ExxonMobil

2012

Financial Statements and Supplemental Information

For the Fiscal Year Ended December 31, 2012

FINANCIAL SECTION

TABLE OF CONTENTS

BUSINESS PROFILE

Financial	Earnings After Income Taxes 2012	2011	Average Capital Employed 2012	2011	Return on Average Capital Employed 2012	2011	Capital and Exploration Expenditures 2012	2011
	(millions of dollars)				(percent)		(millions of dollars)	
Upstream								
United States	3,925	5,096	57,631	54,994	6.8	9.3	11,080	10,741
Non-U.S.	25,970	29,343	81,811	74,813	31.7	39.2	25,004	22,350
Total	29,895	34,439	139,442	129,807	21.4	26.5	36,084	33,091
Downstream								
United States	3,575	2,268	4,630	5,340	77.2	42.5	634	518
Non-U.S.	9,615	2,191	19,401	18,048	49.6	12.1	1,628	1,602
Total	13,190	4,459	24,031	23,388	54.9	19.1	2,262	2,120
Chemical								
United States	2,220	2,215	4,671	4,791	47.5	46.2	408	290
Non-U.S.	1,678	2,168	15,477	15,007	10.8	14.4	1,010	1,160
Total	3,898	4,383	20,148	19,798	19.3	22.1	1,418	1,450
Corporate and financing	(2,103)	(2,221)	(4,527)	(2,272)	-	-	35	105
Total	44,880	41,060	179,094	170,721	25.4	24.2	39,799	36,766

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

Operating	2012	2011
	(thousands of barrels daily)	
Net liquids production		
United States	418	423
Non-U.S.	1,767	1,889
Total	2,185	2,312
	(millions of cubic feet daily)	
Natural gas production available for sale		
United States	3,822	3,917
Non-U.S.	8,500	9,245
Total	12,322	13,162
	(thousands of oil-equivalent barrels daily)	
Oil-equivalent production *(1)*	4,239	4,506

	2012	2011
	(thousands of barrels daily)	
Refinery throughput		
United States	1,816	1,784
Non-U.S.	3,198	3,430
Total	5,014	5,214
	(thousands of barrels daily)	
Petroleum product sales		
United States	2,569	2,530
Non-U.S.	3,605	3,883
Total	6,174	6,413
	(thousands of metric tons)	
Chemical prime product sales *(2)*		
United States	9,381	9,250
Non-U.S.	14,776	15,756
Total	24,157	25,006

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

(2) Prime product sales include ExxonMobil's share of equity-company volumes and finished-product transfers to the Downstream.

FINANCIAL SUMMARY

	2012	2011	2010	2009	2008
	(millions of dollars, except per share amounts)				
Sales and other operating revenue *(1)*	453,123	467,029	370,125	301,500	459,579
Earnings					
Upstream	29,895	34,439	24,097	17,107	35,402
Downstream	13,190	4,459	3,567	1,781	8,151
Chemical	3,898	4,383	4,913	2,309	2,957
Corporate and financing	(2,103)	(2,221)	(2,117)	(1,917)	(1,290)
Net income attributable to ExxonMobil	44,880	41,060	30,460	19,280	45,220
Earnings per common share	9.70	8.43	6.24	3.99	8.70
Earnings per common share – assuming dilution	9.70	8.42	6.22	3.98	8.66
Cash dividends per common share	2.18	1.85	1.74	1.66	1.55
Earnings to average ExxonMobil share of equity (percent)	28.0	27.3	23.7	17.3	38.5
Working capital	321	(4,542)	(3,649)	3,174	23,166
Ratio of current assets to current liabilities (times)	1.01	0.94	0.94	1.06	1.47
Additions to property, plant and equipment	35,179	33,638	74,156	22,491	19,318
Property, plant and equipment, less allowances	226,949	214,664	199,548	139,116	121,346
Total assets	333,795	331,052	302,510	233,323	228,052
Exploration expenses, including dry holes	1,840	2,081	2,144	2,021	1,451
Research and development costs	1,042	1,044	1,012	1,050	847
Long-term debt	7,928	9,322	12,227	7,129	7,025
Total debt	11,581	17,033	15,014	9,605	9,425
Fixed-charge coverage ratio (times)	62.4	53.4	42.2	25.8	54.6
Debt to capital (percent)	6.3	9.6	9.0	7.7	7.4
Net debt to capital (percent) *(2)*	1.2	2.6	4.5	(1.0)	(23.0)
ExxonMobil share of equity at year-end	165,863	154,396	146,839	110,569	112,965
ExxonMobil share of equity per common share	36.84	32.61	29.48	23.39	22.70
Weighted average number of common shares outstanding (millions)	4,628	4,870	4,885	4,832	5,194
Number of regular employees at year-end (thousands) *(3)*	76.9	82.1	83.6	80.7	79.9
CORS employees not included above (thousands) *(4)*	11.1	17.0	20.1	22.0	24.8

(1) Sales and other operating revenue includes sales-based taxes of $32,409 million for 2012, $33,503 million for 2011, $28,547 million for 2010, $25,936 million for 2009 and $34,508 million for 2008.

(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	**2012**	**2011**	**2010**
		(millions of dollars)	
Net cash provided by operating activities	56,170	55,345	48,413
Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments	7,655	11,133	3,261
Cash flow from operations and asset sales	63,825	66,478	51,674

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	**2012**	**2011**	**2010**
		(millions of dollars)	
Business uses: asset and liability perspective			
Total assets	333,795	331,052	302,510
Less liabilities and noncontrolling interests share of assets and liabilities			
Total current liabilities excluding notes and loans payable	(60,486)	(69,794)	(59,846)
Total long-term liabilities excluding long-term debt	(90,068)	(83,481)	(74,971)
Noncontrolling interests share of assets and liabilities	(6,235)	(7,314)	(6,532)
Add ExxonMobil share of debt-financed equity company net assets	5,775	4,943	4,875
Total capital employed	182,781	175,406	166,036
Total corporate sources: debt and equity perspective			
Notes and loans payable	3,653	7,711	2,787
Long-term debt	7,928	9,322	12,227
ExxonMobil share of equity	165,863	154,396	146,839
Less noncontrolling interests share of total debt	(438)	(966)	(692)
Add ExxonMobil share of equity company debt	5,775	4,943	4,875
Total capital employed	182,781	175,406	166,036

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	**2012**	**2011**	**2010**
		(millions of dollars)	
Net income attributable to ExxonMobil	44,880	41,060	30,460
Financing costs (after tax)			
Gross third-party debt	(401)	(153)	(803)
ExxonMobil share of equity companies	(257)	(219)	(333)
All other financing costs – net	100	116	35
Total financing costs	(558)	(256)	(1,101)
Earnings excluding financing costs	45,438	41,316	31,561
Average capital employed	179,094	170,721	145,217
Return on average capital employed – corporate total	25.4%	24.2%	21.7%

QUARTERLY INFORMATION

	2012					2011				
	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)*					
and natural gas liquids, synthetic oil and bitumen	2,214	2,208	2,116	2,203	2,185	2,399	2,351	2,249	2,250	2,312
Refinery throughput	5,330	4,962	4,929	4,837	5,014	5,180	5,193	5,232	5,250	5,214
Petroleum product sales	6,316	6,171	6,105	6,108	6,174	6,267	6,331	6,558	6,493	6,413
Natural gas production					*(millions of cubic feet daily)*					
available for sale	14,036	11,661	11,061	12,541	12,322	14,525	12,267	12,197	13,677	13,162
					(thousands of oil-equivalent barrels daily)					
Oil-equivalent production *(1)*	4,553	4,152	3,960	4,293	4,239	4,820	4,396	4,282	4,530	4,506
					(thousands of metric tons)					
Chemical prime product sales	6,337	5,972	5,947	5,901	24,157	6,322	6,181	6,232	6,271	25,006
Summarized financial data										
Sales and other operating					*(millions of dollars)*					
revenue *(2)*	119,189	112,745	111,554	109,635	453,123	109,251	121,394	120,475	115,909	467,029
Gross profit *(3)*	35,672	32,715	33,209	31,969	133,565	35,473	37,744	37,121	34,306	144,644
Net income attributable to ExxonMobil	9,450	15,910	9,570	9,950	44,880	10,650	10,680	10,330	9,400	41,060
Per share data					*(dollars per share)*					
Earnings per common share *(4)*	2.00	3.41	2.09	2.20	9.70	2.14	2.19	2.13	1.97	8.43
Earnings per common share – assuming dilution *(4)*	2.00	3.41	2.09	2.20	9.70	2.14	2.18	2.13	1.97	8.42
Dividends per common share	0.47	0.57	0.57	0.57	2.18	0.44	0.47	0.47	0.47	1.85
Common stock prices										
High	87.94	87.67	92.57	93.67	93.67	88.23	88.13	85.41	85.63	88.23
Low	83.19	77.13	82.83	84.70	77.13	73.64	76.72	67.03	69.21	67.03

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

(2) Includes amounts for sales-based taxes.

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

(4) 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 468,497 registered shareholders of ExxonMobil common stock at December 31, 2012. At January 31, 2013, the registered shareholders of ExxonMobil common stock numbered 466,674.

On January 30, 2013, the Corporation declared a $0.57 dividend per common share, payable March 11, 2013.

FUNCTIONAL EARNINGS	**2012**	**2011**	**2010**
	(millions of dollars, except per share amounts)		
Earnings (U.S. GAAP)			
Upstream			
United States	3,925	5,096	4,272
Non-U.S.	25,970	29,343	19,825
Downstream			
United States	3,575	2,268	770
Non-U.S.	9,615	2,191	2,797
Chemical			
United States	2,220	2,215	2,422
Non-U.S.	1,678	2,168	2,491
Corporate and financing	(2,103)	(2,221)	(2,117)
Net income attributable to ExxonMobil	44,880	41,060	30,460
Earnings per common share	9.70	8.43	6.24
Earnings per common share – assuming dilution	9.70	8.42	6.22

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 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; the outcome of commercial negotiations; political or regulatory events, and other factors discussed herein and in Item 1A. Risk Factors of ExxonMobil's 2012 Form 10-K.

The term "project" as used in this report does not necessarily have the same meaning as under SEC Rule 13q-1 relating to government payment reporting. For example, a single project for purposes of the rule may encompass numerous properties, agreements, investments, developments, phases, work efforts, activities, and components, each of which we may also informally describe as a "project".

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. 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 tested over a wide range of economic scenarios to establish the resiliency of each opportunity. Once investments are made, a reappraisal process is completed to ensure relevant lessons are learned and improvements are incorporated into future projects.

BUSINESS ENVIRONMENT AND RISK ASSESSMENT

Long-Term Business Outlook

By 2040, the world's population is projected to grow to approximately 8.7 billion people, or about 1.9 billion more than in 2010. Coincident with this population increase, the Corporation expects worldwide economic growth to average close to 3 percent per year. Expanding prosperity across a growing global population is expected to coincide with an increase in primary energy demand of about 35 percent by 2040 versus 2010, even with substantial efficiency gains around the world. This demand increase is expected to be concentrated in developing countries (i.e., those that are not member nations of the Organization for Economic Cooperation and Development).

