ExxonMobil

2015

Financial Statements and Supplemental Information

For the Fiscal Year Ended December 31, 2015

FINANCIAL SECTION

TABLE OF CONTENTS

Financial	Earnings After Income Taxes 2015	2014	Average Capital Employed 2015	2014	Return on Average Capital Employed 2015	2014	Capital and Exploration Expenditures 2015	2014
	(millions of dollars)				*(percent)*		*(millions of dollars)*	
Upstream								
United States	(1,079)	5,197	64,086	62,403	(1.7)	8.3	7,822	9,401
Non-U.S.	8,180	22,351	105,868	102,562	7.7	21.8	17,585	23,326
Total	7,101	27,548	169,954	164,965	4.2	16.7	25,407	32,727
Downstream								
United States	1,901	1,618	7,497	6,070	25.4	26.7	1,039	1,310
Non-U.S.	4,656	1,427	15,756	17,907	29.6	8.0	1,574	1,724
Total	6,557	3,045	23,253	23,977	28.2	12.7	2,613	3,034
Chemical								
United States	2,386	2,804	7,696	6,121	31.0	45.8	1,945	1,690
Non-U.S.	2,032	1,511	16,054	16,076	12.7	9.4	898	1,051
Total	4,418	4,315	23,750	22,197	18.6	19.4	2,843	2,741
Corporate and financing	(1,926)	(2,388)	(8,202)	(8,029)	-	-	188	35
Total	16,150	32,520	208,755	203,110	7.9	16.2	31,051	38,537

See Frequently Used Terms for a definition and calculation of capital employed and return on average capital employed.

Operating	2015	2014		2015	2014
	(thousands of barrels daily)			*(thousands of barrels daily)*	
Net liquids production			Refinery throughput		
United States	476	454	United States	1,709	1,809
Non-U.S.	1,869	1,657	Non-U.S.	2,723	2,667
Total	2,345	2,111	Total	4,432	4,476
	(millions of cubic feet daily)			*(thousands of barrels daily)*	
Natural gas production available for sale			Petroleum product sales *(2)*		
United States	3,147	3,404	United States	2,521	2,655
Non-U.S.	7,368	7,741	Non-U.S.	3,233	3,220
Total	10,515	11,145	Total	5,754	5,875
	(thousands of oil-equivalent barrels daily)			*(thousands of metric tons)*	
Oil-equivalent production *(1)*	4,097	3,969	Chemical prime product sales *(2)(3)*		
			United States	9,664	9,528
			Non-U.S.	15,049	14,707
			Total	24,713	24,235

(1) Gas converted to oil-equivalent at 6 million cubic feet = 1 thousand barrels.

(2) Petroleum product and chemical prime product sales data reported net of purchases/sales contracts with the same counterparty.

(3) Prime product sales are total product sales excluding carbon black oil and sulfur. Prime product sales include ExxonMobil′s share of equity company volumes and finished-product transfers to the Downstream.

FINANCIAL SUMMARY

	2015	2014	2013	2012	2011
	(millions of dollars, except per share amounts)				
Sales and other operating revenue *(1)*	259,488	394,105	420,836	451,509	467,029
Earnings					
Upstream	7,101	27,548	26,841	29,895	34,439
Downstream	6,557	3,045	3,449	13,190	4,459
Chemical	4,418	4,315	3,828	3,898	4,383
Corporate and financing	(1,926)	(2,388)	(1,538)	(2,103)	(2,221)
Net income attributable to ExxonMobil	16,150	32,520	32,580	44,880	41,060
Earnings per common share	3.85	7.60	7.37	9.70	8.43
Earnings per common share – assuming dilution	3.85	7.60	7.37	9.70	8.42
Cash dividends per common share	2.88	2.70	2.46	2.18	1.85
Earnings to average ExxonMobil share of equity (percent)	9.4	18.7	19.2	28.0	27.3
Working capital	(11,353)	(11,723)	(12,416)	321	(4,542)
Ratio of current assets to current liabilities (times)	0.79	0.82	0.83	1.01	0.94
Additions to property, plant and equipment	27,475	34,256	37,741	35,179	33,638
Property, plant and equipment, less allowances	251,605	252,668	243,650	226,949	214,664
Total assets	336,758	349,493	346,808	333,795	331,052
Exploration expenses, including dry holes	1,523	1,669	1,976	1,840	2,081
Research and development costs	1,008	971	1,044	1,042	1,044
Long-term debt	19,925	11,653	6,891	7,928	9,322
Total debt	38,687	29,121	22,699	11,581	17,033
Fixed-charge coverage ratio (times)	17.6	46.9	55.7	62.4	53.4
Debt to capital (percent)	18.0	13.9	11.2	6.3	9.6
Net debt to capital (percent) *(2)*	16.5	11.9	9.1	1.2	2.6
ExxonMobil share of equity at year-end	170,811	174,399	174,003	165,863	154,396
ExxonMobil share of equity per common share	41.10	41.51	40.14	36.84	32.61
Weighted average number of common shares outstanding (millions)	4,196	4,282	4,419	4,628	4,870
Number of regular employees at year-end (thousands) *(3)*	73.5	75.3	75.0	76.9	82.1
CORS employees not included above (thousands) *(4)*	2.1	8.4	9.8	11.1	17.0

(1) Sales and other operating revenue includes sales-based taxes of $22,678 million for 2015, $29,342 million for 2014, $30,589 million for 2013, $32,409 million for 2012 and $33,503 million for 2011.

(2) Debt net of cash, excluding restricted cash.

(3) Regular employees are defined as active executive, management, professional, technical and wage employees who work full time or part time for the Corporation and are covered by the Corporation's benefit plans and programs.

(4) CORS employees are employees of company-operated retail sites.

FREQUENTLY USED TERMS

Listed below are definitions of several of ExxonMobil's key business and financial performance measures. These definitions are provided to facilitate understanding of the terms and their calculation.

Cash Flow From Operations and Asset Sales

Cash flow from operations and asset sales is the sum of the net cash provided by operating activities and proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments from the Consolidated Statement of Cash Flows. This cash flow reflects the total sources of cash from both operating the Corporation's assets and from the divesting of assets. The Corporation employs a long-standing and regular disciplined review process to ensure that all assets are contributing to the Corporation's strategic objectives. Assets are divested when they are no longer meeting these objectives or are worth considerably more to others. Because of the regular nature of this activity, we believe it is useful for investors to consider proceeds associated with asset sales together with cash provided by operating activities when evaluating cash available for investment in the business and financing activities, including shareholder distributions.

Cash flow from operations and asset sales	**2015**	**2014**	**2013**
		(millions of dollars)	
Net cash provided by operating activities	30,344	45,116	44,914
Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments	2,389	4,035	2,707
Cash flow from operations and asset sales	32,733	49,151	47,621

Capital Employed

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

Capital employed	**2015**	**2014**	**2013**
		(millions of dollars)	
Business uses: asset and liability perspective			
Total assets	336,758	349,493	346,808
Less liabilities and noncontrolling interests share of assets and liabilities			
Total current liabilities excluding notes and loans payable	(35,214)	(47,165)	(55,916)
Total long-term liabilities excluding long-term debt	(86,047)	(92,143)	(87,698)
Noncontrolling interests share of assets and liabilities	(8,286)	(9,099)	(8,935)
Add ExxonMobil share of debt-financed equity company net assets	4,447	4,766	6,109
Total capital employed	211,658	205,852	200,368
Total corporate sources: debt and equity perspective			
Notes and loans payable	18,762	17,468	15,808
Long-term debt	19,925	11,653	6,891
ExxonMobil share of equity	170,811	174,399	174,003
Less noncontrolling interests share of total debt	(2,287)	(2,434)	(2,443)
Add ExxonMobil share of equity company debt	4,447	4,766	6,109
Total capital employed	211,658	205,852	200,368

FREQUENTLY USED TERMS

Return on Average Capital Employed

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

Return on average capital employed	**2015**	**2014**	**2013**
		(millions of dollars)	
Net income attributable to ExxonMobil	16,150	32,520	32,580
Financing costs (after tax)			
Gross third-party debt	(362)	(140)	(163)
ExxonMobil share of equity companies	(170)	(256)	(239)
All other financing costs – net	88	(68)	83
Total financing costs	(444)	(464)	(319)
Earnings excluding financing costs	16,594	32,984	32,899
Average capital employed	208,755	203,110	191,575
Return on average capital employed – corporate total	7.9%	16.2%	17.2%

QUARTERLY INFORMATION

	2015					2014				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
Volumes										
Production of crude oil,	*(thousands of barrels daily)*									
natural gas liquids, synthetic oil and bitumen	2,277	2,291	2,331	2,481	2,345	2,148	2,048	2,065	2,182	2,111
Refinery throughput	4,546	4,330	4,457	4,395	4,432	4,509	4,454	4,591	4,349	4,476
Petroleum product sales *(1)*	5,814	5,737	5,788	5,679	5,754	5,817	5,841	5,999	5,845	5,875
Natural gas production	*(millions of cubic feet daily)*									
available for sale	11,828	10,128	9,524	10,603	10,515	12,016	10,750	10,595	11,234	11,145
	(thousands of oil-equivalent barrels daily)									
Oil-equivalent production *(2)*	4,248	3,979	3,918	4,248	4,097	4,151	3,840	3,831	4,054	3,969
	(thousands of metric tons)									
Chemical prime product sales *(1) (3)*	6,069	6,078	6,082	6,484	24,713	6,128	6,139	6,249	5,719	24,235
Summarized financial data										
Sales and other operating	*(millions of dollars)*									
revenue *(4)*	64,758	71,360	65,679	57,691	259,488	101,312	105,719	103,206	83,868	394,105
Gross profit *(5)*	19,030	20,362	20,247	16,211	75,850	29,166	28,746	28,825	23,240	109,977
Net income attributable to ExxonMobil	4,940	4,190	4,240	2,780	16,150	9,100	8,780	8,070	6,570	32,520
Per share data	*(dollars per share)*									
Earnings per common share *(6)*	1.17	1.00	1.01	0.67	3.85	2.10	2.05	1.89	1.56	7.60
Earnings per common share – assuming dilution *(6)*	1.17	1.00	1.01	0.67	3.85	2.10	2.05	1.89	1.56	7.60
Dividends per common share	0.69	0.73	0.73	0.73	2.88	0.63	0.69	0.69	0.69	2.70
Common stock prices										
High	93.45	90.09	83.53	87.44	93.45	101.22	104.61	104.76	97.20	104.76
Low	82.68	82.80	66.55	73.03	66.55	89.25	96.24	93.62	86.19	86.19

(1) Petroleum product and chemical prime product sales data reported net of purchases/sales contracts with the same counterparty.

(2) Gas converted to oil-equivalent at 6 million cubic feet = 1 thousand barrels.

(3) Prime product sales are total product sales excluding carbon black oil and sulfur. Prime product sales include ExxonMobil's share of equity company volumes and finished-product transfers to the Downstream.

(4) Includes amounts for sales-based taxes.

(5) Gross profit equals sales and other operating revenue less estimated costs associated with products sold.

(6) Computed using the average number of shares outstanding during each period. The sum of the four quarters may not add to the full year.

The price range of ExxonMobil common stock is as reported on the composite tape of the several U.S. exchanges where ExxonMobil common stock is traded. The principal market where ExxonMobil common stock (XOM) is traded is the New York Stock Exchange, although the stock is traded on other exchanges in and outside the United States.

There were 419,510 registered shareholders of ExxonMobil common stock at December 31, 2015. At January 31, 2016, the registered shareholders of ExxonMobil common stock numbered 418,587.

On January 27, 2016, the Corporation declared a $0.73 dividend per common share, payable March 10, 2016.

FUNCTIONAL EARNINGS	2015	2014	2013
	(millions of dollars, except per share amounts)		
Earnings (U.S. GAAP)			
Upstream			
United States	(1,079)	5,197	4,191
Non-U.S.	8,180	22,351	22,650
Downstream			
United States	1,901	1,618	2,199
Non-U.S.	4,656	1,427	1,250
Chemical			
United States	2,386	2,804	2,755
Non-U.S.	2,032	1,511	1,073
Corporate and financing	(1,926)	(2,388)	(1,538)
Net income attributable to ExxonMobil (U.S. GAAP)	16,150	32,520	32,580
Earnings per common share	3.85	7.60	7.37
Earnings per common share – assuming dilution	3.85	7.60	7.37

References in this discussion to total corporate earnings mean net income attributable to ExxonMobil (U.S. GAAP) from the consolidated income statement. Unless otherwise indicated, references to earnings, Upstream, Downstream, Chemical and Corporate and Financing segment earnings, and earnings per share are ExxonMobil's share after excluding amounts attributable to noncontrolling interests.

FORWARD-LOOKING STATEMENTS

Statements in this discussion regarding expectations, plans and future events or conditions are forward-looking statements. Actual future financial and operating results, including demand growth and energy source mix; capacity increases; production growth and mix; rates of field decline; financing sources; the resolution of contingencies and uncertain tax positions; environmental and capital expenditures; could differ materially depending on a number of factors, such as changes in the supply of and demand for crude oil, natural gas, and petroleum and petrochemical products and resulting price impacts; the outcome of commercial negotiations; the impact of fiscal and commercial terms; political or regulatory events, and other factors discussed herein and in Item 1A. Risk Factors of ExxonMobil's 2015 Form 10-K.

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

OVERVIEW

The following discussion and analysis of ExxonMobil's financial results, as well as the accompanying financial statements and related notes to consolidated financial statements to which they refer, are the responsibility of the management of Exxon Mobil Corporation. The Corporation's accounting and financial reporting fairly reflect its straightforward business model involving the extracting, manufacturing and marketing of hydrocarbons and hydrocarbon-based products. The Corporation's business model involves the production (or purchase), manufacture and sale of physical products, and all commercial activities are directly in support of the underlying physical movement of goods.

ExxonMobil, with its resource base, financial strength, disciplined investment approach and technology portfolio, is well-positioned to participate in substantial investments to develop new energy supplies. The company's integrated business model, with significant investments in Upstream, Downstream and Chemical segments, reduces the Corporation's risk from changes in commodity prices. While commodity prices are volatile on a short-term basis and depend on supply and demand, ExxonMobil's investment decisions are based on our long-term business outlook, using a disciplined approach in selecting and pursuing the most attractive investment opportunities. The corporate plan is a fundamental annual management process that is the basis for setting near-term operating and capital objectives in addition to providing the longer-term economic assumptions used for investment evaluation purposes. Volumes are based on individual field production profiles, which are also updated annually. Price ranges for crude oil, natural gas, refined products, and chemical products are based on corporate plan assumptions developed annually by major region and are utilized for investment evaluation purposes. Potential investment opportunities are evaluated over a wide range of economic scenarios to establish the resiliency of each opportunity. Once investments are made, a reappraisal process is completed to ensure relevant lessons are learned and improvements are incorporated into future projects.

BUSINESS ENVIRONMENT AND RISK ASSESSMENT

Long-Term Business Outlook

By 2040, the world's population is projected to grow to approximately 9 billion people, or about 1.8 billion more than in 2014. Coincident with this population increase, the Corporation expects worldwide economic growth to average close to 3 percent per year. As economies and populations grow, and as living standards improve for billions of people, the need for energy will continue to rise. Even with significant efficiency gains, global energy demand is projected to rise by about 25 percent from 2014 to 2040. This demand increase is expected to be concentrated in developing countries (i.e., those that are not member nations of the Organisation for Economic Co-operation and Development).

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

Energy for transportation – including cars, trucks, ships, trains and airplanes – is expected to increase by about 30 percent from 2014 to 2040. The growth in transportation energy demand is likely to account for approximately 60 percent of the growth in liquid fuels demand worldwide over this period. Nearly all the world's transportation fleets will continue to run on liquid fuels, which are abundant, widely available, easy to transport, and provide a large quantity of energy in small volumes.

Demand for electricity around the world is likely to increase approximately 65 percent from 2014 to 2040, led by growth in developing countries. Consistent with this projection, power generation is expected to remain the largest and fastest-growing major segment of global energy demand. Meeting the expected growth in power demand will require a diverse set of energy sources. Today, coal-fired generation provides about 40 percent of the world's electricity, but by 2040 its share is likely to decline to about 30 percent, in part as a result of policies to improve air quality and reduce greenhouse gas emissions and the risks of climate change. From 2014 to 2040, the amount of electricity generated using natural gas, nuclear power, and renewables are all likely to double. By 2040, coal, natural gas and renewables are projected to be generating approximately the same share of electricity worldwide, although significant differences will exist across regions reflecting a wide range of factors including the cost and availability of energy types.

Liquid fuels provide the largest share of global energy supplies today due to their broad-based availability, affordability and ease of transportation, distribution and storage to meet consumer needs. By 2040, global demand for liquid fuels is projected to grow to approximately 112 million barrels of oil-equivalent per day, an increase of about 20 percent from 2014. Globally, crude production from traditional conventional sources will likely decrease slightly through 2040, with significant development activity mostly offsetting natural declines from these fields. However, this decrease is expected to be more than offset by rising production from a variety of emerging supply sources – including tight oil, deepwater, oil sands, natural gas liquids and biofuels. The world's resource base is sufficient to meet projected demand through 2040 as technology advances continue to expand the availability of economic supply options. However, access to resources and timely investments will remain critical to meeting global needs with reliable, affordable supplies.

Natural gas is a versatile fuel, suitable for a wide variety of applications, and it is expected to be the fastest-growing major fuel source from 2014 to 2040, meeting about 40 percent of global energy demand growth. Global natural gas demand is expected to rise about 50 percent from 2014 to 2040, with about 45 percent of that increase in the Asia Pacific region. Helping meet these needs will be significant growth in supplies of unconventional gas - the natural gas found in shale and other rock formations that was once considered uneconomic to produce. In total, about 60 percent of the growth in natural gas supplies is expected to be from unconventional sources. However, we expect conventionally-produced natural gas to remain the cornerstone of supply, meeting about two-thirds of global demand in 2040. The worldwide liquefied natural gas (LNG) market is expected to almost triple by 2040, with much of this supply expected to meet rising demand in Asia Pacific.

The world's energy mix is highly diverse and will remain so through 2040. Oil is expected to remain the largest source of energy with its share remaining close to one-third in 2040. Coal is currently the second largest source of energy, but it is likely to lose that position to natural gas in the 2025-2030 timeframe. The share of natural gas is expected to exceed 25 percent by 2040, while the share of coal falls to about 20 percent. Nuclear power is projected to grow significantly, as many nations are likely to expand nuclear capacity to address rising electricity needs as well as energy security and environmental issues. Total renewable energy is likely to reach about 15 percent of total energy by 2040, with biomass, hydro and geothermal contributing a combined share of more than 10 percent. Total energy supplied from wind, solar and biofuels is expected to increase rapidly, growing close to 250 percent from 2014 to 2040, when they will be approaching 4 percent of world energy.

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

International accords and underlying regional and national regulations covering greenhouse gas emissions continue to evolve with uncertain timing and outcome, making it difficult to predict their business impact. For many years, the Corporation has taken into account policies established to reduce energy-related greenhouse gas emissions in its long-term *Outlook for Energy*, which is used as a foundation for assessing the business environment and business strategies and investments. The climate accord reached at the recent Conference of the Parties (COP 21) in Paris set many new goals, and while many related policies are still emerging, the *Outlook for Energy* continues to anticipate that such policies will increase the cost of carbon dioxide emissions over time. For purposes of the *Outlook for Energy*, we continue to assume that governments will enact policies that impose rising costs on energy-related CO_2 emissions, which we assume will reach an implied cost in OECD nations of about $80 per tonne in 2040. China and other leading non-OECD nations are expected to trail OECD policy initiatives. Nevertheless, as people and nations look for ways to reduce risks of global climate change, they will continue to need practical solutions that do not jeopardize the affordability or reliability of the energy they need. Thus, all practical and economically viable energy sources, both conventional and unconventional, will be needed to continue meeting global energy needs – because of the scale of worldwide energy demand.

The information provided in the Long-Term Business Outlook includes ExxonMobil's internal estimates and forecasts based upon internal data and analyses as well as publicly available information from external sources including the International Energy Agency.

Upstream

ExxonMobil continues to maintain a diverse portfolio of exploration and development opportunities, which enables the Corporation to be selective, maximizing shareholder value and mitigating political and technical risks. ExxonMobil's fundamental Upstream business strategies guide our global exploration, development, production, and gas and power marketing activities. These strategies include capturing material and accretive opportunities to continually high-grade the resource portfolio, exercising a disciplined approach to investing and cost management, developing and applying high-impact technologies, pursuing productivity and efficiency gains, growing profitable oil and gas production, and capitalizing on growing natural gas and power markets. These strategies are underpinned by a relentless focus on operational excellence, commitment to innovative technologies, development of our employees, and investment in the communities within which we operate.

As future development projects and drilling activities bring new production online, the Corporation expects a shift in the geographic mix and in the type of opportunities from which volumes are produced. Oil equivalent production from North America is expected to increase over the next several years based on current capital activity plans, contributing over a third of total production. Further, the proportion of our global production from resource types utilizing specialized technologies such as arctic, deepwater, and unconventional drilling and production systems, as well as LNG, is also expected to grow, becoming a slight majority of production in the next few years. We do not anticipate that the expected change in the geographic mix of production volumes, and in the types of opportunities from which volumes will be produced, will have a material impact on the nature and the extent of the risks disclosed in Item 1A. Risk Factors of ExxonMobil's 2015 Form 10-K, or result in a material change in our level of unit operating expenses.

The Corporation anticipates several projects will come online over the next few years providing additional production capacity. However, actual volumes will vary from year to year due to the timing of individual project start-ups; operational outages; reservoir performance; performance of enhanced oil recovery projects; regulatory changes; the impact of fiscal and commercial terms; asset sales; weather events; price effects on production sharing contracts; changes in the amount and timing of capital investments that may vary depending on the oil and gas price environment; and other factors described in Item 1A. Risk Factors of ExxonMobil's 2015 Form 10-K.

The upstream industry environment has been challenged throughout 2015 with abundant crude oil supply causing crude oil prices to decrease to levels not seen since 2004, while natural gas prices remained depressed. However, current market conditions are not necessarily indicative of future conditions. The markets for crude oil and natural gas have a history of significant price volatility. ExxonMobil believes prices over the long term will continue to be driven by market supply and demand, with the demand side largely being a function of global economic growth. On the supply side, prices may be significantly impacted by political events, the actions of OPEC and other large government resource owners, and other factors. To manage the risks associated with price, ExxonMobil evaluates annual plans and all investments across a wide range of price scenarios. The Corporation's assessment is that its operations will exhibit strong performance over the long term. This is the outcome of disciplined investment, cost management, asset enhancement programs, and application of advanced technologies.

Downstream

ExxonMobil's Downstream is a large, diversified business with refining, logistics, and marketing complexes around the world. The Corporation has a presence in mature markets in North America and Europe, as well as in the growing Asia Pacific region.

ExxonMobil's fundamental Downstream business strategies competitively position the company across a range of market conditions. These strategies include targeting best-in-class operations in all aspects of the business, maximizing value from advanced technologies, capitalizing on integration across ExxonMobil businesses, selectively investing for resilient, advantaged returns, operating efficiently and effectively, and providing quality, valued and differentiated products and services to customers.

ExxonMobil's operating results, as noted in Item 2. Properties of ExxonMobil's 2015 Form 10-K, reflect 23 refineries, located in 14 countries, with distillation capacity of 5 million barrels per day and lubricant basestock manufacturing capacity of 136 thousand barrels per day. ExxonMobil's fuels and lubes marketing businesses have significant global reach, with multiple channels to market serving a diverse customer base. Our portfolio of world-renowned brands includes *Exxon*, *Mobil*, *Esso* and *Mobil 1*.

The downstream industry environment improved in 2015. Growth in global demand, stimulated by lower prices for crude oil and transportation fuels, resulted in higher refinery utilization and margins, particularly in Europe and Asia Pacific. Refineries in North America continue to benefit from lower raw material and energy costs due to the abundant supply of crude oil and natural gas. In the near term, we see variability in refining margins, with some regions seeing weaker margins as new capacity additions are expected to outpace growth in global demand for our products, which can also be affected by global economic conditions and regulatory changes.

