	**(14)**	(49)
Benefits paid	**(872)**	**(148)**	(729)	(162)	**(68)**	(63)
Curtailment	**14**	**10**	27	(43)	**3**	8
Settlement	**-**	**(46)**	-	-	**-**	-
Recognition of termination benefits	**14**	**1**	-	68	**-**	-
Foreign currency exchange rate change	**-**	**(358)**	-	(348)	**1**	(4)
Benefit obligation at December 31*	$ **3,416**	**3,445**	3,772	3,321	**286**	352
**Accumulated benefit obligation portion of above at December 31:*	*$ **3,246***	***3,067***	*3,573*	*2,953*		
Change in Fair Value of Plan Assets						
Fair value of plan assets at January 1	$ **2,606**	**3,063**	3,266	3,278	**-**	-
Actual return on plan assets	**133**	**397**	(4)	96	**-**	-
Company contributions	**214**	**125**	73	120	**44**	42
Plan participant contributions	**-**	**3**	-	5	**24**	21
Benefits paid	**(872)**	**(148)**	(729)	(162)	**(68)**	(63)
Foreign currency exchange rate change	**-**	**(372)**	-	(274)	**-**	-
Fair value of plan assets at December 31	$ **2,081**	**3,068**	2,606	3,063	**-**	-
Funded Status	$ **(1,335)**	**(377)**	(1,166)	(258)	**(286)**	(352)

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	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2016		2015		**2016**	2015
	U.S.	**Int l.**	U.S.	Int l.		
Amounts Recognized in the Consolidated Balance Sheet at December 31						
Noncurrent assets	**$ -**	**164**	-	175	**-**	-
Current liabilities	**(101)**	**(7)**	(99)	(34)	**(44)**	(45)
Noncurrent liabilities	**(1,234)**	**(534)**	(1,067)	(399)	**(242)**	(307)
Total recognized	**$ (1,335)**	**(377)**	(1,166)	(258)	**(286)**	(352)
Weighted-Average Assumptions Used to Determine Benefit Obligations at December 31						
Discount rate	**3.95%**	**3.00**	4.50	3.95	**3.60**	3.90
Rate of compensation increase	**4.00**	**3.85**	4.00	4.05	**-**	-
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31						
Discount rate	**3.90%**	**3.95**	4.00	3.55	**3.75**	4.05
Expected return on plan assets	**7.00**	**5.45**	7.00	5.40	**-**	-
Rate of compensation increase	**4.00**	**4.05**	4.75	4.35	**-**	-

For both U.S. and international pensions, the overall expected long-term rate of return is developed from the expected future return of each asset class, weighted by the expected allocation of pension assets to that asset class. We rely on a variety of independent market forecasts in developing the expected rate of return for each class of assets.

Included in accumulated other comprehensive income (loss) at December 31 were the following before-tax amounts that had not been recognized in net periodic benefit cost:

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2016		2015		**2016**	2015
	U.S.	**Int l.**	U.S.	Int l.		
Unrecognized net actuarial (gain) loss	**$ 748**	**479**	773	273	**(27)**	(18)
Unrecognized prior service cost (credit)	**4**	**(20)**	9	(30)	**(285)**	(292)

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	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2016		2015		**2016**	2015
	U.S.	**Int l.**	U.S.	Int l.		
Sources of Change in Other Comprehensive Income (Loss)						
Net gain (loss) arising during the period	**$ (263)**	**(232)**	61	490	**14**	41
Amortization of (gain) loss included in net loss*	**288**	**26**	312	89	**(5)**	2
Net change during the period	**$ 25**	**(206)**	373	579	**9**	43
Prior service credit (cost) arising during the period	**$ -**	**(4)**	-	(2)	**27**	303
Amortization of prior service cost (credit) included in net loss	**5**	**(6)**	7	(11)	**(34)**	(15)
Net change during the period	**$ 5**	**(10)**	7	(13)	**(7)**	288

**Includes settlement losses recognized in 2016 and 2015.*

During the year ended December 31, 2016, there was an amendment to the U.S. other postretirement benefit plan. The benefit obligation decreased by $27 million for changes in the plan made to post-65 retiree medical benefits related to updated cost sharing assumption changes for retirees. The $27 million decrease in the benefit obligation resulted in a corresponding increase in other comprehensive income.

During the year ended December 31, 2015, there were amendments to the U.S. other postretirement benefit plan. The benefit obligation decreased by $303 million for changes in the plan made to retiree medical benefits. The $303 million decrease consists of $149 million related to the discontinuation of all company premium cost-sharing contributions to the post-65 retiree medical plan after December 31, 2025, $91 million related to updated cost sharing assumption changes for retirees, $49 million associated with excluding employees and retirees of Phillips 66 who were not enrolled in a ConocoPhillips retiree medical plan as of July 1, 2015, and $14 million associated with new participants in the post-65 retiree medical plan after December 31, 2015, no longer being eligible for any company premium cost-sharing contributions. The $303 million decrease in the benefit obligation resulted in a corresponding decrease in other comprehensive loss.

Included in accumulated other comprehensive income (loss) at December 31, 2016, were the following before-tax amounts that are expected to be amortized into net periodic benefit cost during 2017:

	Millions of Dollars		
	Pension Benefits		Other Benefits
	U.S.	Int l.	

Unrecognized net actuarial (gain) loss	$ 75	48	(3)
Unrecognized prior service cost (credit)	4	(5)	(36)

For our tax-qualified pension plans with projected benefit obligations in excess of plan assets, the projected benefit obligation, the accumulated benefit obligation, and the fair value of plan assets were $5,498 million, $5,145 million, and $4,208 million, respectively, at December 31, 2016, and $5,720 million, $5,314 million, and $4,759 million, respectively, at December 31, 2015.

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For our unfunded nonqualified key employee supplemental pension plans, the projected benefit obligation and the accumulated benefit obligation were $586 million and $496 million, respectively, at December 31, 2016, and were $639 million and $564 million, respectively, at December 31, 2015.

The components of net periodic benefit cost of all defined benefit plans are presented in the following table:

	Millions of Dollars								
	Pension Benefits						Other Benefits		
	2016		2015		2014		**2016**	2015	2014
	U.S.	**Int l.**	U.S.	Int l.	U.S.	Int l.			
Components of Net Periodic Benefit Cost									
Service cost	**$ 108**	**76**	138	124	124	109	**2**	4	3
Interest cost	**133**	**120**	161	135	165	166	**13**	22	29
Expected return on plan assets	**(149)**	**(147)**	(201)	(164)	(213)	(181)	**-**	-	-
Amortization of prior service cost (credit)	**5**	**(6)**	6	(7)	6	(8)	**(34)**	(17)	(4)
Recognized net actuarial loss (gain)	**86**	**26**	115	82	77	57	**(2)**	2	(3)
Settlements	**202**	**-**	197	7	-	-	**-**	-	-
Curtailment (gain) loss	**14**	**-**	35	(4)	-	-	**1**	2	-
Net periodic benefit cost	**$ 399**	**69**	451	173	159	143	**(20)**	13	25

We recognized pension settlement losses of $202 million in 2016 and $204 million in 2015 as lump-sum benefit payments from certain U.S. and international pension plans exceeded the sum of service and interest costs for those plans and led to recognition of settlement losses.

As part of the 2016 and 2015 restructuring programs, we concluded that actions taken during those years resulted in a significant reduction of future services of active employees primarily in the U.S. qualified pension plan and a U.S. nonqualified supplemental retirement plan. As a result, we recognized an increase in the benefit obligation and a proportionate share of prior service cost from other comprehensive income (loss) as curtailment losses of $15 million and $33 million during the years ended December 31, 2016 and 2015, respectively.

Also as part of the 2016 and 2015 restructuring programs in the U.S. and Europe, we recognized expense for special termination benefits of $15 million during the year ended December 31, 2016, consisting of $14 million in the U.S. and $1 million in Europe, and $124 million during the year ended December 31, 2015, consisting of $46 million in the U.S. and $78 million in Europe. Approximately 62 percent of the 2015 Europe amount was recovered from joint venture partners.

In determining net pension and other postretirement benefit costs, we amortize prior service costs on a straight-line basis over the average remaining service period of employees expected to receive benefits under the plan. For net actuarial gains and losses, we amortize 10 percent of the unamortized balance each year.

We have multiple nonpension postretirement benefit plans for health and life insurance. The health care plans are contributory and subject to various cost sharing features, with participant and company contributions adjusted annually; the life insurance plans are noncontributory. The measurement of the U.S. pre-65 retiree medical accumulated postretirement benefit obligation assumes a health care cost trend rate of 6.50 percent in 2017 that declines to 5 percent by 2023. The measurement of the U.S. post-65 retiree medical accumulated postretirement benefit obligation assumes a health care cost trend rate of 4 percent in 2017 that increases to 5 percent by 2018. A one-percentage-point change in the assumed health care cost trend rate would be immaterial to ConocoPhillips.

Plan Assets We follow a policy of broadly diversifying pension plan assets across asset classes and individual holdings. As a result, our plan assets have no significant concentrations of credit risk. Asset classes that are considered appropriate include U.S. equities, non-U.S. equities, U.S. fixed income, non-U.S. fixed income, real estate and private equity investments. Plan fiduciaries may consider and add other asset classes to the investment program from time to time. The target allocations for plan assets are 57 percent equity securities, 37 percent debt securities and 6 percent real estate. Generally, the plan investments are publicly traded, therefore minimizing liquidity risk in the portfolio.

The following is a description of the valuation methodologies used for the pension plan assets. There have been no changes in the methodologies used at December 31, 2016 and 2015.

Fair values of equity securities and government debt securities categorized in Level 1 are primarily based on quoted market prices in active markets for identical assets and liabilities.

Fair values of corporate debt securities, agency and mortgage-backed securities and government debt securities categorized in Level 2 are estimated using recently executed transactions and quoted market prices for similar assets and liabilities in active markets and for identical assets and liabilities in markets that are not active. If there have been no market transactions in a particular fixed income security, its fair value is calculated by pricing models that benchmark the security against other securities with actual market prices. When observable quoted market prices are not available, fair value is based on pricing models that use something other than actual market prices (e.g., observable inputs such as benchmark yields, reported trades and issuer spreads for similar securities), and these securities are categorized in Level 3 of the fair value hierarchy.

Fair values of investments in common/collective trusts are determined by the issuer of each fund based on the fair value of the underlying assets.

Fair values of mutual funds are based on quoted market prices, which represent the net asset value of shares held.

Cash is valued at cost, which approximates fair value. Fair values of international cash equivalents categorized in Level 2 are valued using observable yield curves, discounting and interest rates. U.S. cash balances held in the form of short-term fund units that are redeemable at the measurement date are categorized as Level 2.

Fair values of exchange-traded derivatives classified in Level 1 are based on quoted market prices. For other derivatives classified in Level 2, the values are generally calculated from pricing models with market input parameters from third-party sources.

Fair values of insurance contracts are valued at the present value of the future benefit payments owed by the insurance company to the plans participants.

Fair values of real estate investments are valued using real estate valuation techniques and other methods that include reference to third-party sources and sales comparables where available.

A portion of U.S. pension plan assets is held as a participating interest in an insurance annuity contract, which is calculated as the market value of investments held under this contract, less the accumulated benefit obligation covered by the contract. The participating interest is classified as Level 3 in the fair value hierarchy as the fair value is determined via a combination of quoted market prices, recently executed transactions, and an actuarial present value computation for contract obligations. At December 31, 2016, the participating interest in the annuity contract was valued at $121 million and consisted of $288 million in debt securities, less $167 million for the accumulated benefit obligation covered by the contract. At December 31, 2015, the participating interest in the annuity contract was valued at $125 million and consisted of $305 million in debt securities, less $180 million for the accumulated benefit obligation covered by the contract. The net change from 2015 to 2016 is due to a decrease in the fair value of the underlying investments of $17 million offset by a decrease in the present value of the contract obligation of $13 million. The participating interest is not available for meeting general pension benefit obligations in the near term. No future company contributions are required and no new benefits are being accrued under this insurance annuity contract.

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The fair values of our pension plan assets at December 31, by asset class were as follows:

	Millions of Dollars							
	U.S.				International			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
2016								
Equity Securities								
U.S.	**$ 632**	**-**	**14**	**646**	**628**	**-**	**-**	**628**
International	**342**	**-**	**-**	**342**	**428**	**-**	**-**	**428**
Common/collective trusts	**62**	**-**	**-**	**62**	**-**	**156**	**-**	**156**
Mutual funds	**-**	**-**	**-**	**-**	**268**	**139**	**-**	**407**
Debt Securities								
Government	**-**	**38**	**-**	**38**	**470**	**-**	**-**	**470**
Corporate	**-**	**54**	**3**	**57**	**-**	**-**	**-**	**-**
Common/collective trusts	**-**	**-**	**-**	**-**	**-**	**385**	**-**	**385**
Mutual funds	**-**	**-**	**-**	**-**	**137**	**-**	**-**	**137**
Cash and cash equivalents	**-**	**-**	**-**	**-**	**48**	**-**	**-**	**48**
Derivatives	**-**	**-**	**-**	**-**	**18**	**-**	**-**	**18**
Real estate	**-**	**-**	**-**	**-**	**-**	**-**	**111**	**111**
Total in fair value hierarchy	**$ 1,036**	**92**	**17**	**1,145**	**1,997**	**680**	**111**	**2,788**
Investments measured at net asset value*								
Equity Securities								
Common/collective trusts	**$ -**	**-**	**-**	**410**	**-**	**-**	**-**	**-**
Debt Securities								
Corporate	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**155**
Agency and mortgage-backed securities	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**27**
Common/collective trusts	**-**	**-**	**-**	**312**	**-**	**-**	**-**	**-**
Cash and cash equivalents	**-**	**-**	**-**	**36**	**-**	**-**	**-**	**11**
Real estate	**-**	**-**	**-**	**69**	**-**	**-**	**-**	**76**
Total**	**$ 1,036**	**92**	**17**	**1,972**	**1,997**	**680**	**111**	**3,057**

**In accordance with FASB ASC Topic 715, Compensation Retirement Benefits, certain investments that are to be measured at fair value using the net asset value per share (or its equivalent) practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the Change in Fair Value of Plan Assets.*

***Excludes the participating interest in the insurance annuity contract with a net asset value of $121 million and net payables related to security transactions of $1 million.*

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The fair values of our pension plan assets at December 31, by asset class were as follows:

	Millions of Dollars							
	U.S.				International			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
2015								
Equity Securities								
U.S.	$ 777	3	2	782	609	-	-	609
International	485	-	-	485	450	-	-	450
Common/collective trusts	-	-	-	-	-	214	-	214
Mutual funds	-	-	-	-	234	106	-	340
Debt Securities								
Government	85	56	-	141	493	-	-	493
Corporate	-	331	17	348	-	-	-	-
Agency and mortgage-backed securities	-	80	-	80	-	-	-	-
Common/collective trusts	-	-	-	-	-	406	-	406
Mutual funds	-	-	-	-	136	-	-	136
Cash and cash equivalents	-	-	-	-	46	-	-	46
Derivatives	-	(7)	-	(7)	(26)	-	-	(26)
Real estate	-	-	-	-	-	-	104	104
Total in fair value hierarchy	$ 1,347	463	19	1,829	1,942	726	104	2,772
Investments measured at net asset value*								
Equity Securities								
Common/collective trusts	$ -	-	-	569	-	-	-	-
Debt Securities								
Corporate	-	-	-	-	-	-	-	172
Agency and mortgage-backed securities	-	-	-	-	-	-	-	36
Cash and cash equivalents	-	-	-	60	-	-	-	10
Real estate	-	-	-	63	-	-	-	65
Total**	$ 1,347	463	19	2,521	1,942	726	104	3,055

**In accordance with FASB ASC Topic 715, Compensation Retirement Benefits, certain investments that are to be measured at fair value using the net asset value per share (or its equivalent) practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the Change in Fair Value of Plan Assets.*

***Excludes the participating interest in the insurance annuity contract with a net asset value of $125 million and net payables related to security transactions of $32 million.*

Level 3 activity was not material for all periods.

Our funding policy for U.S. plans is to contribute at least the minimum required by the Employee Retirement Income Security Act of 1974 and the Internal Revenue Code of 1986, as amended. Contributions to foreign plans are dependent upon local laws and tax regulations. In 2017, we expect to contribute approximately $320 million to our domestic qualified and nonqualified pension and postretirement benefit plans and $110 million to our international qualified and nonqualified pension and postretirement benefit plans.

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The following benefit payments, which are exclusive of amounts to be paid from the insurance annuity contract and which reflect expected future service, as appropriate, are expected to be paid:

	Millions of Dollars		
	Pension Benefits		Other Benefits
	U.S.	Int l.	
2017	$ 352	116	42
2018	290	131	39
2019	287	124	36
2020	277	129	34
2021	292	137	30
2022 2026	1,374	729	109

Severance Accrual

As a result of the current business environment s impact on our operating and capital plans, a reduction in our overall employee workforce occurred during 2015 and 2016. Severance accruals of $129 million were recorded in 2016. The following table summarizes our severance accrual activity for the year ended December 31, 2016:

	Millions of Dollars
Balance at December 31, 2015	$ 156
Accruals	**129**
Benefit payments	**(206)**
Foreign currency translation adjustments	**1**
Balance at December 31, 2016	**$ 80**

Of the remaining balance at December 31, 2016, $52 million is classified as short-term.

Defined Contribution Plans

Most U.S. employees are eligible to participate in the ConocoPhillips Savings Plan (CPSP). Employees can deposit up to 75 percent of their eligible pay, subject to statutory limits, in the CPSP to a choice of approximately 34 investment funds. In 2016, employees who participate in the CPSP and contribute 1 percent of their eligible pay receive a 6 percent company cash match with a potential company discretionary cash contribution of up to 6 percent. Company contributions charged to expense for the CPSP and predecessor plans were $58 million in 2016, $109 million in 2015, and $116 million in 2014.

We have several defined contribution plans for our international employees, each with its own terms and eligibility depending on location. Total compensation expense recognized for these international plans was approximately $44 million in 2016, $55 million in 2015, and $66 million in 2014.

Share-Based Compensation Plans

The 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (the Plan) was approved by shareholders in May 2014. Over its 10-year life, the Plan allows the issuance of up to 79 million shares of our common stock for compensation to our employees and directors; however, as of the effective date of the Plan, (i) any shares of common stock available for future awards under the prior plans and (ii) any shares of common stock represented by awards granted under the prior plans that are forfeited, expire or are cancelled without delivery of shares of common stock or which result in the forfeiture of shares of common stock back to the company shall be available for awards under the Plan, and no new awards shall be granted under the prior plans. Of the 79 million shares available for issuance under the Plan, no more than 40 million shares of common stock are available for incentive stock options. The Human Resources and Compensation Committee of our Board of Directors is authorized to determine the types, terms, conditions and limitations of awards granted.

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Awards may be granted in the form of, but not limited to, stock options, restricted stock units and performance share units to employees and nonemployee directors who contribute to the company s continued success and profitability.