As economic progress for billions of people drives demand higher, increasing penetration of energy-efficient and lower-emission fuels, technologies and practices are expected to contribute to significantly lower levels of energy consumption and emissions per unit of economic output over time. Efficiency gains will result from anticipated improvements in the transportation and power generation sectors, driven by the penetration of advanced technologies, as well as many other improvements that span the residential, commercial and industrial sectors.

Energy for transportation – including cars, trucks, ships, trains and airplanes – is expected to increase by about 40 percent from 2010 to 2040. The global growth in transportation demand is likely to account for approximately 70 percent of the growth in liquid fuels demand over this period. Nearly all the world's transportation fleets will continue to run on liquid fuels because they provide a large quantity of energy in small volumes, making them easy to transport and widely available.

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

Liquid fuels provide the largest share of energy supply today due to their broad-based availability, affordability and ease of transport to meet consumer needs. By 2040, global demand for liquids is expected to grow to approximately 113 million barrels of oil-equivalent per day, an increase of about 30 percent from 2010. Global demand for liquid fuels will be met by a wide variety of sources. Conventional crude and condensate production is expected to remain relatively flat through 2040. However, growth is expected from a wide variety of sources, including deep-water resources, oil sands, tight oil, 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 for a wide variety of applications, and is expected to be the fastest growing major fuel source through 2040. Global demand is expected to rise about 65 percent from 2010 to 2040, with demand increases in major regions around the world requiring new sources of supply. 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. By 2040, unconventional gas is likely to approach one-third of global gas supplies, up from less than 15 percent in 2010. Growing natural gas demand will also stimulate significant growth in the worldwide liquefied natural gas (LNG) market, which is expected to reach about 15 percent of global gas demand by 2040.

The world's energy mix is highly diverse and will remain so through 2040. Oil is expected to remain the largest source of energy with its share remaining close to one-third in 2040. Coal is currently the second largest source of energy, but it is likely to lose that position to natural gas by approximately 2025. The share of natural gas is expected to exceed 25 percent by 2040, while the share of coal falls to less than 20 percent. Nuclear power is projected to grow significantly, albeit at a slower pace than otherwise expected in the aftermath of the Fukushima incident in Japan following the earthquake and tsunami in March 2011. Total renewable energy is likely to reach close to 15 percent of total energy by 2040, including biomass, hydro and geothermal at a combined share of about 11 percent. Total energy supplied from wind, solar and biofuels is expected to increase close to 450 percent from 2010 to 2040, reaching a combined share of 3 to 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 total oil and gas energy needs worldwide over the period 2012-2035 will be close to $19 trillion (measured in 2011 dollars) or close to $800 billion per year on average.

International accords and underlying regional and national regulations for greenhouse gas reduction are evolving with uncertain timing and outcome, making it difficult to predict their business impact. ExxonMobil includes estimates of potential costs related to possible public policies covering energy-related greenhouse gas emissions in its long-term Energy Outlook, which is used for assessing the business environment and in its investment evaluations.

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 identifying and selectively capturing the highest quality opportunities, exercising a disciplined approach to investing and cost management, developing and applying high-impact technologies, maximizing the profitability of existing 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 of its production volumes between now and 2017. Oil and natural gas output from North America is expected to increase over the next five years based on current capital activity plans. Currently, this growth area accounts for 32 percent of the Corporation's production. By 2017, it is expected to generate about 35 percent of total volumes. The remainder of the Corporation's production is expected to include contributions from both established operations and new projects around the globe.

In addition to an evolving geographic mix, we expect there will also be continued change in the type of opportunities from which volumes are produced. Production from diverse resource types utilizing specialized technologies such as arctic technology, deepwater drilling and production systems, heavy oil and oil sands recovery processes, unconventional gas and oil production and LNG is expected to grow from about 45 percent to around 55 percent of the Corporation's output between now and 2017. 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 2012 Form 10-K, or result in a material change in our level of unit operating expenses. The Corporation's overall volume capacity outlook, based on projects coming onstream as anticipated, is for production capacity to grow over the period 2013-2017. However, actual volumes will vary from year to year due to the timing of individual project start-ups and other capital activities, operational outages, reservoir performance, performance of enhanced oil recovery projects, regulatory changes, asset sales, weather events, price effects under production sharing contracts and other factors described in Item 1A. Risk Factors of ExxonMobil's 2012 Form 10-K. Enhanced oil recovery projects extract hydrocarbons from reservoirs in excess of that which may be produced through primary recovery, i.e., through pressure depletion or natural aquifer support. They include the injection of water, gases or chemicals into a reservoir to produce hydrocarbons otherwise unobtainable.

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 position the company to deliver long-term growth in shareholder value that is superior to competition across a range of market conditions. These strategies include maintaining best-in-class operations in all aspects of the business, maximizing value from leading-edge technologies, capitalizing on integration across ExxonMobil businesses, selectively investing for resilient, advantaged returns, leading the industry in efficiency and effectiveness, and providing quality, valued products and services to customers.

ExxonMobil has an ownership interest in 32 refineries, located in 17 countries, with distillation capacity of 5.4 million barrels per day and lubricant basestock manufacturing capacity of 126 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 remains challenging. Demand weakness and overcapacity in the refining sector will continue to put pressure on margins. In the near term, we see variability in refining margins, with some regions seeing stronger margins as refineries rationalize. In markets like North America, lower raw material and energy costs driven by the increasing crude and natural gas production strengthened refining margins in several areas.

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, refinery operations, import/export balances, currency fluctuations, seasonal demand, weather and political climate.

ExxonMobil's long-term outlook is that refining margins will remain weak as competition in the industry remains intense and, in the near term, new capacity additions outpace the growth in global demand. Additionally, as described in more detail in Item 1A. Risk Factors of ExxonMobil's 2012 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 refining business.

In the retail fuels marketing business, competition continues to cause inflation-adjusted margins to decline. In 2012, ExxonMobil progressed the transition of the direct served (i.e., dealer, company-operated) retail network in the U.S. to a more capital-efficient branded distributor model. This transition was announced in 2008 and is nearing completion.

Our lubricants business continues to grow. ExxonMobil is a market leader in high-value synthetic lubricants, and we continue to grow our business in key markets such as China, India and Russia at rates considerably faster than industry.

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 2012, we divested our Downstream businesses in Argentina, Uruguay, Paraguay, Central America, Malaysia, and Switzerland. We also restructured and reduced our holdings in Japan. When investing in the Downstream, ExxonMobil remains focused on selective and resilient projects. These investments capitalize on the Corporation's world-class scale and integration, industry leading efficiency, leading-edge technology and respected brands, enabling ExxonMobil to take advantage of attractive emerging growth opportunities around the globe. In 2012, the company completed the Hydrofiner Conversion Project at the Fawley, United Kingdom, refinery to produce higher-value ultra-low sulfur diesel.

At the Jurong/PAC refinery in Singapore, construction activities to build a new diesel hydrotreater are expected to complete in 2013, adding capacity of more than 2 million gallons per day of ultra-low sulfur diesel to meet increasing demand in the Asia Pacific region. Additionally, construction of a lower sulfur fuels project at the joint Saudi Aramco and ExxonMobil SAMREF Refinery in Yanbu, Saudi Arabia is also underway. The project will include new gasoline and expanded diesel hydrotreating and sulfur recovery equipment, and completion is expected by the end of 2013. We are also expanding our Singapore and China lube oil blending plants to support future demand growth in these emerging markets.

Chemical

Worldwide petrochemical demand grew modestly in 2012 with substantial variations in regional performance. In North America, unconventional natural gas continued to provide advantaged ethane feedstock and low cost energy for steam crackers and a favorable margin environment for integrated chemical producers. Margins in Asia remained low, with excess ethylene supply. Margins and volumes declined in Europe with the weaker economy. Specialty products overall reported firm global demand and margins.

ExxonMobil benefited from continued operational excellence and a balanced portfolio of products. In addition to being a worldwide supplier of commodity petrochemical products, ExxonMobil Chemical also has a number of less-cyclical Specialties business lines, which delivered strong results in 2012. Chemical's competitive advantages are due to its business mix, broad geographic coverage, investment and cost discipline, integration with refineries or upstream gas processing facilities, superior feedstock management, leading proprietary technology and product application expertise.

In 2012 ExxonMobil completed construction of the Singapore petrochemical expansion project and commenced start-up operations at one of the world's largest ethylene steam crackers, the centerpiece of the company's multi-billion dollar expansion at the complex. Powered by a new 220-megawatt cogeneration plant, the expansion adds 2.6 million tonnes per year of new finished product capacity.

REVIEW OF 2012 AND 2011 RESULTS

	2012	2011	2010
		(millions of dollars)	
Earnings (U.S. GAAP)	44,880	41,060	30,460

2012

Earnings in 2012 of $44,880 million increased $3,820 million from 2011.

2011

Earnings in 2011 of $41,060 million increased $10,600 million from 2010.

Upstream

	2012	2011	2010
		(millions of dollars)	
Upstream			
United States	3,925	5,096	4,272
Non-U.S.	25,970	29,343	19,825
Total	29,895	34,439	24,097

2012

Upstream earnings were $29,895 million, down $4,544 million from 2011. Lower liquids realizations, partly offset by improved natural gas realizations, decreased earnings by about $100 million. Production volume and mix effects decreased earnings by $2.3 billion. All other items, including higher operating expenses, unfavorable tax items, lower gains on asset sales, and unfavorable foreign exchange effects, reduced earnings by $2.1 billion. On an oil-equivalent basis, production was down 5.9 percent compared to 2011. Excluding the impacts of entitlement volumes, OPEC quota effects and divestments, production was down 1.7 percent. Liquids production of 2,185 kbd (thousands of barrels per day) decreased 127 kbd from 2011. Excluding the impacts of entitlement volumes, OPEC quota effects and divestments, liquids production was down 1.6 percent, as field decline was partly offset by project ramp-up in West Africa and lower downtime. Natural gas production of 12,322 mcfd (millions of cubic feet per day) decreased 840 mcfd from 2011. Excluding the impacts of entitlement volumes and divestments, natural gas production was down 1.9 percent, as field decline was partially offset by higher demand and lower downtime. Earnings from

U.S. Upstream operations for 2012 were $3,925 million, down $1,171 million from 2011. Earnings outside the U.S. were $25,970 million, down $3,373 million.

2011

Upstream earnings were $34,439 million, up $10,342 million from 2010. Higher crude oil and natural gas realizations increased earnings by $10.6 billion, while volume and production mix effects decreased earnings by $2.5 billion. All other items increased earnings by $2.2 billion, driven by higher gains on asset sales of $2.7 billion, partly offset by increased operating activity. On an oil-equivalent basis, production was up 1 percent compared to 2010. Excluding the impacts of entitlement volumes, OPEC quota effects and divestments, production was up 4 percent. Liquids production of 2,312 kbd decreased 110 kbd from 2010. Excluding the impacts of entitlement volumes, OPEC quota effects and divestments, liquids production was in line with 2010, as higher volumes from Qatar, the U.S., and Iraq offset field decline. Natural gas production of 13,162 mcfd increased 1,014 mcfd from 2010, driven by additional U.S. unconventional gas volumes and project ramp-ups in Qatar. Earnings from U.S. Upstream operations for 2011 were $5,096 million, an increase of $824 million. Earnings outside the U.S. were $29,343 million, up $9,518 million.