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

ExxonMobil's long-term outlook is that industry refining margins will remain subject to intense competition as new capacity additions outpace the growth in global demand. ExxonMobil's integration across the value chain, from refining to marketing, enhances overall value in both fuels and lubricants businesses.

As described in more detail in Item 1A. Risk Factors of ExxonMobil's 2015 Form 10-K, proposed carbon policy and other climate-related regulations in many countries, as well as the continued growth in biofuels mandates, could have negative impacts on the Downstream business

In the retail fuels marketing business, competition has caused inflation-adjusted margins to decline. In 2015, ExxonMobil expanded its branded retail site network and progressed the multi-year transition of the direct served (i.e., dealer, company-operated) retail network in portions of Europe to a more capital-efficient Branded Wholesaler model. The company's lubricants business continues to grow, leveraging world-class brands and integration with industry-leading basestock refining capability. ExxonMobil remains a market leader in the high-value synthetic lubricants sector, despite increasing competition.

The Downstream portfolio is continually evaluated during all parts of the business cycle, and numerous asset divestments have been made over the past decade. In 2015, the company divested its 50 percent share of Chalmette Refining, LLC, and reached an agreement for the sale of the refinery in Torrance, California, with change-in-control expected by mid-2016. When investing in the Downstream, ExxonMobil remains focused on selective and resilient projects. In 2015, construction continued on a new delayed coker unit at the refinery in Antwerp, Belgium, to upgrade low-value bunker fuel into higher value diesel products. Funding was approved for the construction of a proprietary hydrocracker at the refinery in Rotterdam, Netherlands, to produce higher value ultra-low sulfur diesel and Group II basestocks. The company completed an expansion of lubricant basestock capacity at the refinery in Baytown, Texas. Finished lubricant plant expansions in China and Finland were completed, and an expansion in Singapore is underway to support demand growth for finished lubricants and greases in key markets.

Chemical

Worldwide petrochemical demand continued to improve in 2015, led by growing demand from Asia Pacific manufacturers of industrial and consumer products. North America continued to benefit from abundant supplies of natural gas and gas liquids, providing both low-cost feedstock and energy. Specialty product margins improved in 2015, but continued to be impacted by new industry capacity.

ExxonMobil sustained its competitive advantage through continued operational excellence, investment and cost discipline, a balanced portfolio of products, integration with refining and upstream operations, all underpinned by proprietary technology.

In 2015, we neared completion of the specialty elastomers project at our joint venture facility in Al-Jubail, Saudi Arabia. Construction continued on a major expansion at our Texas facilities, including a new world-scale ethane cracker and polyethylene lines, to capitalize on low-cost feedstock and energy supplies in North America and to meet rapidly growing demand for premium polymers. Construction of new halobutyl rubber and hydrocarbon resin units also progressed in Singapore to further extend our specialty product capacity in Asia Pacific.

REVIEW OF 2015 AND 2014 RESULTS

	2015	2014	2013
		(millions of dollars)	
Earnings (U.S. GAAP)			
Net income attributable to ExxonMobil (U.S. GAAP)	16,150	32,520	32,580

Upstream

	2015	2014	2013
		(millions of dollars)	
Upstream			
United States	(1,079)	5,197	4,191
Non-U.S.	8,180	22,351	22,650
Total	7,101	27,548	26,841

2015

Upstream earnings were $7,101 million, down $20,447 million from 2014. Lower realizations decreased earnings by $18.8 billion. Favorable volume and mix effects increased earnings by $810 million, including contributions from new developments. All other items decreased earnings by $2.4 billion, primarily due to lower asset management gains and approximately $500 million of lower favorable one-time tax effects, partly offset by lower expenses of about $230 million. On an oil-equivalent basis, production of 4.1 million barrels per day was up 3.2 percent compared to 2014. Liquids production of 2.3 million barrels per day increased 234,000 barrels per day, with project ramp-up and entitlement effects partly offset by field decline. Natural gas production of 10.5 billion cubic feet per day decreased 630 million cubic feet per day from 2014 as regulatory restrictions in the Netherlands and field decline were partly offset by project ramp-up, work programs and entitlement effects. U.S. Upstream earnings declined $6,276 million from 2014 to a loss of $1,079 million in 2015. Earnings outside the U.S. were $8,180 million, down $14,171 million from the prior year.

2014

Upstream earnings were $27,548 million, up $707 million from 2013. Lower prices decreased earnings by $2 billion. Favorable volume effects increased earnings by $510 million. All other items, primarily asset sales and favorable U.S. deferred income tax items, increased earnings by $2.2 billion. On an oil-equivalent basis, production of 4 million barrels per day was down 4.9 percent compared to 2013. Excluding the impact of the expiry of the Abu Dhabi onshore concession, production decreased 1.7 percent. Liquids production of 2.1 million barrels per day decreased 91,000 barrels per day compared to 2013. The Abu Dhabi onshore concession expiry reduced volumes by 135,000 barrels per day. Excluding this impact, liquids production was up 2 percent, driven by project ramp-up and work programs. Natural gas production of 11.1 billion cubic feet per day decreased 691 million cubic feet per day from 2013, as expected U.S. field decline and lower European demand were partially offset by project ramp-up and work programs. Earnings from U.S. Upstream operations were $5,197 million, up $1,006 million from 2013. Earnings outside the U.S. were $22,351 million, down $299 million from the prior year.

Upstream Additional Information

	2015	2014
	(thousands of barrels daily)	
Volumes Reconciliation (Oil-equivalent production)*(1)*		
Prior year	3,969	4,175
Entitlements - Net Interest	(14)	(4)
Entitlements - Price / Spend / Other	168	(43)
Quotas	-	-
Divestments	(25)	(31)
United Arab Emirates Onshore Concession Expiry	(6)	(135)
Growth / Other	5	7
Current Year	4,097	3,969

(1) Gas converted to oil-equivalent at 6 million cubic feet = 1 thousand barrels.

Listed below are descriptions of ExxonMobil's volumes reconciliation factors which are provided to facilitate understanding of the terms.

Entitlements - Net Interest are changes to ExxonMobil's share of production volumes caused by non-operational changes to volume-determining factors. These factors consist of net interest changes specified in Production Sharing Contracts (PSCs) which typically occur when cumulative investment returns or production volumes achieve defined thresholds, changes in equity upon achieving pay-out in partner investment carry situations, equity redeterminations as specified in venture agreements, or as a result of the termination or expiry of a concession. Once a net interest change has occurred, it typically will not be reversed by subsequent events, such as lower crude oil prices.

Entitlements - Price, Spend and Other are changes to ExxonMobil's share of production volumes resulting from temporary changes to non-operational volume-determining factors. These factors include changes in oil and gas prices or spending levels from one period to another. According to the terms of contractual arrangements or government royalty regimes, price or spending variability can increase or decrease royalty burdens and/or volumes attributable to ExxonMobil. For example, at higher prices, fewer barrels are required for ExxonMobil to recover its costs. These effects generally vary from period to period with field spending patterns or market prices for oil and natural gas. Such factors can also include other temporary changes in net interest as dictated by specific provisions in production agreements.

Quotas are changes in ExxonMobil's allowable production arising from production constraints imposed by countries which are members of the Organization of the Petroleum Exporting Countries (OPEC). Volumes reported in this category would have been readily producible in the absence of the quota.

Divestments are reductions in ExxonMobil's production arising from commercial arrangements to fully or partially reduce equity in a field or asset in exchange for financial or other economic consideration.

Growth and Other factors comprise all other operational and non-operational factors not covered by the above definitions that may affect volumes attributable to ExxonMobil. Such factors include, but are not limited to, production enhancements from project and work program activities, acquisitions including additions from asset exchanges, downtime, market demand, natural field decline, and any fiscal or commercial terms that do not affect entitlements.

Downstream

	2015	2014	2013
		(millions of dollars)	
Downstream			
United States	1,901	1,618	2,199
Non-U.S.	4,656	1,427	1,250
Total	6,557	3,045	3,449

2015

Downstream earnings of $6,557 million increased $3,512 million from 2014. Stronger margins increased earnings by $4.1 billion, while volume and mix effects decreased earnings by $200 million. All other items decreased earnings by $420 million, reflecting nearly $560 million in higher maintenance expense and about $280 million in unfavorable inventory impacts, partly offset by favorable foreign exchange effects. Petroleum product sales of 5.8 million barrels per day were 121,000 barrels per day lower than 2014. U.S. Downstream earnings were $1,901 million, an increase of $283 million from 2014. Non-U.S. Downstream earnings were $4,656 million, up $3,229 million from the prior year.

2014

Downstream earnings of $3,045 million decreased $404 million from 2013. Lower margins decreased earnings by $230 million. Volume and mix effects increased earnings by $480 million. All other items, primarily unfavorable foreign exchange and tax impacts, partially offset by lower expenses, decreased earnings by $650 million. Petroleum product sales of 5.9 million barrels per day were in line with 2013. U.S. Downstream earnings were $1,618 million, a decrease of $581 million from 2013. Non-U.S. Downstream earnings were $1,427 million, up $177 million from the prior year.

Chemical

	2015	2014	2013
		(millions of dollars)	
Chemical			
United States	2,386	2,804	2,755
Non-U.S.	2,032	1,511	1,073
Total	4,418	4,315	3,828

2015

Chemical earnings of $4,418 million increased $103 million from 2014. Stronger margins increased earnings by $590 million. Favorable volume and mix effects increased earnings by $220 million. All other items decreased earnings by $710 million, reflecting about $680 million in unfavorable foreign exchange effects and $220 million in negative tax and inventory impacts, partly offset by asset management gains. Prime product sales of 24.7 million metric tons were up 478,000 metric tons from 2014. U.S. Chemical earnings were $2,386 million, down $418 million from 2014. Non-U.S. Chemical earnings were $2,032 million, $521 million higher than the prior year.

2014

Chemical earnings of $4,315 million increased $487 million from 2013. Higher commodity-driven margins increased earnings by $520 million, while volume and mix effects increased earnings by $100 million. All other items, primarily higher planned expenses, decreased earnings by $130 million. Prime product sales of 24.2 million metric tons were up 172,000 metric tons from 2013, driven by increased Singapore production. U.S. Chemical earnings were $2,804 million, up $49 million from 2013. Non-U.S. Chemical earnings were $1,511 million, $438 million higher than the prior year.

Corporate and Financing

	2015	2014	2013
		(millions of dollars)	
Corporate and financing	(1,926)	(2,388)	(1,538)

2015

Corporate and financing expenses were $1,926 million in 2015 compared to $2,388 million in 2014, with the decrease due mainly to net favorable tax-related items.

2014

Corporate and financing expenses were $2,388 million in 2014, up $850 million from 2013 due primarily to tax-related items.

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

	2015	2014	2013
		(millions of dollars)	
Net cash provided by/(used in)			
Operating activities	30,344	45,116	44,914
Investing activities	(23,824)	(26,975)	(34,201)
Financing activities	(7,037)	(17,888)	(15,476)
Effect of exchange rate changes	(394)	(281)	(175)
Increase/(decrease) in cash and cash equivalents	(911)	(28)	(4,938)
		(December 31)	
Cash and cash equivalents	3,705	4,616	4,644
Cash and cash equivalents - restricted	-	42	269
Total cash and cash equivalents	3,705	4,658	4,913

Total cash and cash equivalents were $3.7 billion at the end of 2015, $1.0 billion lower than the prior year. The major sources of funds in 2015 were net income including noncontrolling interests of $16.6 billion, the adjustment for the noncash provision of $18.0 billion for depreciation and depletion, and a net debt increase of $9.3 billion. The major uses of funds included spending for additions to property, plant and equipment of $26.5 billion, the purchase of shares of ExxonMobil stock of $4.0 billion, dividends to shareholders of $12.1 billion and a change in working capital, excluding cash and debt, of $3.1 billion.

Total cash and cash equivalents were $4.7 billion at the end of 2014, $0.3 billion lower than the prior year. The major sources of funds in 2014 were net income including noncontrolling interests of $33.6 billion, the adjustment for the noncash provision of $17.3 billion for depreciation and depletion, a net debt increase of $7.0 billion and collection of advances of $3.3 billion. The major uses of funds included spending for additions to property, plant and equipment of $33.0 billion, the purchase of shares of ExxonMobil stock of $13.2 billion, dividends to shareholders of $11.6 billion and a change in working capital, excluding cash and debt, of $4.9 billion. Included in total cash and cash equivalents at year-end 2014 was $42 million of restricted cash. For additional details, see the Consolidated Statement of Cash Flows.

The Corporation has access to significant capacity of long-term and short-term liquidity. Internally generated funds are expected to cover the majority of financial requirements, supplemented by long-term and short-term debt. On December 31, 2015, the Corporation had unused committed short-term lines of credit of $6.0 billion and unused committed long-term lines of credit of $0.4 billion. Cash that may be temporarily available as surplus to the Corporation's immediate needs is carefully managed through counterparty quality and investment guidelines to ensure it is secure and readily available to meet the Corporation's cash requirements and to optimize returns.

To support cash flows in future periods the Corporation will need to continually find and develop new fields, and continue to develop and apply new technologies and recovery processes to existing fields, in order to maintain or increase production. After a period of production at plateau rates, it is the nature of oil and gas fields eventually to produce at declining rates for the remainder of their economic life. Averaged over all the Corporation's existing oil and gas fields and without new projects, ExxonMobil's production is expected to decline at an average of approximately 3 percent per year over the next few years. Decline rates can vary widely by individual field due to a number of factors, including, but not limited to, the type of reservoir, fluid properties, recovery mechanisms, work activity, and age of the field. Furthermore, the Corporation's net interest in production for individual fields can vary with price and the impact of fiscal and commercial terms.

The Corporation has long been successful at offsetting the effects of natural field decline through disciplined investments in quality opportunities and project execution. On average over the last decade, this has resulted in net annual additions to proved reserves that have exceeded the amount produced. The Corporation anticipates several projects will come online over the next few years providing additional production capacity. However, actual volumes will vary from year to year due to the timing of individual project start-ups; operational outages; reservoir performance; performance of enhanced oil recovery projects; regulatory changes; the impact of fiscal and commercial terms; asset sales; weather events; price effects on production sharing contracts; and changes in the amount and timing of investments that may vary depending on the oil and gas price environment. The Corporation's cash flows are also highly dependent on crude oil and natural gas prices. Please refer to Item 1A. Risk Factors of ExxonMobil's 2015 Form 10-K for a more complete discussion of risks.

The Corporation's financial strength enables it to make large, long-term capital expenditures. Capital and exploration expenditures in 2015 were $31.1 billion, reflecting the Corporation's continued active investment program. The Corporation anticipates an investment level of $23.2 billion in 2016. The Corporation is emerging from several years of high capital expenditure levels that supported major long-plateau production projects coming on line. Lower levels of capital spending over the next few years, partly due to cost savings and capital efficiencies, are not expected to delay major project schedules nor have a material effect on our volume capacity outlook.

Actual spending could vary depending on the progress of individual projects and property acquisitions. The Corporation has a large and diverse portfolio of development projects and exploration opportunities, which helps mitigate the overall political and technical risks of the Corporation's Upstream segment and associated cash flow. Further, due to its financial strength, debt capacity and diverse portfolio of opportunities, the risk associated with failure or delay of any single project would not have a significant impact on the Corporation's liquidity or ability to generate sufficient cash flows for operations and its fixed commitments.

Cash Flow from Operating Activities

2015

Cash provided by operating activities totaled $30.3 billion in 2015, $14.8 billion lower than 2014. The major source of funds was net income including noncontrolling interests of $16.6 billion, a decrease of $17.1 billion. The noncash provision for depreciation and depletion was $18.0 billion, up $0.8 billion from the prior year. The adjustment for net gains on asset sales was $0.2 billion compared to an adjustment of $3.2 billion in 2014. Changes in operational working capital, excluding cash and debt, decreased cash in 2015 by $3.1 billion.

2014

Cash provided by operating activities totaled $45.1 billion in 2014, $0.2 billion higher than 2013. The major source of funds was net income including noncontrolling interests of $33.6 billion, an increase of $0.2 billion. The noncash provision for depreciation and depletion was $17.3 billion, up $0.1 billion from the prior year. The adjustment for net gains on asset sales was $3.2 billion compared to an adjustment of $1.8 billion in 2013. Changes in operational working capital, excluding cash and debt, decreased cash in 2014 by $4.9 billion.

Cash Flow from Investing Activities

2015

Cash used in investment activities netted to $23.8 billion in 2015, $3.2 billion lower than 2014. Spending for property, plant and equipment of $26.5 billion decreased $6.5 billion from 2014. Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments of $2.4 billion compared to $4.0 billion in 2014. Additional investments and advances were $1.0 billion lower in 2015, while collection of advances was $2.5 billion lower in 2015.

2014

Cash used in investment activities netted to $27.0 billion in 2014, $7.2 billion lower than 2013. Spending for property, plant and equipment of $33.0 billion decreased $0.7 billion from 2013. Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments of $4.0 billion compared to $2.7 billion in 2013. Additional investments and advances were $2.8 billion lower in 2014, while collection of advances was $2.2 billion higher in 2014.

Cash Flow from Financing Activities

2015

Cash used in financing activities was $7.0 billion in 2015, $10.9 billion lower than 2014. Dividend payments on common shares increased to $2.88 per share from $2.70 per share and totaled $12.1 billion, a pay-out of 75 percent of net income. During the first quarter of 2015, the Corporation issued $8.0 billion of long-term debt. Total debt increased $9.6 billion to $38.7 billion at year-end.

ExxonMobil share of equity decreased $3.6 billion to $170.8 billion. The addition to equity for earnings was $16.2 billion. This was offset by reductions for distributions to ExxonMobil shareholders of $15.1 billion, composed of $12.1 billion in dividends and $3.0 billion of share purchases of ExxonMobil stock to reduce shares outstanding. Foreign exchange translation effects of $8.2 billion for the stronger U.S. currency reduced equity, while a $3.6 billion change in the funded status of the postretirement benefits reserves increased equity.

During 2015, Exxon Mobil Corporation purchased 48 million shares of its common stock for the treasury at a gross cost of $4.0 billion. These purchases were to reduce the number of shares outstanding and to offset shares issued in conjunction with company benefit plans and programs. Shares outstanding were reduced by 1.1 percent from 4,201 million to 4,156 million at the end of 2015. Purchases were made in both the open market and through negotiated transactions. Purchases may be increased, decreased or discontinued at any time without prior notice.

2014

Cash used in financing activities was $17.9 billion in 2014, $2.4 billion higher than 2013. Dividend payments on common shares increased to $2.70 per share from $2.46 per share and totaled $11.6 billion, a pay-out of 36 percent of net income. During the first quarter of 2014, the Corporation issued $5.5 billion of long-term debt. Total debt increased $6.4 billion to $29.1 billion at year-end.

ExxonMobil share of equity increased $0.4 billion to $174.4 billion. The addition to equity for earnings was $32.5 billion. This was offset by reductions for distributions to ExxonMobil shareholders of $23.6 billion, composed of $11.6 billion in dividends and $12.0 billion of share purchases of ExxonMobil stock to reduce shares outstanding. Foreign exchange translation effects of $5.1 billion for the stronger U.S. currency and a $3.1 billion change in the funded status of the postretirement benefits reserves also reduced equity.

During 2014, Exxon Mobil Corporation purchased 136 million shares of its common stock for the treasury at a gross cost of $13.2 billion. These purchases were to reduce the number of shares outstanding and to offset shares issued in conjunction with company benefit plans and programs. Shares outstanding were reduced by 3.1 percent from 4,335 million to 4,201 million at the end of 2014. Purchases were made in both the open market and through negotiated transactions.

Commitments

Set forth below is information about the outstanding commitments of the Corporation's consolidated subsidiaries at December 31, 2015. The table combines data from the Consolidated Balance Sheet and from individual notes to the Consolidated Financial Statements.

		Payments Due by Period			
Commitments	**Note Reference Number**	**2016**	**2017-2020**	**2021 and Beyond**	**Total**
			(millions of dollars)		
Long-term debt *(1)*	14	-	9,902	10,023	19,925
– Due in one year *(2)*	6	558	-	-	558
Asset retirement obligations *(3)*	9	871	3,760	9,073	13,704
Pension and other postretirement obligations *(4)*	17	3,495	4,104	15,567	23,166
Operating leases *(5)*	11	1,653	2,167	1,057	4,877
Unconditional purchase obligations *(6)*	16	133	493	310	936
Take-or-pay obligations *(7)*		2,997	9,463	12,410	24,870
Firm capital commitments *(8)*		10,320	4,438	441	15,199

This table excludes commodity purchase obligations (volumetric commitments but no fixed or minimum price) which are resold shortly after purchase, either in an active, highly liquid market or under long-term, unconditional sales contracts with similar pricing terms. Examples include long-term, noncancelable LNG and natural gas purchase commitments and commitments to purchase refinery products at market prices. Inclusion of such commitments would not be meaningful in assessing liquidity and cash flow, because these purchases will be offset in the same periods by cash received from the related sales transactions. The table also excludes unrecognized tax benefits totaling $9.4 billion as of December 31, 2015, because the Corporation is unable to make reasonably reliable estimates of the timing of cash settlements with the respective taxing authorities. Further details on the unrecognized tax benefits can be found in "Note 19: Income, Sales-Based and Other Taxes."

Notes:

(1) Includes capitalized lease obligations of $1,238 million.

(2) The amount due in one year is included in notes and loans payable of $18,762 million.

(3) The fair value of asset retirement obligations, primarily upstream asset removal costs at the completion of field life.

(4) The amount by which the benefit obligations exceeded the fair value of fund assets for certain U.S. and non-U.S. pension and other postretirement plans at year end. The payments by period include expected contributions to funded pension plans in 2016 and estimated benefit payments for unfunded plans in all years.

(5) Minimum commitments for operating leases, shown on an undiscounted basis, cover drilling equipment, tankers, service stations and other properties. Total includes $1,621 million related to drilling rigs and related equipment.

(6) Unconditional purchase obligations (UPOs) are those long-term commitments that are noncancelable or cancelable only under certain conditions, and that third parties have used to secure financing for the facilities that will provide the contracted goods or services. The undiscounted obligations of $936 million mainly pertain to pipeline throughput agreements and include $411 million of obligations to equity companies.

(7) Take-or-pay obligations are noncancelable, long-term commitments for goods and services other than UPOs. The undiscounted obligations of $24,870 million mainly pertain to pipeline, manufacturing supply and terminal agreements.

(8) Firm commitments related to capital projects, shown on an undiscounted basis, totaled approximately $15.2 billion. These commitments were primarily associated with Upstream projects outside the U.S., of which $8.0 billion was associated with projects in Africa, United Arab Emirates, Canada, Malaysia, Kazakhstan and Australia. The Corporation expects to fund the majority of these projects with internally generated funds, supplemented by long-term and short-term debt.

Guarantees

The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2015, for guarantees relating to notes, loans and performance under contracts (Note 16). Where guarantees for environmental remediation and other similar matters do not include a stated cap, the amounts reflect management's estimate of the maximum potential exposure. These guarantees are not reasonably likely to have a material effect on the Corporation's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Financial Strength

On December 31, 2015, the Corporation's unused short-term committed lines of credit totaled approximately $6.0 billion (Note 6) and unused long-term committed lines of credit totaled approximately $0.4 billion (Note 14). The table below shows the Corporation's fixed-charge coverage and consolidated debt-to-capital ratios. The data demonstrate the Corporation's creditworthiness.

	2015	2014	2013
Fixed-charge coverage ratio (times)	17.6	46.9	55.7
Debt to capital (percent)	18.0	13.9	11.2
Net debt to capital (percent)	16.5	11.9	9.1

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

Litigation and Other Contingencies

As discussed in Note 16, a variety of claims have been made against ExxonMobil and certain of its consolidated subsidiaries in a number of pending lawsuits. Based on a consideration of all relevant facts and circumstances, the Corporation does not believe the ultimate outcome of any currently pending lawsuit against ExxonMobil will have a material adverse effect upon the Corporation's operations, financial condition, or financial statements taken as a whole. There are no events or uncertainties beyond those already included in reported financial information that would indicate a material change in future operating results or financial condition. Refer to Note 16 for additional information on legal proceedings and other contingencies.