Total share-based compensation expense is measured using the grant date fair value for our equity-classified awards and the settlement date fair value for our liability-classified awards. We recognize share-based compensation expense over the shorter of the service period (i.e., the stated period of time required to earn the award); or the period beginning at the start of the service period and ending when an employee first becomes eligible for retirement, but not less than six months, as this is the minimum period of time required for an award to not be subject to forfeiture. Our share-based compensation programs generally provide accelerated vesting (i.e., a waiver of the remaining period of service required to earn an award) for awards held by employees at the time of their retirement. Some of our share-based awards vest ratably (i.e., portions of the award vest at different times) while some of our awards cliff vest (i.e., all of the award vests at the same time). We recognize expense on a straight-line basis over the service period for the entire award, whether the award was granted with ratable or cliff vesting.

Compensation Expense Total share-based compensation expense recognized in income (loss) and the associated tax benefit for the years ended December 31 were as follows:

	Millions of Dollars		
	2016	2015	2014
Compensation cost	**$ 272**	362	358
Tax benefit	**92**	123	125

Stock Options Stock options granted under the provisions of the Plan and prior plans permit purchase of our common stock at exercise prices equivalent to the average market price of ConocoPhillips common stock on the date the options were granted. The options have terms of 10 years and generally vest ratably, with one-third of the options awarded vesting and becoming exercisable on each anniversary date following the date of grant. Options awarded to certain employees already eligible for retirement vest within six months of the grant date, but those options do not become exercisable until the end of the normal vesting period.

The fair market values of the options granted over the past three years were measured on the date of grant using the Black-Scholes-Merton option-pricing model. The weighted-average assumptions used were as follows:

	2016	2015	2014
Assumptions used			
Risk-free interest rate	**1.55 %**	1.79	1.86
Dividend yield	**4.00 %**	4.00	4.00
Volatility factor	**26.80 %**	23.32	25.31
Expected life (years)	**6.37**	5.79	6.12

There were no ranges in the assumptions used to determine the fair market values of our options granted over the past three years.

Due to the separation of our Downstream businesses in 2012, expected volatility for grants of options in 2014 was based on a three-year average historical stock price volatility of a group of peer companies. We believe our historical volatility for periods prior to the separation of our Downstream businesses is no longer relevant in estimating expected volatility. For 2015 and 2016, expected volatility was based on the weighted average blend of the company s historical stock price volatility from May 1, 2012 (the date of separation of our Downstream businesses) through the stock option grant date and the average historical stock price volatility of a group of peer companies for the expected term of the options.

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The following summarizes our stock option activity for the year ended December 31, 2016:

	Options	Weighted-Average Exercise Price	Weighted-Average Grant Date Fair Value	Millions of Dollars Aggregate Intrinsic Value
Outstanding at December 31, 2015	20,184,810	$ 55.88		$ 42
Granted	**4,434,400**	**33.13**	**$ 5.39**	
Exercised	**(62,536)**	**48.80**		
Forfeited	**(272,646)**	**34.51**		
Expired or cancelled	**(571,916)**	**45.46**		
Outstanding at December 31, 2016	**23,712,112**	**$ 52.14**		**$ 128**
Vested at December 31, 2016	**20,192,822**	**$ 52.85**		**$ 93**
Exercisable at December 31, 2016	**15,932,144**	**$ 53.56**		**$ 55**

The weighted-average remaining contractual term of outstanding options, vested options and exercisable options at December 31, 2016, was 5.74 years, 5.25 years and 4.40 years, respectively. The weighted-average grant date fair value of stock option awards granted during 2015 and 2014 was $9.54 and $10.17, respectively. The aggregate intrinsic value of options exercised during 2015 and 2014 was $10 million and $89 million, respectively.

During 2016, we received $3 million in cash and realized a tax benefit of $4 million from the exercise of options. At December 31, 2016, the remaining unrecognized compensation expense from unvested options was $8 million, which will be recognized over a weighted-average period of 0.91 years, the longest period being 2.13 years.

Stock Unit Program Generally, restricted stock units are granted annually under the provisions of the Plan. Restricted stock units granted prior to 2013 generally vest ratably in three equal annual installments beginning on the third anniversary of the grant date. Beginning in 2013, restricted stock units granted will vest in an aggregate installment on the third anniversary of the grant date. In addition, beginning in 2012, restricted stock units granted under the Plan for a variable long-term incentive program vest ratably in three equal annual installments beginning on the first anniversary of the grant date. Restricted stock units are also granted ad hoc to attract or retain key personnel, and the terms and conditions under which these restricted stock units vest vary by award. Upon vesting, the restricted stock units are settled by issuing one share of ConocoPhillips common stock per unit. Units awarded to retirement eligible employees vest six months from the grant date; however, those units are not issued as common stock until the earlier of separation from the company or the end of the regularly scheduled vesting period. Until issued as stock, most recipients of the restricted stock units receive a quarterly cash payment of a dividend equivalent that is charged to retained earnings. The grant date fair market value of these restricted stock units is deemed equal to the average ConocoPhillips stock price on the grant date. The grant date fair market value of units that do not receive a dividend equivalent while unvested is deemed equal to the average ConocoPhillips stock price on the grant date, less the net present value of the dividends that will not be received.

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The following summarizes our stock unit activity for the year ended December 31, 2016:

		Weighted-Average	Millions of Dollars
	Stock Units	Grant Date Fair Value	Total Fair Value
Outstanding at December 31, 2015	9,178,165	$ 59.80	
Granted	**4,613,469**	**32.15**	
Forfeited	**(169,018)**	**30.46**	
Issued	**(5,115,112)**		**$ 191**
Outstanding at December 31, 2016	**8,507,504**	**$ 48.65**	
Not Vested at December 31, 2016	**5,990,350**	**$ 48.29**	

At December 31, 2016, the remaining unrecognized compensation cost from the unvested units was $105 million, which will be recognized over a weighted-average period of 1.59 years, the longest period being 2.82 years. The weighted-average grant date fair value of stock unit awards granted during 2015 and 2014 was $65.40 and $62.72, respectively. The total fair value of stock units issued during 2015 and 2014 was $316 million and $256 million, respectively.

Performance Share Program Under the Plan, we also annually grant restricted performance share units (PSUs) to senior management. These PSUs are authorized three years prior to their effective grant date (the performance period). Compensation expense is initially measured using the average fair market value of ConocoPhillips common stock and is subsequently adjusted, based on changes in the ConocoPhillips stock price through the end of each subsequent reporting period, through the grant date for stock-settled awards and the settlement date for cash-settled awards.

Stock-Settled

For performance periods beginning before 2009, PSUs do not vest until the employee becomes eligible for retirement by reaching age 55 with five years of service, and restrictions do not lapse until the employee separates from the company. With respect to awards for performance periods beginning in 2009 through 2012, PSUs do not vest until the earlier of the date the employee becomes eligible for retirement by reaching age 55 with five years of service or five years after the grant date of the award, and restrictions do not lapse until the earlier of the employee s separation from the company or five years after the grant date (although recipients can elect to defer the lapsing of restrictions until separation). We recognize compensation expense for these awards beginning on the grant date and ending on the date the PSUs are scheduled to vest. Since these awards are authorized three years prior to the grant date, for employees eligible for retirement by or shortly after the grant date, we recognize compensation expense over the period beginning on the date of authorization and ending on the date of grant. Until issued as stock, recipients of the PSUs receive a quarterly cash payment of a dividend equivalent that is charged to retained earnings. Beginning in 2013, PSUs authorized for future grants will vest, absent employee election to defer, upon settlement following the conclusion of the three-year performance period. We recognize compensation expense over the period beginning on the date of authorization and ending on the conclusion of the performance period. PSUs are settled by issuing one share of ConocoPhillips common stock per unit.

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The following summarizes our stock-settled Performance Share Program activity for the year ended December 31, 2016:

	Stock Units	Weighted-Average Grant Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2015	4,270,222	$ 51.95	
Granted	**48,065**	**33.13**	
Issued	**(428,763)**		**$ 17**
Outstanding at December 31, 2016	**3,889,524**	**$ 51.93**	
Not Vested at December 31, 2016	**606,085**	**$ 53.34**	

At December 31, 2016, the remaining unrecognized compensation cost from unvested stock-settled performance share awards was $3 million, which includes $1 million related to unvested stock-settled performance share awards tied to Phillips 66 stock held by ConocoPhillips employees, which will be recognized over a weighted-average period of 1.82 years, the longest period being 3.98 years. The weighted-average grant date fair value of stock-settled PSUs granted during 2015 and 2014 was $69.25 and $65.46, respectively. The total fair value of stock-settled PSUs issued during 2015 and 2014 was $25 million and $18 million, respectively.

Cash-Settled

In connection with and immediately following the separation of our Downstream businesses in 2012, grants of new PSUs, subject to a shortened performance period, were authorized. Once granted, these PSUs vest, absent employee election to defer, on the earlier of five years after the grant date of the award or the date the employee becomes eligible for retirement. For employees eligible for retirement by or shortly after the grant date, we recognize compensation expense over the period beginning on the date of authorization and ending on the date of grant. Otherwise, we recognize compensation expense beginning on the grant date and ending on the date the PSUs are scheduled to vest. These PSUs are settled in cash equal to the fair market value of a share of ConocoPhillips common stock per unit on the settlement date and thus are classified as liabilities on the balance sheet. Until settlement occurs, recipients of the PSUs receive a quarterly cash payment of a dividend equivalent that is charged to compensation expense.

Beginning in 2013, PSUs authorized for future grants will vest upon settlement following the conclusion of the three-year performance period. We recognize compensation expense over the period beginning on the date of authorization and ending on the conclusion of the performance period. These PSUs will be settled in cash equal to the fair market value of a share of ConocoPhillips common stock per unit on the settlement date and are classified as liabilities on the balance sheet. During the performance period, recipients of the PSUs do not receive a quarterly cash payment of a dividend equivalent, but after the performance period ends, until settlement in cash occurs, recipients of the PSUs receive a quarterly cash payment of a dividend equivalent that is charged to compensation expense.

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The following summarizes our cash-settled Performance Share Program activity for the year ended December 31, 2016:

	Stock Units	Weighted-Average Grant Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2015	1,459,236	$ 46.54	
Granted	**684,386**	**33.13**	
Settled	**(868,860)**		**$ 31**
Outstanding at December 31, 2016	**1,274,762**	**$ 50.39**	
Not Vested at December 31, 2016	**584,789**	**$ 50.39**	

At December 31, 2016, the remaining unrecognized compensation cost from unvested cash-settled performance share awards was $7 million, which will be recognized over a weighted-average period of 1.75 years, the longest period being 3.13 years. The weighted-average grant date fair value of cash-settled PSUs granted during 2015 and 2014 was $46.54 and $69.23, respectively. The total fair value of cash-settled performance share awards settled during 2015 and 2014 was $6 million and zero, respectively.

From inception of the Performance Share Program through 2013, approved PSU awards were granted after the conclusion of performance periods. Beginning in February 2014, initial target PSU awards are issued near the beginning of new performance periods. These initial target PSU awards will terminate at the end of the performance periods and will be settled after the performance periods have ended. Also in 2014, initial target PSU awards were issued for open performance periods that began in prior years. For the open performance period beginning in 2012, the initial target PSU awards will terminate at the end of the three-year performance period and will be replaced with approved PSU awards. For the open performance period beginning in 2013, the initial target PSU awards will terminate at the end of the three-year performance period and will be settled after the performance period has ended. There is no effect on recognition of compensation expense.

Other In addition to the above active programs, we have outstanding shares of restricted stock and restricted stock units that were either issued to replace awards held by employees of companies we acquired or issued as part of a compensation program that has been discontinued. Generally, the recipients of the restricted shares or units receive a quarterly dividend or dividend equivalent.

The following summarizes the aggregate activity of these restricted shares and units for the year ended December 31, 2016:

	Stock Units	Weighted-Average Grant Date Fair Value	Millions of Dollars Total Fair Value

Outstanding at December 31, 2015	1,272,136	$	33.25	
Granted	**99,300**		**40.36**	
Cancelled	**(15,964)**		**20.69**	
Issued	**(37,508)**			**$ 2**
Outstanding at December 31, 2016	**1,317,964**	**$**	**33.16**	
Not Vested at December 31, 2016	**-**			

At December 31, 2016, all outstanding restricted stock and restricted stock units were fully vested and there was no remaining compensation cost to be recorded. The weighted-average grant date fair value of awards granted during 2015 and 2014 was $58.66 and $71.23, respectively. The total fair value of awards issued during 2015 and 2014 was $3 million and $3 million, respectively.

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Note 19 Income Taxes

Income taxes charged to income (loss) from continuing operations were:

	Millions of Dollars		
	2016	2015	2014
Income Taxes			
Federal			
Current	$ **(9)**	(718)	188
Deferred	**(1,634)**	(1,443)	365
Foreign			
Current	**393**	745	2,846
Deferred	**(519)**	(1,315)	252
State and local			
Current	**(135)**	8	46
Deferred	**(67)**	(145)	(114)
	$ **(1,971)**	(2,868)	3,583

Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for tax purposes. Major components of deferred tax liabilities and assets at December 31 were:

	Millions of Dollars	
	2016	2015
Deferred Tax Liabilities		
PP&E and intangibles	$ **15,099**	16,378
Investment in joint ventures	**933**	866
Inventory	**36**	25
Deferred state income tax	**203**	128
Partnership income deferral	**-**	44
Other	**486**	453
Total deferred tax liabilities	**16,757**	17,894
Deferred Tax Assets		
Benefit plan accruals	**1,280**	1,160

Asset retirement obligations and accrued environmental costs	**3,514**	4,426
Other financial accruals and deferrals	**317**	616
Loss and credit carryforwards	**3,522**	1,579
Other	**250**	134
Total deferred tax assets	**8,883**	7,915
Less: valuation allowance	**(675)**	(734)
Net deferred tax assets	**8,208**	7,181
Net deferred tax liabilities	**$ 8,549**	10,713

At December 31, 2016, noncurrent assets and liabilities include deferred taxes of $400 million and $8,949 million, respectively. At December 31, 2015, noncurrent assets and liabilities include deferred taxes of $286 million and $10,999 million, respectively.

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At December 31, 2016, the components of our loss and credit carryforwards before and after consideration of the applicable valuation allowances are:

	Millions of Dollars		
	Gross Deferred Tax Asset	Net Deferred Tax Asset After Valuation Allowance	Expiration of Net Deferred Tax Asset
U.S. federal net operating loss	$ 1,648	$ 1,648	2036
U.S. foreign tax credits	480	296	2025-2026
U.S. general business credits	96	96	2031
State net operating losses and tax credits	502	49	Post 2024
Foreign net operating losses and tax credits	796	783	Post 2025
	$ 3,522	$ 2,872	

Valuation allowances have been established to reduce deferred tax assets to an amount that will, more likely than not, be realized. During 2016, valuation allowances decreased a total of $59 million. This decrease primarily relates to the expected realization of certain deferred tax assets. Based on our historical taxable income, expectations for the future, and available tax-planning strategies, management expects remaining net deferred tax assets will primarily be realized as offsets to reversing deferred tax liabilities.

At December 31, 2016, unremitted income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures totaled approximately $3,720 million. Deferred income taxes have not been provided on this amount, as we do not plan to initiate any action that would require the payment of income taxes. Due to the nature of our structures within the jurisdictions in which we operate, as well as the complex nature of the relevant tax laws, it is not practicable to estimate the amount of additional tax, if any, that might be payable on this income if distributed.

The following table shows a reconciliation of the beginning and ending unrecognized tax benefits for 2016, 2015 and 2014:

	Millions of Dollars		
	2016	2015	2014
Balance at January 1	**$ 459**	442	655
Additions based on tax positions related to the current year	**32**	54	46
Additions for tax positions of prior years	**19**	4	7
Reductions for tax positions of prior years	**(118)**	(37)	(228)

Settlements	**(9)**	(4)	(28)
Lapse of statute	**(2)**	-	(10)
Balance at December 31	**$ 381**	459	442

Included in the balance of unrecognized tax benefits for 2016, 2015 and 2014 were $359 million, $354 million and $348 million, respectively, which, if recognized, would impact our effective tax rate.

At December 31, 2016, 2015 and 2014, accrued liabilities for interest and penalties totaled $54 million, $79 million and $65 million, respectively, net of accrued income taxes. Interest and penalties resulted in a benefit to earnings of $18 million in 2016, a reduction to earnings of $11 million in 2015, and a benefit to earnings of $43 million in 2014.

We and our subsidiaries file tax returns in the U.S. federal jurisdiction and in many foreign and state jurisdictions. Audits in major jurisdictions are generally complete as follows: United Kingdom (2014), Canada (2009), United States (2010) and Norway (2015). Issues in dispute for audited years and audits for subsequent years are ongoing and in various stages of completion in the many jurisdictions in which we operate around the world.

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As a consequence, the balance in unrecognized tax benefits can be expected to fluctuate from period to period. It is reasonably possible such changes could be significant when compared with our total unrecognized tax benefits, but the amount of change is not estimable.

The amounts of U.S. and foreign income (loss) from continuing operations before income taxes, with a reconciliation of tax at the federal statutory rate with the provision for income taxes, were:

	Millions of Dollars			Percent of Pre-Tax Income (Loss)		
	2016	2015	2014	**2016**	2015	2014
Income (loss) before income taxes from continuing operations						
United States	**$ (4,410)**	(4,150)	2,310	**79.7%**	57.3	24.6
Foreign	**(1,120)**	(3,089)	7,080	**20.3**	42.7	75.4
	$ (5,530)	(7,239)	9,390	**100.0%**	100.0	100.0
Federal statutory income tax	**$ (1,936)**	(2,534)	3,287	**35.0%**	35.0	35.0
Non-U.S. effective tax rates	**365**	381	376	**(6.6)**	(5.3)	4.0
Foreign tax law change	**(161)**	(426)	-	**2.9**	5.9	-
U.S. fair value election	**-**	(185)	-	**-**	2.6	-
Enhanced Oil Recovery Credit	**(62)**	-	-	**1.1**	-	-
State income tax	**(131)**	(89)	(44)	**2.4**	1.2	(0.5)
Other	**(46)**	(15)	(36)	**0.8**	0.2	(0.4)
	$ (1,971)	(2,868)	3,583	**35.6%**	39.6	38.1

The decrease in the effective tax rate for 2016 was primarily due to higher income in high tax jurisdictions, lower losses in low tax jurisdictions, and reduced net tax benefit from tax law changes.

The increase in the effective tax rate for 2015 was primarily due to the U.K. tax law change and electing the fair market value method of apportioning interest expense for prior years, discussed below; partially offset by lower income in high tax jurisdictions and the Canadian tax law change, discussed below.

In the United Kingdom, legislation was enacted on September 15, 2016, to decrease the overall U.K. upstream corporation tax rate from 50 percent to 40 percent effective January 1, 2016. As a result, a $161 million net tax benefit for revaluing the U.K. deferred tax liability is reflected in the Income tax provision (benefit) line on our consolidated income statement.

In the United Kingdom, legislation was enacted on March 26, 2015, to decrease the overall U.K. upstream corporation tax rate from 62 percent to 50 percent effective January 1, 2015. As a result, a $555 million net tax benefit for revaluing the U.K. deferred tax liability is reflected in the Income tax provision (benefit) line on our consolidated income statement.