Downstream

	2012	2011	2010
		(millions of dollars)	
Downstream			
United States	3,575	2,268	770
Non-U.S.	9,615	2,191	2,797
Total	13,190	4,459	3,567

2012

Downstream earnings of $13,190 million increased $8,731 million from 2011. Stronger refining-driven margins increased earnings by $2.6 billion, while volume and mix effects increased earnings by about $200 million. All other items increased earnings by $5.9 billion due primarily to the $5.3 billion gain associated with the Japan restructuring and other divestment gains. Petroleum product sales of 6,174 kbd decreased 239 kbd from 2011 due mainly to the Japan restructuring and divestments. U.S. Downstream earnings were $3,575 million, up $1,307 million from 2011. Non-U.S. Downstream earnings were $9,615 million, an increase of $7,424 million from last year.

2011

Downstream earnings of $4,459 million increased $892 million from 2010. Margins, mainly refining, increased earnings by $800 million. Volume and mix effects improved earnings by $630 million. All other items, primarily the absence of favorable tax effects and higher expenses, decreased earnings by $540 million. Petroleum product sales of 6,413 kbd were in line with 2010. U.S. Downstream earnings were $2,268 million, up $1,498 million from 2010. Non-U.S. Downstream earnings were $2,191 million, $606 million lower than 2010.

Chemical

	2012	2011	2010
		(millions of dollars)	
Chemical			
United States	2,220	2,215	2,422
Non-U.S.	1,678	2,168	2,491
Total	3,898	4,383	4,913

2012

Chemical earnings of $3,898 million were $485 million lower than 2011. Margins decreased earnings by $440 million, while volume effects lowered earnings by $100 million. All other items increased earnings by $50 million, as a $630 million gain associated with the Japan restructuring and favorable tax impacts were mostly offset by unfavorable foreign exchange effects and higher operating expenses. Prime product sales of 24,157 kt (thousands of metric tons) were down 849 kt from 2011. U.S. Chemical earnings were $2,220 million, up $5 million from 2011. Non-U.S. Chemical earnings were $1,678 million, $490 million lower than last year.

2011

Chemical earnings of $4,383 million were down $530 million from 2010. Stronger margins increased earnings by $260 million, while lower volumes reduced earnings by $180 million. Other items, including unfavorable tax effects and higher planned maintenance expense, decreased earnings by $610 million. Prime product sales of 25,006 kt were down 885 kt from 2010. U.S. Chemical earnings were $2,215 million, down $207 million from 2010. Non-U.S. Chemical earnings were $2,168 million, $323 million lower than 2010.

Corporate and Financing

	2012	2011	2010
		(millions of dollars)	
Corporate and financing	(2,103)	(2,221)	(2,117)

2012

Corporate and financing expenses were $2,103 million, down $118 million from 2011.

2011

Corporate and financing expenses were $2,221 million, up $104 million from 2010.

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

	2012	2011	2010
		(millions of dollars)	
Net cash provided by/(used in)			
Operating activities	56,170	55,345	48,413
Investing activities	(25,601)	(22,165)	(24,204)
Financing activities	(33,868)	(28,256)	(26,924)
Effect of exchange rate changes	217	(85)	(153)
Increase/(decrease) in cash and cash equivalents	(3,082)	4,839	(2,868)
		(December 31)	
Cash and cash equivalents	9,582	12,664	7,825
Cash and cash equivalents - restricted	341	404	628
Total cash and cash equivalents	9,923	13,068	8,453

Total cash and cash equivalents were $9.9 billion at the end of 2012, $3.1 billion lower than the prior year. Higher earnings and a higher adjustment for non-cash transactions were more than offset by lower proceeds from sales of subsidiaries and property, plant and equipment, a net debt decrease compared to a prior year debt increase, and a higher adjustment for net gains on asset sales. Included in total cash and cash equivalents at year-end 2012 was $0.3 billion of restricted cash.

Total cash and cash equivalents were $13.1 billion at the end of 2011, $4.6 billion higher than the prior year. Higher earnings, proceeds associated with asset sales, including a $3.6 billion deposit for a potential asset sale, and a net debt increase in contrast with prior year debt repurchases were partially offset by a higher level of purchases of ExxonMobil shares and a higher level of capital spending. Included in total cash and cash equivalents at year-end 2011 was $0.4 billion of restricted cash. For additional details, see the Consolidated Statement of Cash Flows.

Although the Corporation has access to significant capacity of long-term and short-term liquidity, internally generated funds cover the majority of its financial requirements. 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 contractual terms.

The Corporation has long been successful at offsetting the effects of natural field decline through disciplined investments in quality opportunities and project execution. Over the last decade, this has resulted in net annual additions to proved reserves that have exceeded the amount produced. Projects are in progress or planned to increase production capacity. However, these volume increases are subject to a variety of risks including project start-up timing, operational outages, reservoir performance, crude oil and natural gas prices, weather events, and regulatory changes. 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 2012 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 2012 were $39.8 billion, reflecting the Corporation's continued active investment program. The Corporation anticipates an investment profile of about $38 billion per year for the next several years. 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. The purchase and sale of oil and gas properties have not had a significant impact on the amount or timing of cash flows from operating activities.

Cash Flow from Operating Activities

2012

Cash provided by operating activities totaled $56.2 billion in 2012, $0.8 billion higher than 2011. The major source of funds was net income including noncontrolling interests of $47.7 billion, an increase of $5.5 billion. The noncash provision of $15.9 billion for depreciation and depletion was slightly higher than 2011. The adjustments for other noncash transactions and changes in operational working capital, excluding cash and debt, both increased cash in 2012, while the adjustment for net gains on asset sales decreased cash by $13.0 billion in 2012.

2011

Cash provided by operating activities totaled $55.3 billion in 2011, $6.9 billion higher than 2010. The major source of funds was net income including noncontrolling interests of $42.2 billion, adjusted for the noncash provision of $15.6 billion for depreciation and depletion, both of which increased. Changes in operational working capital, excluding cash and debt, and the adjustment for net gains on asset sales decreased cash in 2011. Net working capital continued to be negative as total current liabilities of $77.5 billion exceeded total current assets of $73.0 billion at year-end 2011.

Cash Flow from Investing Activities

2012

Cash used in investment activities netted to $25.6 billion in 2012, $3.4 billion higher than 2011. Spending for property, plant and equipment of $34.3 billion increased $3.3 billion from 2011. Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments of $7.7 billion compared to $11.1 billion in 2011. The decrease reflects that a $3.6 billion deposit was received in 2011 for a sale that closed in 2012. Additional investments and advances were $2.6 billion lower in 2012.

2011

Cash used in investment activities netted to $22.2 billion in 2011, $2.0 billion lower than 2010. Spending for property, plant and equipment of $31.0 billion increased $4.1 billion from 2010. Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments of $11.1 billion compared to $3.3 billion in 2010. The increase primarily reflects the sale of Upstream Canadian, U.K. and other producing properties and assets, the sale of U.S. service stations, and a $3.6 billion deposit for a potential asset sale. Additional investments and advances were $2.3 billion higher in 2011.

Cash Flow from Financing Activities

2012

Cash used in financing activities was $33.9 billion in 2012, $5.6 billion higher than 2011. Dividend payments on common shares increased to $2.18 per share from $1.85 per share and totaled $10.1 billion, a pay-out of 22 percent of net income. Total debt decreased $5.5 billion to $11.6 billion at year-end.

ExxonMobil share of equity increased $11.5 billion to $165.9 billion. The addition to equity for earnings of $44.9 billion was partially offset by reductions for distributions to ExxonMobil shareholders of $10.1 billion of dividends and $20.0 billion of purchases of shares of ExxonMobil stock to reduce shares outstanding.

During 2012, Exxon Mobil Corporation purchased 244 million shares of its common stock for the treasury at a gross cost of $21.1 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 4.9 percent from 4,734 million to 4,502 million at the end of 2012. 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.

2011

Cash used in financing activities was $28.3 billion in 2011, $1.3 billion higher than 2010. Dividend payments on common shares increased to $1.85 per share from $1.74 per share and totaled $9.0 billion, a pay-out of 22 percent of net income. Total debt increased $2.0 billion to $17.0 billion at year-end.

ExxonMobil share of equity increased $7.6 billion to $154.4 billion. The addition to equity for earnings of $41.1 billion was partially offset by reductions for distributions to ExxonMobil shareholders of $9.0 billion of dividends and $20.0 billion of purchases of shares of ExxonMobil stock to reduce shares outstanding. The change in the funded status of the postretirement benefits reserves in 2011 decreased equity by $4.6 billion.

During 2011, Exxon Mobil Corporation purchased 278 million shares of its common stock for the treasury at a gross cost of $22.1 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 4.9 percent from 4,979 million to 4,734 million at the end of 2011. 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, 2012. It combines data from the Consolidated Balance Sheet and from individual notes to the Consolidated Financial Statements.

	Payments Due by Period				
Commitments	**Note Reference Number**	**2013**	**2014-2017**	**2018 and Beyond**	**Total**
			(millions of dollars)		
Long-term debt *(1)*	14	-	2,885	5,043	7,928
– Due in one year *(2)*	6	1,025	-	-	1,025
Asset retirement obligations *(3)*	9	776	3,334	7,863	11,973
Pension and other postretirement obligations *(4)*	17	2,401	4,328	19,475	26,204
Operating leases *(5)*	11	2,254	4,460	1,467	8,181
Unconditional purchase obligations *(6)*	16	184	624	319	1,127
Take-or-pay obligations *(7)*		2,673	10,523	13,013	26,209
Firm capital commitments *(8)*		19,609	12,074	836	32,519

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 $7.7 billion as of December 31, 2012, 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 $431 million.*

(2) *The amount due in one year is included in notes and loans payable of $3,653 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 2013 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.*

(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 $1,127 million mainly pertain to pipeline throughput agreements and include $584 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 $26,209 million mainly pertain to manufacturing supply, pipeline and terminaling agreements and include $187 million of obligations to equity companies.*

(8) *Firm commitments related to capital projects, shown on an undiscounted basis, totaled approximately $32.5 billion. These commitments were primarily associated with Upstream projects outside the U.S., of which $18.4 billion was associated with projects in Canada, Australia, Africa and Malaysia. The Corporation expects to fund the majority of these projects through internal cash flow.*

Guarantees

The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2012, 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, 2012, unused credit lines for short-term financing totaled approximately $3.5 billion (Note 6).

The table below shows the Corporation's fixed-charge coverage and consolidated debt-to-capital ratios. The data demonstrate the Corporation's creditworthiness.