CAPITAL AND EXPLORATION EXPENDITURES

	2015			2014		
	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total
	(millions of dollars)					
Upstream *(1)*	7,822	17,585	25,407	9,401	23,326	32,727
Downstream	1,039	1,574	2,613	1,310	1,724	3,034
Chemical	1,945	898	2,843	1,690	1,051	2,741
Other	188	-	188	35	-	35
Total	10,994	20,057	31,051	12,436	26,101	38,537

(1) Exploration expenses included.

Capital and exploration expenditures in 2015 were $31.1 billion, as the Corporation continued to pursue opportunities to find and produce new supplies of oil and natural gas to meet global demand for energy. The Corporation anticipates an investment level of $23.2 billion in 2016. Actual spending could vary depending on the progress of individual projects and property acquisitions.

Upstream spending of $25.4 billion in 2015 was down 22 percent from 2014, reflecting key project start-ups and capital efficiencies. Investments in 2015 included projects in the U.S. Gulf of Mexico and Alaska, U.S. onshore drilling and continued progress on world-class projects in Canada and Australia. The majority of expenditures are on development projects, which typically take two to four years from the time of recording proved undeveloped reserves to the start of production. The percentage of proved developed reserves was 73 percent of total proved reserves at year-end 2015, and has been over 60 percent for the last ten years.

Capital investments in the Downstream totaled $2.6 billion in 2015, a decrease of $0.4 billion from 2014, mainly reflecting lower refining project spending. The Chemical capital expenditures of $2.8 billion increased $0.1 billion from 2014 with higher investments in the U.S.

TAXES

	2015	2014	2013
		(millions of dollars)	
Income taxes	5,415	18,015	24,263
Effective income tax rate	*34%*	*41%*	*48%*
Sales-based taxes	22,678	29,342	30,589
All other taxes and duties	29,790	35,515	36,396
Total	57,883	82,872	91,248

2015

Income, sales-based and all other taxes and duties totaled $57.9 billion in 2015, a decrease of $25.0 billion or 30 percent from 2014. Income tax expense, both current and deferred, was $5.4 billion, $12.6 billion lower than 2014, as a result of lower earnings and a lower effective tax rate. The effective tax rate was 34 percent compared to 41 percent in the prior year due primarily to a lower share of earnings in higher tax jurisdictions. Sales-based and all other taxes and duties of $52.5 billion in 2015 decreased $12.4 billion as a result of lower sales realizations.

2014

Income, sales-based and all other taxes and duties totaled $82.9 billion in 2014, a decrease of $8.4 billion or 9 percent from 2013. Income tax expense, both current and deferred, was $18.0 billion, $6.2 billion lower than 2013, as a result of a lower effective tax rate. The effective tax rate was 41 percent compared to 48 percent in the prior year due primarily to impacts related to the Corporation's asset management program and favorable U.S. deferred tax items. Sales-based and all other taxes and duties of $64.9 billion in 2014 decreased $2.1 billion.

ENVIRONMENTAL MATTERS

Environmental Expenditures

	2015	2014
	(millions of dollars)	
Capital expenditures	1,869	2,666
Other expenditures	3,777	3,522
Total	5,646	6,188

Throughout ExxonMobil's businesses, new and ongoing measures are taken to prevent and minimize the impact of our operations on air, water and ground. These include a significant investment in refining infrastructure and technology to manufacture clean fuels, as well as projects to monitor and reduce nitrogen oxide, sulfur oxide and greenhouse gas emissions, and expenditures for asset retirement obligations. Using definitions and guidelines established by the American Petroleum Institute, ExxonMobil's 2015 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were $5.6 billion, of which $3.8 billion were included in expenses with the remainder in capital expenditures. The total cost for such activities is expected to decrease to approximately $5 billion in 2016 and 2017, mainly reflecting lower project activity in Canada. Capital expenditures are expected to account for approximately 30 percent of the total.

Environmental Liabilities

The Corporation accrues environmental liabilities when it is probable that obligations have been incurred and the amounts can be reasonably estimated. This policy applies to assets or businesses currently owned or previously disposed. ExxonMobil has accrued liabilities for probable environmental remediation obligations at various sites, including multiparty sites where the U.S. Environmental Protection Agency has identified ExxonMobil as one of the potentially responsible parties. The involvement of other financially responsible companies at these multiparty sites could mitigate ExxonMobil's actual joint and several liability exposure. At present, no individual site is expected to have losses material to ExxonMobil's operations or financial condition. Consolidated company provisions made in 2015 for environmental liabilities were $371 million ($780 million in 2014) and the balance sheet reflects accumulated liabilities of $837 million as of December 31, 2015, and $1,066 million as of December 31, 2014.

MARKET RISKS, INFLATION AND OTHER UNCERTAINTIES

Worldwide Average Realizations *(1)*	2015	2014	2013
Crude oil and NGL ($/barrel)	44.77	87.42	97.48
Natural gas ($/kcf)	2.95	4.68	4.60

(1) Consolidated subsidiaries.

Crude oil, natural gas, petroleum product and chemical prices have fluctuated in response to changing market forces. The impacts of these price fluctuations on earnings from Upstream, Downstream and Chemical operations have varied. In the Upstream, a $1 per barrel change in the weighted-average realized price of oil would have approximately a $375 million annual after-tax effect on Upstream consolidated plus equity company earnings. Similarly, a $0.10 per kcf change in the worldwide average gas realization would have approximately a $150 million annual after-tax effect on Upstream consolidated plus equity company earnings. For any given period, the extent of actual benefit or detriment will be dependent on the price movements of individual types of crude oil, taxes and other government take impacts, price adjustment lags in long-term gas contracts, and crude and gas production volumes. Accordingly, changes in benchmark prices for crude oil and natural gas only provide broad indicators of changes in the earnings experienced in any particular period.

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

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

In general, segment results are not dependent on the ability to sell and/or purchase products to/from other segments. Instead, where such sales take place, they are the result of efficiencies and competitive advantages of integrated refinery/chemical complexes. Additionally, intersegment sales are at market-based prices. The products bought and sold between segments can also be acquired in worldwide markets that have substantial liquidity, capacity and transportation capabilities. About 35 percent of the Corporation's intersegment sales represent Upstream production sold to the Downstream. Other intersegment sales include those between refineries and chemical plants related to raw materials, feedstocks and finished products.

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

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

Risk Management

The Corporation's size, strong capital structure, geographic diversity and the complementary nature of the Upstream, Downstream and Chemical businesses reduce the Corporation's enterprise-wide risk from changes in interest rates, currency rates and commodity prices. As a result, the Corporation makes limited use of derivative instruments to mitigate the impact of such changes. With respect to derivatives activities, the Corporation believes that there are no material market or credit risks to the Corporation's financial position, results of operations or liquidity as a result of the derivatives described in Note 13. The Corporation does not engage in speculative derivative activities or derivative trading activities nor does it use derivatives with leveraged features. Credit risk associated with the Corporation's derivative position is mitigated by several factors, including the use of derivative clearing exchanges and the quality of and financial limits placed on derivative counterparties. The Corporation maintains a system of controls that includes the authorization, reporting and monitoring of derivative activity.

The Corporation is exposed to changes in interest rates, primarily on its short-term debt and the portion of long-term debt that carries floating interest rates. The impact of a 100-basis-point change in interest rates affecting the Corporation's debt would not be material to earnings, cash flow or fair value. The Corporation has access to significant capacity of long-term and short-term liquidity. Internally generated funds are expected to cover the majority of financial requirements, supplemented by long-term and short-term debt. Some joint-venture partners are dependent on the credit markets, and their funding ability may impact the development pace of joint-venture projects.

The Corporation conducts business in many foreign currencies and is subject to exchange rate risk on cash flows related to sales, expenses, financing and investment transactions. The impacts of fluctuations in exchange rates on ExxonMobil's geographically and functionally diverse operations are varied and often offsetting in amount. The Corporation makes limited use of currency exchange contracts to mitigate the impact of changes in currency values, and exposures related to the Corporation's limited use of the currency exchange contracts are not material.

Inflation and Other Uncertainties

The general rate of inflation in many major countries of operation has remained moderate over the past few years, and the associated impact on non-energy costs has generally been mitigated by cost reductions from efficiency and productivity improvements. Beginning several years ago, an extended period of increased demand for certain services and materials resulted in higher operating and capital costs. More recently, multiple market changes, including general commodity price decreases, lower oil prices and reduced upstream industry activity, have contributed to lower prices for oilfield services and materials. The Corporation works to minimize costs in all commodity price environments through its economies of scale in global procurement and its efficient project management practices.

RECENTLY ISSUED ACCOUNTING STANDARDS

In May 2014, the Financial Accounting Standards Board issued a new standard, *Revenue from Contracts with Customers*. The standard establishes a single revenue recognition model for all contracts with customers, eliminates industry specific requirements, and expands disclosure requirements. The standard is required to be adopted beginning January 1, 2018.

“Sales and Other Operating Revenue” on the Consolidated Statement of Income includes sales, excise and value-added taxes on sales transactions. When the Corporation adopts the standard, revenue will exclude sales-based taxes collected on behalf of third parties. This change in reporting will not impact earnings.

The Corporation continues to evaluate other areas of the standard and its effect on the Corporation’s financial statements.

CRITICAL ACCOUNTING ESTIMATES

The Corporation’s accounting and financial reporting fairly reflect its straightforward business model involving the extracting, refining and marketing of hydrocarbons and hydrocarbon-based products. The preparation of financial statements in conformity with U.S. Generally Accepted Accounting Principles (GAAP) requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. The Corporation’s accounting policies are summarized in Note 1.

Oil and Gas Reserves

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

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

The estimation of proved reserves is an ongoing process based on rigorous technical evaluations, commercial and market assessment, and detailed analysis of well information such as flow rates and reservoir pressure declines. The estimation of proved reserves is controlled by the Corporation through long-standing approval guidelines. Reserve changes are made within a well-established, disciplined process driven by senior level geoscience and engineering professionals, assisted by the Reserves Technical Oversight group which has significant technical experience, culminating in reviews with and approval by senior management. Notably, the Corporation does not use specific quantitative reserve targets to determine compensation. Key features of the reserve estimation process are covered in Disclosure of Reserves in Item 2 of ExxonMobil’s 2015 Form 10-K.

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

Proved reserves can be further subdivided into developed and undeveloped reserves. The percentage of proved developed reserves was 73 percent of total proved reserves at year-end 2015 (including both consolidated and equity company reserves), and has been over 60 percent for the last ten years.

Revisions can include upward or downward changes in previously estimated volumes of proved reserves for existing fields due to the evaluation or re-evaluation of (1) already available geologic, reservoir or production data, (2) new geologic, reservoir or production data or (3) changes in prices and year-end costs that are used in the estimation of reserves. Revisions can also result from significant changes in development strategy or production equipment/facility capacity.

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

Impact of Oil and Gas Reserves on Depreciation. The calculation of unit-of-production depreciation is a critical accounting estimate that measures the depreciation of upstream assets. It is the ratio of actual volumes produced to total proved reserves or proved developed reserves (those proved reserves recoverable through existing wells with existing equipment and operating methods), applied to the asset cost. In the event that the unit-of-production method does not result in an equitable allocation of cost over the economic life of an upstream asset, an alternative such as the straight-line method is used. The volumes produced and asset cost are known and, while proved reserves have a high probability of recoverability they are based on estimates that are subject to some variability. While the revisions the Corporation has made in the past are an indicator of variability, they have had a very small impact on the unit-of-production rates because they have been small compared to the large reserves base.

Impact of Oil and Gas Reserves, Prices and Margins on Testing for Impairment. The Corporation performs impairment assessments whenever events or circumstances indicate that the carrying amounts of its long-lived assets (or group of assets) may not be recoverable through future operations or disposition. Assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets for this assessment.

Potential trigger events for impairment evaluation include:

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

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

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

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

An asset group would be impaired if its undiscounted cash flows were less than the asset's carrying value. Impairments are measured by the amount by which the carrying value exceeds fair value. Cash flow estimates for impairment testing exclude the effects of derivative instruments.

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

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

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

Inventories

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

Asset Retirement Obligations

The Corporation incurs retirement obligations for certain assets. The fair values of these obligations are recorded as liabilities on a discounted basis, which is typically at the time the assets are installed. In the estimation of fair value, the Corporation uses assumptions and judgments regarding such factors as the existence of a legal obligation for an asset retirement obligation; technical assessments of the assets; estimated amounts and timing of settlements; discount rates; and inflation rates. Asset retirement obligations are disclosed in Note 9 to the financial statements.

Suspended Exploratory Well Costs

The Corporation continues capitalization of exploratory well costs when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the Corporation is making sufficient progress assessing the reserves and the economic and operating viability of the project. Exploratory well costs not meeting these criteria are charged to expense. The facts and circumstances that support continued capitalization of suspended wells at year-end are disclosed in Note 10 to the financial statements.

Consolidations

The Consolidated Financial Statements include the accounts of those subsidiaries that the Corporation controls. They also include the Corporation's share of the undivided interest in certain upstream assets, liabilities, revenues and expenses. Amounts representing the Corporation's interest in the underlying net assets of other significant entities that it does not control, but over which it exercises significant influence, are accounted for using the equity method of accounting.

Investments in companies that are partially owned by the Corporation are integral to the Corporation's operations. In some cases they serve to balance worldwide risks, and in others they provide the only available means of entry into a particular market or area of interest. The other parties, who also have an equity interest in these companies, are either independent third parties or host governments that share in the business results according to their ownership. The Corporation does not invest in these companies in order to remove liabilities from its balance sheet. In fact, the Corporation has long been on record supporting an alternative accounting method that would require each investor to consolidate its share of all assets and liabilities in these partially-owned companies rather than only its interest in net equity. This method of accounting for investments in partially-owned companies is not permitted by U.S. GAAP except where the investments are in the direct ownership of a share of upstream assets and liabilities. However, for purposes of calculating return on average capital employed, which is not covered by U.S. GAAP standards, the Corporation includes its share of debt of these partially-owned companies in the determination of average capital employed.

Pension Benefits

The Corporation and its affiliates sponsor about 100 defined benefit (pension) plans in over 40 countries. The Pension and Other Postretirement Benefits footnote (Note 17) provides details on pension obligations, fund assets and pension expense.

Some of these plans (primarily non-U.S.) provide pension benefits that are paid directly by their sponsoring affiliates out of corporate cash flow rather than a separate pension fund because tax conventions and regulatory practices do not encourage advance funding. Book reserves are established for these plans. The portion of the pension cost attributable to employee service is expensed as services are rendered. The portion attributable to the increase in pension obligations due to the passage of time is expensed over the term of the obligations, which ends when all benefits are paid. The primary difference in pension expense for unfunded versus funded plans is that pension expense for funded plans also includes a credit for the expected long-term return on fund assets.

For funded plans, including those in the U.S., pension obligations are financed in advance through segregated assets or insurance arrangements. These plans are managed in compliance with the requirements of governmental authorities and meet or exceed required funding levels as measured by relevant actuarial and government standards at the mandated measurement dates. In determining liabilities and required contributions, these standards often require approaches and assumptions that differ from those used for accounting purposes.

The Corporation will continue to make contributions to these funded plans as necessary. All defined-benefit pension obligations, regardless of the funding status of the underlying plans, are fully supported by the financial strength of the Corporation or the respective sponsoring affiliate.

Pension accounting requires explicit assumptions regarding, among others, the long-term expected earnings rate on fund assets, the discount rate for the benefit obligations and the long-term rate for future salary increases. Pension assumptions are reviewed annually by outside actuaries and senior management. These assumptions are adjusted as appropriate to reflect changes in market rates and outlook. The long-term expected earnings rate on U.S. pension plan assets in 2015 was 7.00 percent. The 10-year and 20-year actual returns on U.S. pension plan assets were 5 percent and 8 percent, respectively. The Corporation establishes the long-term expected rate of return by developing a forward-looking, long-term return assumption for each pension fund asset class, taking into account factors such as the expected real return for the specific asset class and inflation. A single, long-term rate of return is then calculated as the weighted average of the target asset allocation percentages and the long-term return assumption for each asset class. A worldwide reduction of 0.5 percent in the long-term rate of return on assets would increase annual pension expense by approximately $150 million before tax.

Differences between actual returns on fund assets and the long-term expected return are not recognized in pension expense in the year that the difference occurs. Such differences are deferred, along with other actuarial gains and losses, and are amortized into pension expense over the expected remaining service life of employees.

Litigation Contingencies

A variety of claims have been made against the Corporation and certain of its consolidated subsidiaries in a number of pending lawsuits. Management has regular litigation reviews, including updates from corporate and outside counsel, to assess the need for accounting recognition or disclosure of these contingencies. The status of significant claims is summarized in Note 16.

The Corporation accrues an undiscounted liability for those contingencies where the incurrence of a loss is probable, and the amount can be reasonably estimated. These amounts are not reduced by amounts that may be recovered under insurance or claims against third parties, but undiscounted receivables from insurers or other third parties may be accrued separately. The Corporation revises such accruals in light of new information. For contingencies where an unfavorable outcome is reasonably possible and which are significant, the Corporation discloses the nature of the contingency and, where feasible, an estimate of the possible loss. For purposes of our litigation contingency disclosures, "significant" includes material matters as well as other items which management believes should be disclosed.

Management judgment is required related to contingent liabilities and the outcome of litigation because both are difficult to predict. However, the Corporation has been successful in defending litigation in the past. Payments have not had a material adverse effect on operations or financial condition. In the Corporation's experience, large claims often do not result in large awards. Large awards are often reversed or substantially reduced as a result of appeal or settlement.

Tax Contingencies

The Corporation is subject to income taxation in many jurisdictions around the world. Significant management judgment is required in the accounting for income tax contingencies and tax disputes because the outcomes are often difficult to predict.

The benefits of uncertain tax positions that the Corporation has taken or expects to take in its income tax returns are recognized in the financial statements if management concludes that it is more likely than not that the position will be sustained with the tax authorities. For a position that is likely to be sustained, the benefit recognized in the financial statements is measured at the largest amount that is greater than 50 percent likely of being realized. A reserve is established for the difference between a position taken or expected to be taken in an income tax return and the amount recognized in the financial statements. The Corporation's unrecognized tax benefits and a description of open tax years are summarized in Note 19.

Foreign Currency Translation

The method of translating the foreign currency financial statements of the Corporation's international subsidiaries into U.S. dollars is prescribed by GAAP. Under these principles, it is necessary to select the functional currency of these subsidiaries. The functional currency is the currency of the primary economic environment in which the subsidiary operates. Management selects the functional currency after evaluating this economic environment.

Factors considered by management when determining the functional currency for a subsidiary include the currency used for cash flows related to individual assets and liabilities; the responsiveness of sales prices to changes in exchange rates; the history of inflation in the country; whether sales are into local markets or exported; the currency used to acquire raw materials, labor, services and supplies; sources of financing; and significance of intercompany transactions.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management, including the Corporation's Chief Executive Officer, Principal Financial Officer, and Principal Accounting Officer, is responsible for establishing and maintaining adequate internal control over the Corporation's financial reporting. Management conducted an evaluation of the effectiveness of internal control over financial reporting based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Exxon Mobil Corporation's internal control over financial reporting was effective as of December 31, 2015.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2015, as stated in their report included in the Financial Section of this report.

Rex W. Tillerson
Chief Executive Officer

Andrew P. Swiger
Senior Vice President
(Principal Financial Officer)

David S. Rosenthal
Vice President and Controller
(Principal Accounting Officer)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

pwc

To the Shareholders of Exxon Mobil Corporation:

In our opinion, the accompanying Consolidated Balance Sheets and the related Consolidated Statements of Income, Comprehensive Income, Changes in Equity, and Cash Flows present fairly, in all material respects, the financial position of Exxon Mobil Corporation and its subsidiaries at December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Corporation's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Corporation's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

PricewaterhouseCoopers LLP

Dallas, Texas
February 24, 2016

CONSOLIDATED STATEMENT OF INCOME

	Note Reference Number	2015	2014	2013
			(millions of dollars)	
Revenues and other income				
Sales and other operating revenue *(1)*		259,488	394,105	420,836
Income from equity affiliates	7	7,644	13,323	13,927
Other income		1,750	4,511	3,492
Total revenues and other income		268,882	411,939	438,255
Costs and other deductions				
Crude oil and product purchases		130,003	225,972	244,156
Production and manufacturing expenses		35,587	40,859	40,525
Selling, general and administrative expenses		11,501	12,598	12,877
Depreciation and depletion		18,048	17,297	17,182
Exploration expenses, including dry holes		1,523	1,669	1,976
Interest expense		311	286	9
Sales-based taxes *(1)*	19	22,678	29,342	30,589
Other taxes and duties	19	27,265	32,286	33,230
Total costs and other deductions		246,916	360,309	380,544
Income before income taxes		21,966	51,630	57,711
Income taxes	19	5,415	18,015	24,263
Net income including noncontrolling interests		16,551	33,615	33,448
Net income attributable to noncontrolling interests		401	1,095	868
Net income attributable to ExxonMobil		16,150	32,520	32,580
Earnings per common share *(dollars)*	12	3.85	7.60	7.37
Earnings per common share - assuming dilution *(dollars)*	12	3.85	7.60	7.37

(1) Sales and other operating revenue includes sales-based taxes of $22,678 million for 2015, $29,342 million for 2014 and $30,589 million for 2013.