In Canada, legislation was enacted on June 29, 2015, to increase the overall Canadian corporation tax rate from 25 percent to 27 percent effective July 1, 2015. As a result, a $129 million net tax expense for revaluing the Canadian deferred tax liability is reflected in the Income tax provision (benefit) line on our consolidated income statement.

In December 2015, we filed refund claims for prior years electing the fair market value method of apportioning interest in the United States. As a result, a $185 million tax benefit was recorded in the fourth quarter of 2015.

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Certain operating losses in jurisdictions outside of the U.S. only yield a tax benefit in the U.S. as a worthless security deduction. For 2016, 2015 and 2014 the amount of the benefit was $60 million, $491 million and $122 million, respectively.

Note 20 Accumulated Other Comprehensive Income

Accumulated other comprehensive income (loss) in the equity section of the balance sheet included:

	Millions of Dollars		
	Defined Benefit Plans	Foreign Currency Translation	Accumulated Other Comprehensive Income (Loss)
December 31, 2013	$ (824)	2,826	2,002
Other comprehensive loss	(437)	(3,467)	(3,904)
December 31, 2014	(1,261)	(641)	(1,902)
Other comprehensive income (loss)	818	(5,163)	(4,345)
December 31, 2015	(443)	(5,804)	(6,247)
Other comprehensive income (loss)	**(104)**	**158**	**54**
December 31, 2016	**$ (547)**	**(5,646)**	**(6,193)**

There were no items within accumulated other comprehensive income (loss) related to noncontrolling interests.

The following table summarizes reclassifications out of accumulated other comprehensive loss during the years ended December 31:

	Millions of Dollars	
	2016	2015
Defined Benefit Plans	**$ 179**	251
Above amounts are included in the computation of net periodic benefit cost and are presented net of tax expense of:	***$ 95***	*133*

See Note 18 Employee Benefit Plans, for additional information.

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Note 21 Cash Flow Information

Amounts included in continuing operations for the years ended December 31 were:

	Millions of Dollars		
	2016	2015	2014
Noncash Investing and Financing Activities			
Increase (decrease) in PP&E related to an increase (decrease) in asset retirement obligations*	**$ (1,017)**	402	1,611
Cash Payments (Receipts)			
Interest	**$ 1,151**	920	669
Income taxes**	**(318)**	523	4,203
Net Sales (Purchases) of Short-Term Investments			
Short-term investments purchased	**$ (1,753)**	-	(876)
Short-term investments sold	**1,702**	-	1,129
	$ (51)	-	253

**Includes $68 million in 2014, primarily related to the impact of U.K. tax law changes on the deductibility of decommissioning costs.*

***Net of $585 million and $642 million in 2016 and 2015, respectively, related to refunds received from the Internal Revenue Service.*

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Note 22 Other Financial Information

Amounts included in continuing operations for the years ended December 31 were:

	Millions of Dollars		
	2016	2015	2014
Interest and Debt Expense			
Incurred			
Debt	**$ 1,279**	1,130	1,063
Other	**123**	84	73
	1,402	1,214	1,136
Capitalized	**(157)**	(294)	(488)
Expensed	**$ 1,245**	920	648
Other Income			
Interest income	**$ 57**	45	83
Other, net	**198**	80	283
	$ 255	125	366
Research and Development Expenditures expensed	**$ 116**	222	263
Shipping and Handling Costs*	**$ 1,139**	1,181	1,360

**Amounts included in production and operating expenses.*

Foreign Currency Transaction (Gains) Losses after-tax			
Alaska	**$ -**	-	-
Lower 48	**-**	-	-
Canada	**1**	-	(4)
Europe and North Africa	**(7)**	(22)	(56)
Asia Pacific and Middle East	**(9)**	(78)	-
Other International	**7**	(9)	-
Corporate and Other	**(18)**	45	16
	$ (26)	(64)	(44)

	Millions of Dollars	
	2016	2015
Properties, Plants and Equipment		
Proved properties	**$ 119,970**	122,796
Unproved properties	**5,150**	7,410
Other	**6,286**	6,653
Gross properties, plants and equipment	**131,406**	136,859
Less: Accumulated depreciation, depletion and amortization	**(73,075)**	(70,413)
Net properties, plants and equipment	**$ 58,331**	66,446

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Note 23 Related Party Transactions

Our related parties primarily include equity method investments and certain trusts for the benefit of employees.

Significant transactions with our equity affiliates were:

	Millions of Dollars		
	2016	2015	2014
Operating revenues and other income	$ **133**	118	119
Purchases	**101**	97	190
Operating expenses and selling, general and administrative expenses	**63**	62	70
Net interest (income) expense*	**(12)**	(9)	(44)

**We paid interest to, or received interest from, various affiliates. See Note 7 Investments, Loans and Long-Term Receivables, for additional information on loans to affiliated companies.*

The table above includes transactions with Freeport LNG through the date of the termination agreement and excludes the termination fee. See Note 7 Investments, Loans and Long-Term Receivables, for additional information.

Note 24 Segment Disclosures and Related Information

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and natural gas liquids on a worldwide basis. We manage our operations through six operating segments, which are primarily defined by geographic region: Alaska, Lower 48, Canada, Europe and North Africa, Asia Pacific and Middle East, and Other International.

After agreeing to sell our Nigeria business in 2012, we completed the sale in 2014. Results for these operations have been reported as discontinued operations in the applicable periods presented. For additional information, see Note 3 Discontinued Operations.

Corporate and Other represents costs not directly associated with an operating segment, such as most interest expense, corporate overhead and certain technology activities, including licensing revenues. Corporate assets include all cash and cash equivalents.

We evaluate performance and allocate resources based on net income (loss) attributable to ConocoPhillips. Segment accounting policies are the same as those in Note 1 Accounting Policies. Intersegment sales are at prices that approximate market.

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Analysis of Results by Operating Segment

	Millions of Dollars		
	2016	2015	2014
Sales and Other Operating Revenues			
Alaska	**$ 3,681**	4,351	8,382
Lower 48	**10,719**	11,976	21,721
Intersegment eliminations	**(17)**	(63)	(107)
Lower 48	**10,702**	11,913	21,614
Canada	**2,192**	2,454	5,162
Intersegment eliminations	**(218)**	(318)	(753)
Canada	**1,974**	2,136	4,409
Europe and North Africa	**3,462**	6,110	10,665
Intersegment eliminations	**-**	(4)	(49)
Europe and North Africa	**3,462**	6,106	10,616
Asia Pacific and Middle East	**3,705**	4,746	7,425
Intersegment eliminations	**-**	(1)	(1)
Asia Pacific and Middle East	**3,705**	4,745	7,424
Other International	**-**	1	-
Corporate and Other	**169**	312	79
Consolidated sales and other operating revenues	**$ 23,693**	29,564	52,524
Depreciation, Depletion, Amortization and Impairments			
Alaska	**$ 868**	690	584
Lower 48	**4,358**	4,227	3,911
Canada	**975**	788	962
Europe and North Africa	**1,253**	2,565	2,345
Asia Pacific and Middle East	**1,606**	2,981	1,275
Other International	**1**	-	1
Corporate and Other	**140**	107	107
Consolidated depreciation, depletion, amortization and impairments	**$ 9,201**	11,358	9,185

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		Millions of Dollars		
		2016	2015	2014
Equity in Earnings of Affiliates				
Alaska	$	**9**	4	9
Lower 48		**(6)**	(5)	1
Canada		**89**	78	1,385
Europe and North Africa		**22**	23	37
Asia Pacific and Middle East		**(51)**	550	1,089
Other International		**-**	8	9
Corporate and Other		**(11)**	(3)	(1)
Consolidated equity in earnings of affiliates	$	**52**	655	2,529
Income Taxes				
Alaska	$	**(59)**	(71)	1,081
Lower 48		**(1,328)**	(1,119)	(92)
Canada		**(383)**	(223)	236
Europe and North Africa		**(46)**	(854)	1,590
Asia Pacific and Middle East		**306**	467	1,194
Other International		**(40)**	(456)	(102)
Corporate and Other		**(421)**	(612)	(324)
Consolidated income taxes	$	**(1,971)**	(2,868)	3,583
Net Income (Loss) Attributable to ConocoPhillips				
Alaska	$	**319**	4	2,041
Lower 48		**(2,257)**	(1,932)	(22)
Canada		**(935)**	(1,044)	940
Europe and North Africa		**394**	409	814
Asia Pacific and Middle East		**209**	(463)	2,939
Other International		**(16)**	(593)	(100)
Corporate and Other		**(1,329)**	(809)	(874)
Discontinued operations		**-**	-	1,131
Consolidated net income (loss) attributable to ConocoPhillips	$	**(3,615)**	(4,428)	6,869
Investments In and Advances To Affiliates				
Alaska	$	**58**	61	53
Lower 48		**426**	455	471
Canada		**8,784**	8,165	9,484
Europe and North Africa		**62**	70	126
Asia Pacific and Middle East		**11,611**	11,780	14,022
Other International		**-**	-	59

Corporate and Other		**4**	15	15
Consolidated investments in and advances to affiliates	**$**	**20,945**	20,546	24,230

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	Millions of Dollars			
		2016	2015	2014
Total Assets				
Alaska	$	**12,314**	12,555	12,655
Lower 48		**22,673**	26,932	30,185
Canada		**17,548**	17,221	21,764
Europe and North Africa		**11,727**	13,703	16,970
Asia Pacific and Middle East		**20,451**	22,318	25,976
Other International		**97**	282	1,116
Corporate and Other		**4,962**	4,473	7,815
Discontinued operations		**-**	-	58
Consolidated total assets	$	**89,772**	97,484	116,539
Capital Expenditures and Investments				
Alaska	$	**883**	1,352	1,564
Lower 48		**1,262**	3,765	6,054
Canada		**698**	1,255	2,340
Europe and North Africa		**1,020**	1,573	2,540
Asia Pacific and Middle East		**838**	1,812	3,877
Other International		**104**	173	520
Corporate and Other		**64**	120	190
Consolidated capital expenditures and investments	$	**4,869**	10,050	17,085
Interest Income and Expense				
Interest income				
Corporate	$	**47**	36	40
Lower 48		**-**	-	35
Europe and North Africa		**2**	2	2
Asia Pacific and Middle East		**8**	6	6
Other International		**-**	1	-
Interest and debt expense				
Corporate	$	**1,245**	920	648
Sales and Other Operating Revenues by Product				
Crude oil	$	**10,801**	12,830	23,784
Natural gas		**9,401**	11,888	20,717
Natural gas liquids		**837**	952	2,245
Other*		**2,654**	3,894	5,778
Consolidated sales and other operating revenues by product	$	**23,693**	29,564	52,524

**Includes LNG and bitumen.*

Geographic Information

	Millions of Dollars					
	Sales and Other Operating Revenues[1]			Long-Lived Assets[2]		
	2016	2015	2014	**2016**	2015	2014
United States	**$ 14,400**	16,284	30,019	**32,949**	37,445	39,641
Australia[3]	**1,353**	2,127	3,258	**12,259**	12,788	14,969
Canada	**1,974**	2,136	4,409	**16,846**	16,766	20,874
China	**551**	782	1,701	**1,372**	1,647	1,913
Indonesia	**938**	1,165	1,963	**856**	1,191	1,526
Malaysia	**735**	598	403	**3,323**	3,599	3,811
Norway	**1,645**	2,107	3,794	**6,228**	6,933	8,142
United Kingdom	**1,816**	4,005	6,594	**3,209**	4,154	5,327
Other foreign countries	**281**	360	383	**2,234**	2,469	3,471
Worldwide consolidated	**$ 23,693**	29,564	52,524	**79,276**	86,992	99,674

(1)Sales and other operating revenues are attributable to countries based on the location of the selling operation.

(2)Defined as net PP&E plus investments in and advances to affiliated companies.

(3)Includes amounts related to the joint petroleum development area with shared ownership held by Australia and Timor-Leste.

Note 25 New Accounting Standards

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers (ASU No. 2014-09), which outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers. This ASU supersedes the revenue recognition requirements in FASB ASC Topic 605, Revenue Recognition, and most industry-specific guidance. This ASU sets forth a five-step model for determining when and how revenue is recognized. Under the model, an entity will be required to recognize revenue to depict the transfer of goods or services to a customer at an amount reflecting the consideration it expects to receive in exchange for those goods or services. Additional disclosures will be required to describe the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts.

In August 2015, the FASB issued ASU No. 2015-14, Deferral of the Effective Date, which defers the effective date of ASU No. 2014-09. The ASU is now effective for interim and annual periods beginning after December 15, 2017. Early adoption is permitted for interim and annual periods beginning after December 15, 2016. Entities may choose to adopt the standard using either a full retrospective approach or a modified retrospective approach.

ASU No. 2014-09 was amended in March 2016 by the provisions of ASU No. 2016-08, Principal versus Agent Considerations (Reporting Revenue Gross versus Net), in April 2016 by the provisions of ASU No. 2016-10, Identifying Performance Obligations and Licensing, in May 2016 by the provisions of ASU No. 2016-12, Narrow-Scope Improvements and Practical Expedients, and in December 2016 by the provisions of ASU

No. 2016-20, Technical Corrections and Improvements to Topic 606, Revenue From Contracts With Customers.

We will adopt the provisions of ASU No. 2014-09, as amended, with effect from January 1, 2018, and have elected not to early adopt the standard. We intend to adopt the new standard using the modified retrospective approach which we will apply only to contracts within the scope of the standard that are not complete at the date of initial application. Under this approach, we will apply the guidance retrospectively only to the most current period presented in the financial statements. Overall, the impact to our financial statements is expected to be immaterial.

In February 2016, the FASB issued ASU No. 2016-02, Leases (ASU No. 2016-02), which establishes comprehensive accounting and financial reporting requirements for leasing arrangements. This ASU supersedes the existing requirements in FASB ASC Topic 840, Leases, and requires lessees to recognize substantially all lease assets and lease liabilities on the balance sheet. The provisions of ASU No. 2016-02 also modify the definition of a lease and outline requirements for recognition, measurement, presentation, and disclosure of leasing arrangements by both lessees and lessors. The ASU is effective for interim and annual periods beginning after December 15, 2018, and early adoption of the standard is permitted. Entities are required to adopt the ASU using a modified retrospective approach, subject to certain optional practical expedients, and apply the provisions of ASU No. 2016-02 to leasing arrangements existing at or entered into after the earliest comparative period presented in the financial statements. While we continue to evaluate the ASU, we expect the adoption of the ASU to have a material impact on our consolidated financial statements and disclosures.

In June 2016, the FASB issued ASU No. 2016-13, Measurement of Credit Losses on Financial Instruments (ASU No. 2016-13), which sets forth the current expected credit loss model, a new forward-looking impairment model for certain financial instruments based on expected losses rather than incurred losses. The ASU is effective for interim and annual periods beginning after December 15, 2019, and early adoption of the standard is permitted. Entities are required to adopt ASU No. 2016-13 using a modified retrospective approach, subject to certain limited exceptions. We are currently evaluating the impact of the adoption of this ASU.

Oil and Gas Operations (Unaudited)

In accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification Topic 932, Extractive Activities Oil and Gas, and regulations of the U.S. Securities and Exchange Commission (SEC), we are making certain supplemental disclosures about our oil and gas exploration and production operations.

These disclosures include information about our consolidated oil and gas activities and our proportionate share of our equity affiliates oil and gas activities in our operating segments. As a result, amounts reported as equity affiliates in Oil and Gas Operations may differ from those shown in the individual segment disclosures reported elsewhere in this report.

As required by current authoritative guidelines, the estimated future date when an asset will be permanently shut down for economic reasons is based on historical 12-month first-of-month average prices and current costs. This estimated date when production will end affects the amount of estimated reserves. Therefore, as prices and cost levels change from year to year, the estimate of proved reserves also changes. Generally, our proved reserves decrease as prices decline and increase as prices rise.

Our proved reserves include estimated quantities related to production sharing contracts (PSCs), which are reported under the economic interest method, as well as variable-royalty regimes, and are subject to fluctuations in commodity prices, recoverable operating expenses and capital costs. If costs remain stable, reserve quantities attributable to recovery of costs will change inversely to changes in commodity prices. For example, if prices increase, then our applicable reserve quantities would decline. At December 31, 2016, approximately 7 percent of our total proved reserves were under PSCs, located in our Asia Pacific/Middle East geographic reporting area, and 23 percent of our total proved reserves were under a variable-royalty regime, located in our Canada geographic reporting area.

Our reserves disclosures by geographic area include the United States, Canada, Europe (Norway and the United Kingdom), Asia Pacific/Middle East, Africa and Other Areas. Other Areas primarily consists of Russia, which we exited in 2015.

As part of our asset disposition program, we sold our interest in the Nigeria business in July 2014. This business was considered held for sale since the fourth quarter of 2012 and has been reported as discontinued operations for the applicable periods presented. Accordingly, the Results of Operations, Average Sales Prices and Net Production tables included within the supplemental oil and gas disclosures reflect the associated earnings and production as discontinued operations. See Note 3 Discontinued Operations, for additional information.

Reserves Governance

The recording and reporting of proved reserves are governed by criteria established by regulations of the SEC and FASB. Proved reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain it will commence the project within a reasonable time.

Proved reserves are further classified as either developed or undeveloped. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods, or in which the cost of the required equipment is relatively minor compared with the cost of a new well, and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Proved undeveloped reserves are proved reserves expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

We have a companywide, comprehensive, SEC-compliant internal policy that governs the determination and reporting of proved reserves. This policy is applied by the geologists and reservoir engineers in our business units around the world. As part of our internal control process, each business unit s reserves processes and controls are reviewed annually by an internal team which is headed by the company s Manager of Reserves Compliance and Reporting. This team, composed of internal reservoir engineers, geologists, finance personnel and a senior representative from DeGolyer and MacNaughton (D&M), a third-party petroleum engineering consulting firm, reviews the business units reserves for adherence to SEC guidelines and company policy through on-site visits, teleconferences and review of documentation. In addition to providing independent reviews, this internal team also ensures reserves are calculated using consistent and appropriate standards and procedures. This team is independent of business unit line management and is responsible for reporting its findings to senior management. The team is responsible for communicating our reserves policy and procedures and is available for internal peer reviews and consultation on major projects or technical issues throughout the year. All of our proved reserves held by consolidated companies and our share of equity affiliates have been estimated by ConocoPhillips.

During 2016, our processes and controls used to assess over 90 percent of proved reserves as of December 31, 2016, were reviewed by D&M. The purpose of their review was to assess whether the adequacy and effectiveness of our internal processes and controls used to determine estimates of proved reserves are in accordance with SEC regulations. In such review, ConocoPhillips technical staff presented D&M with an overview of the reserves data, as well as the methods and assumptions used in estimating reserves. The data presented included pertinent seismic information, geologic maps, well logs, production tests, material balance calculations, reservoir simulation models, well performance data, operating procedures and relevant economic criteria. Management s intent in retaining D&M to review its processes and controls was to provide objective third-party input on these processes and controls. D&M s opinion was the general processes and controls employed by ConocoPhillips in estimating its December 31, 2016, proved reserves for the properties reviewed are in accordance with the SEC reserves definitions. D&M s report is included as Exhibit 99 of this Annual Report on Form 10-K.