	2012	2011	2010
Fixed-charge coverage ratio (times)	62.4	53.4	42.2
Debt to capital (percent)	6.3	9.6	9.0
Net debt to capital (percent)	1.2	2.6	4.5

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

	2012			2011		
	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total
			(millions of dollars)			
Upstream *(1)*	11,080	25,004	36,084	10,741	22,350	33,091
Downstream	634	1,628	2,262	518	1,602	2,120
Chemical	408	1,010	1,418	290	1,160	1,450
Other	35	-	35	105	-	105
Total	12,157	27,642	39,799	11,654	25,112	36,766

(1) Exploration expenses included.

Capital and exploration expenditures in 2012 were $39.8 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 profile of about $38 billion per year for the next several years. Actual spending could vary depending on the progress of individual projects and property acquisitions.

Upstream spending of $36.1 billion in 2012 was up 9 percent from 2011, reflecting investments in the Gulf of Mexico and continued progress on world-class projects in Canada, Australia and Papua New Guinea. Property acquisition costs in 2012 were comparable to 2011. 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 from those reserves. The percentage of proved developed reserves was 61 percent of total proved reserves at year-end 2012, and has been over 60 percent for the last five years, indicating that proved reserves are consistently moved from undeveloped to developed status. Capital investments in the Downstream totaled $2.3 billion in 2012, an increase of $0.1 billion from 2011, mainly reflecting higher environmental and energy-related refining project spending. The Chemical capital expenditures of $1.4 billion were the same level as in 2011 with higher investments in the U.S., Saudi Arabia and China offsetting reduced spending on the Singapore expansion as it approaches full start-up.

TAXES

	2012	2011	2010
		(millions of dollars)	
Income taxes	31,045	31,051	21,561
Effective income tax rate	*44%*	*46%*	*45%*
Sales-based taxes	32,409	33,503	28,547
All other taxes and duties	38,857	43,544	39,127
Total	102,311	108,098	89,235

2012

Income, sales-based and all other taxes and duties totaled $102.3 billion in 2012, a decrease of $5.8 billion or 5 percent from 2011. Income tax expense, both current and deferred, was $31.0 billion, flat with 2011, with the impact of higher earnings offset by the lower effective tax rate. The effective tax rate was 44 percent compared to 46 percent in the prior year due to a lower effective tax rate on divestments. Sales-based and all other taxes and duties of $71.3 billion in 2012 decreased $5.8 billion reflecting the Japan restructuring.

2011

Income, sales based and all other taxes and duties totaled $108.1 billion in 2011, an increase of $18.9 billion or 21 percent from 2010. Income tax expense, both current and deferred, was $31.1 billion, $9.5 billion higher than 2010, reflecting higher pre-tax income in 2011. A higher share of pre-tax income from the Upstream segment in 2011 increased the effective tax rate to 46 percent compared to 45 percent in 2010. Sales-based and all other taxes and duties of $77.0 billion in 2011 increased $9.4 billion, reflecting higher prices.

ENVIRONMENTAL MATTERS

Environmental Expenditures

	2012	2011
	(millions of dollars)	
Capital expenditures	1,989	1,636
Other expenditures	3,523	3,248
Total	5,512	4,884

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 2012 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were about $5.5 billion. The total cost for such activities is expected to have a modest increase in 2013 and 2014 (with capital expenditures approximately 45 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 2012 for environmental liabilities were $391 million ($420 million in 2011) and the balance sheet reflects accumulated liabilities of $841 million as of December 31, 2012, and $886 million as of December 31, 2011.

MARKET RISKS, INFLATION AND OTHER UNCERTAINTIES

Worldwide Average Realizations *(1)*	2012	2011	2010
Crude oil and NGL ($/barrel)	100.29	100.79	74.04
Natural gas ($/kcf)	3.90	4.65	4.31

(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 $350 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 $200 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 are crude oil produced by the Upstream and sold to the Downstream. Other intersegment sales include those between refineries and chemical plants related to raw materials, feedstocks and finished products.

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

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 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. Although the Corporation issues long-term debt from time to time and maintains a commercial paper program, internally generated funds are expected to cover the majority of its net near-term financial requirements. However, 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. Increased demand for certain services and materials has resulted in higher operating and capital costs in recent years. The Corporation works to counter upward pressure on costs through its economies of scale in global procurement and its efficient project management practices.

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 integral to making investment decisions about oil and gas properties such as whether development should proceed. Oil and gas reserve quantities are also used as the basis for calculating unit-of-production depreciation rates and for evaluating impairment.

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

The estimation of proved reserves 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 2012 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 61 percent of total proved reserves at year-end 2012 (including both consolidated and equity company reserves), and has been over 60 percent for the last five years, indicating that proved reserves are consistently moved from undeveloped to developed status.

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.

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 developed reserves (those proved reserves recoverable through existing wells with existing equipment and operating methods), applied to the asset cost. The volumes produced and asset cost are known and, while proved developed 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 and Prices on Testing for Impairment. Proved oil and gas properties held and used by the Corporation are reviewed for impairment whenever events or circumstances indicate that the carrying amounts may not be recoverable. Assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets.

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

Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are recorded based on the estimated economic chance of success and the length of time that the 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.

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

In general, the Corporation does not view temporarily low prices or margins as a trigger event for conducting the impairment tests. The markets for crude oil and natural gas have a history of significant price volatility. Although prices will occasionally drop significantly, 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.

Accordingly, any impairment tests that the Corporation performs make use of the Corporation's price assumptions developed in the annual planning and budgeting process for the crude oil and natural gas markets, petroleum products and chemicals. These are the same price assumptions that are used for capital investment decisions. Volumes are based on field production profiles, which are updated annually. Cash flow estimates for impairment testing exclude the effects of derivative instruments.

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.

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 as of year-end 2012 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 and liabilities. 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 over 100 defined benefit (pension) plans in about 50 countries. Pension and Other Postretirement Benefits (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. Book reserves are established for these plans because tax conventions and regulatory practices do not encourage advance funding. 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 2012 was 7.25 percent. The 10-year and 20-year actual returns on U.S. pension plan assets were both 9 percent. 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* 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, 2012.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2012, as stated in their report included in the Financial Section of this report.

Rex W. Tillerson	Andrew P. Swiger	Patrick T. Mulva
Chief Executive Officer	Senior Vice President	Vice President and Controller
	(Principal Financial Officer)	(Principal Accounting Officer)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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, 2012, and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, 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, 2012, based on criteria established in *Internal Control – Integrated Framework* 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 27, 2013

CONSOLIDATED STATEMENT OF INCOME

	Note Reference Number	2012	2011	2010
			(millions of dollars)	
Revenues and other income				
Sales and other operating revenue *(1)*		453,123	467,029	370,125
Income from equity affiliates	7	15,010	15,289	10,677
Other income		14,162	4,111	2,419
Total revenues and other income		482,295	486,429	383,221
Costs and other deductions				
Crude oil and product purchases		265,149	266,534	197,959
Production and manufacturing expenses		38,521	40,268	35,792
Selling, general and administrative expenses		13,877	14,983	14,683
Depreciation and depletion		15,888	15,583	14,760
Exploration expenses, including dry holes		1,840	2,081	2,144
Interest expense		327	247	259
Sales-based taxes *(1)*	19	32,409	33,503	28,547
Other taxes and duties	19	35,558	39,973	36,118
Total costs and other deductions		403,569	413,172	330,262
Income before income taxes		78,726	73,257	52,959
Income taxes	19	31,045	31,051	21,561
Net income including noncontrolling interests		47,681	42,206	31,398
Net income attributable to noncontrolling interests		2,801	1,146	938
Net income attributable to ExxonMobil		44,880	41,060	30,460
Earnings per common share (dollars)	12	9.70	8.43	6.24
Earnings per common share - assuming dilution (dollars)	12	9.70	8.42	6.22

(1) Sales and other operating revenue includes sales-based taxes of $32,409 million for 2012, $33,503 million for 2011 and $28,547 million for 2010.

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

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	2012	2011	2010
		(millions of dollars)	
Net income including noncontrolling interests	47,681	42,206	31,398
Other comprehensive income (net of income taxes)			
Foreign exchange translation adjustment	920	(867)	1,034
Adjustment for foreign exchange translation (gain)/loss included in net income	(4,352)	-	25
Postretirement benefits reserves adjustment (excluding amortization)	(3,574)	(4,907)	(1,161)
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	2,395	1,217	1,040
Change in fair value of cash flow hedges	-	28	184
Realized (gain)/loss from settled cash flow hedges included in net income	-	(83)	(129)
Total other comprehensive income	(4,611)	(4,612)	993
Comprehensive income including noncontrolling interests	43,070	37,594	32,391
Comprehensive income attributable to noncontrolling interests	1,251	834	1,293
Comprehensive income attributable to ExxonMobil	41,819	36,760	31,098

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

CONSOLIDATED BALANCE SHEET

	Note Reference Number	Dec. 31 2012	Dec. 31 2011
		(millions of dollars)	
Assets			
Current assets			
Cash and cash equivalents		9,582	12,664
Cash and cash equivalents - restricted		341	404
Notes and accounts receivable, less estimated doubtful amounts	6	34,987	38,642
Inventories			
Crude oil, products and merchandise	3	10,836	11,665
Materials and supplies		3,706	3,359
Other current assets		5,008	6,229
Total current assets		64,460	72,963
Investments, advances and long-term receivables	8	34,718	34,333
Property, plant and equipment, at cost, less accumulated depreciation and depletion	9	226,949	214,664
Other assets, including intangibles, net		7,668	9,092
Total assets		333,795	331,052
Liabilities			
Current liabilities			
Notes and loans payable	6	3,653	7,711
Accounts payable and accrued liabilities	6	50,728	57,067
Income taxes payable		9,758	12,727
Total current liabilities		64,139	77,505
Long-term debt	14	7,928	9,322
Postretirement benefits reserves	17	25,267	24,994
Deferred income tax liabilities	19	37,570	36,618
Long-term obligations to equity companies		3,555	1,808
Other long-term obligations		23,676	20,061
Total liabilities		162,135	170,308
Commitments and contingencies	16		
Equity			
Common stock without par value (9,000 million shares authorized, 8,019 million shares issued)		9,653	9,512
Earnings reinvested		365,727	330,939
Accumulated other comprehensive income		(12,184)	(9,123)
Common stock held in treasury (3,517 million shares in 2012 and 3,285 million shares in 2011)		(197,333)	(176,932)
ExxonMobil share of equity		165,863	154,396
Noncontrolling interests		5,797	6,348
Total equity		171,660	160,744
Total liabilities and equity		333,795	331,052