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

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	2015	2014	2013
		(millions of dollars)	
Net income including noncontrolling interests	16,551	33,615	33,448
Other comprehensive income (net of income taxes)			
Foreign exchange translation adjustment	(9,303)	(5,847)	(3,620)
Adjustment for foreign exchange translation (gain)/loss included in net income	(14)	152	(23)
Postretirement benefits reserves adjustment (excluding amortization)	2,358	(4,262)	3,174
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	1,448	1,111	1,820
Unrealized change in fair value of stock investments	33	(63)	-
Realized (gain)/loss from stock investments included in net income	27	3	-
Total other comprehensive income	(5,451)	(8,906)	1,351
Comprehensive income including noncontrolling interests	11,100	24,709	34,799
Comprehensive income attributable to noncontrolling interests	(496)	421	760
Comprehensive income attributable to ExxonMobil	11,596	24,288	34,039

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

CONSOLIDATED BALANCE SHEET

	Note Reference Number	Dec. 31 2015	Dec. 31 2014
		(millions of dollars)	
Assets			
Current assets			
Cash and cash equivalents		3,705	4,616
Cash and cash equivalents - restricted		-	42
Notes and accounts receivable, less estimated doubtful amounts	6	19,875	28,009
Inventories			
Crude oil, products and merchandise	3	12,037	12,384
Materials and supplies		4,208	4,294
Other current assets		2,798	3,565
Total current assets		42,623	52,910
Investments, advances and long-term receivables	8	34,245	35,239
Property, plant and equipment, at cost, less accumulated depreciation and depletion	9	251,605	252,668
Other assets, including intangibles, net		8,285	8,676
Total assets		336,758	349,493
Liabilities			
Current liabilities			
Notes and loans payable	6	18,762	17,468
Accounts payable and accrued liabilities	6	32,412	42,227
Income taxes payable		2,802	4,938
Total current liabilities		53,976	64,633
Long-term debt	14	19,925	11,653
Postretirement benefits reserves	17	22,647	25,802
Deferred income tax liabilities	19	36,818	39,230
Long-term obligations to equity companies		5,417	5,325
Other long-term obligations		21,165	21,786
Total liabilities		159,948	168,429
Commitments and contingencies	16		
Equity			
Common stock without par value (9,000 million shares authorized, 8,019 million shares issued)		11,612	10,792
Earnings reinvested		412,444	408,384
Accumulated other comprehensive income		(23,511)	(18,957)
Common stock held in treasury (3,863 million shares in 2015 and 3,818 million shares in 2014)		(229,734)	(225,820)
ExxonMobil share of equity		170,811	174,399
Noncontrolling interests		5,999	6,665
Total equity		176,810	181,064
Total liabilities and equity		336,758	349,493

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

CONSOLIDATED STATEMENT OF CASH FLOWS

	Note Reference Number	2015	2014	2013
			(millions of dollars)	
Cash flows from operating activities				
Net income including noncontrolling interests		16,551	33,615	33,448
Adjustments for noncash transactions				
Depreciation and depletion		18,048	17,297	17,182
Deferred income tax charges/(credits)		(1,832)	1,540	754
Postretirement benefits expense in excess of/(less than) net payments		2,153	524	2,291
Other long-term obligation provisions in excess of/(less than) payments		(380)	1,404	(2,566)
Dividends received greater than/(less than) equity in current earnings of equity companies		(691)	(358)	3
Changes in operational working capital, excluding cash and debt				
Reduction/(increase) - Notes and accounts receivable		4,692	3,118	(305)
- Inventories		(379)	(1,343)	(1,812)
- Other current assets		45	(68)	(105)
Increase/(reduction) - Accounts and other payables		(7,471)	(6,639)	(2,498)
Net (gain) on asset sales	5	(226)	(3,151)	(1,828)
All other items - net	5	(166)	(823)	350
Net cash provided by operating activities		30,344	45,116	44,914
Cash flows from investing activities				
Additions to property, plant and equipment	5	(26,490)	(32,952)	(33,669)
Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments	5	2,389	4,035	2,707
Decrease/(increase) in restricted cash and cash equivalents		42	227	72
Additional investments and advances		(607)	(1,631)	(4,435)
Collection of advances		842	3,346	1,124
Net cash used in investing activities		(23,824)	(26,975)	(34,201)
Cash flows from financing activities				
Additions to long-term debt	5	8,028	5,731	345
Reductions in long-term debt		(26)	(69)	(13)
Additions to short-term debt		-	-	16
Reductions in short-term debt		(506)	(745)	(756)
Additions/(reductions) in commercial paper, and debt with three months or less maturity	5	1,759	2,049	12,012
Cash dividends to ExxonMobil shareholders		(12,090)	(11,568)	(10,875)
Cash dividends to noncontrolling interests		(170)	(248)	(304)
Changes in noncontrolling interests		-	-	(1)
Tax benefits related to stock-based awards		2	115	48
Common stock acquired		(4,039)	(13,183)	(15,998)
Common stock sold		5	30	50
Net cash used in financing activities		(7,037)	(17,888)	(15,476)
Effects of exchange rate changes on cash		(394)	(281)	(175)
Increase/(decrease) in cash and cash equivalents		(911)	(28)	(4,938)
Cash and cash equivalents at beginning of year		4,616	4,644	9,582
Cash and cash equivalents at end of year		3,705	4,616	4,644

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

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	ExxonMobil Share of Equity						
	Common Stock	Earnings Reinvested	Accumulated Other Comprehensive Income	Common Stock Held in Treasury	ExxonMobil Share of Equity	Non-controlling Interests	Total Equity
				(millions of dollars)			
Balance as of December 31, 2012	9,653	365,727	(12,184)	(197,333)	165,863	5,797	171,660
Amortization of stock-based awards	761	-	-	-	761	-	761
Tax benefits related to stock-based awards	162	-	-	-	162	-	162
Other	(499)	-	-	-	(499)	240	(259)
Net income for the year	-	32,580	-	-	32,580	868	33,448
Dividends - common shares	-	(10,875)	-	-	(10,875)	(304)	(11,179)
Other comprehensive income	-	-	1,459	-	1,459	(108)	1,351
Acquisitions, at cost	-	-	-	(15,998)	(15,998)	(1)	(15,999)
Dispositions	-	-	-	550	550	-	550
Balance as of December 31, 2013	10,077	387,432	(10,725)	(212,781)	174,003	6,492	180,495
Amortization of stock-based awards	780	-	-	-	780	-	780
Tax benefits related to stock-based awards	49	-	-	-	49	-	49
Other	(114)	-	-	-	(114)	-	(114)
Net income for the year	-	32,520	-	-	32,520	1,095	33,615
Dividends - common shares	-	(11,568)	-	-	(11,568)	(248)	(11,816)
Other comprehensive income	-	-	(8,232)	-	(8,232)	(674)	(8,906)
Acquisitions, at cost	-	-	-	(13,183)	(13,183)	-	(13,183)
Dispositions	-	-	-	144	144	-	144
Balance as of December 31, 2014	10,792	408,384	(18,957)	(225,820)	174,399	6,665	181,064
Amortization of stock-based awards	828	-	-	-	828	-	828
Tax benefits related to stock-based awards	116	-	-	-	116	-	116
Other	(124)	-	-	-	(124)	-	(124)
Net income for the year	-	16,150	-	-	16,150	401	16,551
Dividends - common shares	-	(12,090)	-	-	(12,090)	(170)	(12,260)
Other comprehensive income	-	-	(4,554)	-	(4,554)	(897)	(5,451)
Acquisitions, at cost	-	-	-	(4,039)	(4,039)	-	(4,039)
Dispositions	-	-	-	125	125	-	125
Balance as of December 31, 2015	11,612	412,444	(23,511)	(229,734)	170,811	5,999	176,810

Common Stock Share Activity	Issued	Held in Treasury	Outstanding
		(millions of shares)	
Balance as of December 31, 2012	8,019	(3,517)	4,502
Acquisitions	-	(177)	(177)
Dispositions	-	10	10
Balance as of December 31, 2013	8,019	(3,684)	4,335
Acquisitions	-	(136)	(136)
Dispositions	-	2	2
Balance as of December 31, 2014	8,019	(3,818)	4,201
Acquisitions	-	(48)	(48)
Dispositions	-	3	3
Balance as of December 31, 2015	8,019	(3,863)	4,156

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The accompanying consolidated financial statements and the supporting and supplemental material are the responsibility of the management of Exxon Mobil Corporation.

The Corporation's principal business is energy, involving the worldwide exploration, production, transportation and sale of crude oil and natural gas (Upstream) and the manufacture, transportation and sale of petroleum products (Downstream). The Corporation is also a major worldwide manufacturer and marketer of petrochemicals (Chemical).

The preparation of financial statements in conformity with U.S. Generally Accepted Accounting Principles (GAAP) requires management to make estimates that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Actual results could differ from these estimates. Prior years' data has been reclassified in certain cases to conform to the 2015 presentation basis.

1. Summary of Accounting Policies

Principles of Consolidation. The Consolidated Financial Statements include the accounts of subsidiaries the Corporation controls. They also include the Corporation's share of the undivided interest in certain upstream assets, liabilities, revenues and expenses.

Amounts representing the Corporation's interest in entities that it does not control, but over which it exercises significant influence, are included in "Investments, advances and long-term receivables." The Corporation's share of the net income of these companies is included in the Consolidated Statement of Income caption "Income from equity affiliates."

Majority ownership is normally the indicator of control that is the basis on which subsidiaries are consolidated. However, certain factors may indicate that a majority-owned investment is not controlled and therefore should be accounted for using the equity method of accounting. These factors occur where the minority shareholders are granted by law or by contract substantive participating rights. These include the right to approve operating policies, expense budgets, financing and investment plans, and management compensation and succession plans.

The Corporation's share of the cumulative foreign exchange translation adjustment for equity method investments is reported in Accumulated Other Comprehensive Income.

Evidence of loss in value that might indicate impairment of investments in companies accounted for on the equity method is assessed to determine if such evidence represents a loss in value of the Corporation's investment that is other than temporary. Examples of key indicators include a history of operating losses, negative earnings and cash flow outlook, significant downward revisions to oil and gas reserves, and the financial condition and prospects for the investee's business segment or geographic region. If evidence of an other than temporary loss in fair value below carrying amount is determined, an impairment is recognized. In the absence of market prices for the investment, discounted cash flows are used to assess fair value.

Revenue Recognition. The Corporation generally sells crude oil, natural gas and petroleum and chemical products under short-term agreements at prevailing market prices. In some cases (e.g., natural gas), products may be sold under long-term agreements, with periodic price adjustments. Revenues are recognized when the products are delivered, which occurs when the customer has taken title and has assumed the risks and rewards of ownership, prices are fixed or determinable and collectibility is reasonably assured.

Revenues from the production of natural gas properties in which the Corporation has an interest with other producers are recognized on the basis of the Corporation's net working interest. Differences between actual production and net working interest volumes are not significant.

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

Sales-Based Taxes. The Corporation reports sales, excise and value-added taxes on sales transactions on a gross basis in the Consolidated Statement of Income (included in both revenues and costs).

Derivative Instruments. The Corporation makes limited use of derivative instruments. The Corporation does not engage in speculative derivative activities or derivative trading activities, nor does it use derivatives with leveraged features. When the Corporation does enter into derivative transactions, it is to offset exposures associated with interest rates, foreign currency exchange rates and hydrocarbon prices that arise from existing assets, liabilities and forecasted transactions.

The gains and losses resulting from changes in the fair value of derivatives are recorded in income. In some cases, the Corporation designates derivatives as fair value hedges, in which case the gains and losses are offset in income by the gains and losses arising from changes in the fair value of the underlying hedged item.

Fair Value. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. Hierarchy Levels 1, 2 and 3 are terms for the priority of inputs to valuation techniques used to measure fair value. Hierarchy Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Hierarchy

Level 2 inputs are inputs other than quoted prices included within Level 1 that are directly or indirectly observable for the asset or liability. Hierarchy Level 3 inputs are inputs that are not observable in the market.

Inventories. Crude oil, products and merchandise inventories are carried at the lower of current market value or cost (generally determined under the last-in, first-out method – LIFO). Inventory costs include expenditures and other charges (including depreciation) directly and indirectly incurred in bringing the inventory to its existing condition and location. Selling expenses and general and administrative expenses are reported as period costs and excluded from inventory cost. Inventories of materials and supplies are valued at cost or less.

Property, Plant and Equipment. Depreciation, depletion and amortization, based on cost less estimated salvage value of the asset, are primarily determined under either the unit-of-production method or the straight-line method, which is based on estimated asset service life taking obsolescence into consideration. Maintenance and repairs, including planned major maintenance, are expensed as incurred. Major renewals and improvements are capitalized and the assets replaced are retired.

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

Acquisition costs of proved properties are amortized using a unit-of-production method, computed on the basis of total proved oil and gas reserves. Capitalized exploratory drilling and development costs associated with productive depletable extractive properties are amortized using unit-of-production rates based on the amount of proved developed reserves of oil, gas and other minerals that are estimated to be recoverable from existing facilities using current operating methods. Under the unit-of-production method, oil and gas volumes are considered produced once they have been measured through meters at custody transfer or sales transaction points at the outlet valve on the lease or field storage tank. In the event that the unit-of-production method does not result in an equitable allocation of cost over the economic life of an upstream asset, an alternative such as the straight-line method is used.

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

The Corporation performs impairment assessments whenever events or circumstances indicate that the carrying amounts of its long-lived assets (or group of assets) may not be recoverable through future operations or disposition. Assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets for this assessment.

Potential trigger events for impairment evaluation include:

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

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

In general, the Corporation does not view temporarily low prices or margins as a trigger event for conducting impairment tests. The markets for crude oil, natural gas and petroleum products, have a history of significant price volatility. Although prices will occasionally drop significantly, industry prices over the long term will continue to be driven by market supply and demand.

On the supply side, industry production from mature fields is declining, but this is being offset by production from new discoveries and field developments. OPEC production policies also have an impact on world oil supplies. The demand side is largely a function of global economic growth. The relative growth/decline in supply versus demand will determine industry prices over the long term, and these cannot be accurately predicted.

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

An asset group would be impaired if its undiscounted cash flows were less than the asset's carrying value. Impairments are measured by the amount by which the carrying value exceeds fair value. Cash flow estimates for impairment testing exclude the effects of derivative instruments.

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

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

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

Interest costs incurred to finance expenditures during the construction phase of multiyear projects are capitalized as part of the historical cost of acquiring the constructed assets. The project construction phase commences with the development of the detailed engineering design and ends when the constructed assets are ready for their intended use. Capitalized interest costs are included in property, plant and equipment and are depreciated over the service life of the related assets.

Asset Retirement Obligations and Environmental Liabilities. The Corporation incurs retirement obligations for certain assets. The fair values of these obligations are recorded as liabilities on a discounted basis, which is typically at the time the assets are installed. The costs associated with these liabilities are capitalized as part of the related assets and depreciated. Over time, the liabilities are accreted for the change in their present value.

Liabilities for environmental costs are recorded when it is probable that obligations have been incurred and the amounts can be reasonably estimated. These liabilities are not reduced by possible recoveries from third parties and projected cash expenditures are not discounted.

Foreign Currency Translation. The Corporation selects the functional reporting currency for its international subsidiaries based on the currency of the primary economic environment in which each subsidiary operates.

Downstream and Chemical operations primarily use the local currency. However, the U.S. dollar is used in countries with a history of high inflation (primarily in Latin America) and Singapore, which predominantly sells into the U.S. dollar export market. Upstream operations which are relatively self-contained and integrated within a particular country, such as Canada, the United Kingdom, Norway and continental Europe, use the local currency. Some Upstream operations, primarily in Asia and Africa, use the U.S. dollar because they predominantly sell crude and natural gas production into U.S. dollar-denominated markets.

For all operations, gains or losses from remeasuring foreign currency transactions into the functional currency are included in income.

Stock-Based Payments. The Corporation awards stock-based compensation to employees in the form of restricted stock and restricted stock units. Compensation expense is measured by the price of the stock at the date of grant and is recognized in income over the requisite service period.

2. Accounting Changes

The Corporation did not adopt authoritative guidance in 2015 that had a material impact on the Corporation's financial statements.

In May 2014, the Financial Accounting Standards Board issued a new standard, *Revenue from Contracts with Customers*. The standard establishes a single revenue recognition model for all contracts with customers, eliminates industry specific requirements, and expands disclosure requirements. The standard is required to be adopted beginning January 1, 2018.

"Sales and Other Operating Revenue" on the Consolidated Statement of Income includes sales, excise and value-added taxes on sales transactions. When the Corporation adopts the standard, revenue will exclude sales-based taxes collected on behalf of third parties. This change in reporting will not impact earnings.

The Corporation continues to evaluate other areas of the standard and its effect on the Corporation's financial statements.

3. Miscellaneous Financial Information

Research and development expenses totaled $1,008 million in 2015, $971 million in 2014 and $1,044 million in 2013.

Net income included before-tax aggregate foreign exchange transaction losses of $119 million and $225 million in 2015 and 2014, respectively, and gains of $155 million in 2013.

In 2015, 2014 and 2013, net income included a loss of $186 million, and gains of $187 million and $282 million, respectively, attributable to the combined effects of LIFO inventory accumulations and drawdowns. The aggregate replacement cost of inventories was estimated to exceed their LIFO carrying values by $4.5 billion and $10.6 billion at December 31, 2015, and 2014, respectively.

Crude oil, products and merchandise as of year-end 2015 and 2014 consist of the following:

	2015	2014
	(billions of dollars)	
Crude oil	4.2	4.6
Petroleum products	4.1	4.1
Chemical products	2.7	2.9
Gas/other	1.0	0.8
Total	12.0	12.4

4. Other Comprehensive Income Information

ExxonMobil Share of Accumulated Other Comprehensive Income	Cumulative Foreign Exchange Translation Adjustment	Post-retirement Benefits Reserves Adjustment	Unrealized Change in Stock Investments	Total
		(millions of dollars)		
Balance as of December 31, 2012	2,410	(14,594)	-	(12,184)
Current period change excluding amounts reclassified from accumulated other comprehensive income	(3,233)	2,963	-	(270)
Amounts reclassified from accumulated other comprehensive income	(23)	1,752	-	1,729
Total change in accumulated other comprehensive income	(3,256)	4,715	-	1,459
Balance as of December 31, 2013	(846)	(9,879)	-	(10,725)
Balance as of December 31, 2013	(846)	(9,879)	-	(10,725)
Current period change excluding amounts reclassified from accumulated other comprehensive income	(5,258)	(4,132)	(63)	(9,453)
Amounts reclassified from accumulated other comprehensive income	152	1,066	3	1,221
Total change in accumulated other comprehensive income	(5,106)	(3,066)	(60)	(8,232)
Balance as of December 31, 2014	(5,952)	(12,945)	(60)	(18,957)
Balance as of December 31, 2014	(5,952)	(12,945)	(60)	(18,957)
Current period change excluding amounts reclassified from accumulated other comprehensive income	(8,204)	2,202	33	(5,969)
Amounts reclassified from accumulated other comprehensive income	(14)	1,402	27	1,415
Total change in accumulated other comprehensive income	(8,218)	3,604	60	(4,554)
Balance as of December 31, 2015	(14,170)	(9,341)	-	(23,511)

Amounts Reclassified Out of Accumulated Other Comprehensive Income - Before-tax Income/(Expense)	2015	2014	2013
		(millions of dollars)	
Foreign exchange translation gain/(loss) included in net income (Statement of Income line: Other income)	14	(152)	23
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs *(1)*	(2,066)	(1,571)	(2,616)
Realized change in fair value of stock investments included in net income (Statement of Income line: Other income)	(42)	(5)	-

(1) These accumulated other comprehensive income components are included in the computation of net periodic pension cost. (See Note 17 – Pension and Other Postretirement Benefits for additional details.)

Income Tax (Expense)/Credit For Components of Other Comprehensive Income	2015	2014	2013
		(millions of dollars)	
Foreign exchange translation adjustment	170	292	218
Postretirement benefits reserves adjustment (excluding amortization)	(1,192)	2,009	(1,540)
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	(618)	(460)	(796)
Unrealized change in fair value of stock investments	(17)	34	-
Realized change in fair value of stock investments included in net income	(15)	(2)	-
Total	(1,672)	1,873	(2,118)

5. Cash Flow Information

The Consolidated Statement of Cash Flows provides information about changes in cash and cash equivalents. Highly liquid investments with maturities of three months or less when acquired are classified as cash equivalents.

For 2015, the "Net (gain) on asset sales" on the Consolidated Statement of Cash Flows includes before-tax amounts from the sale of service stations in Europe, the sale of Upstream properties in the U.S., the sale of ExxonMobil's interests in Chemical and Refining joint ventures, and the pending sale of the Torrance refinery. For 2014, the amount includes before-tax gains from the sale of Hong Kong power operations, additional proceeds related to the 2013 sale of a partial interest in Iraq, the sale of Downstream affiliates in the Caribbean and the sale or exchange of Upstream properties in the U.S., Canada, and Malaysia. For 2013, the amount includes before-tax gains from the sale of a partial interest in Iraq, the sale of Downstream affiliates in the Caribbean and the sale of service stations. These net gains are reported in "Other income" on the Consolidated Statement of Income.

In 2015, the "Additions/(reductions) in commercial paper, and debt with three months or less maturity" on the Consolidated Statement of Cash Flows includes a net $358 million addition of commercial paper with maturity over three months. The gross amount issued was $8.1 billion, while the gross amount repaid was $7.7 billion.

In 2015, ExxonMobil completed an asset exchange that resulted in value received of approximately $500 million including $100 million in cash. The non-cash portion was not included in the "Sales of subsidiaries, investments, and property, plant and equipment" or the "All other items-net" lines on the Statement of Cash Flows. Capital leases of approximately $1 billion were not included in the "Additions to long-term debt" or "Additions to property, plant and equipment" lines on the Statement of Cash Flows.

In 2014, ExxonMobil completed asset exchanges, primarily non-cash transactions, of approximately $1.2 billion. This amount is not included in the "Sales of subsidiaries, investments, and property, plant and equipment" or the "Additions to property, plant and equipment" lines on the Statement of Cash Flows.

	2015	2014	2013
		(millions of dollars)	
Cash payments for interest	586	380	426
Cash payments for income taxes	7,269	18,085	25,066

6. Additional Working Capital Information

	Dec. 31 2015	Dec. 31 2014
	(millions of dollars)	
Notes and accounts receivable		
Trade, less reserves of $107 million and $113 million	13,243	18,541
Other, less reserves of $4 million and $48 million	6,632	9,468
Total	19,875	28,009
Notes and loans payable		
Bank loans	231	473
Commercial paper	17,973	16,225
Long-term debt due within one year	558	770
Total	18,762	17,468
Accounts payable and accrued liabilities		
Trade payables	18,074	25,286
Payables to equity companies	4,639	6,589
Accrued taxes other than income taxes	2,937	3,290
Other	6,762	7,062
Total	32,412	42,227

The Corporation has short-term committed lines of credit of $6.0 billion which were unused as of December 31, 2015. These lines are available for general corporate purposes.

The weighted-average interest rate on short-term borrowings outstanding was 0.4 percent and 0.3 percent at December 31, 2015, and 2014, respectively.

7. Equity Company Information

The summarized financial information below includes amounts related to certain less-than-majority-owned companies and majority-owned subsidiaries where minority shareholders possess the right to participate in significant management decisions (see Note 1). These companies are primarily engaged in oil and gas exploration and production, and natural gas marketing in North America; natural gas exploration, production and distribution, and downstream operations in Europe; and exploration, production, liquefied natural gas (LNG) operations, refining operations, petrochemical manufacturing, and fuel sales in Asia. Also included are several refining, petrochemical manufacturing, and marketing ventures.

The Corporation's ownership in these ventures is in the form of shares in corporate joint ventures as well as interests in partnerships. Differences between the company's carrying value of an equity investment and its underlying equity in the net assets of the affiliate are assigned to the extent practicable to specific assets and liabilities based on the company's analysis of the factors giving rise to the difference. The amortization of this difference, as appropriate, is included in "income from equity affiliates."

The share of total equity company revenues from sales to ExxonMobil consolidated companies was 15 percent, 14 percent and 13 percent in the years 2015, 2014 and 2013, respectively.

In 2013 and 2014, the Corporation and Rosneft established various entities to conduct exploration and research activities. Periods of disproportionate funding will result in the Corporation recognizing, during the early phases of the projects, an investment that is larger than its equity share in these entities. These joint ventures are considered Variable Interest Entities. However, since the Corporation is not the primary beneficiary of these entities, the joint ventures are reported as equity companies. In 2014, the European Union and United States imposed sanctions relating to the Russian energy sector. With respect to the foregoing, each joint venture continues to comply with all applicable laws, rules and regulations. The Corporation's maximum before-tax exposure to loss from these joint ventures as of December 31, 2015, is $1.0 billion.

Equity Company Financial Summary	**2015**		**2014**		**2013**	
	Total	**ExxonMobil Share**	**Total**	**ExxonMobil Share**	**Total**	**ExxonMobil Share**
	(millions of dollars)					
Total revenues	111,866	34,297	183,708	55,855	236,161	68,084
Income before income taxes	36,379	10,670	65,549	19,014	69,454	19,999
Income taxes	11,048	3,019	20,520	5,684	21,618	6,069
Income from equity affiliates	25,331	7,651	45,029	13,330	47,836	13,930
Current assets	32,879	11,244	49,905	16,802	62,398	19,545
Long-term assets	109,684	32,878	110,754	33,619	116,450	35,695
Total assets	142,563	44,122	160,659	50,421	178,848	55,240
Current liabilities	22,947	6,738	37,333	11,472	54,550	15,243
Long-term liabilities	60,388	17,165	66,231	19,470	68,857	20,873
Net assets	59,228	20,219	57,095	19,479	55,441	19,124

A list of significant equity companies as of December 31, 2015, together with the Corporation's percentage ownership interest, is detailed below:

	Percentage Ownership Interest
Upstream	
Aera Energy LLC	48
BEB Erdgas und Erdoel GmbH & Co. KG	50
Cameroon Oil Transportation Company S.A.	41
Cross Timbers Energy, LLC	50
Golden Pass LNG Terminal LLC	18
Karmorneftegaz Holding SARL	33
Marine Well Containment Company LLC	10
Nederlandse Aardolie Maatschappij B.V.	50
Qatar Liquefied Gas Company Limited	10
Qatar Liquefied Gas Company Limited (2)	24
Ras Laffan Liquefied Natural Gas Company Limited	25
Ras Laffan Liquefied Natural Gas Company Limited (II)	31
Ras Laffan Liquefied Natural Gas Company Limited (3)	30
South Hook LNG Terminal Company Limited	24
Tengizchevroil, LLP	25
Terminale GNL Adriatico S.r.l.	71
Downstream	
Fujian Refining & Petrochemical Co. Ltd.	25
Saudi Aramco Mobil Refinery Company Ltd.	50
Chemical	
Al-Jubail Petrochemical Company	50
Infineum Holdings B.V.	50
Infineum Italia s.r.l.	50
Infineum USA L.P.	50
Saudi Yanbu Petrochemical Co.	50

8. Investments, Advances and Long-Term Receivables

	Dec. 31, 2015	Dec. 31, 2014
	(millions of dollars)	
Companies carried at equity in underlying assets		
Investments	20,337	20,017
Advances	9,110	9,818
Total equity company investments and advances	29,447	29,835
Companies carried at cost or less and stock investments carried at fair value	274	526
Long-term receivables and miscellaneous investments at cost or less, net of reserves of $3,040 million and $2,662 million	4,524	4,878
Total	34,245	35,239

9. Property, Plant and Equipment and Asset Retirement Obligations

Property, Plant and Equipment	December 31, 2015 Cost	December 31, 2015 Net	December 31, 2014 Cost	December 31, 2014 Net
	(millions of dollars)			
Upstream	347,821	203,822	347,170	205,308
Downstream	50,742	21,330	53,327	22,639
Chemical	32,481	16,247	30,717	14,918
Other	16,293	10,206	15,575	9,803
Total	447,337	251,605	446,789	252,668

In the Upstream segment, depreciation is generally on a unit-of-production basis, so depreciable life will vary by field. In the Downstream segment, investments in refinery and lubes basestock manufacturing facilities are generally depreciated on a straight-line basis over a 25-year life and service station buildings and fixed improvements over a 20-year life. In the Chemical segment, investments in process equipment are generally depreciated on a straight-line basis over a 20-year life.