The technical person primarily responsible for overseeing the processes and internal controls used in the preparation of the company s reserves estimates is the Manager of Reserves Compliance and Reporting. This individual holds a master s degree in petroleum engineering. He is a member of the Society of Petroleum Engineers with over 25 years of oil and gas industry experience and has held positions of increasing responsibility in reservoir engineering, subsurface and asset management in the United States and several international field locations.

Engineering estimates of the quantities of proved reserves are inherently imprecise. See the Critical Accounting Estimates section of Management s Discussion and Analysis of Financial Condition and Results of Operations for additional discussion of the sensitivities surrounding these estimates.

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Proved Reserves

Years Ended December 31	Crude Oil Millions of Barrels								
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
Developed and Undeveloped									
Consolidated operations									
End of 2013	1,106	606	1,712	22	456	232	237	-	2,659
Revisions	(6)	25	19	3	(1)	5	-	-	26
Improved recovery	8	-	8	2	-	3	-	-	13
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	16	116	132	2	-	16	-	-	150
Production	(61)	(71)	(132)	(5)	(44)	(29)	(5)	-	(215)
Sales	-	-	-	-	-	-	(28)	-	(28)
End of 2014	1,063	676	1,739	24	411	227	204	-	2,605
Revisions	(115)	(69)	(184)	-	(21)	(29)	-	-	(234)
Improved recovery	4	4	8	1	-	31	-	-	40
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	20	57	77	1	-	7	-	-	85
Production	(57)	(78)	(135)	(4)	(44)	(33)	-	-	(216)
Sales	-	(2)	(2)	(8)	-	-	-	-	(10)
End of 2015	915	588	1,503	14	346	203	204	-	2,270
Revisions	(57)	(93)	(150)	3	-	6	-	-	(141)
Improved recovery	6	3	9	-	-	7	-	-	16
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	33	79	112	-	-	7	-	-	119
Production	(60)	(71)	(131)	(3)	(43)	(35)	(1)	-	(213)
Sales	-	-	-	(1)	-	(3)	-	-	(4)
End of 2016	837	506	1,343	13	303	185	203	-	2,047
Equity affiliates									
End of 2013	-	-	-	-	-	86	-	4	90
Revisions	-	-	-	-	-	17	-	3	20
Improved recovery	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	(5)	-	(2)	(7)
Sales	-	-	-	-	-	-	-	-	-
End of 2014	-	-	-	-	-	98	-	5	103
Revisions	-	-	-	-	-	-	-	-	-

Improved recovery	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	(5)	-	(1)	(6)
Sales	-	-	-	-	-	-	-	(4)	(4)
End of 2015	-	-	-	-	-	93	-	-	93
Revisions	-	-	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	(5)	-	-	(5)
Sales	-	-	-	-	-	-	-	-	-
End of 2016	-	-	-	-	-	88	-	-	88
Total company									
End of 2013	1,106	606	1,712	22	456	318	237	4	2,749
End of 2014	1,063	676	1,739	24	411	325	204	5	2,708
End of 2015	915	588	1,503	14	346	296	204	-	2,363
End of 2016	837	506	1,343	13	303	273	203	-	2,135

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Years Ended December 31	Crude Oil Millions of Barrels								
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
Developed									
Consolidated operations									
End of 2013	1,003	268	1,271	22	247	126	230	-	1,896
End of 2014	950	313	1,263	23	237	142	199	-	1,864
End of 2015	819	283	1,102	13	200	139	204	-	1,658
End of 2016	747	256	1,003	13	184	106	203	-	1,509
Equity affiliates									
End of 2013	-	-	-	-	-	86	-	4	90
End of 2014	-	-	-	-	-	98	-	5	103
End of 2015	-	-	-	-	-	93	-	-	93
End of 2016	-	-	-	-	-	88	-	-	88
Undeveloped									
Consolidated operations									
End of 2013	103	338	441	-	209	106	7	-	763
End of 2014	113	363	476	1	174	85	5	-	741
End of 2015	96	305	401	1	146	64	-	-	612
End of 2016	90	250	340	-	119	79	-	-	538
Equity affiliates									
End of 2013	-	-	-	-	-	-	-	-	-
End of 2014	-	-	-	-	-	-	-	-	-
End of 2015	-	-	-	-	-	-	-	-	-
End of 2016	-	-	-	-	-	-	-	-	-

Notable changes in proved crude oil reserves in the three years ended December 31, 2016, included:

Revisions: In 2016, revisions in Lower 48 and Alaska were primarily due to lower prices. In 2015, revisions in Alaska, Lower 48 and Asia Pacific/Middle East were primarily due to lower prices.

Extensions and discoveries: In 2016, extensions and discoveries in Alaska were primarily due to drilling success in the Western North Slope. In 2016 and 2014, extensions and discoveries in Lower 48 were primarily due to continued drilling success in Eagle Ford and Bakken.

Sales: In 2014, sales in Africa reflect the sale of the Nigeria business.

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Years Ended December 31	Natural Gas Liquids Millions of Barrels							
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total
Developed and Undeveloped								
Consolidated operations								
End of 2013	125	462	587	56	28	14	14	699
Revisions	-	(13)	(13)	15	(1)	2	-	3
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	26	26	3	-	-	-	29
Production	(5)	(35)	(40)	(8)	(3)	(3)	(1)	(55)
Sales	-	-	-	(1)	-	-	(13)	(14)
End of 2014	120	440	560	65	24	13	-	662
Revisions	(1)	(84)	(85)	(10)	(1)	(2)	-	(98)
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	10	10	2	-	-	-	12
Production	(5)	(36)	(41)	(9)	(3)	(3)	-	(56)
Sales	-	(9)	(9)	(3)	-	-	-	(12)
End of 2015	114	321	435	45	20	8	-	508
Revisions	(3)	(29)	(32)	9	2	-	-	(21)
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	18	18	2	-	-	-	20
Production	(4)	(32)	(36)	(8)	(3)	(3)	-	(50)
Sales	-	-	-	-	-	-	-	-
End of 2016	107	278	385	48	19	5	-	457
Equity affiliates								
End of 2013	-	-	-	-	-	45	-	45
Revisions	-	-	-	-	-	10	-	10
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	(2)	-	(2)
Sales	-	-	-	-	-	-	-	-
End of 2014	-	-	-	-	-	53	-	53
Revisions	-	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	(3)	-	(3)

Sales	-	-	-	-	-	-	-	-
End of 2015	-	-	-	-	-	50	-	50
Revisions	-	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	(3)	-	(3)
Sales	-	-	-	-	-	-	-	-
End of 2016	-	-	-	-	-	47	-	47
Total company								
End of 2013	125	462	587	56	28	59	14	744
End of 2014	120	440	560	65	24	66	-	715
End of 2015	114	321	435	45	20	58	-	558
End of 2016	107	278	385	48	19	52	-	504

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Years Ended December 31	Natural Gas Liquids Millions of Barrels							
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total
Developed								
Consolidated operations								
End of 2013	125	362	487	50	19	13	14	583
End of 2014	120	337	457	57	18	11	-	543
End of 2015	114	235	349	45	16	8	-	418
End of 2016	107	209	316	47	15	5	-	383
Equity affiliates								
End of 2013	-	-	-	-	-	45	-	45
End of 2014	-	-	-	-	-	53	-	53
End of 2015	-	-	-	-	-	50	-	50
End of 2016	-	-	-	-	-	47	-	47
Undeveloped								
Consolidated operations								
End of 2013	-	100	100	6	9	1	-	116
End of 2014	-	103	103	8	6	2	-	119
End of 2015	-	86	86	-	4	-	-	90
End of 2016	-	69	69	1	4	-	-	74
Equity affiliates								
End of 2013	-	-	-	-	-	-	-	-
End of 2014	-	-	-	-	-	-	-	-
End of 2015	-	-	-	-	-	-	-	-
End of 2016	-	-	-	-	-	-	-	-

Notable changes in proved natural gas liquids reserves in the three years ended December 31, 2016, included:

Revisions: In 2015, revisions in Lower 48 and Canada were primarily due to lower prices.

Extensions and discoveries: In 2014, extensions and discoveries in Lower 48 were primarily due to continued drilling success in Eagle Ford and Bakken.

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Years Ended December 31	Natural Gas Billions of Cubic Feet							
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total
Developed and Undeveloped								
Consolidated operations								
End of 2013	2,865	6,711	9,576	1,878	1,809	2,046	950	16,259
Revisions	(75)	581	506	225	(54)	115	-	792
Improved recovery	-	-	-	-	-	3	-	3
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	7	256	263	85	-	3	-	351
Production	(78)	(601)	(679)	(259)	(182)	(289)	(34)	(1,443)
Sales	-	(2)	(2)	(13)	-	-	(689)	(704)
End of 2014	2,719	6,945	9,664	1,916	1,573	1,878	227	15,258
Revisions	(293)	(884)	(1,177)	(111)	(27)	110	-	(1,205)
Improved recovery	-	-	-	1	-	8	-	9
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	4	103	107	44	-	2	-	153
Production	(83)	(588)	(671)	(261)	(187)	(285)	-	(1,404)
Sales	-	(405)	(405)	(482)	-	-	-	(887)
End of 2015	2,347	5,171	7,518	1,107	1,359	1,713	227	11,924
Revisions	(105)	(124)	(229)	111	56	18	-	(44)
Improved recovery	-	-	-	-	-	1	-	1
Purchases	-	-	-	1	-	-	-	1
Extensions and discoveries	2	162	164	43	-	124	-	331
Production	(73)	(494)	(567)	(192)	(177)	(288)	-	(1,224)
Sales	(69)	(1)	(70)	(33)	-	(42)	-	(145)
End of 2016	2,102	4,714	6,816	1,037	1,238	1,526	227	10,844
Equity affiliates								
End of 2013	-	-	-	-	-	4,129	-	4,129
Revisions	-	-	-	-	-	768	-	768
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	531	-	531
Production	-	-	-	-	-	(186)	-	(186)
Sales	-	-	-	-	-	-	-	-
End of 2014	-	-	-	-	-	5,242	-	5,242
Revisions	-	-	-	-	-	(2)	-	(2)

Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	268	-	268
Production	-	-	-	-	-	(239)	-	(239)
Sales	-	-	-	-	-	-	-	-
End of 2015	-	-	-	-	-	5,269	-	5,269
Revisions	-	-	-	-	-	(676)	-	(676)
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	125	-	125
Production	-	-	-	-	-	(337)	-	(337)
Sales	-	-	-	-	-	-	-	-
End of 2016	-	-	-	-	-	4,381	-	4,381
Total company								
End of 2013	2,865	6,711	9,576	1,878	1,809	6,175	950	20,388
End of 2014	2,719	6,945	9,664	1,916	1,573	7,120	227	20,500
End of 2015	2,347	5,171	7,518	1,107	1,359	6,982	227	17,193
End of 2016	2,102	4,714	6,816	1,037	1,238	5,907	227	15,225

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Years Ended December 31	Natural Gas Billions of Cubic Feet							
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total
Developed								
Consolidated operations								
End of 2013	2,815	5,822	8,637	1,786	1,276	1,593	881	14,173
End of 2014	2,663	5,922	8,585	1,801	1,182	1,553	226	13,347
End of 2015	2,313	4,458	6,771	1,101	1,088	1,421	227	10,608
End of 2016	2,094	4,199	6,293	1,031	998	1,188	227	9,737
Equity affiliates								
End of 2013	-	-	-	-	-	2,606	-	2,606
End of 2014	-	-	-	-	-	3,954	-	3,954
End of 2015	-	-	-	-	-	4,482	-	4,482
End of 2016	-	-	-	-	-	4,110	-	4,110
Undeveloped								
Consolidated operations								
End of 2013	50	889	939	92	533	453	69	2,086
End of 2014	56	1,023	1,079	115	391	325	1	1,911
End of 2015	34	713	747	6	271	292	-	1,316
End of 2016	8	515	523	6	240	338	-	1,107
Equity affiliates								
End of 2013	-	-	-	-	-	1,523	-	1,523
End of 2014	-	-	-	-	-	1,288	-	1,288
End of 2015	-	-	-	-	-	787	-	787
End of 2016	-	-	-	-	-	271	-	271

Natural gas production in the reserves table may differ from gas production (delivered for sale) in our statistics disclosure, primarily because the quantities above include gas consumed in production operations.

Natural gas reserves are computed at 14.65 pounds per square inch absolute and 60 degrees Fahrenheit.

Notable changes in proved natural gas reserves in the three years ended December 31, 2016, included:

Revisions: In 2016, revisions in our equity affiliates in Asia Pacific/Middle East were primarily due to lower prices. In 2015, revisions in Lower 48, Alaska and Canada were primarily due to lower prices, partially offset by positive revisions in Asia Pacific/Middle East from Indonesia. In 2014, revisions were primarily due to higher prices, increased development activity and strong well performance in Lower 48 and higher prices and improved well performance in Canada and our consolidated operations in Asia Pacific/Middle East. This was partially offset by lower prices and higher costs in Alaska. For our equity affiliates in Asia Pacific/Middle East, 2014 revisions were primarily due to strong field performance.

Extensions and discoveries: In 2015 and 2014, for our equity affiliates in Asia Pacific/Middle East, extensions and discoveries were due to APLNG s ongoing development drilling onshore Australia. In 2014, extensions and discoveries in Lower 48 and Canada were primarily due to continued drilling success in Eagle Ford and Bakken and ongoing development activity in western Canada.

Sales: In 2015, Lower 48 sales were due to the disposition of non-core assets in South Texas, East Texas and North Louisiana and sales of assets in British Columbia, Saskatchewan and Alberta impacted Canada. In 2014, for our consolidated operations in Africa, sales were due to the disposition of the Nigeria business.

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Years Ended December 31	**Bitumen** Millions of Barrels Canada
Developed and Undeveloped	
Consolidated operations	
End of 2013	579
Revisions	(8)
Improved recovery	-
Purchases	-
Extensions and discoveries	31
Production	(4)
Sales	-
End of 2014	598
Revisions	94
Improved recovery	-
Purchases	-
Extensions and discoveries	-
Production	(5)
Sales	-
End of 2015	687
Revisions	(515)
Improved recovery	-
Purchases	-
Extensions and discoveries	-
Production	(13)
Sales	-
End of 2016	159
Equity affiliates	
End of 2013	1,451
Revisions	(14)
Improved recovery	-
Purchases	-
Extensions and discoveries	74
Production	(43)
Sales	-
End of 2014	1,468
Revisions	190
Improved recovery	-
Purchases	-
Extensions and discoveries	99
Production	(51)
Sales	-

End of 2015	1,706
Revisions	(573)
Improved recovery	-
Purchases	-
Extensions and discoveries	10
Production	(54)
Sales	-
End of 2016	1,089
Total company	
End of 2013	2,030
End of 2014	2,066
End of 2015	2,393
End of 2016	1,248

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Years Ended December 31	Bitumen Millions of Barrels Canada
Developed	
Consolidated operations	
End of 2013	16
End of 2014	13
End of 2015	111
End of 2016	159
Equity affiliates	
End of 2013	181
End of 2014	187
End of 2015	311
End of 2016	322
Undeveloped	
Consolidated operations	
End of 2013	563
End of 2014	585
End of 2015	576
End of 2016	-
Equity affiliates	
End of 2013	1,270
End of 2014	1,281
End of 2015	1,395
End of 2016	767

Notable changes in proved bitumen reserves in the three years ended December 31, 2016, included:

Revisions: In 2016, for both our consolidated operations and equity affiliates revisions were primarily related to lower prices which resulted in reserve reductions at Surmont, Foster Creek, Christina Lake and Narrows Lake. In 2015, for both our consolidated operations and equity affiliates revisions were primarily related to reduced royalties from lower prices at Surmont, Foster Creek, Christina Lake and Narrows Lake.

Extensions and discoveries: In 2015, for our equity affiliates extensions and discoveries were related to approval of development at Christina Lake. In 2014, for our consolidated operations extensions and discoveries were primarily related to delineation activity at Surmont. In 2014, for our equity affiliates extensions and discoveries were primarily related to delineation activity at Foster Creek and Christina Lake, as well as regulatory approval of a development area at Foster Creek.

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Years Ended December 31	Total Proved Reserves Millions of Barrels of Oil Equivalent								
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
Developed and Undeveloped									
Consolidated operations									
End of 2013	1,708	2,187	3,895	970	785	588	409	-	6,647
Revisions	(19)	109	90	48	(10)	26	-	-	154
Improved recovery	8	-	8	2	-	3	-	-	13
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	17	184	201	50	-	17	-	-	268
Production	(78)	(206)	(284)	(61)	(78)	(81)	(11)	-	(515)
Sales	-	-	-	(3)	-	-	(156)	-	(159)
End of 2014	1,636	2,274	3,910	1,006	697	553	242	-	6,408
Revisions	(165)	(301)	(466)	66	(26)	(12)	-	-	(438)
Improved recovery	4	4	8	2	-	32	-	-	42
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	20	84	104	10	-	8	-	-	122
Production	(75)	(211)	(286)	(62)	(78)	(84)	-	-	(510)
Sales	-	(79)	(79)	(92)	-	-	-	-	(171)
End of 2015	1,420	1,771	3,191	930	593	497	242	-	5,453
Revisions	(77)	(143)	(220)	(484)	11	9	-	-	(684)
Improved recovery	6	3	9	-	-	7	-	-	16
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	33	124	157	9	-	28	-	-	194
Production	(76)	(185)	(261)	(55)	(76)	(87)	(1)	-	(480)
Sales	(12)	-	(12)	(7)	-	(10)	-	-	(29)
End of 2016	1,294	1,570	2,864	393	528	444	241	-	4,470
Equity affiliates									
End of 2013	-	-	-	1,451	-	819	-	4	2,274
Revisions	-	-	-	(14)	-	155	-	3	144
Improved recovery	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	74	-	89	-	-	163

Production	-	-	-	(43)	-	(38)	-	(2)	(83)
Sales	-	-	-	-	-	-	-	-	-
End of 2014	-	-	-	1,468	-	1,025	-	5	2,498
Revisions	-	-	-	190	-	(1)	-	-	189
Improved recovery	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	99	-	45	-	-	144
Production	-	-	-	(51)	-	(48)	-	(1)	(100)
Sales	-	-	-	-	-	-	-	(4)	(4)
End of 2015	-	-	-	1,706	-	1,021	-	-	2,727
Revisions	-	-	-	(573)	-	(113)	-	-	(686)
Improved recovery	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	10	-	21	-	-	31
Production	-	-	-	(54)	-	(64)	-	-	(118)
Sales	-	-	-	-	-	-	-	-	-
End of 2016	-	-	-	1,089	-	865	-	-	1,954
Total company									
End of 2013	1,708	2,187	3,895	2,421	785	1,407	409	4	8,921
End of 2014	1,636	2,274	3,910	2,474	697	1,578	242	5	8,906
End of 2015	1,420	1,771	3,191	2,636	593	1,518	242	-	8,180
End of 2016	1,294	1,570	2,864	1,482	528	1,309	241	-	6,424

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Years Ended December 31	Total Proved Reserves Millions of Barrels of Oil Equivalent								
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
Developed									
Consolidated operations									
End of 2013	1,597	1,600	3,197	386	478	405	391	-	4,857
End of 2014	1,514	1,637	3,151	393	452	412	237	-	4,645
End of 2015	1,318	1,261	2,579	352	398	384	242	-	3,955
End of 2016	1,203	1,165	2,368	391	365	309	241	-	3,674
Equity affiliates									
End of 2013	-	-	-	181	-	565	-	4	750
End of 2014	-	-	-	187	-	810	-	5	1,002
End of 2015	-	-	-	311	-	890	-	-	1,201
End of 2016	-	-	-	322	-	820	-	-	1,142
Undeveloped									
Consolidated operations									
End of 2013	111	587	698	584	307	183	18	-	1,790
End of 2014	122	637	759	613	245	141	5	-	1,763
End of 2015	102	510	612	578	195	113	-	-	1,498
End of 2016	91	405	496	2	163	135	-	-	796
Equity affiliates									
End of 2013	-	-	-	1,270	-	254	-	-	1,524
End of 2014	-	-	-	1,281	-	215	-	-	1,496
End of 2015	-	-	-	1,395	-	131	-	-	1,526
End of 2016	-	-	-	767	-	45	-	-	812

Natural gas reserves are converted to barrels of oil equivalent (BOE) based on a 6:1 ratio: six thousand cubic feet of natural gas converts to one BOE.