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

CONSOLIDATED STATEMENT OF CASH FLOWS

	Note Reference Number	2012	2011	2010
			(millions of dollars)	
Cash flows from operating activities				
Net income including noncontrolling interests		47,681	42,206	31,398
Adjustments for noncash transactions				
Depreciation and depletion		15,888	15,583	14,760
Deferred income tax charges/(credits)		3,142	142	(1,135)
Postretirement benefits expense in excess of/(less than) net payments		(315)	544	1,700
Other long-term obligation provisions in excess of/(less than) payments		1,643	(151)	160
Dividends received greater than/(less than) equity in current earnings of equity companies		(1,157)	(273)	(596)
Changes in operational working capital, excluding cash and debt				
Reduction/(increase) - Notes and accounts receivable		(1,082)	(7,906)	(5,863)
- Inventories		(1,873)	(2,208)	(1,148)
- Other current assets		(42)	222	913
Increase/(reduction) - Accounts and other payables		3,624	8,880	9,943
Net (gain) on asset sales	5	(13,018)	(2,842)	(1,401)
All other items - net		1,679	1,148	(318)
Net cash provided by operating activities		56,170	55,345	48,413
Cash flows from investing activities				
Additions to property, plant and equipment		(34,271)	(30,975)	(26,871)
Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments	5	7,655	11,133	3,261
Decrease/(increase) in restricted cash and cash equivalents		63	224	(628)
Additional investments and advances		(972)	(3,586)	(1,239)
Collection of advances		1,924	1,119	1,133
Additions to marketable securities		-	(1,754)	(15)
Sales of marketable securities		-	1,674	155
Net cash used in investing activities		(25,601)	(22,165)	(24,204)
Cash flows from financing activities				
Additions to long-term debt		995	702	1,143
Reductions in long-term debt		(147)	(266)	(6,224)
Additions to short-term debt		958	1,063	598
Reductions in short-term debt		(4,488)	(1,103)	(2,436)
Additions/(reductions) in debt with three months or less maturity		(226)	1,561	709
Cash dividends to ExxonMobil shareholders		(10,092)	(9,020)	(8,498)
Cash dividends to noncontrolling interests		(327)	(306)	(281)
Changes in noncontrolling interests		204	(16)	(7)
Tax benefits related to stock-based awards		130	260	122
Common stock acquired		(21,068)	(22,055)	(13,093)
Common stock sold		193	924	1,043
Net cash used in financing activities		(33,868)	(28,256)	(26,924)
Effects of exchange rate changes on cash		217	(85)	(153)
Increase/(decrease) in cash and cash equivalents		(3,082)	4,839	(2,868)
Cash and cash equivalents at beginning of year		12,664	7,825	10,693
Cash and cash equivalents at end of year		9,582	12,664	7,825

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, 2009	5,503	276,937	(5,461)	(166,410)	110,569	4,823	115,392
Amortization of stock-based awards	751	-	-	-	751	-	751
Tax benefits related to stock-based awards	280	-	-	-	280	-	280
Other	(683)	-	-	-	(683)	10	(673)
Net income for the year	-	30,460	-	-	30,460	938	31,398
Dividends - common shares	-	(8,498)	-	-	(8,498)	(281)	(8,779)
Other comprehensive income	-	-	638	-	638	355	993
Acquisitions, at cost	-	-	-	(13,093)	(13,093)	(5)	(13,098)
Issued for XTO merger	3,520	-	-	21,139	24,659	-	24,659
Other dispositions	-	-	-	1,756	1,756	-	1,756
Balance as of December 31, 2010	9,371	298,899	(4,823)	(156,608)	146,839	5,840	152,679
Amortization of stock-based awards	742	-	-	-	742	-	742
Tax benefits related to stock-based awards	202	-	-	-	202	-	202
Other	(803)	-	-	-	(803)	(5)	(808)
Net income for the year	-	41,060	-	-	41,060	1,146	42,206
Dividends - common shares	-	(9,020)	-	-	(9,020)	(306)	(9,326)
Other comprehensive income	-	-	(4,300)	-	(4,300)	(312)	(4,612)
Acquisitions, at cost	-	-	-	(22,055)	(22,055)	(15)	(22,070)
Dispositions	-	-	-	1,731	1,731	-	1,731
Balance as of December 31, 2011	9,512	330,939	(9,123)	(176,932)	154,396	6,348	160,744
Amortization of stock-based awards	806	-	-	-	806	-	806
Tax benefits related to stock-based awards	178	-	-	-	178	-	178
Other	(843)	-	-	-	(843)	(1,441)	(2,284)
Net income for the year	-	44,880	-	-	44,880	2,801	47,681
Dividends - common shares	-	(10,092)	-	-	(10,092)	(327)	(10,419)
Other comprehensive income	-	-	(3,061)	-	(3,061)	(1,550)	(4,611)
Acquisitions, at cost	-	-	-	(21,068)	(21,068)	(34)	(21,102)
Dispositions	-	-	-	667	667	-	667
Balance as of December 31, 2012	9,653	365,727	(12,184)	(197,333)	165,863	5,797	171,660

Common Stock Share Activity	**Issued**	**Held in Treasury**	**Outstanding**
		(millions of shares)	
Balance as of December 31, 2009	8,019	(3,292)	4,727
Acquisitions	-	(199)	(199)
Issued for XTO merger	-	416	416
Other dispositions	-	35	35
Balance as of December 31, 2010	8,019	(3,040)	4,979
Acquisitions	-	(278)	(278)
Dispositions	-	33	33
Balance as of December 31, 2011	8,019	(3,285)	4,734
Acquisitions	-	(244)	(244)
Dispositions	-	12	12
Balance as of December 31, 2012	8,019	(3,517)	4,502

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) and participates in electric power generation (Upstream).

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 2012 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 and liabilities.

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, a 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.

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.

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 with certain exploratory expenditures and exploratory dry holes being expensed as incurred. Costs of productive wells and development dry holes are capitalized and amortized on the unit-of-production method.

The Corporation carries as an asset exploratory well costs 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.

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.

Production costs are expensed as incurred. 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. 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.

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

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 annually updated corporate plan investment evaluation assumptions for crude oil commodity prices, refining and chemical margins and foreign currency exchange rates. Annual volumes are based on field production profiles, which are also updated annually. Prices for natural gas and other products are based on corporate plan assumptions developed annually by major region and also for investment evaluation purposes. Cash flow estimates for impairment testing exclude derivative instruments.

Impairment analyses are generally based on proved reserves. Where probable reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the impairment evaluation. An asset group would be impaired if the undiscounted cash flows were less than its carrying value. Impairments are measured by the amount the carrying value exceeds fair value.

Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are recorded based on the estimated economic chance of success and the length of time that the 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. The valuation allowances are reviewed at least annually.

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

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 market price of the restricted shares at the date of grant and is recognized in the income statement over the requisite service period of each award. See Note 15, Incentive Program, for further details.

2. Accounting Changes

The Corporation did not adopt authoritative guidance in 2012 that had a material impact on the Corporation's financial statements.

3. Miscellaneous Financial Information

Research and development expenses totaled $1,042 million in 2012, $1,044 million in 2011 and $1,012 million in 2010.

Net income included before-tax aggregate foreign exchange transaction gains of $159 million, and losses of $184 million and $251 million in 2012, 2011 and 2010, respectively.

In 2012, 2011 and 2010, net income included gains of $328 million, $292 million and $317 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 $21.3 billion and $25.6 billion at December 31, 2012, and 2011, respectively.

Crude oil, products and merchandise as of year-end 2012 and 2011 consist of the following:

	2012	**2011**
	(billions of dollars)	
Petroleum products	3.6	4.1
Crude oil	4.0	4.8
Chemical products	2.9	2.3
Gas/other	0.3	0.5
Total	10.8	11.7

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 Fair Value on Cash Flow Hedges	Total
		(millions of dollars)		
Balance as of December 31, 2009	4,402	(9,863)	-	(5,461)
Current period change excluding amounts reclassified from accumulated other comprehensive income	584	(1,014)	184	(246)
Amounts reclassified from accumulated other comprehensive income	25	988	(129)	884
Total change in accumulated other comprehensive income	609	(26)	55	638
Balance as of December 31, 2010	5,011	(9,889)	55	(4,823)
Balance as of December 31, 2010	5,011	(9,889)	55	(4,823)
Current period change excluding amounts reclassified from accumulated other comprehensive income	(843)	(4,557)	28	(5,372)
Amounts reclassified from accumulated other comprehensive income	-	1,155	(83)	1,072
Total change in accumulated other comprehensive income	(843)	(3,402)	(55)	(4,300)
Balance as of December 31, 2011	4,168	(13,291)	-	(9,123)
Balance as of December 31, 2011	4,168	(13,291)	-	(9,123)
Current period change excluding amounts reclassified from accumulated other comprehensive income	842	(3,402)	-	(2,560)
Amounts reclassified from accumulated other comprehensive income	(2,600)	2,099	-	(501)
Total change in accumulated other comprehensive income	(1,758)	(1,303)	-	(3,061)
Balance as of December 31, 2012	2,410	(14,594)	-	(12,184)

Income Tax (Expense)/Credit For Components of Other Comprehensive Income	2012	2011	2010
		(millions of dollars)	
Foreign exchange translation adjustment	(236)	89	(42)
Postretirement benefits reserves adjustment			
Postretirement benefits reserves adjustment (excluding amortization)	1,619	2,039	689
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	(1,226)	(544)	(654)
Unrealized change in fair value on cash flow hedges			
Change in fair value of cash flow hedges	-	(16)	(113)
Settled cash flow hedges included in net income	-	50	79
Total	157	1,618	(41)

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.

The "Net (gain) on asset sales" in net cash provided by operating activities on the Consolidated Statement of Cash Flows includes before-tax gains from the Japan restructuring, the sale of an Upstream property in Angola, exchanges of Upstream properties, the sale of U.S. service stations, and the sale of the Downstream affiliates in Malaysia and Switzerland in 2012; from the sale of some Upstream Canadian, U.K. and other producing properties and assets, and the sale of U.S. service stations in 2011; and from the sale of some Upstream Gulf of Mexico and other producing properties, the sale of U.S. service stations and other Downstream assets and investments and the formation of a Chemical joint venture in 2010. These gains are reported in "Other income" on the Consolidated Statement of Income.

In 2012, the Corporation's interest in a cost company was redeemed. As part of the redemption, a variable note due in 2035 issued by Mobil Services (Bahamas) Ltd. was assigned to a consolidated ExxonMobil affiliate. This note is no longer classified as third party long-term debt. This assignment did not result in a "Reduction in long-term debt" on the Statement of Cash Flows.

In 2012, ExxonMobil completed asset exchanges, primarily noncash transactions, of approximately $1 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.

In 2011, included in "Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments" is a $3.6 billion deposit for an asset that was sold in 2012.

In 2010, the Corporation acquired all the outstanding equity of XTO Energy Inc. in an all-stock transaction valued at $24,659 million.