The Corporation periodically reviews the estimated asset service life of its property, plant and equipment. Effective January 1, 2016, the Corporation revised the estimated asset service life of its investments in process equipment in the Chemical segment to 25 years. This revision will not have a material impact on the Corporation's financial statements.

Accumulated depreciation and depletion totaled $195,732 million at the end of 2015 and $194,121 million at the end of 2014. Interest capitalized in 2015, 2014 and 2013 was $482 million, $344 million and $309 million, respectively.

Asset Retirement Obligations

The Corporation incurs retirement obligations for certain assets. The fair values of these obligations are recorded as liabilities on a discounted basis, which is typically at the time the assets are installed. In the estimation of fair value, the Corporation uses assumptions and judgments regarding such factors as the existence of a legal obligation for an asset retirement obligation; technical assessments of the assets; estimated amounts and timing of settlements; discount rates; and inflation rates. Asset retirement obligations incurred in the current period were Level 3 fair value measurements. The costs associated with these liabilities are capitalized as part of the related assets and depreciated as the reserves are produced. Over time, the liabilities are accreted for the change in their present value.

Asset retirement obligations for downstream and chemical facilities generally become firm at the time the facilities are permanently shut down and dismantled. These obligations may include the costs of asset disposal and additional soil remediation. However, these sites have indeterminate lives based on plans for continued operations and as such, the fair value of the conditional legal obligations cannot be measured, since it is impossible to estimate the future settlement dates of such obligations.

The following table summarizes the activity in the liability for asset retirement obligations:

	2015	2014
	(millions of dollars)	
Beginning balance	13,424	12,988
Accretion expense and other provisions	775	871
Reduction due to property sales	(208)	(151)
Payments made	(928)	(724)
Liabilities incurred	283	122
Foreign currency translation	(931)	(908)
Revisions	1,289	1,226
Ending balance	13,704	13,424

10. Accounting for Suspended Exploratory Well Costs

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

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

Change in capitalized suspended exploratory well costs:

	2015	2014	2013
		(millions of dollars)	
Balance beginning at January 1	3,587	2,707	2,679
Additions pending the determination of proved reserves	847	1,095	293
Charged to expense	(5)	(28)	(52)
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(43)	(160)	(107)
Divestments/Other	(14)	(27)	(106)
Ending balance at December 31	4,372	3,587	2,707
Ending balance attributed to equity companies included above	696	645	13

Period end capitalized suspended exploratory well costs:

	2015	2014	2013
		(millions of dollars)	
Capitalized for a period of one year or less	847	1,095	293
Capitalized for a period of between one and five years	2,386	1,659	1,705
Capitalized for a period of between five and ten years	826	544	470
Capitalized for a period of greater than ten years	313	289	239
Capitalized for a period greater than one year - subtotal	3,525	2,492	2,414
Total	4,372	3,587	2,707

Exploration activity often involves drilling multiple wells, over a number of years, to fully evaluate a project. The table below provides a breakdown of the number of projects with suspended exploratory well costs which had their first capitalized well drilled in the preceding 12 months and those that have had exploratory well costs capitalized for a period greater than 12 months, which includes the Rosneft joint venture exploration activity (refer to the relevant portion of Note 7).

	2015	2014	2013
Number of projects with first capitalized well drilled in the preceding 12 months	4	8	8
Number of projects that have exploratory well costs capitalized for a period of greater than 12 months	55	53	50
Total	59	61	58

Of the 55 projects that have exploratory well costs capitalized for a period greater than 12 months as of December 31, 2015, 18 projects have drilling in the preceding 12 months or exploratory activity either planned in the next two years or subject to sanctions. The remaining 37 projects are those with completed exploratory activity progressing toward development.

The table below provides additional detail for those 37 projects, which total $1,154 million.

Country/Project	Dec. 31, 2015	Years Wells Drilled	Comment
	(millions of dollars)		
Angola			
- Kaombo Split Hub Phase 2	20	2005 - 2006	Evaluating development plan to tie into planned production facilities.
- Perpetua-Zinia-Acacia	15	2008 - 2009	Oil field near Pazflor development, awaiting capacity in existing/planned infrastructure.
Australia			
- East Pilchard	7	2001	Gas field near Kipper/Tuna development, awaiting capacity in existing/planned infrastructure.
- SE Longtom	11	2010	Gas field near Tuna development, awaiting capacity in existing/planned infrastructure.
- SE Remora	34	2010	Gas field near Marlin development, awaiting capacity in existing/planned infrastructure.
Canada			
- Horn River	241	2009 - 2012	Evaluating development alternatives to tie into planned infrastructure.
Indonesia			
- Alas Tua West	16	2010	Evaluating development plan to tie into planned production facilities.
- Cepu Gas	29	2008 - 2011	Development activity under way, while continuing commercial discussions with the government.
- Kedung Keris	11	2011	Evaluating development plan to tie into planned production facilities.
- Natuna	118	1981 - 1983	Development activity under way, while continuing discussions with the government on contract terms pursuant to executed Heads of Agreement.
Kazakhstan			
- Kairan	53	2004 - 2007	Evaluating commercialization and field development alternatives, while continuing discussions with the government regarding the development plan.
- Kalamkas	18	2006 - 2009	Evaluating development alternatives, while continuing discussions with the government regarding development plan.
Malaysia			
- Bindu	2	1995	Awaiting capacity in existing/planned infrastructure.
Nigeria			
- Bolia	15	2002 - 2006	Evaluating development plan, while continuing discussions with the government regarding regional hub strategy.
- Bosi	79	2002 - 2006	Development activity under way, while continuing discussions with the government regarding development plan.
- Bosi Central	16	2006	Development activity under way, while continuing discussions with the government regarding development plan.
- Erha Northeast	26	2008	Evaluating development plan for tieback to existing production facilities.
- Pegi	32	2009	Awaiting capacity in existing/planned infrastructure.
- Satellite Field Development Phase 2	12	2013	Evaluating development plan to tie into planned production facilities.
- Other (4 projects)	14	2002	Evaluating and pursuing development of several additional discoveries.
Norway			
- Gamma	13	2008 - 2009	Evaluating development plan for tieback to existing production facilities.
- Lavrans	15	1995 - 1999	Evaluating development plan, awaiting capacity in existing Kristin production facility.
- Other (7 projects)	25	2008 - 2014	Evaluating development plans, including potential for tieback to existing production facilities.
Papua New Guinea			
- Juha	28	2007	Progressing development plans to tie into existing LNG facilities.
Republic of Congo			
- Mer Tres Profonde Sud	56	2000 - 2007	Evaluating development alternatives, while continuing discussions with the government regarding development plan.
United Kingdom			
- Phyllis	8	2004	Evaluating development plan for tieback to existing production facilities.
United States			
- Hadrian North	209	2010 - 2013	Evaluating development plan to tie into existing production facilities.
- Tip Top	31	2009	Evaluating development concept and requisite facility upgrades.
Total 2015 (37 projects)	1,154		

11. Leased Facilities

At December 31, 2015, the Corporation and its consolidated subsidiaries held noncancelable operating charters and leases covering drilling equipment, tankers, service stations and other properties with minimum undiscounted lease commitments totaling $4,877 million as indicated in the table. Estimated related rental income from noncancelable subleases is $32 million.

	Lease Payments Under Minimum Commitments			Related
	Drilling Rigs and Related Equipment	Other	Total	Sublease Rental Income
	(millions of dollars)			
2016	827	826	1,653	7
2017	408	595	1,003	6
2018	134	421	555	2
2019	89	255	344	2
2020	77	188	265	2
2021 and beyond	86	971	1,057	13
Total	1,621	3,256	4,877	32

Net rental cost under both cancelable and noncancelable operating leases incurred during 2015, 2014 and 2013 were as follows:

	2015	2014	2013
	(millions of dollars)		
Rental cost			
Drilling rigs and related equipment	1,853	1,763	1,424
Other	2,120	2,314	2,417
Total	3,973	4,077	3,841
Less sublease rental income	44	52	44
Net rental cost	3,929	4,025	3,797

12. Earnings Per Share

	2015	2014	2013
Earnings per common share			
Net income attributable to ExxonMobil *(millions of dollars)*	16,150	32,520	32,580
Weighted average number of common shares outstanding *(millions of shares)*	4,196	4,282	4,419
Earnings per common share *(dollars) (1)*	3.85	7.60	7.37
Dividends paid per common share *(dollars)*	2.88	2.70	2.46

(1) The earnings per common share and earnings per common share - assuming dilution are the same in each period shown.

13. Financial Instruments and Derivatives

Financial Instruments. The fair value of financial instruments is determined by reference to observable market data and other valuation techniques as appropriate. The only category of financial instruments where the difference between fair value and recorded book value is notable is long-term debt. The estimated fair value of total long-term debt, excluding capitalized lease obligations, was $18.9 billion and $11.7 billion at December 31, 2015, and 2014, respectively, as compared to recorded book values of $18.7 billion and $11.3 billion at December 31, 2015, and 2014, respectively. The increase in the estimated fair value and book value of long-term debt reflects the Corporation's issuance of $8.0 billion of long-term debt in the first quarter of 2015.

The fair value of long-term debt by hierarchy level at December 31, 2015, is: Level 1 $18,584 million; Level 2 $208 million; and Level 3 $62 million.

Derivative Instruments. The Corporation's size, strong capital structure, geographic diversity and the complementary nature of the Upstream, Downstream and Chemical businesses reduce the Corporation's enterprise-wide risk from changes in interest rates, currency rates and commodity prices. As a result, the Corporation makes limited use of derivatives to mitigate the impact of such changes. The Corporation does not engage in speculative derivative activities or derivative trading activities nor does it use derivatives with leveraged features. When the Corporation does enter into derivative transactions, it is to offset exposures associated with interest rates, foreign currency exchange rates and hydrocarbon prices that arise from existing assets, liabilities and forecasted transactions.

The estimated fair value of derivative instruments outstanding and recorded on the balance sheet was a net asset of $21 million at year-end 2015 and a net asset of $75 million at year-end 2014. Assets and liabilities associated with derivatives are usually recorded either in "Other current assets" or "Accounts payable and accrued liabilities."

The Corporation's fair value measurement of its derivative instruments use either Level 1 or Level 2 inputs.

The Corporation recognized a before-tax gain or (loss) related to derivative instruments of $39 million, $110 million and $(7) million during 2015, 2014 and 2013, respectively. Income statement effects associated with derivatives are usually recorded either in "Sales and other operating revenue" or "Crude oil and product purchases."

The Corporation believes there are no material market or credit risks to the Corporation's financial position, results of operations or liquidity as a result of the derivative activities described above.

14. Long-Term Debt

At December 31, 2015, long-term debt consisted of $19,217 million due in U.S. dollars and $708 million representing the U.S. dollar equivalent at year-end exchange rates of amounts payable in foreign currencies. These amounts exclude that portion of long-term debt, totaling $558 million, which matures within one year and is included in current liabilities. The increase in the book value of long-term debt reflects the Corporation's issuance of $8.0 billion of long-term debt in the first quarter of 2015. The amounts of long-term debt, including capitalized lease obligations, maturing in each of the four years after December 31, 2016, in millions of dollars, are: 2017 – $2,959; 2018 – $2,967; 2019 – $2,374; and 2020 – $1,602. At December 31, 2015, the Corporation's unused long-term credit lines were $0.4 billion.

Summarized long-term debt at year-end 2015 and 2014 are shown in the table below:

	2015	2014
	(millions of dollars)	
Exxon Mobil Corporation		
0.921% notes due 2017	1,500	1,500
Floating-rate notes due 2017 *(1)*	750	750
Floating-rate notes due 2018 *(2)*	500	-
1.305% notes due 2018	1,600	-
1.819% notes due 2019	1,750	1,750
Floating-rate notes due 2019 *(3)*	500	500
1.912% notes due 2020	1,500	-
2.397% notes due 2022	1,150	-
Floating-rate notes due 2022 *(4)*	500	-
3.176% notes due 2024	1,000	1,000
2.709% notes due 2025	1,750	-
3.567% notes due 2045	1,000	-
XTO Energy Inc. *(5)*		
5.650% senior notes due 2016	-	207
6.250% senior notes due 2017	465	477
5.500% senior notes due 2018	377	383
6.500% senior notes due 2018	463	474
6.100% senior notes due 2036	198	199
6.750% senior notes due 2037	307	309
6.375% senior notes due 2038	235	236
Mobil Producing Nigeria Unlimited *(6)*		
Variable notes due 2016-2019	101	399
Esso (Thailand) Public Company Ltd. *(7)*		
Variable notes due 2016-2020	83	121
Mobil Corporation		
8.625% debentures due 2021	249	249
Industrial revenue bonds due 2017-2051 *(8)*	2,611	2,611
Other U.S. dollar obligations *(9)*	97	104
Other foreign currency obligations	1	9
Capitalized lease obligations *(10)*	1,238	375
Total long-term debt	19,925	11,653

(1) Average effective interest rate of 0.3% in 2015 and 0.3% in 2014.
(2) Average effective interest rate of 0.4% in 2015.
(3) Average effective interest rate of 0.5% in 2015 and 0.4% in 2014.
(4) Average effective interest rate of 0.7% in 2015.
(5) Includes premiums of $179 million in 2015 and $219 million in 2014.
(6) Average effective interest rate of 4.6% in 2015 and 4.5% in 2014.
(7) Average effective interest rate of 2.1% in 2015 and 2.4% in 2014.
(8) Average effective interest rate of 0.02% in 2015 and 0.03% in 2014.
(9) Average effective interest rate of 3.8% in 2015 and 4.2% in 2014.
(10) Average imputed interest rate of 9.2% in 2015 and 7.0% in 2014.

15. Incentive Program

The 2003 Incentive Program provides for grants of stock options, stock appreciation rights (SARs), restricted stock and other forms of award. Awards may be granted to eligible employees of the Corporation and those affiliates at least 50 percent owned. Outstanding awards are subject to certain forfeiture provisions contained in the program or award instrument. Options and SARs may be granted at prices not less than 100 percent of market value on the date of grant and have a maximum life of 10 years. The maximum number of shares of stock that may be issued under the 2003 Incentive Program is 220 million. Awards that are forfeited, expire or are settled in cash, do not count against this maximum limit. The 2003 Incentive Program does not have a specified term. New awards may be made until the available shares are depleted, unless the Board terminates the plan early. At the end of 2015, remaining shares available for award under the 2003 Incentive Program were 100 million.

Restricted Stock and Restricted Stock Units. Awards totaling 9,681 thousand, 9,775 thousand, and 9,729 thousand of restricted (nonvested) common stock units were granted in 2015, 2014 and 2013, respectively. Compensation expense for these awards is based on the price of the stock at the date of grant and is recognized in income over the requisite service period. Shares for these awards are issued to employees from treasury stock. The units that are settled in cash are recorded as liabilities and their changes in fair value are recognized over the vesting period. During the applicable restricted periods, the shares and units may not be sold or transferred and are subject to forfeiture. The majority of the awards have graded vesting periods, with 50 percent of the shares and units in each award vesting after three years and the remaining 50 percent vesting after seven years. Awards granted to a small number of senior executives have vesting periods of five years for 50 percent of the award and of 10 years or retirement, whichever occurs later, for the remaining 50 percent of the award.

The Corporation has purchased shares in the open market and through negotiated transactions to offset shares issued in conjunction with benefit plans and programs. Purchases may be discontinued at any time without prior notice.

The following tables summarize information about restricted stock and restricted stock units for the year ended December 31, 2015.

	2015	
Restricted stock and units outstanding	**Shares**	**Weighted Average Grant-Date Fair Value per Share**
	(thousands)	*(dollars)*
Issued and outstanding at January 1	44,439	81.45
2014 award issued in 2015	9,758	95.20
Vested	(9,945)	79.86
Forfeited	(189)	82.26
Issued and outstanding at December 31	44,063	84.85

Value of restricted stock and units	**2015**	**2014**	**2013**
Grant price *(dollars)*	81.27	95.20	94.47
Value at date of grant:		*(millions of dollars)*	
Restricted stock and units settled in stock	727	858	843
Units settled in cash	60	73	76
Total value	787	931	919

As of December 31, 2015, there was $2,222 million of unrecognized compensation cost related to the nonvested restricted awards. This cost is expected to be recognized over a weighted-average period of 4.5 years. The compensation cost charged against income for the restricted stock and restricted stock units was $855 million, $831 million and $854 million for 2015, 2014 and 2013, respectively. The income tax benefit recognized in income related to this compensation expense was $78 million, $76 million and $78 million for the same periods, respectively. The fair value of shares and units vested in 2015, 2014 and 2013 was $808 million, $946 million and $1,040 million, respectively. Cash payments of $64 million, $73 million and $67 million for vested restricted stock units settled in cash were made in 2015, 2014 and 2013, respectively.

16. Litigation and Other Contingencies

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

Other Contingencies. The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2015, for guarantees relating to notes, loans and performance under contracts. Where guarantees for environmental remediation and other similar matters do not include a stated cap, the amounts reflect management's estimate of the maximum potential exposure.

	Dec. 31, 2015		
	Equity Company Obligations *(1)*	**Other Third-Party Obligations**	**Total**
		(millions of dollars)	
Guarantees			
Debt-related	98	35	133
Other	2,539	4,553	7,092
Total	2,637	4,588	7,225

(1) ExxonMobil share.

Additionally, the Corporation and its affiliates have numerous long-term sales and purchase commitments in their various business activities, all of which are expected to be fulfilled with no adverse consequences material to the Corporation's operations or financial condition. Unconditional purchase obligations as defined by accounting standards are those long-term commitments that are noncancelable or cancelable only under certain conditions, and that third parties have used to secure financing for the facilities that will provide the contracted goods or services.

	Payments Due by Period			
	2016	**2017-2020**	**2021 and Beyond**	**Total**
		(millions of dollars)		
Unconditional purchase obligations *(1)*	133	493	310	936

(1) Undiscounted obligations of $936 million mainly pertain to pipeline throughput agreements and include $411 million of obligations to equity companies. The present value of these commitments, which excludes imputed interest of $144 million, totaled $792 million.

In accordance with a nationalization decree issued by Venezuela's president in February 2007, by May 1, 2007, a subsidiary of the Venezuelan National Oil Company (PdVSA) assumed the operatorship of the Cerro Negro Heavy Oil Project. This Project had been operated and owned by ExxonMobil affiliates holding a 41.67 percent ownership interest in the Project. The decree also required conversion of the Cerro Negro Project into a "mixed enterprise" and an increase in PdVSA's or one of its affiliate's ownership interest in the Project, with the stipulation that if ExxonMobil refused to accept the terms for the formation of the mixed enterprise within a specified period of time, the government would "directly assume the activities" carried out by the joint venture. ExxonMobil refused to accede to the terms proffered by the government, and on June 27, 2007, the government expropriated ExxonMobil's 41.67 percent interest in the Cerro Negro Project.

On September 6, 2007, affiliates of ExxonMobil filed a Request for Arbitration with the International Centre for Settlement of Investment Disputes (ICSID). The ICSID Tribunal issued a decision on June 10, 2010, finding that it had jurisdiction to proceed on the basis of the Netherlands-Venezuela Bilateral Investment Treaty. On October 9, 2014, the ICSID Tribunal issued its final award finding in favor of the ExxonMobil affiliates and awarding $1.6 billion as of the date of expropriation, June 27, 2007, and interest from that date at 3.25% compounded annually until the date of payment in full. The Tribunal also noted that one of the Cerro Negro Project agreements provides a mechanism to prevent double recovery between the ICSID award and all or part of an earlier award of $908 million to an ExxonMobil affiliate, Mobil Cerro Negro, Ltd., against PdVSA and a PdVSA affiliate, PdVSA CN, in an arbitration under the rules of the International Chamber of Commerce.

On June 12, 2015, the Tribunal rejected in its entirety Venezuela's October 23, 2014, application to revise the ICSID award. The Tribunal also lifted the associated stay of enforcement that had been entered upon the filing of the application to revise.

Still pending is Venezuela's February 2, 2015, application to ICSID seeking annulment of the ICSID award. That application alleges that, in issuing the ICSID award, the Tribunal exceeded its powers, failed to state reasons on which the ICSID award was based, and departed from a fundamental rule of procedure. A separate stay of the ICSID award was entered following the filing of the annulment application. On July 7, 2015, the ICSID Committee considering the annulment application heard arguments from the parties on whether to lift the stay of the award associated with that application. On July 28, 2015, the Committee issued an order that would lift the stay of enforcement unless, within 30 days, Venezuela delivered a commitment to pay the award if the application to annul is denied. On September 17, 2015, the Committee ruled that Venezuela had complied with the requirement to submit a written commitment to pay the award and so left the stay of enforcement in place. A hearing on Venezuela's application for annulment, previously scheduled for January 25-27, 2016, has been rescheduled for March 8-9, 2016.

The United States District Court for the Southern District of New York entered judgment on the ICSID award on October 10, 2014. Motions filed by Venezuela to vacate that judgment on procedural grounds and to modify the judgment by reducing the rate of interest to be paid on the ICSID award from the entry of the court's judgment, until the date of payment, were denied on February 13, 2015, and March 4, 2015, respectively. On March 9, 2015, Venezuela filed a notice of appeal of the court's actions on the two motions. Oral arguments on this appeal were held before the United States Court of Appeals for the Second Circuit on January 7, 2016.

The District Court's judgment on the ICSID award is currently stayed until such time as ICSID's stay of the award entered following Venezuela's filing of its application to annul has been lifted. The net impact of these matters on the Corporation's consolidated financial results cannot be reasonably estimated. Regardless, the Corporation does not expect the resolution to have a material effect upon the Corporation's operations or financial condition.

An affiliate of ExxonMobil is one of the Contractors under a Production Sharing Contract (PSC) with the Nigerian National Petroleum Corporation (NNPC) covering the Erha block located in the offshore waters of Nigeria. ExxonMobil's affiliate is the operator of the block and owns a 56.25 percent interest under the PSC. The Contractors are in dispute with NNPC regarding NNPC's lifting of crude oil in excess of its entitlement under the terms of the PSC. In accordance with the terms of the PSC, the Contractors initiated arbitration in Abuja, Nigeria, under the Nigerian Arbitration and Conciliation Act. On October 24, 2011, a three-member arbitral Tribunal issued an award upholding the Contractors' position in all material respects and awarding damages to the Contractors jointly in an amount of approximately $1.8 billion plus $234 million in accrued interest. The Contractors petitioned a Nigerian federal court for enforcement of the award, and NNPC petitioned the same court to have the award set aside. On May 22, 2012, the court set aside the award. The Contractors appealed that judgment to the Court of Appeal, Abuja Judicial Division. In June 2013, the Contractors filed a lawsuit against NNPC in the Nigerian federal high court in order to preserve their ability to seek enforcement of the PSC in the courts if necessary. In October 2014, the Contractors filed suit in the United States District Court for the Southern District of New York to enforce, if necessary, the arbitration award against NNPC assets residing within that jurisdiction. NNPC has moved to dismiss the lawsuit. Proceedings in the Southern District of New York are currently stayed. At this time, the net impact of this matter on the Corporation's consolidated financial results cannot be reasonably estimated. However, regardless of the outcome of enforcement proceedings, the Corporation does not expect the proceedings to have a material effect upon the Corporation's operations or financial condition.