Proved Undeveloped Reserves

We had 1,608 million BOE of proved undeveloped reserves at year-end 2016, compared with 3,024 million BOE at year-end 2015. The following table shows changes in total proved undeveloped reserves for 2016:

	Proved Undeveloped Reserves Millions of Barrels of Oil Equivalent
End of 2015	3,024

Transfers to proved developed	(310)
Revisions	(1,328)
Improved recovery	13
Purchases	-
Extensions and discoveries	212
Sales	(3)
End of 2016	1,608

Revisions, primarily in the oil sands, decreased proved undeveloped reserves due to lower prices. This was partially offset by extensions and discoveries added from ongoing development primarily in the Lower 48, Asia Pacific/Middle East and Alaska.

As a result, at December 31, 2016, our proved undeveloped reserves represented 25 percent of total proved reserves, compared with 37 percent at December 31, 2015. Costs incurred for the year ended December 31, 2016, relating to the development of proved undeveloped reserves were $2.9 billion.

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A portion of our costs incurred each year relate to development projects where the proved undeveloped reserves will be converted to proved developed reserves in future years.

Approximately 70 percent of our proved undeveloped reserves at year-end 2016 were associated with four major development areas. All of the major development areas are currently producing and are expected to have proved undeveloped reserves convert to proved developed over time, as development activities continue and/or production facilities are expanded or upgraded, and include:

- FCCL oil sands Foster Creek and Christina Lake in Canada.
- The Eagle Ford and Bakken areas in the Lower 48.

At the end of 2016, approximately 46 percent of our total proved undeveloped reserves are currently scheduled for development five years or more from initial disclosure which are located in the Athabasca oil sands in Canada. The oil sands in Canada consist of the FCCL and Surmont steam-assisted gravity drainage (SAGD) projects. The majority of our remaining proved undeveloped reserves in this area were recorded beginning in 2007. Our SAGD projects are large, multi-year projects with steady, long-term production at consistent levels. The associated undeveloped reserves are expected to be developed over the life of the project, as additional well pairs are drilled to maintain throughput at the central processing facilities.

Results of Operations

The company s results of operations from oil and gas activities for the years 2016, 2015 and 2014 are shown in the following tables. Non-oil and gas activities, such as pipeline and marine operations, liquefied natural gas operations, crude oil and gas marketing activities, and the profit element of transportation operations in which we have an ownership interest are excluded. Additional information about selected line items within the results of operations tables is shown below:

- Sales include sales to unaffiliated entities attributable primarily to the company s net working interests and royalty interests. Sales are net of fees to transport our produced hydrocarbons beyond the production function to a final delivery point using transportation operations which are not consolidated.
- Transportation costs reflect fees to transport our produced hydrocarbons beyond the production function to a final delivery point using transportation operations which are consolidated.
- Other revenues include gains and losses from asset sales, certain amounts resulting from the purchase and sale of hydrocarbons, and other miscellaneous income.
- Production costs include costs incurred to operate and maintain wells, related equipment and facilities used in the production of petroleum liquids and natural gas.

Taxes other than income taxes include production, property and other non-income taxes.

Depreciation of support equipment is reclassified as applicable.

Other related expenses include inventory fluctuations, foreign currency transaction gains and losses and other miscellaneous expenses.

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Results of Operations

Year Ended					Millions of Dollars				
December 31, 2016	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
Consolidated operations									
Sales	$ 2,793	4,117	6,910	661	2,678	2,350	-	-	12,599
Transfers	8	-	8	-	-	347	-	-	355
Transportation costs	(676)	-	(676)	-	-	(40)	-	-	(716)
Other revenues	375	111	486	48	(34)	(25)	147	9	631
Total revenues	2,500	4,228	6,728	709	2,644	2,632	147	9	12,869
Production costs excluding taxes	1,056	1,967	3,023	790	795	640	23	(2)	5,269
Taxes other than income taxes	231	308	539	55	31	30	1	-	656
Exploration expenses	45	1,227	1,272	332	90	38	138	41	1,911
Depreciation, depletion and amortization	738	4,167	4,905	881	1,390	1,402	2	-	8,580
Impairments	1	148	149	88	(161)	44	-	-	120
Other related expenses	52	70	122	(51)	(77)	(13)	4	4	(11)
Accretion	52	72	124	32	210	35	-	-	401
	325	(3,731)	(3,406)	(1,418)	366	456	(21)	(34)	(4,057)
Income tax provision (benefit)	(29)	(1,349)	(1,378)	(406)	3	250	(72)	(13)	(1,616)
Results of operations	$ 354	(2,382)	(2,028)	(1,012)	363	206	51	(21)	(2,441)
Equity affiliates									
Sales	$ -	-	-	860	-	449	-	-	1,309
Transfers	-	-	-	-	-	825	-	-	825
Transportation costs	-	-	-	-	-	-	-	-	-
Other revenues	-	-	-	-	-	(2)	-	-	(2)

Total revenues		-	-	-	860	-	1,272	-	-	2,132
Production costs excluding taxes		-	-	-	431	-	256	-	-	687
Taxes other than income taxes		-	-	-	15	-	476	-	-	491
Exploration expenses		-	-	-	6	-	-	-	-	6
Depreciation, depletion and amortization		-	-	-	309	-	548	-	-	857
Impairments		-	-	-	9	-	-	-	-	9
Other related expenses		-	-	-	(7)	-	8	-	24	25
Accretion		-	-	-	8	-	7	-	-	15
		-	-	-	89	-	(23)	-	(24)	42
Income tax provision (benefit)		-	-	-	24	-	(201)	-	-	(177)
Results of operations	$	-	-	-	65	-	178	-	(24)	219

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Year Ended December 31, 2015	Millions of Dollars								
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
Consolidated operations									
Sales	$ 3,206	4,992	8,198	930	3,637	2,741	-	-	15,506
Transfers	15	-	15	-	-	629	-	-	644
Transportation costs	(599)	-	(599)	-	-	(40)	-	-	(639)
Other revenues	(5)	452	447	(19)	(28)	6	13	2	421
Total revenues	2,617	5,444	8,061	911	3,609	3,336	13	2	15,932
Production costs excluding taxes	1,242	2,420	3,662	923	1,137	815	42	1	6,580
Taxes other than income taxes	281	358	639	62	35	33	3	1	773
Exploration expenses	682	1,583	2,265	457	170	268	990	43	4,193
Depreciation, depletion and amortization	548	4,192	4,740	777	1,813	1,321	-	-	8,651
Impairments	8	(2)	6	3	724	3	-	-	736
Other related expenses	(30)	78	48	8	9	(2)	(8)	5	60
Accretion	52	83	135	49	240	34	-	-	458
	(166)	(3,268)	(3,434)	(1,368)	(519)	864	(1,014)	(48)	(5,519)
Income tax provision (benefit)	(89)	(1,193)	(1,282)	(244)	(816)	430	(406)	(27)	(2,345)
Results of operations	$ (77)	(2,075)	(2,152)	(1,124)	297	434	(608)	(21)	(3,174)
Equity affiliates									
Sales	$ -	-	-	917	-	536	-	50	1,503
Transfers	-	-	-	-	-	950	-	-	950
Transportation costs	-	-	-	-	-	-	-	-	-
Other revenues	-	-	-	34	-	4	-	58	96
Total revenues	-	-	-	951	-	1,490	-	108	2,549
Production costs excluding taxes	-	-	-	474	-	248	-	13	735
Taxes other than income taxes	-	-	-	15	-	723	-	13	751

Exploration expenses		-	-	-	12	-	190	-	-	202
Depreciation, depletion and amortization		-	-	-	367	-	197	-	5	569
Impairments		-	-	-	-	-	1,396	-	3	1,399
Other related expenses		-	-	-	(2)	-	(13)	-	23	8
Accretion		-	-	-	7	-	10	-	1	18
		-	-	-	78	-	(1,261)	-	50	(1,133)
Income tax provision (benefit)		-	-	-	20	-	(155)	-	10	(125)
Results of operations	$	-	-	-	58	-	(1,106)	-	40	(1,008)

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Year Ended December 31, 2014	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Disc Ops	Total
	Millions of Dollars									
Consolidated operations										
Sales	$ 6,202	9,098	15,300	2,091	6,160	4,550	185	-	278	28,564
Transfers	47	94	141	-	-	938	-	-	-	1,079
Transportation costs	(659)	-	(659)	-	-	(43)	-	-	-	(702)
Other revenues	13	29	42	185	(25)	46	26	154	1,052	1,480
Total revenues	5,603	9,221	14,824	2,276	6,135	5,491	211	154	1,330	30,421
Production costs excluding taxes	1,205	2,482	3,687	1,106	1,410	994	83	1	128	7,409
Taxes other than income taxes	842	700	1,542	62	44	299	5	1	8	1,961
Exploration expenses	46	1,042	1,088	317	148	123	303	40	4	2,023
Depreciation, depletion and amortization	423	3,662	4,085	919	1,777	1,125	6	-	-	7,912
Impairments	56	107	163	38	529	7	-	-	-	737
Other related expenses	2	96	98	7	(233)	(6)	(1)	9	(9)	(135)
Accretion	52	80	132	57	245	26	-	-	-	460
	2,977	1,052	4,029	(230)	2,215	2,923	(185)	103	1,199	10,054
Income tax provision (benefit)	1,043	322	1,365	(101)	1,452	1,216	4	(13)	79	4,002
Results of operations	$ 1,934	730	2,664	(129)	763	1,707	(189)	116	1,120	6,052
Equity affiliates										
Sales	$ -	-	-	2,307	-	851	-	96	-	3,254
Transfers	-	-	-	-	-	1,663	-	-	-	1,663
Transportation costs	-	-	-	-	-	-	-	-	-	-
Other revenues	-	-	-	33	-	3	-	-	-	36
Total revenues	-	-	-	2,340	-	2,517	-	96	-	4,953
Production costs excluding taxes	-	-	-	651	-	221	-	18	-	890
Taxes other than income taxes	-	-	-	14	-	1,214	-	51	-	1,279

Exploration expenses		-	-	-	13	7	8	-	-	-	28
Depreciation, depletion and amortization		-	-	-	337	-	171	-	7	-	515
Impairments		-	-	-	-	-	27	-	-	-	27
Other related expenses		-	-	-	(65)	1	(2)	-	27	-	(39)
Accretion		-	-	-	6	-	8	-	1	-	15
		-	-	-	1,384	(8)	870	-	(8)	-	2,238
Income tax provision (benefit)		-	-	-	331	-	(62)	-	2	-	271
Results of operations	$	-	-	-	1,053	(8)	932	-	(10)	-	1,967

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Statistics

Net Production	2016	2015	2014
	Thousands of Barrels Daily		
Crude Oil			
Consolidated operations			
Alaska	**163**	158	162
Lower 48	**195**	206	188
United States	**358**	364	350
Canada	**7**	12	13
Europe	**120**	120	126
Asia Pacific/Middle East	**97**	91	79
Africa	**2**	-	8
Total consolidated operations	**584**	587	576
Equity affiliates			
Asia Pacific/Middle East	**14**	14	15
Other areas	**-**	4	4
Total equity affiliates	**14**	18	19
Total continuing operations	**598**	605	595
Discontinued operations	**-**	-	5
Total company	**598**	605	600
Natural Gas Liquids			
Consolidated operations			
Alaska	**12**	13	13
Lower 48	**88**	94	97
United States	**100**	107	110
Canada	**23**	26	23
Europe	**7**	7	8
Asia Pacific/Middle East	**7**	9	10
Total consolidated operations	**137**	149	151
Equity affiliates Asia Pacific/Middle East	**8**	7	8
Total continuing operations	**145**	156	159

Discontinued operations	**-**	-	1
Total company	**145**	156	160
Bitumen			
Consolidated operations Canada	**35**	13	12
Equity affiliates Canada	**148**	138	117
Total company	**183**	151	129
Natural Gas	Millions of Cubic Feet Daily		
Consolidated operations			
Alaska	**25**	42	49
Lower 48	**1,219**	1,472	1,491
United States	**1,244**	1,514	1,540
Canada	**524**	715	711
Europe	**459**	475	461
Asia Pacific/Middle East	**730**	717	723
Africa	**1**	1	3
Total consolidated operations	**2,958**	3,422	3,438
Equity affiliates Asia Pacific/Middle East	**899**	638	505
Total continuing operations	**3,857**	4,060	3,943
Discontinued operations	**-**	-	88
Total company	**3,857**	4,060	4,031

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Average Sales Prices		2016	2015	2014
Crude Oil Per Barrel				
Consolidated operations				
Alaska	$	**31.68**	41.84	87.21
Lower 48		**37.49**	42.62	84.18
United States		**34.70**	42.27	85.63
Canada		**35.25**	39.52	77.87
Europe		**43.66**	52.75	99.56
Asia Pacific/Middle East		**42.23**	49.70	95.32
Africa		**-**	60.79	86.71
Total international		**42.76**	50.79	96.48
Total consolidated operations		**37.67**	45.48	89.72
Equity affiliates				
Asia Pacific/Middle East		**44.11**	53.12	99.01
Other areas		**-**	37.21	64.14
Total equity affiliates		**44.11**	49.92	91.48
Total continuing operations		**37.82**	45.61	89.77
Discontinued operations		**-**	-	110.61
Natural Gas Liquids Per Barrel				
Consolidated operations				
Lower 48	$	**14.34**	14.01	30.74
United States		**14.34**	14.01	30.74
Canada		**14.82**	17.02	46.23
Europe		**22.62**	27.56	52.65
Asia Pacific/Middle East		**29.00**	37.78	69.36
Total international		**19.06**	23.21	53.26
Total consolidated operations		**15.72**	16.83	37.45
Equity affiliates Asia Pacific/Middle East		**31.13**	35.79	67.20
Total continuing operations		**16.68**	17.79	38.99
Discontinued operations		**-**	-	13.41
Bitumen Per Barrel				
Consolidated operations Canada	$	**12.91**	20.13	60.03
Equity affiliates Canada		**15.80**	18.58	54.62
Natural Gas Per Thousand Cubic Feet				
Consolidated operations				
Alaska	$	**5.22**	4.33	5.42
Lower 48		**2.20**	2.43	4.29
United States		**2.24**	2.47	4.32
Canada		**1.49**	1.91	4.13
Europe		**4.71**	7.14	9.29
Asia Pacific/Middle East		**4.15**	6.08	9.64
Africa		**-**	-	3.40
Total international		**3.49**	4.78	7.48
Total consolidated operations		**2.97**	3.77	6.07
Equity affiliates Asia Pacific/Middle East		**2.97**	4.83	9.79

Total continuing operations	**2.97**	3.93	6.54
Discontinued operations	**-**	-	2.53

Average sales prices for Alaska crude oil and Asia Pacific/Middle East natural gas above reflect a reduction for transportation costs in which we have an ownership interest that are incurred subsequent to the terminal point of the production function. Accordingly, the average sales prices differ from those discussed in Item 7 of Management s Discussion and Analysis of Financial Condition and Results of Operations.

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		2016	2015	2014
Average Production Costs Per Barrel of Oil Equivalent*				
Consolidated operations				
Alaska	$	**16.12**	19.12	18.04
Lower 48		**11.06**	12.17	12.76
United States		**12.42**	13.88	14.11
Canada		**14.20**	14.88	18.14
Europe		**10.70**	15.05	18.31
Asia Pacific/Middle East		**7.74**	10.20	12.97
Africa		**31.42**	-	28.42
Total international		**10.53**	13.41	16.52
Total consolidated continuing operations		**11.54**	13.67	15.20
Equity affiliates				
Canada		**7.96**	9.41	15.24
Asia Pacific/Middle East		**4.04**	5.31	5.66
Other areas		**-**	8.90	12.33
Total equity affiliates		**5.85**	7.46	10.69
Discontinued operations		**-**	-	16.70
Average Production Costs Per Barrel Bitumen				
Consolidated operations Canada**	$	**24.59**	61.87	66.89
Equity affiliates Canada		**7.96**	9.41	15.24
Taxes Other Than Income Taxes Per Barrel of Oil Equivalent				
Consolidated operations				
Alaska	$	**3.53**	4.33	12.61
Lower 48		**1.73**	1.80	3.60
United States		**2.21**	2.42	5.90
Canada		**0.99**	1.00	1.02
Europe		**0.42**	0.46	0.57
Asia Pacific/Middle East		**0.36**	0.41	3.90
Africa		**1.37**	-	1.71
Total international		**0.55**	0.62	1.89
Total consolidated continuing operations		**1.44**	1.61	4.08
Equity affiliates				
Canada		**0.28**	0.30	0.33
Asia Pacific/Middle East		**7.52**	15.48	31.08
Other areas		**-**	8.90	34.93
Total equity affiliates		**4.18**	7.62	15.37
Discontinued operations		**-**	-	1.04
Depreciation, Depletion and Amortization Per Barrel of Oil Equivalent				
Consolidated operations				
Alaska	$	**11.26**	8.43	6.33
Lower 48		**23.43**	21.07	18.82
United States		**20.15**	17.96	15.63
Canada		**15.84**	12.52	15.08
Europe		**18.71**	24.00	23.07
Asia Pacific/Middle East		**16.95**	16.53	14.68

Africa	**2.73**	-	2.05
Total international	**17.22**	17.98	17.59
Total consolidated continuing operations	**18.78**	17.97	16.52
Equity affiliates			
Canada	**5.70**	7.29	7.89
Asia Pacific/Middle East	**8.65**	4.22	4.38
Other areas	**-**	3.42	4.79
Total equity affiliates	**7.29**	5.77	6.19

**Includes bitumen.*

***2015 revised to conform to current period presentation.*

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Development and Exploration Activities

The following two tables summarize our net interest in productive and dry exploratory and development wells in the years ended December 31, 2016, 2015 and 2014. A development well is a well drilled within the proved area of a reservoir to the depth of a stratigraphic horizon known to be productive. An exploratory well is a well drilled to find and produce crude oil or natural gas in an unknown field or a new reservoir within a proven field. Exploratory wells also include wells drilled in areas near or offsetting current production, or in areas where well density or production history have not achieved statistical certainty of results. Excluded from the exploratory well count are stratigraphic-type exploratory wells, primarily relating to oil sands delineation wells located in Canada and coalbed methane test wells located in Asia Pacific/Middle East.