	2012	2011	2010
		(millions of dollars)	
Cash payments for interest	555	557	703
Cash payments for income taxes	24,349	27,254	18,941

6. Additional Working Capital Information

	Dec. 31 2012	Dec. 31 2011
	(millions of dollars)	
Notes and accounts receivable		
Trade, less reserves of $109 million and $128 million	28,373	30,044
Other, less reserves of $36 million and $39 million	6,614	8,598
Total	34,987	38,642
Notes and loans payable		
Bank loans	663	1,237
Commercial paper	1,963	2,281
Long-term debt due within one year	1,025	3,431
Other	2	762
Total	3,653	7,711
Accounts payable and accrued liabilities		
Trade payables	33,789	33,969
Payables to equity companies	6,114	5,553
Accrued taxes other than income taxes	4,130	7,123
Other	6,695	10,422
Total	50,728	57,067

On December 31, 2012, unused credit lines for short-term financing totaled approximately $3.5 billion. Of this total, $3.0 billion supports commercial paper programs under terms negotiated when drawn. The weighted-average interest rate on short-term borrowings outstanding at December 31, 2012, and 2011, was 1.7 percent and 1.9 percent, 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 crude production, natural gas production, natural gas marketing and refining operations in North America; natural gas production, natural gas distribution and downstream operations in Europe; refining operations, petrochemical manufacturing, fuel sales and power generation in Asia; crude production in Kazakhstan; and liquefied natural gas (LNG) operations in Qatar. Also included are several refining, petrochemical manufacturing and chemical 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 16 percent, 19 percent and 18 percent in the years 2012, 2011 and 2010, respectively.

Equity Company Financial Summary	2012 Total	2012 ExxonMobil Share	2011 Total	2011 ExxonMobil Share	2010 Total	2010 ExxonMobil Share
			(millions of dollars)			
Total revenues	224,953	67,572	204,635	65,147	153,020	48,355
Income before income taxes	69,411	20,882	68,908	20,892	48,075	14,735
Income taxes	20,703	5,868	19,812	5,603	13,962	4,058
Income from equity affiliates	48,708	15,014	49,096	15,289	34,113	10,677
Current assets	59,612	18,483	52,879	17,317	48,573	15,860
Long-term assets	111,131	33,798	96,908	30,833	90,646	29,805
Total assets	170,743	52,281	149,787	48,150	139,219	45,665
Current liabilities	49,698	14,265	41,016	12,454	33,160	10,260
Long-term liabilities	68,855	19,715	62,472	18,728	59,596	17,976
Net assets	52,190	18,301	46,299	16,968	46,463	17,429

A list of significant equity companies as of December 31, 2012, 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
Castle Peak Power Company Limited	60
Cross Timbers Energy, LLC	50
Golden Pass LNG Terminal LLC	18
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

	Percentage Ownership Interest
Downstream	
Chalmette Refining, LLC	50
Fujian Refining & Petrochemical Co. Ltd.	25
Saudi Aramco Mobil Refinery Company Ltd.	50
TonenGeneral Sekiyu K.K.	22
Chemical	
Al-Jubail Petrochemical Company	50
Infineum Holdings B.V.	50
Saudi Yanbu Petrochemical Co.	50

8. Investments, Advances and Long-Term Receivables

	Dec. 31, 2012	Dec. 31, 2011
	(millions of dollars)	
Companies carried at equity in underlying assets		
Investments	18,530	16,968
Advances	9,959	9,740
Total equity company investments and advances	28,489	26,708
Companies carried at cost or less and stock investments carried at fair value	437	1,544
Long-term receivables and miscellaneous investments at cost or less, net of reserves of $2,499 million and $469 million	5,792	6,081
Total	34,718	34,333

9. Property, Plant and Equipment and Asset Retirement Obligations

	December 31, 2012		December 31, 2011	
Property, Plant and Equipment	Cost	Net	Cost	Net
	(millions of dollars)			
Upstream	313,181	181,795	283,710	163,975
Downstream	53,737	23,053	67,900	28,801
Chemical	29,437	14,085	30,405	14,469
Other	12,959	8,016	11,980	7,419
Total	409,314	226,949	393,995	214,664

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.

Accumulated depreciation and depletion totaled $182,365 million at the end of 2012 and $179,331 million at the end of 2011. Interest capitalized in 2012, 2011 and 2010 was $506 million, $593 million and $532 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 (unobservable inputs) 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:

	2012	**2011**
	(millions of dollars)	
Beginning balance	10,578	9,614
Accretion expense and other provisions	709	581
Reduction due to property sales	(176)	(854)
Payments made	(816)	(662)
Liabilities incurred	163	117
Foreign currency translation	290	(62)
Revisions	1,225	1,844
Ending balance	11,973	10,578

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 does not necessarily have the same meaning as under SEC Rule 13q-1 relating to government payment reporting. For example, a single project for purposes of the rule may encompass numerous properties, agreements, investments, developments, phases, work efforts, activities, and components, each of which we may also informally describe as a "project."

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:

	2012	2011	2010
		(millions of dollars)	
Balance beginning at January 1	2,881	2,893	2,005
Additions pending the determination of proved reserves	868	310	1,103
Charged to expense	(95)	(213)	(104)
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(631)	(149)	(136)
Divestments/Other	(344)	40	25
Ending balance at December 31	2,679	2,881	2,893
Ending balance attributed to equity companies included above	3	-	-

Period end capitalized suspended exploratory well costs:

	2012	2011	2010
		(millions of dollars)	
Capitalized for a period of one year or less	866	310	1,103
Capitalized for a period of between one and five years	1,176	1,922	1,294
Capitalized for a period of between five and ten years	401	409	278
Capitalized for a period of greater than ten years	236	240	218
Capitalized for a period greater than one year - subtotal	1,813	2,571	1,790
Total	2,679	2,881	2,893

Exploration activity often involves drilling multiple wells, over a number of years, to fully evaluate a project. The table below provides a numerical breakdown of the number of projects with suspended exploratory well costs which had their first capitalized well drilled in the preceding 12 months and those that have had exploratory well costs capitalized for a period greater than 12 months.

	2012	2011	2010
Number of projects with first capitalized well drilled in the preceding 12 months	10	4	9
Number of projects that have exploratory well costs capitalized for a period of greater than 12 months	45	58	59
Total	55	62	68

Of the 45 projects that have exploratory well costs capitalized for a period greater than 12 months as of December 31, 2012, 17 projects have drilling in the preceding 12 months or exploratory activity planned in the next two years, while the remaining 28 projects are those with completed exploratory activity progressing toward development. The table below provides additional detail for those 28 projects, which total $557 million.

Country/Project	Dec. 31, 2012	Years Wells Drilled	Comment
	(millions of dollars)		
Angola			
- Perpetua-Zina-Acacia	15	2008 - 2009	Oil field near Pazflor development, awaiting capacity in existing/planned infrastructure.
Australia			
- East Pilchard	10	2001	Gas field near Kipper/Tuna development, awaiting capacity in existing/planned infrastructure.
- SE Longtom	16	2010	Gas field near Tuna development, awaiting capacity in existing/planned infrastructure.
Indonesia			
- 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.
Malaysia			
- Besar	18	1992 - 2010	Gas field off the east coast of Malaysia; progressing development plan.
- 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.
- Pegi	32	2009	Awaiting capacity in existing/planned infrastructure.
- Usan South Strip	16	2011	Evaluating development plans to tie into planned infrastructure.
- Other (5 projects)	16	2001 - 2002	Evaluating and pursuing development of several additional discoveries.
Norway			
- Gamma	21	2008 - 2009	Evaluating development plan for tieback to existing production facilities.
- H-North	16	2007	Progressing development and commercialization plans.
- Lavrans	24	1995 - 1999	Development awaiting capacity in existing Kristin production facility; evaluating development concepts for phased ullage scenarios.
- Other (5 projects)	23	2008 - 2010	Evaluating development plans, including potential for tieback to existing production facilities.
Papua New Guinea			
- Juha	28	2007	Working on development plans to tie into planned LNG facilities.
United Kingdom			
- Phyllis	8	2004	Evaluating development plan for tieback to existing production facilities.
United States			
- Tip Top	31	2009	Evaluating development concept and requisite facility upgrades.
Total 2012 (28 projects)	557		

11. Leased Facilities

At December 31, 2012, 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 $8,181 million as indicated in the table. Estimated related rental income from noncancelable subleases is $111 million.

	Lease Payments Under Minimum Commitments	Related Sublease Rental Income
	(millions of dollars)	
2013	2,254	33
2014	2,041	31
2015	1,381	26
2016	688	4
2017	350	3
2018 and beyond	1,467	14
Total	8,181	111

Net rental cost under both cancelable and noncancelable operating leases incurred during 2012, 2011 and 2010 were as follows:

	2012	2011	2010
		(millions of dollars)	
Rental cost	3,851	4,061	3,762
Less sublease rental income	44	74	90
Net rental cost	3,807	3,987	3,672

12. Earnings Per Share

	2012	2011	2010
Earnings per common share			
Net income attributable to ExxonMobil *(millions of dollars)*	44,880	41,060	30,460
Weighted average number of common shares outstanding *(millions of shares)*	4,628	4,870	4,885
Earnings per common share *(dollars)*	9.70	8.43	6.24
Earnings per common share - assuming dilution			
Net income attributable to ExxonMobil *(millions of dollars)*	44,880	41,060	30,460
Weighted average number of common shares outstanding *(millions of shares)*	4,628	4,870	4,885
Effect of employee stock-based awards	-	5	12
Weighted average number of common shares outstanding - assuming dilution	4,628	4,875	4,897
Earnings per common share - assuming dilution *(dollars)*	9.70	8.42	6.22
Dividends paid per common share *(dollars)*	2.18	1.85	1.74

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, including capitalized lease obligations, was $8.5 billion and $9.8 billion at December 31, 2012, and 2011, respectively, as compared to recorded book values of $7.9 billion and $9.3 billion at December 31, 2012, and 2011, respectively. The fair value of long-term debt by hierarchy level at December 31, 2012 is shown below:

	As of December 31, 2012			
	Level 1	Level 2	Level 3	Total
	(millions of dollars)			
Long-term debt fair value	6,482	1,480	496	8,458

The fair value hierarchy for long-term debt is primarily Level 1 and represents quoted prices in active markets. Level 2 includes debt whose fair value is based upon a publicly available index. The Level 3 amount is primarily capitalized leases whose value is typically determined through the use of present value and specific contract terms.

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 $2 million at year-end 2012 and a net liability of $3 million at year-end 2011. 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 (observable quoted prices on active exchanges) or Level 2 (derivatives that are determined by either market prices on an active market for similar assets or by prices quoted by a broker or other market-corroborated prices) inputs.

The Corporation recognized a before-tax gain or (loss) related to derivative instruments of $(23) million, $131 million and $221 million during 2012, 2011 and 2010, 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, 2012, long-term debt consisted of $7,325 million due in U.S. dollars and $603 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 $1,025 million, which matures within one year and is included in current liabilities. The amounts of long-term debt maturing in each of the four years after December 31, 2013, in millions of dollars, are: 2014 – $907; 2015 – $710; 2016 – $454; and 2017 – $814. At December 31, 2012, the Corporation's unused long-term credit lines were not material.