17. Pension and Other Postretirement Benefits

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

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2015	2014	2015	2014	2015	2014
			(percent)			
Weighted-average assumptions used to determine benefit obligations at December 31						
Discount rate	4.25	4.00	3.60	3.10	4.25	4.00
Long-term rate of compensation increase	5.75	5.75	4.80	5.30	5.75	5.75
			(millions of dollars)			
Change in benefit obligation						
Benefit obligation at January 1	20,529	17,304	30,047	27,357	9,436	7,868
Service cost	864	677	689	590	170	140
Interest cost	785	807	850	1,138	346	383
Actuarial loss/(gain)	(545)	3,192	(1,517)	4,929	(617)	1,522
Benefits paid *(1) (2)*	(2,050)	(1,427)	(1,287)	(1,366)	(482)	(525)
Foreign exchange rate changes	-	-	(3,242)	(2,540)	(106)	(48)
Amendments, divestments and other	-	(24)	(423)	(61)	(465)	96
Benefit obligation at December 31	19,583	20,529	25,117	30,047	8,282	9,436
Accumulated benefit obligation at December 31	15,666	16,385	22,362	26,318	-	-

(1) Benefit payments for funded and unfunded plans.

(2) For 2015 and 2014, other postretirement benefits paid are net of $15 million and $21 million of Medicare subsidy receipts, respectively.

For selection of the discount rate for U.S. plans, several sources of information are considered, including interest rate market indicators and the discount rate determined by use of a yield curve based on high-quality, noncallable bonds with cash flows that match estimated outflows for benefit payments. For major non-U.S. plans, the discount rate is determined by using bond portfolios with an average maturity approximating that of the liabilities or spot yield curves, both of which are constructed using high-quality, local-currency-denominated bonds.

The measurement of the accumulated postretirement benefit obligation assumes a health care cost trend rate of 4.5 percent in 2017 and subsequent years. A one-percentage-point increase in the health care cost trend rate would increase service and interest cost by $88 million and the postretirement benefit obligation by $963 million. A one-percentage-point decrease in the health care cost trend rate would decrease service and interest cost by $66 million and the postretirement benefit obligation by $764 million.

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2015	2014	2015	2014	2015	2014
			(millions of dollars)			
Change in plan assets						
Fair value at January 1	12,915	11,190	20,095	19,283	468	620
Actual return on plan assets	(307)	1,497	918	3,153	-	41
Foreign exchange rate changes	-	-	(2,109)	(1,738)	-	-
Company contribution	-	1,476	515	554	42	31
Benefits paid *(1)*	(1,623)	(1,248)	(890)	(912)	(96)	(224)
Other	-	-	(112)	(245)	-	-
Fair value at December 31	10,985	12,915	18,417	20,095	414	468

(1) Benefit payments for funded plans.

The funding levels of all qualified pension plans are in compliance with standards set by applicable law or regulation. As shown in the table below, certain smaller U.S. pension plans and a number of non-U.S. pension plans are not funded because local tax conventions and regulatory practices do not encourage funding of these plans. All defined benefit pension obligations, regardless of the funding status of the underlying plans, are fully supported by the financial strength of the Corporation or the respective sponsoring affiliate.

	Pension Benefits			
	U.S.		Non-U.S.	
	2015	2014	2015	2014
	(millions of dollars)			
Assets in excess of/(less than) benefit obligation				
Balance at December 31				
Funded plans	(5,782)	(4,590)	(588)	(2,113)
Unfunded plans	(2,816)	(3,024)	(6,112)	(7,839)
Total	(8,598)	(7,614)	(6,700)	(9,952)

The authoritative guidance for defined benefit pension and other postretirement plans requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through other comprehensive income.

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2015	2014	2015	2014	2015	2014
	(millions of dollars)					
Assets in excess of/(less than) benefit obligation						
Balance at December 31 *(1)*	(8,598)	(7,614)	(6,700)	(9,952)	(7,868)	(8,968)
Amounts recorded in the consolidated balance sheet consist of:						
Other assets	-	-	454	302	-	-
Current liabilities	(311)	(340)	(299)	(325)	(363)	(369)
Postretirement benefits reserves	(8,287)	(7,274)	(6,855)	(9,929)	(7,505)	(8,599)
Total recorded	(8,598)	(7,614)	(6,700)	(9,952)	(7,868)	(8,968)
Amounts recorded in accumulated other comprehensive income consist of:						
Net actuarial loss/(gain)	6,138	6,589	6,413	9,642	2,171	2,997
Prior service cost	21	27	(83)	429	(460)	51
Total recorded in accumulated other comprehensive income	6,159	6,616	6,330	10,071	1,711	3,048

(1) Fair value of assets less benefit obligation shown on the preceding page.

The long-term expected rate of return on funded assets shown below is established for each benefit plan by developing a forward-looking, long-term return assumption for each asset class, taking into account factors such as the expected real return for the specific asset class and inflation. A single, long-term rate of return is then calculated as the weighted average of the target asset allocation percentages and the long-term return assumption for each asset class.

	Pension Benefits						Other Postretirement Benefits		
	U.S.			Non-U.S.					
	2015	2014	2013	2015	2014	2013	2015	2014	2013
Weighted-average assumptions used to determine net periodic benefit cost for years ended December 31					*(percent)*				
Discount rate	4.00	5.00	4.00	3.10	4.30	3.80	4.00	5.00	4.00
Long-term rate of return on funded assets	7.00	7.25	7.25	5.90	6.30	6.40	7.00	7.25	7.25
Long-term rate of compensation increase	5.75	5.75	5.75	5.30	5.40	5.50	5.75	5.75	5.75
Components of net periodic benefit cost					*(millions of dollars)*				
Service cost	864	677	801	689	590	697	170	140	176
Interest cost	785	807	749	850	1,138	1,076	346	383	352
Expected return on plan assets	(830)	(799)	(835)	(1,094)	(1,193)	(1,128)	(28)	(37)	(41)
Amortization of actuarial loss/(gain)	544	409	646	730	628	852	206	116	228
Amortization of prior service cost	6	8	7	87	120	117	(24)	14	21
Net pension enhancement and curtailment/settlement cost	499	276	723	22	-	22	-	-	-
Net periodic benefit cost	1,868	1,378	2,091	1,284	1,283	1,636	670	616	736
Changes in amounts recorded in accumulated other comprehensive income:									
Net actuarial loss/(gain)	592	2,494	(1,302)	(1,375)	2,969	(1,938)	(589)	1,518	(1,290)
Amortization of actuarial (loss)/gain	(1,043)	(685)	(1,369)	(752)	(628)	(874)	(206)	(116)	(228)
Prior service cost/(credit)	-	(25)	-	(401)	(70)	30	(535)	-	-
Amortization of prior service (cost)/credit	(6)	(8)	(7)	(87)	(120)	(117)	24	(14)	(21)
Foreign exchange rate changes	-	-	-	(1,126)	(688)	(155)	(31)	(8)	(10)
Total recorded in other comprehensive income	(457)	1,776	(2,678)	(3,741)	1,463	(3,054)	(1,337)	1,380	(1,549)
Total recorded in net periodic benefit cost and other comprehensive income, before tax	1,411	3,154	(587)	(2,457)	2,746	(1,418)	(667)	1,996	(813)

Costs for defined contribution plans were \$405 million, \$393 million and \$392 million in 2015, 2014 and 2013, respectively.

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

	Total Pension and Other Postretirement Benefits		
	2015	2014	2013
	(millions of dollars)		
(Charge)/credit to other comprehensive income, before tax			
U.S. pension	457	(1,776)	2,678
Non-U.S. pension	3,741	(1,463)	3,054
Other postretirement benefits	1,337	(1,380)	1,549
Total (charge)/credit to other comprehensive income, before tax	5,535	(4,619)	7,281
(Charge)/credit to income tax (see Note 4)	(1,810)	1,549	(2,336)
(Charge)/credit to investment in equity companies	81	(81)	49
(Charge)/credit to other comprehensive income including noncontrolling interests, after tax	3,806	(3,151)	4,994
Charge/(credit) to equity of noncontrolling interests	(202)	85	(279)
(Charge)/credit to other comprehensive income attributable to ExxonMobil	3,604	(3,066)	4,715

The Corporation's investment strategy for benefit plan assets reflects a long-term view, a careful assessment of the risks inherent in various asset classes and broad diversification to reduce the risk of the portfolio. The benefit plan assets are primarily invested in passive equity and fixed income index funds to diversify risk while minimizing costs. The equity funds hold ExxonMobil stock only to the extent necessary to replicate the relevant equity index. The fixed income funds are largely invested in high-quality corporate and government debt securities.

Studies are periodically conducted to establish the preferred target asset allocation percentages. The target asset allocation for the U.S. benefit plans and the major non-U.S. plans is 40 percent equity securities and 60 percent debt securities. The equity targets for the U.S. and non-U.S. plans include an allocation to private equity partnerships that primarily focus on early-stage venture capital of 5 percent and 3 percent, respectively.

The fair value measurement levels are accounting terms that refer to different methods of valuing assets. The terms do not represent the relative risk or credit quality of an investment.

The 2015 fair value of the benefit plan assets, including the level within the fair value hierarchy, is shown in the tables below:

	U.S. Pension				Non-U.S. Pension			
	Fair Value Measurement at December 31, 2015, Using:				Fair Value Measurement at December 31, 2015, Using:			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
				(millions of dollars)				
Asset category:								
Equity securities								
U.S.	-	1,992 *(1)*	-	1,992	-	3,179 *(1)*	-	3,179
Non-U.S.	-	1,775 *(1)*	-	1,775	179 *(2)*	3,429 *(1)*	-	3,608
Private equity	-	-	595 *(3)*	595	-	-	581 *(3)*	581
Debt securities								
Corporate	-	4,161 *(4)*	-	4,161	-	2,561 *(4)*	-	2,561
Government	-	2,394 *(4)*	-	2,394	243 *(5)*	8,125 *(4)*	-	8,368
Asset-backed	-	3 *(4)*	-	3	-	71 *(4)*	-	71
Real estate funds	-	-	-	-	-	-	-	-
Cash	-	50 *(6)*	-	50	11	12 *(7)*	-	23
Total at fair value	-	10,375	595	10,970	433	17,377	581	18,391
Insurance contracts at contract value				15				26
Total plan assets				10,985				18,417

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

(2) For non-U.S. equity securities held in separate accounts, fair value is based on observable quoted prices on active exchanges.

(3) For private equity, fair value is generally established by using revenue or earnings multiples or other relevant market data including Initial Public Offerings.

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

(5) For corporate and government debt securities that are traded on active exchanges, fair value is based on observable quoted prices.

(6) For cash balances held in the form of short-term fund units that are redeemable at the measurement date, the fair value is treated as a Level 2 input.

(7) For cash balances that are subject to withdrawal penalties or other adjustments, the fair value is treated as a Level 2 input.

	Other Postretirement			
	Fair Value Measurement at December 31, 2015, Using:			
	Level 1	Level 2	Level 3	Total
	(millions of dollars)			
Asset category:				
Equity securities				
U.S.	-	96 *(1)*	-	96
Non-U.S.	-	67 *(1)*	-	67
Private equity	-	-	-	-
Debt securities				
Corporate	-	79 *(2)*	-	79
Government	-	170 *(2)*	-	170
Asset-backed	-	1 *(2)*	-	1
Cash	-	1	-	1
Total at fair value	-	414	-	414

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

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

The change in the fair value in 2015 of Level 3 assets that use significant unobservable inputs to measure fair value is shown in the table below:

	2015			
	Pension			Other
	U.S.	Non-U.S.		Postretirement
	Private Equity	Private Equity	Real Estate	Private Equity
	(millions of dollars)			
Fair value at January 1	562	535	57	2
Net realized gains/(losses)	1	26	(5)	-
Net unrealized gains/(losses)	106	64	-	-
Net purchases/(sales)	(74)	(44)	(52)	(2)
Fair value at December 31	595	581	-	-

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

	U.S. Pension Fair Value Measurement at December 31, 2014, Using:				Non-U.S. Pension Fair Value Measurement at December 31, 2014, Using:			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(millions of dollars)							
Asset category:								
Equity securities								
U.S.	-	2,331 (1)	-	2,331	-	3,284 (1)	-	3,284
Non-U.S.	-	2,144 (1)	-	2,144	229 (2)	3,776 (1)	-	4,005
Private equity	-	-	562 (3)	562	-	-	535 (3)	535
Debt securities								
Corporate	-	4,841 (4)	-	4,841	-	2,686 (4)	-	2,686
Government	-	2,890 (4)	-	2,890	249 (5)	9,050 (4)	-	9,299
Asset-backed	-	5 (4)	-	5	-	146 (4)	-	146
Real estate funds	-	-	-	-	-	-	57 (6)	57
Cash	-	131 (7)	-	131	25	31 (8)	-	56
Total at fair value	-	12,342	562	12,904	503	18,973	592	20,068
Insurance contracts at contract value				11				27
Total plan assets				12,915				20,095

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

(2) For non-U.S. equity securities held in separate accounts, fair value is based on observable quoted prices on active exchanges.

(3) For private equity, fair value is generally established by using revenue or earnings multiples or other relevant market data including Initial Public Offerings.

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

(5) For corporate and government debt securities that are traded on active exchanges, fair value is based on observable quoted prices.

(6) For real estate funds, fair value is based on appraised values developed using comparable market transactions.

(7) For cash balances held in the form of short-term fund units that are redeemable at the measurement date, the fair value is treated as a Level 2 input.

(8) For cash balances that are subject to withdrawal penalties or other adjustments, the fair value is treated as a Level 2 input.

	Other Postretirement			
	Fair Value Measurement at December 31, 2014, Using:			
	Level 1	Level 2	Level 3	Total
	(millions of dollars)			
Asset category:				
Equity securities				
U.S.	-	106 (1)	-	106
Non-U.S.	-	75 (1)	-	75
Private equity	-	-	2 (2)	2
Debt securities				
Corporate	-	103 (3)	-	103
Government	-	171 (3)	-	171
Asset-backed	-	9 (3)	-	9
Cash	-	2	-	2
Total at fair value	-	466	2	468

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

(2) For private equity, fair value is generally established by using revenue or earnings multiples or other relevant market data including Initial Public Offerings.

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

The change in the fair value in 2014 of Level 3 assets that use significant unobservable inputs to measure fair value is shown in the table below:

	2014			
	Pension			Other
	U.S.	Non-U.S.		Postretirement
	Private Equity	Private Equity	Real Estate	Private Equity
	(millions of dollars)			
Fair value at January 1	523	502	136	9
Net realized gains/(losses)	2	23	(17)	-
Net unrealized gains/(losses)	89	31	8	-
Net purchases/(sales)	(52)	(21)	(70)	(7)
Fair value at December 31	562	535	57	2

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

	Pension Benefits			
	U.S.		Non-U.S.	
	2015	2014	2015	2014
	(millions of dollars)			
For funded pension plans with an accumulated benefit obligation in excess of plan assets:				
Projected benefit obligation	16,767	17,505	1,827	5,031
Accumulated benefit obligation	13,913	14,493	1,373	4,590
Fair value of plan assets	10,985	12,915	1,299	3,890
For unfunded pension plans:				
Projected benefit obligation	2,816	3,024	6,112	7,839
Accumulated benefit obligation	1,753	1,892	5,290	6,573

	Pension Benefits		Other Postretirement Benefits
	U.S.	Non-U.S.	
	(millions of dollars)		
Estimated 2016 amortization from accumulated other comprehensive income:			
Net actuarial loss/(gain) *(1)*	930	543	152
Prior service cost *(2)*	6	55	(30)

(1) The Corporation amortizes the net balance of actuarial losses/(gains) as a component of net periodic benefit cost over the average remaining service period of active plan participants.

(2) The Corporation amortizes prior service cost on a straight-line basis as permitted under authoritative guidance for defined benefit pension and other postretirement benefit plans.

	Pension Benefits		Other Postretirement Benefits	
	U.S.	Non-U.S.	Gross	Medicare Subsidy Receipt
	(millions of dollars)			
Contributions expected in 2016	2,000	525	-	-
Benefit payments expected in:				
2016	1,548	1,145	457	24
2017	1,491	1,128	470	25
2018	1,411	1,178	481	26
2019	1,382	1,193	490	28
2020	1,342	1,227	497	29
2021 - 2025	6,594	6,359	2,518	170

18. Disclosures about Segments and Related Information

The Upstream, Downstream and Chemical functions best define the operating segments of the business that are reported separately. The factors used to identify these reportable segments are based on the nature of the operations that are undertaken by each segment. The Upstream segment is organized and operates to explore for and produce crude oil and natural gas. The Downstream segment is organized and operates to manufacture and sell petroleum products. The Chemical segment is organized and operates to manufacture and sell petrochemicals. These segments are broadly understood across the petroleum and petrochemical industries.

These functions have been defined as the operating segments of the Corporation because they are the segments (1) that engage in business activities from which revenues are earned and expenses are incurred; (2) whose operating results are regularly reviewed by the Corporation's chief operating decision maker to make decisions about resources to be allocated to the segment and to assess its performance; and (3) for which discrete financial information is available.

Earnings after income tax include transfers at estimated market prices.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

In corporate and financing activities, interest revenue relates to interest earned on cash deposits and marketable securities. Interest expense includes non-debt-related interest expense of $100 million and $129 million in 2015 and 2014, respectively. For 2013, non-debt-related interest expense was a net credit of $123 million, primarily reflecting the effect of credits from the favorable resolution of prior year tax positions.

	Upstream		Downstream		Chemical		Corporate and	Corporate
	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.	Financing	Total
				(millions of dollars)				
As of December 31, 2015								
Earnings after income tax	(1,079)	8,180	1,901	4,656	2,386	2,032	(1,926)	16,150
Earnings of equity companies included above	226	5,831	170	444	144	1,235	(406)	7,644
Sales and other operating revenue *(1)*	8,241	15,812	73,063	134,230	10,880	17,254	8	259,488
Intersegment revenue	4,344	20,839	12,440	22,166	7,442	5,168	274	-
Depreciation and depletion expense	5,301	9,227	664	1,003	375	654	824	18,048
Interest revenue	-	-	-	-	-	-	46	46
Interest expense	26	27	8	4	-	1	245	311
Income taxes	(879)	4,703	866	1,325	646	633	(1,879)	5,415
Additions to property, plant and equipment	6,915	14,561	916	1,477	1,865	629	1,112	27,475
Investments in equity companies	5,160	10,980	95	1,179	125	3,025	(227)	20,337
Total assets	93,648	155,316	16,498	29,808	10,174	18,236	13,078	336,758
As of December 31, 2014								
Earnings after income tax	5,197	22,351	1,618	1,427	2,804	1,511	(2,388)	32,520
Earnings of equity companies included above	1,235	10,859	29	82	186	1,377	(445)	13,323
Sales and other operating revenue *(1)*	14,826	22,336	118,771	199,976	15,115	23,063	18	394,105
Intersegment revenue	7,723	38,846	17,281	44,231	10,117	8,098	274	-
Depreciation and depletion expense	5,139	8,523	654	1,228	370	645	738	17,297
Interest revenue	-	-	-	-	-	-	75	75
Interest expense	40	17	6	4	-	-	219	286
Income taxes	1,300	15,165	610	968	1,032	358	(1,418)	18,015
Additions to property, plant and equipment	9,098	19,225	1,050	1,356	1,564	564	1,399	34,256
Investments in equity companies	5,089	10,877	69	1,006	258	3,026	(308)	20,017
Total assets	92,555	161,033	18,371	33,299	8,798	18,449	16,988	349,493
As of December 31, 2013								
Earnings after income tax	4,191	22,650	2,199	1,250	2,755	1,073	(1,538)	32,580
Earnings of equity companies included above	1,576	11,627	(460)	22	189	1,422	(449)	13,927
Sales and other operating revenue *(1)*	13,712	25,349	123,802	218,904	15,295	23,753	21	420,836
Intersegment revenue	8,343	45,761	20,781	52,624	11,993	8,232	285	-
Depreciation and depletion expense	5,170	8,277	633	1,390	378	632	702	17,182
Interest revenue	-	-	-	-	-	-	87	87
Interest expense	30	26	7	8	1	-	(63)	9
Income taxes	2,197	21,554	721	481	989	363	(2,042)	24,263
Additions to property, plant and equipment	7,480	26,075	616	1,072	840	272	1,386	37,741
Investments in equity companies	4,975	9,740	62	1,749	217	3,103	(227)	19,619
Total assets	88,698	157,465	19,261	40,661	7,816	19,659	13,248	346,808

(1) Sales and other operating revenue includes sales-based taxes of $22,678 million for 2015, $29,342 million for 2014 and $30,589 million for 2013. See Note 1, Summary of Accounting Policies.

Geographic

Sales and other operating revenue *(1)*	**2015**	**2014**	**2013**
		(millions of dollars)	
United States	92,184	148,713	152,820
Non-U.S.	167,304	245,392	268,016
Total	259,488	394,105	420,836
Significant non-U.S. revenue sources include:			
United Kingdom	23,651	31,346	34,061
Canada	22,876	36,072	35,924
Italy	13,795	18,880	19,273
Belgium	13,154	20,953	20,973
France	11,808	17,639	18,444
Singapore	10,790	15,407	15,623
Germany	10,045	14,816	15,701

(1) Sales and other operating revenue includes sales-based taxes of $22,678 million for 2015, $29,342 million for 2014 and $30,589 million for 2013. See Note 1, Summary of Accounting Policies.

Long-lived assets	**2015**	**2014**	**2013**
		(millions of dollars)	
United States	107,039	104,000	98,271
Non-U.S.	144,566	148,668	145,379
Total	251,605	252,668	243,650
Significant non-U.S. long-lived assets include:			
Canada	39,775	43,858	41,522
Australia	15,894	15,328	14,258
Nigeria	12,222	12,265	12,343
Kazakhstan	9,705	9,138	8,530
Singapore	9,681	9,620	9,570
Angola	8,777	9,057	8,262
Papua New Guinea	5,985	6,099	5,768

19. Income, Sales-Based and Other Taxes

	2015			2014			2013		
	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total
					(millions of dollars)				
Income tax expense									
Federal and non-U.S.									
Current	-	7,126	7,126	1,456	14,755	16,211	1,073	22,115	23,188
Deferred - net	(1,166)	(571)	(1,737)	900	1,398	2,298	(116)	757	641
U.S. tax on non-U.S. operations	38	-	38	5	-	5	37	-	37
Total federal and non-U.S.	(1,128)	6,555	5,427	2,361	16,153	18,514	994	22,872	23,866
State *(1)*	(12)	-	(12)	(499)	-	(499)	397	-	397
Total income tax expense	(1,140)	6,555	5,415	1,862	16,153	18,015	1,391	22,872	24,263
Sales-based taxes	6,402	16,276	22,678	6,310	23,032	29,342	5,992	24,597	30,589
All other taxes and duties									
Other taxes and duties	162	27,103	27,265	378	31,908	32,286	955	32,275	33,230
Included in production and manufacturing expenses	1,157	828	1,985	1,454	1,179	2,633	1,318	1,182	2,500
Included in SG&A expenses	150	390	540	155	441	596	150	516	666
Total other taxes and duties	1,469	28,321	29,790	1,987	33,528	35,515	2,423	33,973	36,396
Total	6,731	51,152	57,883	10,159	72,713	82,872	9,806	81,442	91,248

(1) In 2014, state taxes included a favorable adjustment of deferred taxes of approximately $830 million.

All other taxes and duties include taxes reported in production and manufacturing and selling, general and administrative (SG&A) expenses. The above provisions for deferred income taxes include a net charge of $177 million in 2015 and net credits of $40 million in 2014 and $310 million in 2013 for the effect of changes in tax laws and rates.