Net Wells Completed	Productive			Dry		
	2016	2015	2014	**2016**	2015	2014
Exploratory						
Consolidated operations						
Alaska	**2**	-	*	**1**	-	*
Lower 48	**8**	47	30	**1**	4	3
United States	**10**	47	30	**2**	4	3
Canada	**8**	16	9	**1**	3	*
Europe	*****	*	1	**1**	*	1
Asia Pacific/Middle East	**1**	1	2	**-**	2	*
Africa	**1**	*	*	**-**	*	*
Other areas	**-**	-	-	**-**	-	-
Total consolidated operations	**20**	64	42	**4**	9	4
Equity affiliates						
Asia Pacific/Middle East	**20**	19	36	**-**	*	2
Total equity affiliates	**20**	19	36	**-**	-	2
Development						
Consolidated operations						
Alaska	**9**	18	8	**-**	-	-
Lower 48	**119**	347	450	**-**	-	1
United States	**128**	365	458	**-**	-	1
Canada	**47**	47	98	**2**	-	-
Europe	**7**	10	7	**-**	-	-
Asia Pacific/Middle East	**6**	3	14	**-**	*	-
Africa	**-**	-	1	**-**	-	-
Other areas	**-**	-	-	**-**	-	-

Total consolidated operations	**188**	425	578	**2**	-	1
Equity affiliates						
Canada	**48**	22	38	**-**	-	-
Asia Pacific/Middle East	**108**	166	294	**-**	2	1
Other areas	**-**	*	1	**-**	-	-
Total equity affiliates	**156**	188	333	**-**	2	1

**Our total proportionate interest was less than one.*

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The table below represents the status of our wells drilling at December 31, 2016, and includes wells in the process of drilling or in active completion. It also represents gross and net productive wells, including producing wells and wells capable of production at December 31, 2016.

Wells at December 31, 2016			Productive*			
	In Progress		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net
Consolidated operations						
Alaska	2	1	1,749	781	-	-
Lower 48	208	94	10,142	5,107	20,076	13,134
United States	210	95	11,891	5,888	20,076	13,134
Canada	41	24	987	538	4,320	2,966
Europe	20	3	471	86	174	67
Asia Pacific/Middle East	13	5	356	148	55	28
Africa	-	-	825	135	9	1
Other areas	3	2	-	-	-	-
Total consolidated operations	287	129	14,530	6,795	24,634	16,196
Equity affiliates						
Canada	125	62	457	228	-	-
Asia Pacific/Middle East	187	64	-	-	3,520	827
Total equity affiliates	312	126	457	228	3,520	827

**Includes 151 gross and 122 net multiple completion wells.*

Acreage at December 31, 2016	Thousands of Acres			
	Developed		Undeveloped	
	Gross	Net	Gross	Net
Consolidated operations				
Alaska	608	298	683	469
Lower 48	4,903	3,918	10,479	8,475
United States	5,511	4,216	11,162	8,944
Canada	3,038	2,099	9,471	4,165
Europe	834	257	2,219	610

Asia Pacific/Middle East	1,593	741	10,483	5,422
Africa	358	58	12,545	2,049
Other areas	-	-	487	264
Total consolidated operations	11,334	7,371	46,367	21,454
Equity affiliates				
Canada	53	22	651	273
Asia Pacific/Middle East	818	183	6,365	1,794
Total equity affiliates	871	205	7,016	2,067

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Costs Incurred

Year Ended December 31		Millions of Dollars								
		Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East*	Africa	Other Areas	Total
2016										
Consolidated operations										
Unproved property acquisition	$	-	127	127	59	-	-	-	-	186
Proved property acquisition		-	5	5	19	-	-	-	-	24
		-	132	132	78	-	-	-	-	210
Exploration		110	656	766	286	65	52	215	67	1,451
Development		720	782	1,502	209	62	387	6	-	2,166
	$	830	1,570	2,400	573	127	439	221	67	3,827
Equity affiliates										
Unproved property acquisition	$	-	-	-	-	-	2	-	-	2
Proved property acquisition		-	-	-	-	-	-	-	-	-
		-	-	-	-	-	2	-	-	2
Exploration		-	-	-	15	-	19	-	-	34
Development		-	-	-	367	-	312	-	-	679
	$	-	-	-	382	-	333	-	-	715
2015										
Consolidated operations										
Unproved property acquisition	$	-	168	168	52	-	-	-	-	220
Proved property		-	5	5	1	-	-	-	-	6

acquisition										
		-	173	173	53	-	-	-	-	226
Exploration		87	1,369	1,456	298	107	118	394	47	2,420
Development		1,217	2,875	4,092	827	1,742	587	4	-	7,252
	$	1,304	4,417	5,721	1,178	1,849	705	398	47	9,898
Equity affiliates										
Unproved property acquisition	$	-	-	-	-	-	-	-	-	-
Proved property acquisition		-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-
Exploration		-	-	-	17	-	60	-	-	77
Development		-	-	-	847	-	655	-	3	1,505
	$	-	-	-	864	-	715	-	3	1,582
2014										
Consolidated operations										
Unproved property acquisition	$	-	159	159	61	90	-	6	-	316
Proved property acquisition		-	10	10	-	-	-	-	-	10
		-	169	169	61	90	-	6	-	326
Exploration		130	1,347	1,477	332	243	166	556	58	2,832
Development		1,263	4,881	6,144	2,185	3,618	1,353	71	-	13,371
	$	1,393	6,397	7,790	2,578	3,951	1,519	633	58	16,529
Equity affiliates										
Unproved property acquisition	$	-	-	-	-	-	2	-	-	2
Proved property acquisition		-	-	-	-	-	-	-	-	-
		-	-	-	-	-	2	-	-	2
Exploration		-	-	-	23	36	117	-	-	176
Development		-	-	-	1,627	-	1,965	-	9	3,601

	$ -	-	-	1,650	36	2,084	-	9	3,779

**Certain amounts in Asia Pacific/Middle East equity affiliates have been restated in 2015 and 2014 to remove amounts considered to be non-oil and gas producing activities.*

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Capitalized Costs

At December 31	Millions of Dollars								
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East*	Africa	Other Areas	Total
2016									
Consolidated operations									
Proved property	$ 17,376	46,050	63,426	16,970	24,858	13,837	879	-	119,970
Unproved property	1,099	1,376	2,475	1,435	269	787	123	61	5,150
	18,475	47,426	65,901	18,405	25,127	14,624	1,002	61	125,120
Accumulated depreciation, depletion and amortization	8,548	26,858	35,406	10,344	15,754	7,635	297	1	69,437
	$ 9,927	20,568	30,495	8,061	9,373	6,989	705	60	55,683
Equity affiliates									
Proved property	$ -	-	-	9,459	-	8,501	-	-	17,960
Unproved property	-	-	-	891	-	2,756	-	-	3,647
	-	-	-	10,350	-	11,257	-	-	21,607
Accumulated depreciation, depletion and amortization	-	-	-	1,906	-	1,369	-	-	3,275
	$ -	-	-	8,444	-	9,888	-	-	18,332
2015									
Consolidated operations									
Proved property	$ 17,007	45,256	62,263	16,552	26,851	16,254	873	3	122,796

Unproved property	1,609	2,414	4,023	1,418	330	781	823	35	7,410
	18,616	47,670	66,286	17,970	27,181	17,035	1,696	38	130,206
Accumulated depreciation, depletion and amortization	8,688	22,993	31,681	9,371	16,166	8,853	788	4	66,863
	$ 9,928	24,677	34,605	8,599	11,015	8,182	908	34	63,343
Equity affiliates									
Proved property	$ -	-	-	8,763	-	8,086	-	-	16,849
Unproved property	-	-	-	906	-	3,040	-	-	3,946
	-	-	-	9,669	-	11,126	-	-	20,795
Accumulated depreciation, depletion and amortization	-	-	-	1,537	-	1,017	-	-	2,554
	$ -	-	-	8,132	-	10,109	-	-	18,241

**Certain amounts in Asia Pacific/Middle East equity affiliates have been restated in 2015 to remove amounts considered to be non-oil and gas producing activities.*

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Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities

In accordance with SEC and FASB requirements, amounts were computed using 12-month average prices (adjusted only for existing contractual terms) and end-of-year costs, appropriate statutory tax rates and a prescribed 10 percent discount factor. Twelve-month average prices are calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. For all years, continuation of year-end economic conditions was assumed. The calculations were based on estimates of proved reserves, which are revised over time as new data becomes available. Probable or possible reserves, which may become proved in the future, were not considered. The calculations also require assumptions as to the timing of future production of proved reserves and the timing and amount of future development costs, including dismantlement, and future production costs, including taxes other than income taxes.

While due care was taken in its preparation, we do not represent that this data is the fair value of our oil and gas properties, or a fair estimate of the present value of cash flows to be obtained from their development and production.

Discounted Future Net Cash Flows

	Millions of Dollars							
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total
2016								
Consolidated operations								
Future cash inflows	$ 29,697	31,963	61,660	4,739	18,533	12,770	10,715	108,417
Less:								
Future production costs	24,965	16,936	41,901	5,103	7,469	5,288	1,420	61,181
Future development costs	7,961	8,932	16,893	1,586	9,949	2,777	537	31,742
Future income tax provisions (benefit)	-	744	744	-	(325)	1,563	7,885	9,867
Future net cash flows	(3,229)	5,351	2,122	(1,950)	1,440	3,142	873	5,627
10 percent annual discount	(3,143)	976	(2,167)	(1,297)	(2)	572	370	(2,524)
Discounted future net cash flows	$ (86)	4,375	4,289	(653)	1,442	2,570	503	8,151
Equity affiliates								
Future cash inflows	$ -	-	-	15,139	-	17,829	-	32,968
Less:								
Future production costs	-	-	-	8,514	-	10,620	-	19,134

Future development costs		-	-	-	4,993	-	980	-	5,973
Future income tax provisions		-	-	-	164	-	1,309	-	1,473
Future net cash flows		-	-	-	1,468	-	4,920	-	6,388
10 percent annual discount		-	-	-	540	-	1,911	-	2,451
Discounted future net cash flows	$	-	-	-	928	-	3,009	-	3,937
Total company									
Discounted future net cash flows	$	(86)	4,375	4,289	275	1,442	5,579	503	12,088

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	Millions of Dollars							
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total
2015								
Consolidated operations								
Future cash inflows	$ 44,054	42,575	86,629	22,317	27,782	19,368	13,875	169,971
Less:								
Future production costs	32,732	21,638	54,370	13,103	10,574	7,529	1,422	86,998
Future development costs	9,885	12,967	22,852	6,471	12,793	2,884	437	45,437
Future income tax provisions	-	844	844	-	1,506	2,708	10,998	16,056
Future net cash flows	1,437	7,126	8,563	2,743	2,909	6,247	1,018	21,480
10 percent annual discount	(502)	1,573	1,071	1,265	733	1,349	500	4,918
Discounted future net cash flows	$ 1,939	5,553	7,492	1,478	2,176	4,898	518	16,562
Equity affiliates								
Future cash inflows	$ -	-	-	36,211	-	34,257	-	70,468
Less:								
Future production costs	-	-	-	16,417	-	17,874	-	34,291
Future development costs	-	-	-	11,869	-	2,391	-	14,260
Future income tax provisions	-	-	-	1,648	-	3,117	-	4,765
Future net cash flows	-	-	-	6,277	-	10,875	-	17,152
10 percent annual discount	-	-	-	3,827	-	4,298	-	8,125
Discounted future net cash flows	$ -	-	-	2,450	-	6,577	-	9,027
Total company								
Discounted future net cash flows	$ 1,939	5,553	7,492	3,928	2,176	11,475	518	25,589

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	Millions of Dollars								
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
2014									
Consolidated operations									
Future cash inflows	$ 106,506	100,322	206,828	50,209	55,878	39,492	25,997	-	378,404
Less:									
Future production costs	57,924	37,872	95,796	21,342	16,372	12,555	1,338	-	147,403
Future development costs	10,815	19,666	30,481	10,400	14,194	2,985	437	-	58,497
Future income tax provisions	12,483	14,800	27,283	3,159	15,757	7,728	22,526	-	76,453
Future net cash flows	25,284	27,984	53,268	15,308	9,555	16,224	1,696	-	96,051
10 percent annual discount	12,499	10,150	22,649	8,915	2,741	4,607	791	-	39,703
Discounted future net cash flows	$ 12,785	17,834	30,619	6,393	6,814	11,617	905	-	56,348
Equity affiliates									
Future cash inflows	$ -	-	-	88,716	-	61,480	-	357	150,553
Less:									
Future production costs	-	-	-	25,455	-	27,274	-	276	53,005
Future development costs	-	-	-	11,595	-	3,007	-	16	14,618
Future income tax provisions	-	-	-	12,322	-	7,225	-	10	19,557
Future net cash flows	-	-	-	39,344	-	23,974	-	55	63,373
10 percent annual discount	-	-	-	25,601	-	10,897	-	6	36,504
	$ -	-	-	13,743	-	13,077	-	49	26,869

Discounted future net cash flows									
Total company									
Discounted future net cash flows	$ 12,785	17,834	30,619	20,136	6,814	24,694	905	49	83,217

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Sources of Change in Discounted Future Net Cash Flows

	Millions of Dollars								
	Consolidated Operations			Equity Affiliates			Total Company		
	2016	2015	2014	**2016**	2015*	2014*	**2016**	2015*	2014*
Discounted future net cash flows at the beginning of the year	**$ 16,562**	56,348	56,003	**9,027**	26,869	21,509	**25,589**	83,217	77,512
Changes during the year									
Revenues less production costs for the year	**(6,313)**	(8,158)	(19,571)	**(956)**	(966)	(2,748)	**(7,269)**	(9,124)	(22,319)
Net change in prices and production costs	**(16,476)**	(82,923)	(9,243)	**(9,317)**	(27,670)	4,517	**(25,793)**	(110,593)	(4,726)
Extensions, discoveries and improved recovery, less estimated future costs	**1,358**	1,791	7,033	**(77)**	319	1,822	**1,281**	2,110	8,855
Development costs for the year	**3,118**	6,854	11,785	**722**	1,493	3,453	**3,840**	8,347	15,238
Changes in estimated future development costs	**6,646**	2,073	(7,771)	**2,435**	(227)	(1,613)	**9,081**	1,846	(9,384)
Purchases of reserves in place, less estimated future costs	**2**	-	-	**-**	-	5	**2**	-	5

Sales of reserves in place, less estimated future costs	**(123)**	(424)	(1,280)	**-**	(38)	-	**(123)**	(462)	(1,280)
Revisions of previous quantity estimates	**(3,252)**	(1,790)	1,348	**(436)**	938	(1,166)	**(3,688)**	(852)	182
Accretion of discount	**2,540**	9,342	10,045	**1,058**	3,297	2,648	**3,598**	12,639	12,693
Net change in income taxes	**4,089**	33,449	7,999	**1,481**	5,012	(1,558)	**5,570**	38,461	6,441
Total changes	**(8,411)**	(39,786)	345	**(5,090)**	(17,842)	5,360	**(13,501)**	(57,628)	5,705
Discounted future net cash flows at year end	$ **8,151**	16,562	56,348	**3,937**	9,027	26,869	**12,088**	25,589	83,217

**Certain amounts in equity affiliates were restated to reclassify amounts between Development costs for the year and Changes in estimated future development costs.*

The net change in prices and production costs is the beginning-of-year reserve-production forecast multiplied by the net annual change in the per-unit sales price and production cost, discounted at 10 percent.

Purchases and sales of reserves in place, along with extensions, discoveries and improved recovery, are calculated using production forecasts of the applicable reserve quantities for the year multiplied by the 12-month average sales prices, less future estimated costs, discounted at 10 percent.

Revisions of previous quantity estimates are calculated using production forecast changes for the year, including changes in the timing of production, multiplied by the 12-month average sales prices, less future estimated costs, discounted at 10 percent.

The accretion of discount is 10 percent of the prior year s discounted future cash inflows, less future production and development costs.

The net change in income taxes is the annual change in the discounted future income tax provisions.

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Selected Quarterly Financial Data (Unaudited)

	Millions of Dollars				Per Share of Common Stock	
	Sales and Other Operating Revenues	Income (Loss) From Continuing Operations Before Income Taxes	Net Income (Loss)	Net Income (Loss) Attributable to ConocoPhillips	Net Income (Loss) Attributable to ConocoPhillips Basic	Net Income (Loss) Attributable to ConocoPhillips Diluted
2016						
First	**$ 5,121**	**(2,224)**	**(1,456)**	**(1,469)**	**(1.18)**	**(1.18)**
Second	**5,348**	**(1,644)**	**(1,058)**	**(1,071)**	**(0.86)**	**(0.86)**
Third	**6,415**	**(1,654)**	**(1,026)**	**(1,040)**	**(0.84)**	**(0.84)**
Fourth	**6,809**	**(8)**	**(19)**	**(35)**	**(0.03)**	**(0.03)**
2015						
First	$ 7,716	(356)	286	272	0.22	0.22
Second	8,293	(91)	(164)	(179)	(0.15)	(0.15)
Third	7,262	(1,741)	(1,056)	(1,071)	(0.87)	(0.87)
Fourth	6,293	(5,051)	(3,437)	(3,450)	(2.78)	(2.78)

For additional information on the commodity price environment, see the Business Environment and Executive Overview section of Management s Discussion and Analysis of Financial Condition and Results of Operations.

Supplementary Information Condensed Consolidating Financial Information

We have various cross guarantees among ConocoPhillips, ConocoPhillips Company and ConocoPhillips Canada Funding Company I, with respect to publicly held debt securities. ConocoPhillips Company is 100 percent owned by ConocoPhillips. ConocoPhillips Canada Funding Company I is an indirect, 100 percent owned subsidiary of ConocoPhillips Company. ConocoPhillips and ConocoPhillips Company have fully and unconditionally guaranteed the payment obligations of ConocoPhillips Canada Funding Company I, with respect to their publicly held debt securities. Similarly, ConocoPhillips has fully and unconditionally guaranteed the payment obligations of ConocoPhillips Company with respect to its publicly held debt securities. In addition, ConocoPhillips Company has fully and unconditionally guaranteed the payment obligations of ConocoPhillips with respect to its publicly held debt securities. All guarantees are joint and several. The following condensed consolidating financial information presents the results of operations, financial position and cash flows for:

- ConocoPhillips, ConocoPhillips Company and ConocoPhillips Canada Funding Company I (in each case, reflecting investments in subsidiaries utilizing the equity method of accounting).
- All other nonguarantor subsidiaries of ConocoPhillips.
- The consolidating adjustments necessary to present ConocoPhillips results on a consolidated basis.