Summarized long-term debt at year-end 2012 and 2011 are shown in the table below:

	2012	2011
	(millions of dollars)	
XTO Energy Inc. *(1)*		
6.250% senior note due 2013	-	185
4.625% senior note due 2013	-	145
5.750% senior note due 2013	-	346
4.900% senior note due 2014	254	260
5.000% senior note due 2015	135	138
5.300% senior note due 2015	249	255
5.650% senior note due 2016	217	222
6.250% senior note due 2017	501	513
5.500% senior note due 2018	396	402
6.500% senior note due 2018	495	506
6.100% senior note due 2036	201	203
6.750% senior note due 2037	314	317
6.375% senior note due 2038	240	241
Mobil Services (Bahamas) Ltd.		
Variable note due 2035 *(2)*	-	972
Variable note due 2034 *(3)*	311	311
Mobil Producing Nigeria Unlimited *(4)*		
Variable notes due 2013-2019	751	543
Esso (Thailand) Public Company Ltd. *(5)*		
Variable notes due 2014-2017	414	413
Mobil Corporation		
8.625% debentures due 2021	249	248
Industrial revenue bonds due 2014-2051 *(6)*	2,690	2,315
Other U.S. dollar obligations *(7)*	74	496
Other foreign currency obligations	6	31
Capitalized lease obligations *(8)*	431	260
Total long-term debt	7,928	9,322

(1) Includes premiums of $326 million.

(2) Average effective interest rate of 0.2% in 2011.

(3) Average effective interest rate of 0.5% in 2012 and 0.3% in 2011.

(4) Average effective interest rate of 4.6% in 2012 and 4.2% in 2011.

(5) Average effective interest rate of 3.5% in 2012 and 3.2% in 2011.

(6) Average effective interest rate of 0.1% in 2012 and 0.1% in 2011.

(7) Average effective interest rate of 2.7% in 2012 and 4.8% in 2011.

(8) Average imputed interest rate of 7.6% in 2012 and 8.5% in 2011.

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 2012, remaining shares available for award under the 2003 Incentive Program were 124,736 thousand.

Restricted Stock. Awards totaling 10,017 thousand, 10,533 thousand, and 10,648 thousand (excluding XTO merger-related grants) of restricted (nonvested) common stock and restricted (nonvested) common stock units were granted in 2012, 2011 and 2010, 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. These shares 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 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 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.

Additionally, in 2010 long-term incentive awards totaling 4,206 thousand shares of restricted (nonvested) common stock, with a value of $250 million, were granted in association with the XTO merger. The majority of these awards vest over periods of up to three years after the initial grant.

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, 2012.

	2012	
Restricted stock and units outstanding	**Shares**	**Weighted Average Grant-Date Fair Value per Share**
	(thousands)	*(dollars)*
Issued and outstanding at January 1	46,781	70.76
2011 award issued in 2012	10,522	79.52
Vested	(10,537)	65.56
Forfeited	(315)	68.50
Issued and outstanding at December 31	46,451	73.94

Value of restricted stock and units	**2012**	**2011**	**2010**
Grant price *(dollars)*	87.24	79.52	66.07
Value at date of grant:		*(millions of dollars)*	
Restricted stock and units settled in stock	797	766	672
Merger-related granted and converted XTO awards	-	-	250
Units settled in cash	77	72	60
Total value	874	838	982

As of December 31, 2012, there was $2,179 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 units was $854 million, $793 million and $801 million for 2012, 2011 and 2010, respectively. The income tax benefit recognized in income related to this compensation expense was $79 million, $73 million and $81 million for the same periods, respectively. The fair value of shares and units vested in 2012, 2011 and 2010 was $926 million, $801 million and $718 million, respectively. Cash payments of $66 million, $46 million and $42 million for vested restricted stock units settled in cash were made in 2012, 2011 and 2010, respectively.

Stock Options. The Corporation has not granted any stock options under the 2003 Incentive Program and all stock options granted under the prior program were exercised by the end of 2011. In 2010, the Corporation granted 12,393 thousand of converted XTO stock options with a grant-date fair value of $182 million as a result of the XTO merger. These stock options generally vest and become exercisable ratably over a three-year period, and may include a provision for accelerated vesting when the common stock price reaches specified levels. Some stock option tranches vest only when the common stock price reaches specified levels. There were 2,355 thousand stock options, with an average exercise price of $78.60, outstanding at December 31, 2012.

Cash received from stock option exercises was $193 million, $924 million and $1,043 million for 2012, 2011 and 2010, respectively. The cash tax benefit realized for the options exercised was $54 million, $221 million and $89 million for 2012, 2011 and 2010, respectively. The aggregate intrinsic value of stock options exercised in 2012, 2011 and 2010 was $79 million, $986 million and $539 million, 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.

On June 30, 2011, a state district court jury in Baltimore County, Maryland returned a verdict against Exxon Mobil Corporation in *Allison, et al v. Exxon Mobil Corporation,* a case involving an accidental 26,000 gallon gasoline leak at a suburban Baltimore service station. The verdict included approximately $497 million in compensatory damages and approximately $1.0 billion in punitive damages in a finding that ExxonMobil fraudulently misled the plaintiff-residents about the events leading up to the leak, the leak's discovery, and the nature and extent of any groundwater contamination. ExxonMobil believes the verdict is not justified by the evidence and that the amount of the compensatory award is grossly excessive and the imposition of punitive damages is improper and unconstitutional. The trial court denied a post-trial motion that ExxonMobil filed to overturn the punitive damages verdict and entered a final judgment in the amount of $1,488 million. ExxonMobil appealed the verdict and judgment. In a prior trial involving the same leak and different plaintiffs, the jury awarded compensatory damages but rejected the plaintiffs' punitive damage claims. Those plaintiffs did not appeal the jury's denial of punitive damages. On February 9, 2012, the Maryland Court of Special Appeals reversed in part and affirmed in part the trial court's decision on compensatory damages in that case. The Maryland Court of Appeals granted writs of certiorari to both parties in response to their separate petitions seeking reversals of portions of the Court of Special Appeals' decision. The appeals in both of these cases were consolidated before the Maryland Court of Appeals and arguments were held on November 5, 2012. On February 26, 2013, the Maryland Court of Appeals issued its opinion in the consolidated appeal. The court unanimously reversed the fraud and punitive damages judgment, and also reversed a majority of the compensatory damage claims. The court remanded a limited number of claims related to alleged property damage for a new trial.

Other Contingencies. The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2012, 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, 2012		
	Equity Company Obligations *(1)*	Other Third-Party Obligations	Total
		(millions of dollars)	
Guarantees			
Debt-related	2,423	53	2,476
Other	2,729	4,994	7,723
Total	5,152	5,047	10,199

(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			
	2013	2014-2017	2018 and Beyond	Total
	(millions of dollars)			
Unconditional purchase obligations *(1)*	184	624	319	1,127

(1) Undiscounted obligations of $1,127 million mainly pertain to pipeline throughput agreements and include $584 million of obligations to equity companies. The present value of these commitments, which excludes imputed interest of $198 million, totaled $929 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. ExxonMobil's remaining net book investment in Cerro Negro producing assets is about $750 million.

On September 6, 2007, affiliates of ExxonMobil filed a Request for Arbitration with the International Centre for Settlement of Investment Disputes (ICSID) invoking ICSID jurisdiction under Venezuela's Investment Law and the Netherlands-Venezuela Bilateral Investment Treaty. 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. The ICSID arbitration proceeding is continuing and a hearing on the merits was held in February 2012. At this time, 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 have appealed that judgment. 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.			
	2012	2011	2012	2011	2012	2011
	(percent)					
Weighted-average assumptions used to determine benefit obligations at December 31						
Discount rate	4.00	5.00	3.80	4.00	4.00	5.00
Long-term rate of compensation increase	5.75	5.75	5.50	5.40	5.75	5.75
	(millions of dollars)					
Change in benefit obligation						
Benefit obligation at January 1	17,035	15,007	29,068	25,722	7,880	7,331
Service cost	665	546	648	574	134	121
Interest cost	820	792	1,145	1,267	380	393
Actuarial loss/(gain)	2,553	1,954	2,335	3,086	1,035	427
Benefits paid *(1) (2)*	(1,294)	(1,264)	(1,330)	(1,470)	(476)	(473)
Foreign exchange rate changes	-	-	651	(303)	13	(11)
Japan restructuring and other divestments	-	-	(3,952)	(16)	-	-
Plan amendments, other	-	-	105	208	92	92
Benefit obligation at December 31	19,779	17,035	28,670	29,068	9,058	7,880
Accumulated benefit obligation at December 31	15,902	14,081	24,345	25,480	-	-

(1) Benefit payments for funded and unfunded plans.

(2) For 2012 and 2011, other postretirement benefits paid are net of $23 million and $29 million of Medicare subsidy receipts, respectively.

For U.S. plans, the discount rate is determined by constructing a portfolio of 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 an initial health care cost trend rate of 5.0 percent that declines to 4.5 percent by 2015. A one-percentage-point increase in the health care cost trend rate would increase service and interest cost by $74 million and the postretirement benefit obligation by $871 million. A one-percentage-point decrease in the health care cost trend rate would decrease service and interest cost by $57 million and the postretirement benefit obligation by $700 million.

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2012	2011	2012	2011	2012	2011
	(millions of dollars)					
Change in plan assets						
Fair value at January 1	10,656	10,835	17,117	16,765	538	558
Actual return on plan assets	1,457	505	1,541	123	65	-
Foreign exchange rate changes	-	-	462	(192)	-	-
Company contribution	1,560	370	1,604	1,623	38	39
Benefits paid *(1)*	(1,041)	(1,054)	(922)	(1,046)	(60)	(59)
Japan restructuring and other divestments	-	-	(1,696)	(7)	-	-
Other	-	-	(16)	(149)	-	-
Fair value at December 31	12,632	10,656	18,090	17,117	581	538

(1) Benefit payments for funded plans.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.	
	2012	2011	2012	2011
	(millions of dollars)			
Assets in excess of/(less than) benefit obligation				
Balance at December 31				
Funded plans	(4,438)	(4,141)	(3,247)	(5,319)
Unfunded plans	(2,709)	(2,238)	(7,333)	(6,632)
Total	(7,147)	(6,379)	(10,580)	(11,951)

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.			
	2012	2011	2012	2011	2012	2011
	(millions of dollars)					
Assets in excess of/(less than) benefit obligation						
Balance at December 31 *(1)*	(7,147)	(6,379)	(10,580)	(11,951)	(8,477)	(7,342)
Amounts recorded in the consolidated balance sheet consist of:						
Other assets	1	1	49	245	-	-
Current liabilities	(279)	(237)	(352)	(346)	(356)	(341)
Postretirement benefits reserves	(6,869)	(6,143)	(10,277)	(11,850)	(8,121)	(7,001)
Total recorded	(7,147)	(6,379)	(10,580)	(11,951)	(8,477)	(7,342)
Amounts recorded in accumulated other comprehensive income consist of:						
Net actuarial loss/(gain)	7,451	6,475	10,904	11,170	3,132	2,291
Prior service cost	67	74	758	745	85	119
Total recorded in accumulated other comprehensive income	7,518	6,549	11,662	11,915	3,217	2,410

(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.					
	2012	2011	2010	2012	2011	2010	2012	2011	2010
Weighted-average assumptions used to determine net periodic benefit cost for years ended December 31					*(percent)*				
Discount rate	5.00	5.50	6.00	4.00	4.80	5.20	5.00	5.50	6.00
Long-term rate of return on funded assets	7.25	7.50	7.50	6.60	6.80	6.70	7.25	7.50	7.50
Long-term rate of compensation increase	5.75	5.25	5.25	5.40	5.20	5.00	5.75	5.25	5.25
Components of net periodic benefit cost					*(millions of dollars)*				
Service cost	665	546	468	648	574	480	134	121	101
Interest cost	820	792	798	1,145	1,267	1,175	380	393	395
Expected return on plan assets	(789)	(769)	(726)	(1,109)	(1,168)	(1,010)	(38)	(41)	(37)
Amortization of actuarial loss/(gain)	576	485	525	844	647	554	170	162	147
Amortization of prior service cost	7	9	2	117	103	84	34	35	52
Net pension enhancement and curtailment/settlement cost *(1)*	333	286	321	1,540	34	9	-	-	-
Net periodic benefit cost	1,612	1,349	1,388	3,185	1,457	1,292	680	670	658

(1) Non-U.S. net pension enhancement and curtailment/settlement cost for 2012 includes $1,420 million (on a consolidated-company, before-tax basis) of accumulated other comprehensive income for the postretirement benefit reserves adjustment that was recycled into earnings and included in the Japan restructuring gain reported in "Other income" (See Note 20).