The reconciliation between income tax expense and a theoretical U.S. tax computed by applying a rate of 35 percent for 2015, 2014 and 2013 is as follows:

	2015	2014	2013
		(millions of dollars)	
Income before income taxes			
United States	147	9,080	9,746
Non-U.S.	21,819	42,550	47,965
Total	21,966	51,630	57,711
Theoretical tax	7,688	18,071	20,199
Effect of equity method of accounting	(2,675)	(4,663)	(4,874)
Non-U.S. taxes in excess of theoretical U.S. tax	1,415	5,442	10,528
U.S. tax on non-U.S. operations	38	5	37
State taxes, net of federal tax benefit	(8)	(324)	258
Other	(1,043)	(516)	(1,885)
Total income tax expense	5,415	18,015	24,263
Effective tax rate calculation			
Income taxes	5,415	18,015	24,263
ExxonMobil share of equity company income taxes	3,011	5,678	6,061
Total income taxes	8,426	23,693	30,324
Net income including noncontrolling interests	16,551	33,615	33,448
Total income before taxes	24,977	57,308	63,772
Effective income tax rate	34%	41%	48%

Deferred income taxes reflect the impact of temporary differences between the amount of assets and liabilities recognized for financial reporting purposes and such amounts recognized for tax purposes.

Deferred tax liabilities/(assets) are comprised of the following at December 31:

Tax effects of temporary differences for:	**2015**	**2014**
	(millions of dollars)	
Property, plant and equipment	49,409	51,643
Other liabilities	4,613	4,359
Total deferred tax liabilities	54,022	56,002
Pension and other postretirement benefits	(6,286)	(8,140)
Asset retirement obligations	(6,277)	(6,162)
Tax loss carryforwards	(4,983)	(4,099)
Other assets	(5,592)	(6,446)
Total deferred tax assets	(23,138)	(24,847)
Asset valuation allowances	1,730	2,570
Net deferred tax liabilities	32,614	33,725

In 2015, asset valuation allowances of $1,730 million decreased by $840 million and included net provisions of $681 million and effects of foreign currency translation of $159 million.

Deferred income tax (assets) and liabilities are included in the balance sheet as shown below. Deferred income tax (assets) and liabilities are classified as current or long term consistent with the classification of the related temporary difference – separately by tax jurisdiction.

Balance sheet classification	**2015**	**2014**
	(millions of dollars)	
Other current assets	(1,329)	(2,001)
Other assets, including intangibles, net	(3,421)	(3,955)
Accounts payable and accrued liabilities	546	451
Deferred income tax liabilities	36,818	39,230
Net deferred tax liabilities	32,614	33,725

The Corporation had $51 billion of indefinitely reinvested, undistributed earnings from subsidiary companies outside the U.S. that were retained to fund prior and future capital project expenditures. Deferred taxes have not been recorded for potential future tax obligations as these earnings are expected to be indefinitely reinvested for the foreseeable future. As of December 31, 2015, it is not practical to estimate the unrecognized deferred tax liability associated with these earnings given the future availability of foreign tax credits and uncertainties about the timing of potential remittances.

Unrecognized Tax Benefits. The Corporation is subject to income taxation in many jurisdictions around the world. Unrecognized tax benefits reflect the difference between positions taken or expected to be taken on income tax returns and the amounts recognized in the financial statements. The following table summarizes the movement in unrecognized tax benefits:

Gross unrecognized tax benefits	2015	2014	2013
		(millions of dollars)	
Balance at January 1	8,986	7,838	7,663
Additions based on current year's tax positions	903	1,454	1,460
Additions for prior years' tax positions	496	448	464
Reductions for prior years' tax positions	(190)	(532)	(249)
Reductions due to lapse of the statute of limitations	(4)	(117)	(588)
Settlements with tax authorities	(725)	(43)	(849)
Foreign exchange effects/other	(70)	(62)	(63)
Balance at December 31	9,396	8,986	7,838

The gross unrecognized tax benefit balances shown above are predominantly related to tax positions that would reduce the Corporation’s effective tax rate if the positions are favorably resolved. Unfavorable resolution of these tax positions generally would not increase the effective tax rate. The 2015, 2014 and 2013 changes in unrecognized tax benefits did not have a material effect on the Corporation’s net income.

Resolution of these tax positions through negotiations with the relevant tax authorities or through litigation will take many years to complete. It is difficult to predict the timing of resolution for tax positions since such timing is not entirely within the control of the Corporation. In the United States, the Corporation has various U.S. federal income tax positions at issue with the Internal Revenue Service for tax years 2006-2011. Unfavorable resolution of these issues would not have a materially adverse effect on the Corporation’s net income or liquidity. The Internal Revenue Service has not completed its audit of tax years after 2011.

It is reasonably possible that the total amount of unrecognized tax benefits could increase by up to 20 percent in the next 12 months, with no material impact on the Corporation’s net income.

The following table summarizes the tax years that remain subject to examination by major tax jurisdiction:

Country of Operation	Open Tax Years
Abu Dhabi	2012 - 2015
Angola	2009 - 2015
Australia	2005, 2008 - 2015
Canada	2008 - 2015
Equatorial Guinea	2007 - 2015
Malaysia	2009 - 2015
Nigeria	2005 - 2015
Norway	2007 - 2015
Qatar	2009 - 2015
Russia	2012 - 2015
United Kingdom	2011 - 2015
United States	2006 - 2015

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

The Corporation incurred $39 million and $42 million in interest expense on income tax reserves in 2015 and 2014, respectively. For 2013, the Corporation’s net interest expense was a credit of $207 million, reflecting the effect of credits from the favorable resolution of prior year tax positions. The related interest payable balances were $223 million and $205 million at December 31, 2015, and 2014, respectively.

SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES (unaudited)

The results of operations for producing activities shown below do not include earnings from other activities that ExxonMobil includes in the Upstream function, such as oil and gas transportation operations, LNG liquefaction and transportation operations, coal and power operations, technical service agreements, other nonoperating activities and adjustments for noncontrolling interests. These excluded amounts for both consolidated and equity companies totaled $831 million in 2015, $3,223 million in 2014, and $886 million in 2013. Oil sands mining operations are included in the results of operations in accordance with Securities and Exchange Commission and Financial Accounting Standards Board rules.

Results of Operations	United States	Canada/ South America	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
2015 - Revenue							
Sales to third parties	4,830	1,756	3,933	1,275	2,651	1,408	15,853
Transfers	2,557	2,858	2,024	8,135	4,490	608	20,672
	7,387	4,614	5,957	9,410	7,141	2,016	36,525
Production costs excluding taxes	4,252	3,690	2,232	1,993	1,562	527	14,256
Exploration expenses	182	473	187	319	254	108	1,523
Depreciation and depletion	5,054	1,315	1,641	3,874	1,569	392	13,845
Taxes other than income	630	111	200	734	706	171	2,552
Related income tax	(976)	(79)	807	1,556	2,117	238	3,663
Results of producing activities for consolidated subsidiaries	(1,755)	(896)	890	934	933	580	686
Equity Companies							
2015 - Revenue							
Sales to third parties	608	-	2,723	-	11,174	-	14,505
Transfers	459	-	31	-	379	-	869
	1,067	-	2,754	-	11,553	-	15,374
Production costs excluding taxes	554	-	565	-	422	-	1,541
Exploration expenses	12	-	21	-	18	-	51
Depreciation and depletion	271	-	146	-	457	-	874
Taxes other than income	47	-	1,258	-	3,197	-	4,502
Related income tax	-	-	263	-	2,559	-	2,822
Results of producing activities for equity companies	183	-	501	-	4,900	-	5,584
Total results of operations	(1,572)	(896)	1,391	934	5,833	580	6,270

Results of Operations	United States	Canada/ South America	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
2014 - Revenue							
Sales to third parties	9,453	2,841	4,608	1,943	4,383	1,374	24,602
Transfers	5,554	5,417	5,206	14,884	7,534	1,553	40,148
	15,007	8,258	9,814	16,827	11,917	2,927	64,750
Production costs excluding taxes	4,637	4,251	3,117	2,248	1,568	583	16,404
Exploration expenses	231	363	274	427	287	87	1,669
Depreciation and depletion	4,877	1,193	1,929	3,387	1,242	454	13,082
Taxes other than income	1,116	160	412	1,539	1,542	399	5,168
Related income tax	1,208	524	2,954	5,515	4,882	435	15,518
Results of producing activities for consolidated subsidiaries	2,938	1,767	1,128	3,711	2,396	969	12,909
Equity Companies							
2014 - Revenue							
Sales to third parties	1,239	-	4,923	-	20,028	-	26,190
Transfers	924	-	63	-	685	-	1,672
	2,163	-	4,986	-	20,713	-	27,862
Production costs excluding taxes	620	-	602	-	548	-	1,770
Exploration expenses	61	-	22	-	219	-	302
Depreciation and depletion	253	-	195	-	383	-	831
Taxes other than income	57	-	2,650	-	5,184	-	7,891
Related income tax	-	-	553	-	5,099	-	5,652
Results of producing activities for equity companies	1,172	-	964	-	9,280	-	11,416
Total results of operations	4,110	1,767	2,092	3,711	11,676	969	24,325
Consolidated Subsidiaries							
2013 - Revenue							
Sales to third parties	8,371	2,252	5,649	3,079	5,427	730	25,508
Transfers	6,505	5,666	5,654	15,738	8,936	1,405	43,904
	14,876	7,918	11,303	18,817	14,363	2,135	69,412
Production costs excluding taxes	4,191	3,965	2,859	2,396	1,763	654	15,828
Exploration expenses	394	386	245	288	571	92	1,976
Depreciation and depletion	4,926	989	1,881	3,269	1,680	334	13,079
Taxes other than income	1,566	94	474	1,583	1,794	427	5,938
Related income tax	1,788	542	4,124	6,841	5,709	202	19,206
Results of producing activities for consolidated subsidiaries	2,011	1,942	1,720	4,440	2,846	426	13,385
Equity Companies							
2013 - Revenue							
Sales to third parties	1,320	-	6,768	-	21,463	-	29,551
Transfers	1,034	-	64	-	6,091	-	7,189
	2,354	-	6,832	-	27,554	-	36,740
Production costs excluding taxes	551	-	459	-	660	-	1,670
Exploration expenses	19	-	15	-	426	-	460
Depreciation and depletion	207	-	169	-	955	-	1,331
Taxes other than income	51	-	3,992	-	7,352	-	11,395
Related income tax	-	-	832	-	8,482	-	9,314
Results of producing activities for equity companies	1,526	-	1,365	-	9,679	-	12,570
Total results of operations	3,537	1,942	3,085	4,440	12,525	426	25,955

Oil and Gas Exploration and Production Costs

The amounts shown for net capitalized costs of consolidated subsidiaries are $14,685 million less at year-end 2015 and $12,856 million less at year-end 2014 than the amounts reported as investments in property, plant and equipment for the Upstream in Note 9. This is due to the exclusion from capitalized costs of certain transportation and research assets and assets relating to LNG operations. Assets related to oil sands and oil shale mining operations are included in the capitalized costs in accordance with Financial Accounting Standards Board rules.

Capitalized Costs	United States	Canada/ South America	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
As of December 31, 2015							
Property (acreage) costs - Proved	15,989	2,202	143	873	1,648	741	21,596
- Unproved	23,071	4,014	44	367	409	116	28,021
Total property costs	39,060	6,216	187	1,240	2,057	857	49,617
Producing assets	84,270	38,108	36,262	49,621	32,359	9,414	250,034
Incomplete construction	6,980	5,708	1,928	4,395	8,620	4,564	32,195
Total capitalized costs	130,310	50,032	38,377	55,256	43,036	14,835	331,846
Accumulated depreciation and depletion	46,864	13,873	29,747	31,579	16,073	4,573	142,709
Net capitalized costs for consolidated subsidiaries	83,446	36,159	8,630	23,677	26,963	10,262	189,137
Equity Companies							
As of December 31, 2015							
Property (acreage) costs - Proved	78	-	4	-	-	-	82
- Unproved	14	-	-	-	59	-	73
Total property costs	92	-	4	-	59	-	155
Producing assets	6,181	-	5,089	-	8,563	-	19,833
Incomplete construction	194	-	77	-	3,727	-	3,998
Total capitalized costs	6,467	-	5,170	-	12,349	-	23,986
Accumulated depreciation and depletion	2,122	-	3,916	-	5,563	-	11,601
Net capitalized costs for equity companies	4,345	-	1,254	-	6,786	-	12,385
Consolidated Subsidiaries							
As of December 31, 2014							
Property (acreage) costs - Proved	14,664	2,598	161	876	1,660	808	20,767
- Unproved	24,062	4,824	74	615	601	136	30,312
Total property costs	38,726	7,422	235	1,491	2,261	944	51,079
Producing assets	79,138	32,635	39,996	44,700	30,219	10,051	236,739
Incomplete construction	7,051	15,344	2,114	6,075	10,163	4,621	45,368
Total capitalized costs	124,915	55,401	42,345	52,266	42,643	15,616	333,186
Accumulated depreciation and depletion	43,031	15,197	32,608	27,995	17,273	4,630	140,734
Net capitalized costs for consolidated subsidiaries	81,884	40,204	9,737	24,271	25,370	10,986	192,452
Equity Companies							
As of December 31, 2014							
Property (acreage) costs - Proved	78	-	4	-	-	-	82
- Unproved	35	-	-	-	59	-	94
Total property costs	113	-	4	-	59	-	176
Producing assets	5,538	-	5,309	-	8,500	-	19,347
Incomplete construction	473	-	251	-	2,972	-	3,696
Total capitalized costs	6,124	-	5,564	-	11,531	-	23,219
Accumulated depreciation and depletion	1,872	-	4,205	-	5,095	-	11,172
Net capitalized costs for equity companies	4,252	-	1,359	-	6,436	-	12,047

Oil and Gas Exploration and Production Costs (continued)

The amounts reported as costs incurred include both capitalized costs and costs charged to expense during the year. Costs incurred also include new asset retirement obligations established in the current year, as well as increases or decreases to the asset retirement obligation resulting from changes in cost estimates or abandonment date. Total consolidated costs incurred in 2015 were $21,887 million, down $7,228 million from 2014, due primarily to lower development costs and property acquisition costs. In 2014 costs were $29,115 million, down $4,508 million from 2013, due primarily to lower property acquisition costs and development costs. Total equity company costs incurred in 2015 were $1,464 million, down $1,213 million from 2014, due primarily to exploration costs.

Costs Incurred in Property Acquisitions, Exploration and Development Activities		United States	Canada/ South America	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)				
During 2015								
Consolidated Subsidiaries								
Property acquisition costs	- Proved	6	-	-	-	31	-	37
	- Unproved	305	39	-	93	1	2	440
Exploration costs		195	621	411	425	405	157	2,214
Development costs		6,774	3,764	1,439	3,149	3,068	1,002	19,196
Total costs incurred for consolidated subsidiaries		7,280	4,424	1,850	3,667	3,505	1,161	21,887
Equity Companies								
Property acquisition costs	- Proved	-	-	-	-	-	-	-
	- Unproved	-	-	-	-	-	-	-
Exploration costs		9	-	41	-	(19)	-	31
Development costs		411	-	143	-	879	-	1,433
Total costs incurred for equity companies		420	-	184	-	860	-	1,464
During 2014								
Consolidated Subsidiaries								
Property acquisition costs	- Proved	80	-	-	-	41	-	121
	- Unproved	1,253	3	19	34	-	-	1,309
Exploration costs		319	453	458	628	467	121	2,446
Development costs		7,540	6,877	1,390	4,255	3,321	1,856	25,239
Total costs incurred for consolidated subsidiaries		9,192	7,333	1,867	4,917	3,829	1,977	29,115
Equity Companies								
Property acquisition costs	- Proved	-	-	-	-	-	-	-
	- Unproved	-	-	-	-	42	-	42
Exploration costs		17	-	45	-	964	-	1,026
Development costs		490	-	233	-	886	-	1,609
Total costs incurred for equity companies		507	-	278	-	1,892	-	2,677
During 2013								
Consolidated Subsidiaries								
Property acquisition costs	- Proved	93	67	-	-	47	-	207
	- Unproved	533	4,270	-	153	-	4	4,960
Exploration costs		557	485	277	361	598	111	2,389
Development costs		6,919	8,527	2,117	3,278	3,493	1,733	26,067
Total costs incurred for consolidated subsidiaries		8,102	13,349	2,394	3,792	4,138	1,848	33,623
Equity Companies								
Property acquisition costs	- Proved	2	-	-	-	-	-	2
	- Unproved	-	-	-	-	17	-	17
Exploration costs		60	-	29	-	494	-	583
Development costs		720	-	192	-	828	-	1,740
Total costs incurred for equity companies		782	-	221	-	1,339	-	2,342

Oil and Gas Reserves

The following information describes changes during the years and balances of proved oil and gas reserves at year-end 2013, 2014, and 2015.

The definitions used are in accordance with the Securities and Exchange Commission's Rule 4-10 (a) of Regulation S-X.

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

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

Revisions can include upward or downward changes in previously estimated volumes of proved reserves for existing fields due to the evaluation or re-evaluation of (1) already available geologic, reservoir or production data, (2) new geologic, reservoir or production data or (3) changes in average prices and year-end costs that are used in the estimation of reserves. This category can also include significant changes in either development strategy or production equipment/facility capacity.

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

Proved reserves include 100 percent of each majority-owned affiliate's participation in proved reserves and ExxonMobil's ownership percentage of the proved reserves of equity companies, but exclude royalties and quantities due others. Gas reserves exclude the gaseous equivalent of liquids expected to be removed from the gas on leases, at field facilities and at gas processing plants. These liquids are included in net proved reserves of crude oil and natural gas liquids.

In the proved reserves tables, consolidated reserves and equity company reserves are reported separately. However, the Corporation does not view equity company reserves any differently than those from consolidated companies.

Reserves reported under production sharing and other nonconcessionary agreements are based on the economic interest as defined by the specific fiscal terms in the agreement. The production and reserves that we report for these types of arrangements typically vary inversely with oil and gas price changes. As oil and gas prices increase, the cash flow and value received by the company increase; however, the production volumes and reserves required to achieve this value will typically be lower because of the higher prices. When prices decrease, the opposite effect generally occurs. The percentage of total liquids and natural gas proved reserves (consolidated subsidiaries plus equity companies) at year-end 2015 that were associated with production sharing contract arrangements was 10 percent of liquids, 10 percent of natural gas and 10 percent on an oil-equivalent basis (gas converted to oil-equivalent at 6 billion cubic feet = 1 million barrels).

Net proved developed reserves are those volumes that are 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 to the cost of a new well. Net proved undeveloped reserves are those volumes that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Crude oil and natural gas liquids and natural gas production quantities shown are the net volumes withdrawn from ExxonMobil's oil and gas reserves. The natural gas quantities differ from the quantities of gas delivered for sale by the producing function as reported in the Operating Summary due to volumes consumed or flared and inventory changes.

The changes between 2014 year-end proved reserves and 2015 year-end proved reserves primarily reflect extensions and purchases in the United States and Asia, and revisions in the United States and Canada. Due to low natural gas prices during 2015, the Corporation reclassified approximately 4,800 billion cubic feet of natural gas reserves in the United States which no longer meet the SEC definition of proved reserves.

Crude Oil, Natural Gas Liquids, Bitumen and Synthetic Oil Proved Reserves

	Crude Oil							Natural Gas Liquids *(1)*	Bitumen	Synthetic Oil	
	United States	Canada/ S. Amer.	Europe	Africa	Asia	Australia/ Oceania	Total	Worldwide	Canada/ S. Amer.	Canada/ S. Amer.	Total
						(millions of barrels)					
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2013	1,905	270	289	1,293	1,604	163	5,524	1,031	3,560	599	10,714
Revisions	21	20	13	13	411	3	481	(1)	124	4	608
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	15	15	-	-	-	-	30	27	-	-	57
Sales	(18)	-	-	-	-	-	(18)	(6)	-	-	(24)
Extensions/discoveries	188	-	-	52	262	-	502	39	-	-	541
Production	(103)	(21)	(57)	(165)	(114)	(11)	(471)	(67)	(54)	(24)	(616)
December 31, 2013	2,008	284	245	1,193	2,163	155	6,048	1,023	3,630	579	11,280
Proportional interest in proved reserves of equity companies											
January 1, 2013	340	-	28	-	1,260	-	1,628	474	-	-	2,102
Revisions	12	-	2	-	21	-	35	8	-	-	43
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-	-
Sales	-	-	-	-	-	-	-	-	-	-	-
Extensions/discoveries	-	-	-	-	-	-	-	-	-	-	-
Production	(22)	-	(2)	-	(136)	-	(160)	(26)	-	-	(186)
December 31, 2013	330	-	28	-	1,145	-	1,503	456	-	-	1,959
Total liquids proved reserves at December 31, 2013	2,338	284	273	1,193	3,308	155	7,551	1,479	3,630	579	13,239
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2014	2,008	284	245	1,193	2,163	155	6,048	1,023	3,630	579	11,280
Revisions	37	23	9	42	42	-	153	59	669	(23)	858
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	42	-	-	-	-	-	42	11	-	-	53
Sales	(24)	(11)	-	-	(1)	-	(36)	(14)	-	-	(50)
Extensions/discoveries	156	5	-	38	35	-	234	79	-	-	313
Production	(111)	(19)	(55)	(171)	(107)	(14)	(477)	(66)	(66)	(22)	(631)
December 31, 2014	2,108	282	199	1,102	2,132	141	5,964	1,092	4,233	534	11,823
Proportional interest in proved reserves of equity companies											
January 1, 2014	330	-	28	-	1,145	-	1,503	456	-	-	1,959
Revisions	19	-	1	-	41	-	61	5	-	-	66
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	1	-	-	-	-	-	1	-	-	-	1
Sales	-	-	-	-	-	-	-	-	-	-	-
Extensions/discoveries	1	-	-	-	-	-	1	-	-	-	1
Production	(23)	-	(2)	-	(86)	-	(111)	(26)	-	-	(137)
December 31, 2014	328	-	27	-	1,100	-	1,455	435	-	-	1,890
Total liquids proved reserves at December 31, 2014	2,436	282	226	1,102	3,232	141	7,419	1,527	4,233	534	13,713

(See footnote on next page)

Crude Oil, Natural Gas Liquids, Bitumen and Synthetic Oil Proved Reserves (continued)

	Crude Oil							Natural Gas Liquids *(1)*	Bitumen	Synthetic Oil	
	United States	Canada/ S. Amer.	Europe	Africa	Asia	Australia/ Oceania	Total	Worldwide	Canada/ S. Amer.	Canada/ S. Amer.	Total
						(millions of barrels)					
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2015	2,108	282	199	1,102	2,132	141	5,964	1,092	4,233	534	11,823
Revisions	(150)	(10)	46	48	123	(4)	53	(95)	433	68	459
Improved recovery	-	-	2	-	-	-	2	-	-	-	2
Purchases	161	3	1	-	-	-	165	46	-	-	211
Sales	(9)	-	(1)	-	(2)	-	(12)	(1)	-	-	(13)
Extensions/discoveries	387	2	-	-	698	-	1,087	101	-	-	1,188
Production	(119)	(17)	(63)	(187)	(126)	(12)	(524)	(65)	(106)	(21)	(716)
December 31, 2015	2,378	260	184	963	2,825	125	6,735	1,078	4,560	581	12,954
Proportional interest in proved reserves of equity companies											
January 1, 2015	328	-	27	-	1,100	-	1,455	435	-	-	1,890
Revisions	(52)	-	(1)	-	65	-	12	5	-	-	17
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-	-
Sales	-	-	-	-	-	-	-	-	-	-	-
Extensions/discoveries	-	-	-	-	-	-	-	-	-	-	-
Production	(22)	-	(1)	-	(88)	-	(111)	(26)	-	-	(137)
December 31, 2015	254	-	25	-	1,077	-	1,356	414	-	-	1,770
Total liquids proved reserves at December 31, 2015	2,632	260	209	963	3,902	125	8,091	1,492	4,560	581	14,724

(1) Includes total proved reserves attributable to Imperial Oil Limited of 11 million barrels in 2013, 8 million barrels in 2014 and 7 million barrels in 2015, as well as proved developed reserves of 9 million barrels in 2013, 5 million barrels in 2014 and 4 million barrels in 2015, and in addition, proved undeveloped reserves of 2 million barrels in 2013, 3 million barrels in 2014 and 3 million in 2015, in which there is a 30.4 percent noncontrolling interest.