In May 2014, we filed a universal shelf registration statement with the SEC under which ConocoPhillips, as a well-known seasoned issuer, has the ability to issue and sell an indeterminate amount of various types of debt and equity securities, with certain debt securities guaranteed by ConocoPhillips Company. Also as part of that registration statement, ConocoPhillips Trust I and ConocoPhillips Trust II have the ability to issue and sell preferred trust securities, guaranteed by ConocoPhillips. ConocoPhillips Trust I and ConocoPhillips Trust II have not issued any trust-preferred securities under this registration statement, and thus have no assets or liabilities. Accordingly, columns for these two trusts are not included in the condensed consolidating financial information.

In 2014, ConocoPhillips received $34.5 billion in dividends from ConocoPhillips Company to settle certain accumulated intercompany balances. This consisted of a $17.5 billion distribution of earnings and a $17 billion return of capital. These transactions had no impact on our consolidated financial statements.

In 2015, ConocoPhillips received a $3.5 billion return of capital from ConocoPhillips Company to settle certain accumulated intercompany balances. The transaction had no impact on our consolidated financial statements.

In 2016, ConocoPhillips received a $2.3 billion return of capital from ConocoPhillips Company to settle certain accumulated intercompany balances. The transaction had no impact on our consolidated financial statements.

In 2016, ConocoPhillips Canada Funding Company I repaid $1.25 billion of external debt. This transaction is reflected in our consolidated financial statements.

This condensed consolidating financial information should be read in conjunction with the accompanying consolidated financial statements and notes.

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Income Statement	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Canada Funding Company I	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
	Millions of Dollars					
	Year Ended December 31, 2016					
Revenues and Other Income						
Sales and other operating revenues	$ -	10,352	-	13,341	-	23,693
Equity in earnings (losses) of affiliates	(3,351)	(1,051)	-	(91)	4,545	52
Gain on dispositions	-	120	-	240	-	360
Other income (loss)	1	(11)	-	265	-	255
Intercompany revenues	88	277	220	3,036	(3,621)	-
Total Revenues and Other Income	(3,262)	9,687	220	16,791	924	24,360
Costs and Expenses						
Purchased commodities	-	9,144	-	3,562	(2,712)	9,994
Production and operating expenses	-	779	-	5,131	(243)	5,667
Selling, general and administrative expenses	8	581	-	140	(6)	723
Exploration expenses	-	1,231	-	684	-	1,915
Depreciation, depletion and amortization	-	1,178	-	7,884	-	9,062
Impairments	-	67	-	72	-	139
Taxes other than income taxes	-	162	-	577	-	739

Accretion on discounted liabilities		-	46	-	379	-	425
Interest and debt expense		506	622	207	570	(660)	1,245
Foreign currency transaction (gains) losses		(19)	2	174	(176)	-	(19)
Total Costs and Expenses		495	13,812	381	18,823	(3,621)	29,890
Loss from continuing operations before income taxes		(3,757)	(4,125)	(161)	(2,032)	4,545	(5,530)
Income tax benefit		(142)	(774)	(9)	(1,046)	-	(1,971)
Net loss		(3,615)	(3,351)	(152)	(986)	4,545	(3,559)
Less: net income attributable to noncontrolling interests		-	-	-	(56)	-	(56)
Loss Attributable to ConocoPhillips	$	(3,615)	(3,351)	(152)	(1,042)	4,545	(3,615)
Comprehensive Loss Attributable to ConocoPhillips	$	(3,561)	(3,297)	(27)	(952)	4,276	(3,561)

Income Statement		Year Ended December 31, 2015					
Revenues and Other Income							
Sales and other operating revenues	$	-	11,473	-	18,091	-	29,564
Equity in earnings (losses) of affiliates		(4,081)	(1,950)	-	1,364	5,322	655
Gain on dispositions		-	332	-	259	-	591

Other income	-	12	-	113	-	125
Intercompany revenues	74	341	246	3,365	(4,026)	-
Total Revenues and Other Income	(4,007)	10,208	246	23,192	1,296	30,935
Costs and Expenses						
Purchased commodities	-	9,905	-	5,838	(3,317)	12,426
Production and operating expenses	-	1,469	-	5,585	(38)	7,016
Selling, general and administrative expenses	9	744	1	209	(10)	953
Exploration expenses	-	2,093	-	2,099	-	4,192
Depreciation, depletion and amortization	-	1,201	-	7,912	-	9,113
Impairments	-	15	-	2,230	-	2,245
Taxes other than income taxes	-	173	-	728	-	901
Accretion on discounted liabilities	-	58	-	425	-	483
Interest and debt expense	485	423	226	447	(661)	920
Foreign currency transaction (gains) losses	114	1	(708)	518	-	(75)
Total Costs and Expenses	608	16,082	(481)	25,991	(4,026)	38,174
Income (loss) from continuing operations before income taxes	(4,615)	(5,874)	727	(2,799)	5,322	(7,239)
Income tax provision (benefit)	(187)	(1,793)	21	(909)	-	(2,868)
	(4,428)	(4,081)	706	(1,890)	5,322	(4,371)

Net income (loss)							
Less: net income attributable to noncontrolling interests		-	-	-	(57)	-	(57)
Net Income (Loss) Attributable to ConocoPhillips	$	(4,428)	(4,081)	706	(1,947)	5,322	(4,428)
Comprehensive Income (Loss) Attributable to ConocoPhillips	$	(8,773)	(8,426)	71	(6,705)	15,060	(8,773)

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	Millions of Dollars					
	Year Ended December 31, 2014					
Income Statement	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Canada Funding Company I	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Revenues and Other Income						
Sales and other operating revenues	$ -	20,083	-	32,441	-	52,524
Equity in earnings of affiliates	6,108	8,090	-	2,932	(14,601)	2,529
Gain on dispositions	-	9	-	89	-	98
Other income (loss)	(6)	67	-	305	-	366
Intercompany revenues	79	465	283	5,883	(6,710)	-
Total Revenues and Other Income	6,181	28,714	283	41,650	(21,311)	55,517
Costs and Expenses						
Purchased commodities	-	17,591	-	10,415	(5,907)	22,099
Production and operating expenses	-	2,600	-	6,368	(59)	8,909
Selling, general and administrative expenses	9	575	1	166	(16)	735
Exploration expenses	-	1,036	-	1,009	-	2,045
Depreciation, depletion and amortization	-	1,059	-	7,270	-	8,329
Impairments	-	127	-	729	-	856
Taxes other than income taxes	-	285	-	1,803	-	2,088

Accretion on discounted liabilities		-	58	-	426	-	484
Interest and debt expense		571	299	231	275	(728)	648
Foreign currency transaction (gains) losses		62	10	(372)	234	-	(66)
Total Costs and Expenses		642	23,640	(140)	28,695	(6,710)	46,127
Income from continuing operations before income taxes		5,539	5,074	423	12,955	(14,601)	9,390
Income tax provision (benefit)		(199)	(1,034)	19	4,797	-	3,583
Income From Continuing Operations		5,738	6,108	404	8,158	(14,601)	5,807
Income from discontinued operations		1,131	1,131	-	113	(1,244)	1,131
Net income		6,869	7,239	404	8,271	(15,845)	6,938
Less: net income attributable to noncontrolling interests		-	-	-	(69)	-	(69)
Net Income Attributable to ConocoPhillips	$	6,869	7,239	404	8,202	(15,845)	6,869
Comprehensive Income Attributable to ConocoPhillips	$	2,965	3,335	58	4,589	(7,982)	2,965

Balance Sheet		Millions of Dollars At December 31, 2016				
	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Canada Funding Company I	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Assets						
Cash and cash equivalents	$ -	358	13	3,239	-	3,610
Short-term investments	-	-	-	50	-	50
Accounts and notes receivable	22	1,968	23	6,103	(4,702)	3,414
Inventories	-	84	-	934	-	1,018
Prepaid expenses and other current assets	2	116	8	415	(24)	517
Total Current Assets	24	2,526	44	10,741	(4,726)	8,609
Investments, loans and long-term receivables*	37,901	64,434	2,296	31,643	(114,602)	21,672
Net properties, plants and equipment	-	6,301	-	52,030	-	58,331
Other assets	40	2,194	220	1,240	(2,534)	1,160
Total Assets	$ 37,965	75,455	2,560	95,654	(121,862)	89,772
Liabilities and Stockholders Equity						
Accounts payable	$ -	4,683	1	3,671	(4,702)	3,653
Short-term debt	(10)	999	6	94	-	1,089
Accrued income and other taxes	-	85	-	399	-	484
	-	489	-	200	-	689

Employee benefit obligations							
Other accruals		171	271	40	536	(24)	994
Total Current Liabilities		161	6,527	47	4,900	(4,726)	6,909
Long-term debt		8,975	12,635	1,710	2,866	-	26,186
Asset retirement obligations and accrued environmental costs		-	925	-	7,500	-	8,425
Deferred income taxes		-	-	-	10,972	(2,023)	8,949
Employee benefit obligations		-	1,901	-	651	-	2,552
Other liabilities and deferred credits*		417	10,391	748	17,832	(27,863)	1,525
Total Liabilities		9,553	32,379	2,505	44,721	(34,612)	54,546
Retained earnings		25,025	14,015	(541)	12,883	(19,834)	31,548
Other common stockholders equity		3,387	29,061	596	37,798	(67,416)	3,426
Noncontrolling interests		-	-	-	252	-	252
Total Liabilities and Stockholders Equity	$	37,965	75,455	2,560	95,654	(121,862)	89,772

Balance Sheet				At December 31, 2015			
Assets							
Cash and cash equivalents	$	-	4	15	2,349	-	2,368
Accounts and notes receivable		21	2,905	21	7,228	(5,661)	4,514
Inventories		-	142	-	982	-	1,124

Prepaid expenses and other current assets		2	206	252	589	(266)	783
Total Current Assets		23	3,257	288	11,148	(5,927)	8,789
Investments, loans and long-term receivables*		43,532	64,015	3,264	27,839	(117,464)	21,186
Net properties, plants and equipment		-	8,110	-	58,336	-	66,446
Other assets		7	950	233	1,158	(1,285)	1,063
Total Assets	$	43,562	76,332	3,785	98,481	(124,676)	97,484
Liabilities and Stockholders Equity							
Accounts payable	$	-	5,684	13	4,897	(5,661)	4,933
Short-term debt		(9)	1	1,255	180	-	1,427
Accrued income and other taxes		-	62	-	437	-	499
Employee benefit obligations		-	629	-	258	-	887
Other accruals		170	465	52	1,087	(264)	1,510
Total Current Liabilities		161	6,841	1,320	6,859	(5,925)	9,256
Long-term debt		7,518	10,660	1,716	3,559	-	23,453
Asset retirement obligations and accrued environmental costs		-	1,107	-	8,473	-	9,580
Deferred income taxes		-	-	-	11,814	(815)	10,999
Employee benefit obligations		-	1,760	-	526	-	2,286
		2,681	7,291	667	15,181	(23,992)	1,828

Other liabilities and deferred credits*							
Total Liabilities		10,360	27,659	3,703	46,412	(30,732)	57,402
Retained earnings		29,892	17,366	(389)	15,177	(25,632)	36,414
Other common stockholders equity		3,310	31,307	471	36,572	(68,312)	3,348
Noncontrolling interests		-	-	-	320	-	320
Total Liabilities and Stockholders Equity	$	43,562	76,332	3,785	98,481	(124,676)	97,484

**Includes intercompany loans.*

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Statement of Cash Flows	Millions of Dollars						
	Year Ended December 31, 2016						
		ConocoPhillips	ConocoPhillips Company	ConocoPhillips Canada Funding Company I	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Cash Flows From Operating Activities							
Net Cash Provided by (Used in) Operating Activities	$	(306)	(322)	(2)	5,903	(870)	4,403
Cash Flows From Investing Activities							
Capital expenditures and investments		-	(989)	-	(4,281)	401	(4,869)
Working capital changes associated with investing activities		-	(126)	-	(205)	-	(331)
Proceeds from asset dispositions		2,300	266	-	1,114	(2,394)	1,286
Net sales of short-term investments		-	-	-	(51)	-	(51)
Long-term advances/loans related parties		-	(812)	-	-	812	-
Collection of advances/loans related parties		-	391	1,250	272	(1,805)	108
Intercompany cash management		(2,214)	1,433	-	781	-	-
Other		-	1	-	(3)	-	(2)
Net Cash Provided by (Used in) Investing Activities		86	164	1,250	(2,373)	(2,986)	(3,859)
Cash Flows From Financing Activities							
Issuance of debt		1,600	2,994	-	812	(812)	4,594
Repayment of debt		(150)	(164)	(1,250)	(2,492)	1,805	(2,251)
		148	-	-	-	(211)	(63)

Issuance of company common stock							
Repurchase of company common stock		(126)	-	-	-	-	(126)
Dividends paid		(1,253)	-	-	(1,081)	1,081	(1,253)
Other		1	(2,315)	-	184	1,993	(137)
Net Cash Provided by (Used in) Financing Activities		220	515	(1,250)	(2,577)	3,856	764
Effect of Exchange Rate Changes on Cash and Cash Equivalents		-	(3)	-	(63)	-	(66)
Net Change in Cash and Cash Equivalents		-	354	(2)	890	-	1,242
Cash and cash equivalents at beginning of period		-	4	15	2,349	-	2,368
Cash and Cash Equivalents at End of Period	$	-	358	13	3,239	-	3,610

Statement of Cash Flows	Year Ended December 31, 2015					
Cash Flows From Operating Activities						
Net Cash Provided by (Used in) Operating Activities	(225)	245	9	7,519	24	7,572
Cash Flows From Investing Activities						
Capital expenditures and investments	-	(3,064)	-	(8,386)	1,400	(10,050)
Working capital changes associated with investing activities	-	(4)	-	(964)	-	(968)
Proceeds from asset dispositions	3,500	826	-	1,225	(3,599)	1,952

Long-term advances/loans related parties	-	(278)	-	(2,245)	2,523	-
Collection of advances/loans related parties	-	-	-	205	(100)	105
Intercompany cash management	102	46	-	(148)	-	-
Other	-	304	-	1	1	306
Net Cash Provided by (Used in) Investing Activities	3,602	(2,170)	-	(10,312)	225	(8,655)
Cash Flows From Financing Activities						
Issuance of debt	-	4,743	-	278	(2,523)	2,498
Repayment of debt	-	(100)	-	(103)	100	(103)
Issuance of company common stock	283	-	-	(2)	(363)	(82)
Dividends paid	(3,664)	-	-	(339)	339	(3,664)
Other	4	(3,484)	-	1,204	2,198	(78)
Net Cash Provided by (Used in) Financing Activities	(3,377)	1,159	-	1,038	(249)	(1,429)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	-	-	(1)	(181)	-	(182)
Net Change in Cash and Cash Equivalents	-	(766)	8	(1,936)	-	(2,694)
Cash and cash equivalents at beginning of period	-	770	7	4,285	-	5,062
Cash and Cash Equivalents at End of Period	$ -	4	15	2,349	-	2,368

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Statement of Cash Flows	Millions of Dollars					
	Year Ended December 31, 2014					
	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Canada Funding Company I	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Cash Flows From Operating Activities						
Net cash provided by (used in) continuing operating activities	$ 17,259	2,948	27	16,941	(20,763)	16,412
Net cash provided by discontinued operations	-	202	-	408	(453)	157
Net Cash Provided by (Used in) Operating Activities	17,259	3,150	27	17,349	(21,216)	16,569
Cash Flows From Investing Activities						
Capital expenditures and investments	-	(6,507)	-	(14,840)	4,262	(17,085)
Working capital changes associated with investing activities	-	17	-	163	-	180
Proceeds from asset dispositions	16,912	1,588	-	253	(17,150)	1,603
Net purchases of short-term investments	-	-	-	253	-	253
Long-term advances/loans related parties	-	(736)	(241)	(7)	984	-
Collection of advances/loans related parties	-	593	-	112	(102)	603
Intercompany cash management	(29,113)	31,993	-	(2,880)	-	-
Other	-	(415)	-	(31)	-	(446)
Net cash provided by (used in) continuing	(12,201)	26,533	(241)	(16,977)	(12,006)	(14,892)

investing activities						
Net cash provided by (used in) discontinued operations	-	133	-	(73)	(133)	(73)
Net Cash Provided by (Used in) Investing Activities	(12,201)	26,666	(241)	(17,050)	(12,139)	(14,965)
Cash Flows From Financing Activities						
Issuance of debt	-	2,994	-	984	(984)	2,994
Repayment of debt	(1,909)	(16)	-	(191)	102	(2,014)
Issuance of company common stock	377	-	-	-	(342)	35
Dividends paid	(3,525)	(17,588)	-	(3,768)	21,356	(3,525)
Other	(1)	(16,870)	-	3,919	12,888	(64)
Net cash used in continuing financing activities	(5,058)	(31,480)	-	944	33,020	(2,574)
Net cash used in discontinued operations	-	-	-	(335)	335	-
Net Cash Used in Financing Activities	(5,058)	(31,480)	-	609	33,355	(2,574)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	-	-	(8)	(206)	-	(214)
Net Change in Cash and Cash Equivalents	-	(1,664)	(222)	702	-	(1,184)
Cash and cash equivalents at beginning of period	-	2,434	229	3,583	-	6,246
Cash and Cash Equivalents at End of Period	$ -	770	7	4,285	-	5,062

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Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

Item 9A. CONTROLS AND PROCEDURES

We maintain disclosure controls and procedures designed to ensure information required to be disclosed in reports we file or submit under the Securities Exchange Act of 1934, as amended (the Act), is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms, and that such information is accumulated and communicated to management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. As of December 31, 2016, with the participation of our management, our Chairman and Chief Executive Officer (principal executive officer) and our Executive Vice President, Finance, Commercial and Chief Financial Officer (principal financial officer) carried out an evaluation, pursuant to Rule 13a-15(b) of the Act, of ConocoPhillips disclosure controls and procedures (as defined in Rule 13a-15(e) of the Act). Based upon that evaluation, our Chairman and Chief Executive Officer and our Executive Vice President, Finance, Commercial and Chief Financial Officer concluded our disclosure controls and procedures were operating effectively as of December 31, 2016.

There have been no changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of the Act, in the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management s Annual Report on Internal Control Over Financial Reporting

This report is included in Item 8 on page 78 and is incorporated herein by reference.

Report of Independent Registered Public Accounting Firm

This report is included in Item 8 on page 80 and is incorporated herein by reference.

Item 9B. OTHER INFORMATION

None.

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PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information regarding our executive officers appears in Part I of this report on pages 29 and 30.

Code of Business Ethics and Conduct for Directors and Employees

We have a Code of Business Ethics and Conduct for Directors and Employees (Code of Ethics), including our principal executive officer, principal financial officer, principal accounting officer and persons performing similar functions. We have posted a copy of our Code of Ethics on the Corporate Governance section of our internet website at *www.conocophillips.com* (within the Investors>Corporate Governance section). Any waivers of the Code of Ethics must be approved, in advance, by our full Board of Directors. Any amendments to, or waivers from, the Code of Ethics that apply to our executive officers and directors will be posted on the Corporate Governance section of our internet website.

All other information required by Item 10 of Part III will be included in our Proxy Statement relating to our 2017 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 29, 2017, and is incorporated herein by reference.*

Item 11. EXECUTIVE COMPENSATION

Information required by Item 11 of Part III will be included in our Proxy Statement relating to our 2017 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 29, 2017, and is incorporated herein by reference.*

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by Item 12 of Part III will be included in our Proxy Statement relating to our 2017 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 29, 2017, and is incorporated herein by reference.*

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required by Item 13 of Part III will be included in our Proxy Statement relating to our 2017 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 29, 2017, and is incorporated herein by reference.*

Item 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information required by Item 14 of Part III will be included in our Proxy Statement relating to our 2017 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 29, 2017, and is incorporated herein by reference.*

**Except for information or data specifically incorporated herein by reference under Items 10 through 14, other information and data appearing in our 2017 Proxy Statement are not deemed to be a part of this Annual Report on Form 10-K or deemed to be filed with the Commission as a part of this report.*

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PART IV

Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) 1. Financial Statements and Supplementary Data
The financial statements and supplementary information listed in the Index to Financial Statements, which appears on page 77, are filed as part of this annual report.

2. Financial Statement Schedules
Schedule II Valuation and Qualifying Accounts, appears below. All other schedules are omitted because they are not required, not significant, not applicable or the information is shown in another schedule, the financial statements or the notes to consolidated financial statements.

3. Exhibits
The exhibits listed in the Index to Exhibits, which appears on pages 180 through 188, are filed as part of this annual report.

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS (Consolidated)

ConocoPhillips

	Millions of Dollars				
Description	Balance at January 1	Charged to Expense	Other(a)	Deductions	Balance at December 31
2016					
Deducted from asset accounts:					
Allowance for doubtful accounts and notes receivable	**$ 7**	**3**	**(1)**	**(4)(b)**	**5**
Deferred tax asset valuation allowance	**734**	**(31)**	**(12)**	**(16)**	**675**
Included in other liabilities:					
Restructuring accruals	**156**	**129**	**1**	**(206)(c)**	**80**
2015					
Deducted from asset accounts:					
Allowance for doubtful accounts and notes receivable	$ 5	4	(2)	- (b)	7
	970	6	(21)	(221)	734

Deferred tax asset valuation allowance						
Included in other liabilities:						
Restructuring accruals		61	303	(8)	(200)(c)	156
2014						
Deducted from asset accounts:						
Allowance for doubtful accounts and notes receivable	$	8	-	(2)	(1)(b)	5
Deferred tax asset valuation allowance		969	127	(26)	(100)	970
Included in other liabilities:						
Restructuring accruals		19	71	(6)	(23)(c)	61

(a)Represents acquisitions/dispositions/revisions and the effect of translating foreign financial statements.

(b)Amounts charged off less recoveries of amounts previously charged off.

(c)Benefit payments.

CONOCOPHILLIPS

INDEX TO EXHIBITS

Exhibit Number	Description
2.1	Separation and Distribution Agreement Between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 2.1 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395).
3.1	Amended and Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended June 30, 2008; File No. 001-32395).
3.2	Certificate of Designations of Series A Junior Participating Preferred Stock of ConocoPhillips (incorporated by reference to Exhibit 3.2 to the Current Report of ConocoPhillips on Form 8-K filed on August 30, 2002; File No. 000-49987).
3.3	Amended and Restated By-Laws of ConocoPhillips, as amended and restated as of December 6, 2013 (incorporated by reference to Exhibit 3.1 to the Current Report of ConocoPhillips on Form 8-K filed December 10, 2013; File No. 001-32395).
3.4	Amended and Restated By-Laws of ConocoPhillips, as amended and restated as of October 9, 2015 (incorporated by reference to Exhibit 3.1 to the Current Report of ConocoPhillips on Form 8-K filed on October 13, 2015; File No. 001-32395).
	ConocoPhillips and its subsidiaries are parties to several debt instruments under which the total amount of securities authorized does not exceed 10 percent of the total assets of ConocoPhillips and its subsidiaries on a consolidated basis. Pursuant to paragraph 4(iii)(A) of Item 601(b) of Regulation S-K, ConocoPhillips agrees to furnish a copy of such instruments to the SEC upon request.
10.1	1986 Stock Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.11 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.2	1990 Stock Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.12 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.3	Annual Incentive Compensation Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.13 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.4	Incentive Compensation Plan of Phillips Petroleum Company (incorporated by reference to Exhibit

	10(g) to the Annual Report of ConocoPhillips Company on Form 10-K for the year ended December 31, 1999; File No. 001-00720).
10.5	Amendment and Restatement of ConocoPhillips Supplemental Executive Retirement Plan, dated April 19, 2012 (incorporated by reference to Exhibit 10.14 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).

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Exhibit Number	Description
10.6	Non-Employee Director Retirement Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.18 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.7	Omnibus Securities Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.19 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.8	Key Employee Missed Credited Service Retirement Plan of ConocoPhillips (incorporated by reference to Exhibit 10.10 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.9	Phillips Petroleum Company Stock Plan for Non-Employee Directors (incorporated by reference to Exhibit 10.22 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.10.1	Amendment and Restatement of ConocoPhillips Key Employee Supplemental Retirement Plan, dated April 19, 2012 (incorporated by reference to Exhibit 10.13 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.10.2	First Amendment to the ConocoPhillips Key Employee Supplemental Retirement Plan, dated July 20, 2015 (incorporated by reference to Exhibit 10.10.2 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395).
10.10.3	Second Amendment to the ConocoPhillips Key Employee Supplemental Retirement Plan, dated March 14, 2016 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2016; File No. 001-32395).
10.11.1	Amendment and Restatement of Defined Contribution Make-Up Plan of ConocoPhillips Title I, dated April 19, 2012 (incorporated by reference to Exhibit 10.11.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.11.2	Amendment and Restatement of Defined Contribution Make-Up Plan of ConocoPhillips Title II, dated April 19, 2012 (incorporated by reference to Exhibit 10.11.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.11.3	First Amendment to the Defined Contribution Make-Up Plan of ConocoPhillips Title II, dated October 11, 2012 (incorporated by reference to Exhibit 10.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2012; File No. 001-32395).
10.11.4	Second Amendment to the Defined Contribution Make-Up Plan of ConocoPhillips Title II, dated December 17, 2015 (incorporated by reference to Exhibit 10.11.4 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395).
10.12	

2002 Omnibus Securities Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.26 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).

10.13 Amendment and Restatement of 1998 Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.27 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).

Exhibit Number	Description
10.14	Amendment and Restatement of 1998 Key Employee Stock Performance Plan of ConocoPhillips (incorporated by reference to Exhibit 10.28 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.15	Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips (incorporated by reference to Exhibit 10.17 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.16	ConocoPhillips Form Indemnity Agreement with Directors (incorporated by reference to Exhibit 10.34 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.17.1	Rabbi Trust Agreement dated December 17, 1999 (incorporated by reference to Exhibit 10.11 of the Annual Report of ConocoPhillips Holding Company on Form 10-K for the year ended December 31, 1999; File No. 001-14521).
10.17.2	Amendment to Rabbi Trust Agreement dated February 25, 2002 (incorporated by reference to Exhibit 10.39.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.17.3	Phillips Petroleum Company Grantor Trust Agreement, dated June 1, 1998 (incorporated by reference to Exhibit 10.17.3 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395).
10.17.4	First Amendment to the Trust Agreement under the Phillips Petroleum Company Grantor Trust Agreement, dated May 3, 1999 (incorporated by reference to Exhibit 10.17.4 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395).
10.17.5	Second Amendment to the Trust Agreement under the Phillips Petroleum Company Grantor Trust Agreement, dated January 15, 2002 (incorporated by reference to Exhibit 10.17.5 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395).
10.17.6	Third Amendment to the Trust Agreement under the Phillips Petroleum Company Grantor Trust Agreement, dated October 5, 2006 (incorporated by reference to Exhibit 10.17.6 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395).
10.17.7	Fourth Amendment to the Trust Agreement under the ConocoPhillips Company Grantor Trust Agreement, dated May 1, 2012 (incorporated by reference to Exhibit 10.17.7 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395).
10.17.8	Fifth Amendment to the Trust Agreement under the ConocoPhillips Company Grantor Trust Agreement, dated May 20, 2015 (incorporated by reference to Exhibit 10.17.8 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395).
10.18.1	

ConocoPhillips Directors Charitable Gift Program (incorporated by reference to Exhibit 10.40 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2003; File No. 000-49987).

10.18.2	First and Second Amendments to the ConocoPhillips Directors Charitable Gift Program (incorporated by reference to Exhibit 10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended June 30, 2008; File No. 001-32395).

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Exhibit Number	Description
10.19	ConocoPhillips Matching Gift Plan for Directors and Executives (incorporated by reference to Exhibit 10.41 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2003; File No. 000-49987).
10.20.1	Amendment and Restatement of Key Employee Deferred Compensation Plan of ConocoPhillips Title I, dated April 19, 2012 (incorporated by reference to Exhibit 10.12.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.20.2	Amendment and Restatement of Key Employee Deferred Compensation Plan of ConocoPhillips Title II, dated April 19, 2012 (incorporated by reference to Exhibit 10.12.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.20.3	First Amendment to the Key Employee Deferred Compensation Plan of ConocoPhillips Title II (incorporated by reference to Exhibit 10.20.3 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2010; File No. 001-32395).
10.20.4	Second Amendment to the Key Employee Deferred Compensation Plan of ConocoPhillips Title II (incorporated by reference to Exhibit 10.20.4 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2010; File No. 001-32395).
10.20.5	Amendment and Restatement of Key Employee Deferred Compensation Plan of ConocoPhillips Title II, 2013 Restatement dated November 17, 2014 (Amended and Restated effective as of January 1, 2013) (incorporated by reference to Exhibit 10.20.5 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2014; File No. 001-32395).
10.21	Amendment and Restatement of ConocoPhillips Key Employee Change in Control Severance Plan, effective January 1, 2014 (incorporated by reference to Exhibit 10.21 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2013; File No. 001-32395).
10.22	ConocoPhillips Executive Severance Plan (incorporated by reference to Exhibit 10.23 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395).
10.23.1	2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Appendix C of ConocoPhillips Proxy Statement on Schedule 14A relating to the 2004 Annual Meeting of Shareholders; File No. 000-49987).
10.23.2	Form of Stock Option Award Agreement under the Stock Option and Stock Appreciation Rights Program under the 2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.26 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395).
10.23.3	Form of Performance Share Unit Award Agreement under the Performance Share Program under the 2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.27 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File

No. 001-32395).

10.24 Omnibus Amendments to certain ConocoPhillips employee benefit plans, adopted December 7, 2007 (incorporated by reference to Exhibit 10.30 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2007; File No. 001-32395).

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Exhibit Number	Description
10.25	2009 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Appendix A of ConocoPhillips Proxy Statement on Schedule 14A relating to the 2009 Annual Meeting of Shareholders; File No. 001-32395).
10.26.1	2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Appendix A of ConocoPhillips Proxy Statement on Schedule 14A relating to the 2011 Annual Meeting of Shareholders; File No. 001-32395).
10.26.2	Form of Stock Option Award Agreement under the Stock Option and Stock Appreciation Rights Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, effective February 9, 2012 (incorporated by reference to Exhibit 10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2012; File No. 001-32395).
10.26.3	Form of Restricted Stock Units Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, effective April 4, 2012 (incorporated by reference to Exhibit 10.6 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.26.4	Form of Restricted Stock Award Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, effective May 8, 2012 (incorporated by reference to Exhibit 10.7 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.26.5	Form of Restricted Stock Award Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated September 18, 2012 (incorporated by reference to Exhibit 10.26.5 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395).
10.26.6	Form of Performance Share Unit Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 5, 2013 (incorporated by reference to Exhibit 10.26.6 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395).
10.26.7	Form of Performance Share Unit Agreement Canada under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 5, 2013 (incorporated by reference to Exhibit 10.26.7 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395).
10.26.8	Form of Restricted Stock Award Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 5, 2013 (incorporated by reference to Exhibit 10.26.8 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395).
10.26.9	Form of Stock Option Award Agreement under the Stock Option and Stock Appreciation Rights

	Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 5, 2013 (incorporated by reference to Exhibit 10.26.9 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395).
10.26.10	Form of Make-up Grant Award Agreement under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated January 1, 2012 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2013; File No. 001-32395).

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Exhibit Number	Description
10.26.11	Form of Key Employee Award Agreement, as part of the ConocoPhillips Stock Option Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395).
10.26.12	Form of Key Employee Award Agreement, as part of the ConocoPhillips Stock Option Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 16, 2016 (incorporated by reference to Exhibit 10.26.12 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395).
10.26.13	Form of Key Employee Award Agreement, as part of the ConocoPhillips Restricted Stock Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395).
10.26.14	Form of Key Employee Award Agreement, as part of the ConocoPhillips Restricted Stock Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 16, 2016 (incorporated by reference to Exhibit 10.26.14 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395).
10.26.15	Form of Performance Period IX Award Agreement, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.3 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395).
10.26.16	Form of Performance Period IX Award Agreement Canada, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.4 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395).
10.26.17	Form of Performance Period X Award Agreement, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.5 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395).
10.26.18	Form of Performance Period X Award Agreement Canada, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.6 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395).
10.26.19	Form of Performance Period XI Award Agreement, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.7 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395).

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Exhibit Number	Description
10.26.20	Form of Performance Period XI Award Agreement Canada, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.8 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395).
10.26.21	Form of Performance Period XII Award Agreement, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.9 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395).
10.26.22	Form of Performance Period XII Award Agreement Canada, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395).
10.26.23	Form of Performance Period XIV Award Agreement, as part of the ConocoPhillips Performance Share Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 16, 2016 (incorporated by reference to Exhibit 10.26.23 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395).
10.26.24	Form of Performance Period XIV Award Agreement Canada, as part of the ConocoPhillips Performance Share Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 16, 2016 (incorporated by reference to Exhibit 10.26.24 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395).
10.26.25	Form of Inducement Grant Award Agreement under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated March 31, 2014 (incorporated by reference to Exhibit 10.11 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395).
10.27.1	2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.1 to the Current Report of ConocoPhillips on Form 8-K filed on May 14, 2014; File No. 001-32395).
10.27.2	Form of Key Employee Award Terms and Conditions, as part of the ConocoPhillips Targeted Variable Long Term Incentive Program of ConocoPhillips, granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated September 15, 2014 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2014; File No. 001-32395).
10.27.3	Form of Key Employee Award Terms and Conditions, as part of the ConocoPhillips Targeted Variable Long Term Incentive Program, granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated September 3, 2015 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2015; File No. 001-32395).

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Exhibit Number	Description
10.27.4	Form of Retention Award Terms and Conditions, as part of the Restricted Stock Unit Award, granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2015; File No. 001-32395).
10.27.5	Form of Non-Employee Director Restricted Stock Units Terms and Conditions, as part of the Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips, dated January 15, 2016 (incorporated by reference to Exhibit 10.3 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2016; File No. 001-32395).
10.27.6	Form of Non-Employee Director Restricted Stock Units Terms and Conditions Canadian Non-Employee Directors, as part of the Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips, dated January 15, 2016 (incorporated by reference to Exhibit 10.4 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2016; File No. 001-32395).
10.27.7	Form of Non-Employee Director Restricted Stock Units Terms and Conditions Norwegian Non-Employee Directors, as part of the Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips, dated January 15, 2016 (incorporated by reference to Exhibit 10.5 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2016; File No. 001-32395).
10.28	Amendment and Restatement of Annex to Nonqualified Deferred Compensation Arrangements of ConocoPhillips, dated April 19, 2012 (incorporated by reference to Exhibit 10.8 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.29	Amendment, Change of Sponsorship, and Restatement of Certain Nonqualified Deferred Compensation Plans of ConocoPhillips, dated April 19, 2012 (incorporated by reference to Exhibit 10.10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.30	Amendment and Restatement of the Burlington Resources Inc. Management Supplemental Benefits Plan, dated April 19, 2012 (incorporated by reference to Exhibit 10.9 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.31	Amendment and Restatement of Deferred Compensation Trust Agreement for Non-Employee Directors of Phillips Petroleum Company, dated June 23, 1995 (incorporated by reference to Exhibit 10.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2016; File No. 001-32395).
10.32	Indemnification and Release Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 10.1 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395).
10.33	Intellectual Property Assignment and License Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 10.2 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395).

10.34	Tax Sharing Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 10.3 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395).

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Exhibit Number	Description
10.35	Employee Matters Agreement between ConocoPhillips and Phillips 66, dated April 12, 2012 (incorporated by reference to Exhibit 10.4 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395).
10.36	Transition Services Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 10.5 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395).
10.37	ConocoPhillips Clawback Policy dated October 3, 2012 (incorporated by reference to Exhibit 10.3 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2012; File No. 001-32395).
10.38	Term Loan Agreement, between ConocoPhillips, as borrower, ConocoPhillips Company, as guarantor, Toronto Dominion (Texas) LLC, as administrative agent and the banks party thereto, with TD Securities (USA) LLC, as lead arranger and bookrunner, dated March 18, 2016 (incorporated by reference to Exhibit 10.1 to the Current Report of ConocoPhillips on Form 8-K filed on March 21, 2016; File No. 001-32395).
12*	Computation of Ratio of Earnings to Fixed Charges.
21*	List of Subsidiaries of ConocoPhillips.
23.1*	Consent of Ernst & Young LLP.
23.2*	Consent of DeGolyer and MacNaughton.
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
32*	Certifications pursuant to 18 U.S.C. Section 1350.
99*	Report of DeGolyer and MacNaughton.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Schema Document.
101.CAL*	XBRL Calculation Linkbase Document.
101.DEF*	XBRL Definition Linkbase Document.
101.LAB*	XBRL Labels Linkbase Document.

101.PRE*	XBRL Presentation Linkbase Document.

* Filed herewith.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CONOCOPHILLIPS

February 21, 2017

/s/ Ryan M. Lance
Ryan M. Lance

Chairman of the Board of Directors

and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed, as of February 21, 2017, on behalf of the registrant by the following officers in the capacity indicated and by a majority of directors.

Signature	Title
/s/ Ryan M. Lance Ryan M. Lance	Chairman of the Board of Directors and Chief Executive Officer (Principal executive officer)
/s/ Don E. Wallette, Jr. Don E. Wallette, Jr.	Executive Vice President, Finance, Commercial and Chief Financial Officer (Principal financial officer)
/s/ Glenda M. Schwarz Glenda M. Schwarz	Vice President and Controller (Principal accounting officer)

/s/ Richard L. Armitage Richard L. Armitage	Director
/s/ Richard H. Auchinleck Richard H. Auchinleck	Director
/s/ Charles E. Bunch Charles E. Bunch	Director
/s/ James E. Copeland, Jr. James E. Copeland, Jr.	Director
/s/ Gay Huey Evans Gay Huey Evans	Director
/s/ John V. Faraci John V. Faraci	Director
/s/ Jody Freeman Jody Freeman	Director
/s/ Arjun N. Murti Arjun N. Murti	Director
/s/ Robert A. Niblock Robert A. Niblock	Director
/s/ Harald J. Norvik	Director

Harald J. Norvik