Crude Oil, Natural Gas Liquids, Bitumen and Synthetic Oil Proved Reserves (continued)

	Crude Oil and Natural Gas Liquids							Bitumen	Synthetic Oil	
	United States	Canada/ South Amer. *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total	Canada/ South Amer. *(2)*	Canada/ South Amer. *(3)*	Total
					(millions of barrels)					
Proved developed reserves, as of December 31, 2013										
Consolidated subsidiaries	1,469	126	249	945	1,663	105	4,557	1,810	579	6,946
Equity companies	268	-	27	-	1,292	-	1,587	-	-	1,587
Proved undeveloped reserves, as of December 31, 2013										
Consolidated subsidiaries	1,068	177	51	449	638	131	2,514	1,820	-	4,334
Equity companies	77	-	1	-	294	-	372	-	-	372
Total liquids proved reserves at December 31, 2013	2,882	303	328	1,394	3,887	236	9,030	3,630	579	13,239
Proved developed reserves, as of December 31, 2014										
Consolidated subsidiaries	1,502	111	205	894	1,615	112	4,439	2,122	534	7,095
Equity companies	269	-	26	-	1,188	-	1,483	-	-	1,483
Proved undeveloped reserves, as of December 31, 2014										
Consolidated subsidiaries	1,234	190	42	401	651	99	2,617	2,111	-	4,728
Equity companies	75	-	1	-	331	-	407	-	-	407
Total liquids proved reserves at December 31, 2014	3,080	301	274	1,295	3,785	211	8,946	4,233	534	13,713
Proved developed reserves, as of December 31, 2015										
Consolidated subsidiaries	1,427	101	192	900	1,707	107	4,434	4,108	581	9,123
Equity companies	228	-	25	-	1,151	-	1,404	-	-	1,404
Proved undeveloped reserves, as of December 31, 2015										
Consolidated subsidiaries	1,619	174	34	230	1,239	83	3,379	452	-	3,831
Equity companies	39	-	-	-	327	-	366	-	-	366
Total liquids proved reserves at December 31, 2015	3,313	275	251	1,130	4,424	190	9,583 *(4)*	4,560	581	14,724

(1) Includes total proved reserves attributable to Imperial Oil Limited of 62 million barrels in 2013, 46 million barrels in 2014 and 34 million barrels in 2015, as well as proved developed reserves of 55 million barrels in 2013, 36 million barrels in 2014 and 23 million barrels in 2015, and in addition, proved undeveloped reserves of 7 million barrels in 2013, 10 million barrels in 2014 and 11 million barrels in 2015, in which there is a 30.4 percent noncontrolling interest.

(2) Includes total proved reserves attributable to Imperial Oil Limited of 2,867 million barrels in 2013, 3,274 million barrels in 2014 and 3,515 million barrels in 2015, as well as proved developed reserves of 1,417 million barrels in 2013, 1,635 million barrels in 2014 and 3,063 million barrels in 2015, and in addition, proved undeveloped reserves of 1,450 million barrels in 2013, 1,639 million barrels in 2014 and 452 million barrels in 2015, in which there is a 30.4 percent noncontrolling interest.

(3) Includes total proved reserves attributable to Imperial Oil Limited of 579 million barrels in 2013, 534 million barrels in 2014 and 581 million barrels in 2015, as well as proved developed reserves of 579 million barrels in 2013, 534 million barrels in 2014 and 581 million barrels in 2015, in which there is a 30.4 percent noncontrolling interest.

(4) See previous pages for natural gas liquids proved reserves attributable to consolidated subsidiaries and equity companies. For additional information on natural gas liquids proved reserves see Item 2. Properties in ExxonMobil's 2015 Form 10-K.

Natural Gas and Oil-Equivalent Proved Reserves

	Natural Gas							Oil-Equivalent Total All Products *(2)*
	United States	Canada/ South Amer. *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total	
	(billions of cubic feet)							*(millions of oil-equivalent barrels)*
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2013	26,215	925	3,249	929	5,845	7,568	44,731	18,169
Revisions	79	(56)	61	(22)	364	86	512	693
Improved recovery	-	-	-	-	-	-	-	-
Purchases	153	522	-	-	-	-	675	170
Sales	(106)	(8)	-	-	-	-	(114)	(43)
Extensions/discoveries	1,083	2	-	-	14	-	1,099	724
Production	(1,404)	(150)	(500)	(40)	(489)	(139)	(2,722)	(1,069)
December 31, 2013	26,020	1,235	2,810	867	5,734	7,515	44,181	18,644
Proportional interest in proved reserves of equity companies								
January 1, 2013	155	-	9,535	-	19,670	-	29,360	6,995
Revisions	135	-	58	-	9	-	202	77
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Sales	-	-	-	-	-	-	-	-
Extensions/discoveries	1	-	8	-	-	-	9	2
Production	(10)	-	(717)	-	(1,165)	-	(1,892)	(502)
December 31, 2013	281	-	8,884	-	18,514	-	27,679	6,572
Total proved reserves at December 31, 2013	26,301	1,235	11,694	867	24,248	7,515	71,860	25,216
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2014	26,020	1,235	2,810	867	5,734	7,515	44,181	18,644
Revisions	49	80	49	(21)	173	(38)	292	906
Improved recovery	-	-	-	-	-	-	-	-
Purchases	60	-	-	-	-	-	60	63
Sales	(314)	(48)	-	-	(3)	-	(365)	(111)
Extensions/discoveries	1,518	91	-	7	4	-	1,620	583
Production	(1,346)	(132)	(476)	(42)	(448)	(201)	(2,645)	(1,072)
December 31, 2014	25,987	1,226	2,383	811	5,460	7,276	43,143	19,013
Proportional interest in proved reserves of equity companies								
January 1, 2014	281	-	8,884	-	18,514	-	27,679	6,572
Revisions	5	-	117	-	110	-	232	105
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	1
Sales	-	-	-	-	-	-	-	-
Extensions/discoveries	1	-	-	-	-	-	1	1
Production	(15)	-	(583)	-	(1,119)	-	(1,717)	(423)
December 31, 2014	272	-	8,418	-	17,505	-	26,195	6,256
Total proved reserves at December 31, 2014	26,259	1,226	10,801	811	22,965	7,276	69,338	25,269

(See footnotes on next page)

Natural Gas and Oil-Equivalent Proved Reserves (continued)

	Natural Gas							
	United States	Canada/ South Amer. *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total	**Oil-Equivalent Total All Products *(2)***
	(billions of cubic feet)							*(millions of oil-equivalent barrels)*
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2015	25,987	1,226	2,383	811	5,460	7,276	43,143	19,013
Revisions	(6,693)	(45)	63	25	303	23	(6,324)	(595)
Improved recovery	-	-	-	-	-	-	-	2
Purchases	182	29	-	-	-	-	211	246
Sales	(9)	(5)	(56)	-	(89)	-	(159)	(39)
Extensions/discoveries	1,167	34	-	-	102	-	1,303	1,405
Production	(1,254)	(112)	(434)	(43)	(447)	(258)	(2,548)	(1,140)
December 31, 2015	19,380	1,127	1,956	793	5,329	7,041	35,626	18,892
Proportional interest in proved reserves of equity companies								
January 1, 2015	272	-	8,418	-	17,505	-	26,195	6,256
Revisions	(38)	-	(83)	-	86	-	(35)	11
Improved recovery	-	-	-	-	-	-	-	-
Purchases	1	-	-	-	-	-	1	-
Sales	-	-	-	-	-	-	-	-
Extensions/discoveries	-	-	-	-	-	-	-	-
Production	(15)	-	(432)	-	(1,130)	-	(1,577)	(400)
December 31, 2015	220	-	7,903	-	16,461	-	24,584	5,867
Total proved reserves at December 31, 2015	19,600	1,127	9,859	793	21,790	7,041	60,210	24,759

(1) Includes total proved reserves attributable to Imperial Oil Limited of 678 billion cubic feet in 2013, 627 billion cubic feet in 2014 and 583 billion cubic feet in 2015, as well as proved developed reserves of 368 billion cubic feet in 2013, 300 billion cubic feet in 2014 and 283 billion cubic feet in 2015, and in addition, proved undeveloped reserves of 310 billion cubic feet in 2013, 327 billion cubic feet in 2014 and 300 billion cubic feet in 2015, in which there is a 30.4 percent noncontrolling interest.

(2) Natural gas is converted to oil-equivalent basis at six million cubic feet per one thousand barrels.

Natural Gas and Oil-Equivalent Proved Reserves (continued)

	Natural Gas							
	United States	Canada/ South Amer. *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total	**Oil-Equivalent Total All Products *(2)***
	(billions of cubic feet)							*(millions of oil-equivalent barrels)*
Proved developed reserves, as of December 31, 2013								
Consolidated subsidiaries	14,655	664	2,189	779	5,241	969	24,497	11,029
Equity companies	197	-	6,852	-	17,288	-	24,337	5,643
Proved undeveloped reserves, as of December 31, 2013								
Consolidated subsidiaries	11,365	571	621	88	493	6,546	19,684	7,615
Equity companies	84	-	2,032	-	1,226	-	3,342	929
Total proved reserves at December 31, 2013	26,301	1,235	11,694	867	24,248	7,515	71,860	25,216
Proved developed reserves, as of December 31, 2014								
Consolidated subsidiaries	14,169	615	1,870	764	5,031	2,179	24,628	11,199
Equity companies	194	-	6,484	-	16,305	-	22,983	5,314
Proved undeveloped reserves, as of December 31, 2014								
Consolidated subsidiaries	11,818	611	513	47	429	5,097	18,515	7,814
Equity companies	78	-	1,934	-	1,200	-	3,212	942
Total proved reserves at December 31, 2014	26,259	1,226	10,801	811	22,965	7,276	69,338	25,269
Proved developed reserves, as of December 31, 2015								
Consolidated subsidiaries	13,353	552	1,593	750	4,917	1,962	23,127	12,977
Equity companies	156	-	6,146	-	15,233	-	21,535	4,993
Proved undeveloped reserves, as of December 31, 2015								
Consolidated subsidiaries	6,027	575	363	43	412	5,079	12,499	5,915
Equity companies	64	-	1,757	-	1,228	-	3,049	874
Total proved reserves at December 31, 2015	19,600	1,127	9,859	793	21,790	7,041	60,210	24,759

(See footnotes on previous page)

Standardized Measure of Discounted Future Cash Flows

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

Standardized Measure of Discounted Future Cash Flows	United States	Canada/ South America *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
As of December 31, 2013							
Future cash inflows from sales of oil and gas	276,051	293,377	58,235	146,407	245,482	87,808	1,107,360
Future production costs	113,571	106,884	18,053	30,960	57,328	22,507	349,303
Future development costs	40,702	43,102	15,215	14,300	10,666	10,191	134,176
Future income tax expenses	50,144	31,901	17,186	53,766	117,989	16,953	287,939
Future net cash flows	71,634	111,490	7,781	47,381	59,499	38,157	335,942
Effect of discounting net cash flows at 10%	42,336	78,700	1,278	18,406	34,878	21,266	196,864
Discounted future net cash flows	29,298	32,790	6,503	28,975	24,621	16,891	139,078
Equity Companies							
As of December 31, 2013							
Future cash inflows from sales of oil and gas	34,957	-	82,539	-	324,666	-	442,162
Future production costs	8,231	-	60,518	-	107,656	-	176,405
Future development costs	3,675	-	2,994	-	8,756	-	15,425
Future income tax expenses	-	-	7,237	-	70,887	-	78,124
Future net cash flows	23,051	-	11,790	-	137,367	-	172,208
Effect of discounting net cash flows at 10%	12,994	-	5,549	-	72,798	-	91,341
Discounted future net cash flows	10,057	-	6,241	-	64,569	-	80,867
Total consolidated and equity interests in standardized measure of discounted future net cash flows	39,355	32,790	12,744	28,975	89,190	16,891	219,945

(1) Includes discounted future net cash flows attributable to Imperial Oil Limited of $25,160 million in 2013, in which there is a 30.4 percent noncontrolling interest.

Standardized Measure of Discounted Future Cash Flows (continued)	United States	Canada/ South America *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
As of December 31, 2014							
Future cash inflows from sales of oil and gas	283,767	354,223	42,882	125,125	224,885	78,365	1,109,247
Future production costs	116,929	140,368	14,358	27,917	57,562	20,467	377,601
Future development costs	42,276	48,525	13,000	14,603	12,591	8,956	139,951
Future income tax expenses	49,807	36,787	10,651	44,977	102,581	15,050	259,853
Future net cash flows	74,755	128,543	4,873	37,628	52,151	33,892	331,842
Effect of discounting net cash flows at 10%	44,101	87,799	(52)	13,831	30,173	17,326	193,178
Discounted future net cash flows	30,654	40,744	4,925	23,797	21,978	16,566	138,664
Equity Companies							
As of December 31, 2014							
Future cash inflows from sales of oil and gas	31,924	-	71,031	-	286,124	-	389,079
Future production costs	8,895	-	50,826	-	99,193	-	158,914
Future development costs	3,386	-	2,761	-	11,260	-	17,407
Future income tax expenses	-	-	6,374	-	59,409	-	65,783
Future net cash flows	19,643	-	11,070	-	116,262	-	146,975
Effect of discounting net cash flows at 10%	10,970	-	5,534	-	61,550	-	78,054
Discounted future net cash flows	8,673	-	5,536	-	54,712	-	68,921
Total consolidated and equity interests in standardized measure of discounted future net cash flows	39,327	40,744	10,461	23,797	76,690	16,566	207,585
Consolidated Subsidiaries							
As of December 31, 2015							
Future cash inflows from sales of oil and gas	144,910	176,452	23,330	57,702	156,378	29,535	588,307
Future production costs	82,678	115,285	8,735	17,114	50,745	8,889	283,446
Future development costs	35,016	36,923	11,332	11,170	15,371	8,237	118,049
Future income tax expenses	5,950	3,042	1,780	14,018	62,353	5,012	92,155
Future net cash flows	21,266	21,202	1,483	15,400	27,909	7,397	94,657
Effect of discounting net cash flows at 10%	13,336	13,415	(945)	5,226	17,396	3,454	51,882
Discounted future net cash flows	7,930	7,787	2,428	10,174	10,513	3,943	42,775
Equity Companies							
As of December 31, 2015							
Future cash inflows from sales of oil and gas	13,065	-	49,061	-	143,692	-	205,818
Future production costs	6,137	-	35,409	-	57,080	-	98,626
Future development costs	2,903	-	2,190	-	12,796	-	17,889
Future income tax expenses	-	-	4,027	-	24,855	-	28,882
Future net cash flows	4,025	-	7,435	-	48,961	-	60,421
Effect of discounting net cash flows at 10%	1,936	-	4,287	-	26,171	-	32,394
Discounted future net cash flows	2,089	-	3,148	-	22,790	-	28,027
Total consolidated and equity interests in standardized measure of discounted future net cash flows	10,019	7,787	5,576	10,174	33,303	3,943	70,802

(1) Includes discounted future net cash flows attributable to Imperial Oil Limited of $30,189 million in 2014 and $5,607 million in 2015, in which there is a 30.4 percent noncontrolling interest.

Change in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

Consolidated and Equity Interests	2013		
	Consolidated Subsidiaries	Share of Equity Method Investees	Total Consolidated and Equity Interests
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2012	137,549	87,238	224,787
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	11,928	48	11,976
Changes in value of previous-year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of production (lifting) costs	(48,742)	(23,757)	(72,499)
Development costs incurred during the year	24,821	1,389	26,210
Net change in prices, lifting and development costs	(32,423)	(5,296)	(37,719)
Revisions of previous reserves estimates	24,353	4,960	29,313
Accretion of discount	20,596	9,830	30,426
Net change in income taxes	996	6,455	7,451
Total change in the standardized measure during the year	1,529	(6,371)	(4,842)
Discounted future net cash flows as of December 31, 2013	139,078	80,867	219,945

Consolidated and Equity Interests	2014		
	Consolidated Subsidiaries	Share of Equity Method Investees	Total Consolidated and Equity Interests
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2013	139,078	80,867	219,945
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	3,497	94	3,591
Changes in value of previous-year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of production (lifting) costs	(44,446)	(18,366)	(62,812)
Development costs incurred during the year	24,189	1,453	25,642
Net change in prices, lifting and development costs	(50,672)	(13,165)	(63,837)
Revisions of previous reserves estimates	35,072	3,298	38,370
Accretion of discount	20,098	8,987	29,085
Net change in income taxes	11,848	5,753	17,601
Total change in the standardized measure during the year	(414)	(11,946)	(12,360)
Discounted future net cash flows as of December 31, 2014	138,664	68,921	207,585

Change in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

Consolidated and Equity Interests (continued)	**2015**		
	Consolidated Subsidiaries	**Share of Equity Method Investees**	**Total Consolidated and Equity Interests**
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2014	138,664	68,921	207,585
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	5,678	-	5,678
Changes in value of previous-year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of production (lifting) costs	(20,694)	(9,492)	(30,186)
Development costs incurred during the year	18,359	1,198	19,557
Net change in prices, lifting and development costs	(203,224)	(57,478)	(260,702)
Revisions of previous reserves estimates	6,888	(134)	6,754
Accretion of discount	17,828	7,257	25,085
Net change in income taxes	79,276	17,755	97,031
Total change in the standardized measure during the year	(95,889)	(40,894)	(136,783)
Discounted future net cash flows as of December 31, 2015	42,775	28,027	70,802

OPERATING SUMMARY (unaudited)

	2015	2014	2013	2012	2011
Production of crude oil, natural gas liquids, bitumen and synthetic oil					
Net production			*(thousands of barrels daily)*		
United States	476	454	431	418	423
Canada/South America	402	301	280	251	252
Europe	204	184	190	207	270
Africa	529	489	469	487	508
Asia	684	624	784	772	808
Australia/Oceania	50	59	48	50	51
Worldwide	2,345	2,111	2,202	2,185	2,312
Natural gas production available for sale					
Net production			*(millions of cubic feet daily)*		
United States	3,147	3,404	3,545	3,822	3,917
Canada/South America	261	310	354	362	412
Europe	2,286	2,816	3,251	3,220	3,448
Africa	5	4	6	17	7
Asia	4,139	4,099	4,329	4,538	5,047
Australia/Oceania	677	512	351	363	331
Worldwide	10,515	11,145	11,836	12,322	13,162
			(thousands of oil-equivalent barrels daily)		
Oil-equivalent production *(1)*	4,097	3,969	4,175	4,239	4,506
Refinery throughput			*(thousands of barrels daily)*		
United States	1,709	1,809	1,819	1,816	1,784
Canada	386	394	426	435	430
Europe	1,496	1,454	1,400	1,504	1,528
Asia Pacific	647	628	779	998	1,180
Other Non-U.S.	194	191	161	261	292
Worldwide	4,432	4,476	4,585	5,014	5,214
Petroleum product sales *(2)*					
United States	2,521	2,655	2,609	2,569	2,530
Canada	488	496	464	453	455
Europe	1,542	1,555	1,497	1,571	1,596
Asia Pacific and other Eastern Hemisphere	1,124	1,085	1,206	1,381	1,556
Latin America	79	84	111	200	276
Worldwide	5,754	5,875	5,887	6,174	6,413
Gasoline, naphthas	2,363	2,452	2,418	2,489	2,541
Heating oils, kerosene, diesel oils	1,924	1,912	1,838	1,947	2,019
Aviation fuels	413	423	462	473	492
Heavy fuels	377	390	431	515	588
Specialty petroleum products	677	698	738	750	773
Worldwide	5,754	5,875	5,887	6,174	6,413
Chemical prime product sales *(2)(3)*			*(thousands of metric tons)*		
United States	9,664	9,528	9,679	9,381	9,250
Non-U.S.	15,049	14,707	14,384	14,776	15,756
Worldwide	24,713	24,235	24,063	24,157	25,006

Operating statistics include 100 percent of operations of majority-owned subsidiaries; for other companies, crude production, gas, petroleum product and chemical prime product sales include ExxonMobil's ownership percentage and refining throughput includes quantities processed for ExxonMobil. Net production excludes royalties and quantities due others when produced, whether payment is made in kind or cash.

(1) Gas converted to oil-equivalent at 6 million cubic feet = 1 thousand barrels.

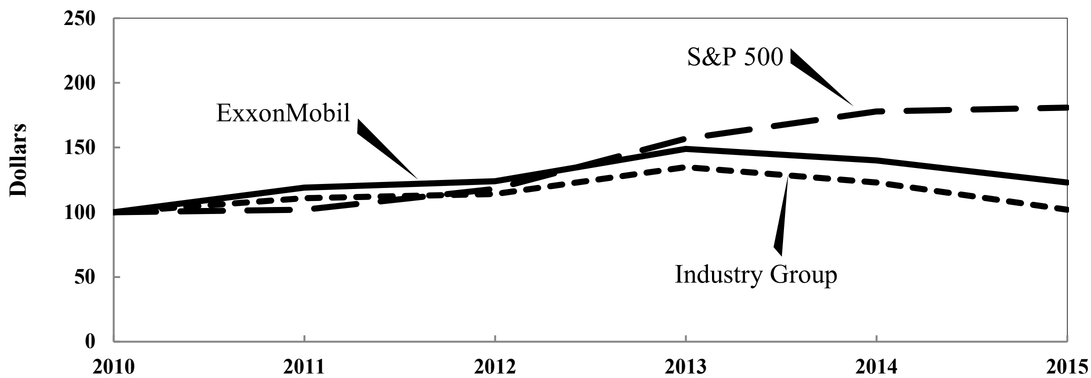
(2) Petroleum product and chemical prime product sales data reported net of purchases/sales contracts with the same counterparty.

(3) Prime product sales are total product sales excluding carbon black oil and sulfur. Prime product sales include ExxonMobil's share of equity company volumes and finished-product transfers to the Downstream.

STOCK PERFORMANCE GRAPHS (unaudited)

Annual total returns to ExxonMobil shareholders were 20 percent in 2013, -6 percent in 2014, and -13 percent in 2015. Total returns mean share price increase plus dividends paid, with dividends reinvested. The graphs below show the relative investment performance of ExxonMobil common stock, the S&P 500, and an industry competitor group over the last five and 10 years. The industry competitor group consists of four other international integrated oil companies: BP, Chevron, Royal Dutch Shell, and Total.

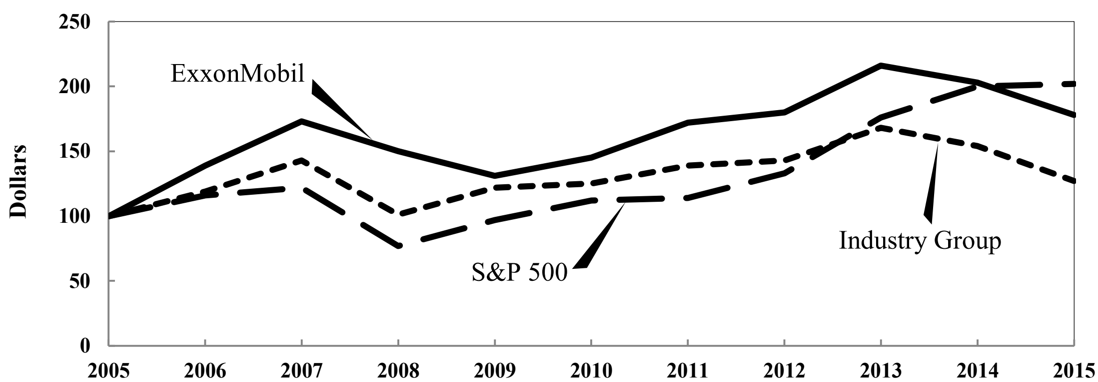
FIVE-YEAR CUMULATIVE TOTAL RETURNS
Value of $100 Invested at Year-End 2010



Fiscal Years Ended December 31

ExxonMobil	100	119	124	149	140	123
S&P 500	100	102	118	157	178	181
Industry Group	100	111	114	135	123	102

TEN-YEAR CUMULATIVE TOTAL RETURNS
Value of $100 Invested at Year-End 2005



Fiscal Years Ended December 31

ExxonMobil	100	139	173	150	131	145	172	180	216	203	178
S&P 500	100	116	122	77	97	112	114	133	176	200	202
Industry Group	100	119	143	101	122	125	139	143	168	154	127

Printed entirely on recycled paper. 002CSN61B6