	U.S. 2012	U.S. 2011	U.S. 2010	Non-U.S. 2012	Non-U.S. 2011	Non-U.S. 2010	Other 2012	Other 2011	Other 2010
Changes in amounts recorded in accumulated other comprehensive income:									
Net actuarial loss/(gain)	1,885	2,218	44	1,906	4,133	1,202	1,008	468	251
Amortization of actuarial (loss)/gain	(909)	(771)	(846)	(2,384)	(681)	(563)	(170)	(162)	(147)
Prior service cost/(credit)	-	-	80	71	187	160	-	-	26
Amortization of prior service (cost)/credit	(7)	(9)	(2)	(117)	(103)	(84)	(34)	(35)	(52)
Foreign exchange rate changes	-	-	-	271	(90)	96	3	-	2
Total recorded in other comprehensive income	969	1,438	(724)	(253)	3,446	811	807	271	80
Total recorded in net periodic benefit cost and other comprehensive income, before tax	2,581	2,787	664	2,932	4,903	2,103	1,487	941	738

Costs for defined contribution plans were $382 million, $378 million and $347 million in 2012, 2011 and 2010, respectively.

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

	Total Pension and Other Postretirement Benefits		
	2012	**2011**	**2010**
	(millions of dollars)		
(Charge)/credit to other comprehensive income, before tax			
U.S. pension	(969)	(1,438)	724
Non-U.S. pension	253	(3,446)	(811)
Other postretirement benefits	(807)	(271)	(80)
Total (charge)/credit to other comprehensive income, before tax	(1,523)	(5,155)	(167)
(Charge)/credit to income tax (see Note 4)	393	1,495	35
(Charge)/credit to investment in equity companies	(49)	(30)	11
(Charge)/credit to other comprehensive income including noncontrolling interests, after tax	(1,179)	(3,690)	(121)
Charge/(credit) to equity of noncontrolling interests	(124)	288	95
(Charge)/credit to other comprehensive income attributable to ExxonMobil	(1,303)	(3,402)	(26)

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 is 50 percent equity securities and 50 percent debt securities. The target asset allocation for the non-U.S. plans in aggregate is 50 percent equity securities and 50 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The 2012 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, 2012, Using:				Fair Value Measurement at December 31, 2012, Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
				(millions of dollars)				
Asset category:								
Equity securities								
U.S.	-	2,600 *(1)*	-	2,600	-	2,671 *(1)*	-	2,671
Non-U.S.	-	3,227 *(1)*	-	3,227	203 *(2)*	5,308 *(1)*	-	5,511
Private equity	-	-	489 *(3)*	489	-	-	448 *(3)*	448
Debt securities								
Corporate	-	3,872 *(4)*	-	3,872	-	2,005 *(4)*	-	2,005
Government	-	2,223 *(4)*	-	2,223	271 *(5)*	6,643 *(4)*	-	6,914
Asset-backed	-	10 *(4)*	-	10	-	95 *(4)*	-	95
Private mortgages	-	-	-	-	-	-	5 *(6)*	5
Real estate funds	-	-	-	-	-	-	293 *(7)*	293
Cash	-	198 *(8)*	-	198	93	35 *(9)*	-	128
Total at fair value	-	12,130	489	12,619	567	16,757	746	18,070
Insurance contracts at contract value				13				20
Total plan assets				12,632				18,090

(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 private mortgages, fair value is estimated to equal the principal outstanding at the measurement date.

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

(8) 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.

(9) 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, 2012, Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(millions of dollars)			
Asset category:				
Equity securities				
U.S.	-	166 *(1)*	-	166
Non-U.S.	-	160 *(1)*	-	160
Private equity	-	-	7 *(2)*	7
Debt securities				
Corporate	-	91 *(3)*	-	91
Government	-	136 *(3)*	-	136
Asset-backed	-	14 *(3)*	-	14
Cash	-	7	-	7
Total at fair value	-	574	7	581

(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 2012 of Level 3 assets that use significant unobservable inputs to measure fair value is shown in the table below:

	2012				
	Pension				Other Postretirement
	U.S.	Non-U.S.			
	Private Equity	Private Equity	Private Mortgages	Real Estate	Private Equity
	(millions of dollars)				
Fair value at January 1	458	393	4	397	7
Net realized gains/(losses)	2	2	-	(14)	-
Net unrealized gains/(losses)	41	22	1	(1)	-
Net purchases/(sales)	(12)	31	-	(89)	-
Fair value at December 31	489	448	5	293	7

The 2011 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, 2011, Using:				Fair Value Measurement at December 31, 2011, Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
				(millions of dollars)				
Asset category:								
Equity securities								
U.S.	-	2,247 *(1)*	-	2,247	-	2,589 *(1)*	-	2,589
Non-U.S.	-	2,636 *(1)*	-	2,636	194 *(2)*	4,835 *(1)*	-	5,029
Private equity	-	-	458 *(3)*	458	-	-	393 *(3)*	393
Debt securities								
Corporate	-	2,728 *(4)*	-	2,728	2 *(5)*	1,857 *(4)*	-	1,859
Government	-	2,482 *(4)*	-	2,482	186 *(5)*	6,317 *(4)*	-	6,503
Asset-backed	-	11 *(4)*	-	11	-	102 *(4)*	-	102
Private mortgages	-	-	-	-	-	-	4 *(6)*	4
Real estate funds	-	-	-	-	-	-	397 *(7)*	397
Cash	-	71 *(8)*	-	71	76	13 *(9)*	-	89
Total at fair value	-	10,175	458	10,633	458	15,713	794	16,965
Insurance contracts at contract value				23				152
Total plan assets				10,656				17,117

(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 private mortgages, fair value is estimated to equal the principal outstanding at the measurement date.

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

(8) 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.

(9) 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, 2011, Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(millions of dollars)		
Asset category:				
Equity securities				
U.S.	-	166 *(1)*	-	166
Non-U.S.	-	155 *(1)*	-	155
Private equity	-	-	7 *(2)*	7
Debt securities				
Corporate	-	77 *(3)*	-	77
Government	-	120 *(3)*	-	120
Asset-backed	-	12 *(3)*	-	12
Cash	-	1	-	1
Total at fair value	-	531	7	538

(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 2011 of Level 3 assets that use significant unobservable inputs to measure fair value is shown in the table below:

	2011						
	Pension					Other Postretirement	
	U.S.		Non-U.S.				
	Private Equity	Private Mortgages	Private Equity	Private Mortgages	Real Estate	Private Equity	Private Mortgages
			(millions of dollars)				
Fair value at January 1	408	128	315	4	417	5	2
Net realized gains/(losses)	1	5	7	-	3	-	-
Net unrealized gains/(losses)	56	-	33	-	6	2	-
Net purchases/(sales)	(7)	(133)	38	-	(29)	-	(2)
Fair value at December 31	458	-	393	4	397	7	-

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.	
	2012	2011	2012	2011
	(millions of dollars)			
For funded pension plans with an accumulated benefit obligation in excess of plan assets:				
Projected benefit obligation	17,070	14,797	9,422	17,668
Accumulated benefit obligation	14,171	12,606	8,184	16,175
Fair value of plan assets	12,631	10,655	7,048	12,832
For unfunded pension plans:				
Projected benefit obligation	2,709	2,238	7,333	6,632
Accumulated benefit obligation	1,731	1,475	6,103	5,753

	Pension Benefits		Other Postretirement Benefits
	U.S.	Non-U.S.	
	(millions of dollars)		
Estimated 2013 amortization from accumulated other comprehensive income:			
Net actuarial loss/(gain) *(1)*	1,173	882	233
Prior service cost *(2)*	7	121	21

(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 2013	100	1,250	-	-
Benefit payments expected in:				
2013	1,643	1,237	453	23
2014	1,611	1,237	469	25
2015	1,597	1,294	482	26
2016	1,558	1,329	494	27
2017	1,510	1,384	506	28
2018 - 2022	6,716	7,319	2,633	163

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 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 $202 million, $165 million and $41 million in 2012, 2011 and 2010, respectively.

	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, 2012								
Earnings after income tax	3,925	25,970	3,575	9,615	2,220	1,678	(2,103)	44,880
Earnings of equity companies above	1,759	11,900	6	387	183	1,267	(492)	15,010
Sales and other operating revenue *(1)*	11,472	28,854	125,088	248,959	14,723	24,003	24	453,123
Intersegment revenue	8,764	47,507	20,963	62,130	12,409	9,750	258	-
Depreciation and depletion expense	5,104	7,340	594	1,280	376	508	686	15,888
Interest revenue	-	-	-	-	-	-	117	117
Interest expense	37	13	3	36	-	(1)	239	327
Income taxes	2,025	25,362	1,811	1,892	755	232	(1,032)	31,045
Additions to property, plant and equipment	9,697	21,769	480	1,153	338	659	1,083	35,179
Investments in equity companies	4,020	9,147	195	2,069	233	3,143	(277)	18,530
Total assets	86,146	140,848	18,451	40,956	7,238	18,886	21,270	333,795
As of December 31, 2011								
Earnings after income tax	5,096	29,343	2,268	2,191	2,215	2,168	(2,221)	41,060
Earnings of equity companies above	2,045	11,768	7	353	198	1,365	(447)	15,289
Sales and other operating revenue *(1)*	14,023	32,419	120,844	257,779	15,466	26,476	22	467,029
Intersegment revenue	9,807	49,910	18,489	73,549	12,226	10,563	262	-
Depreciation and depletion expense	4,879	7,021	650	1,560	380	458	635	15,583
Interest revenue	-	-	-	-	-	-	135	135
Interest expense	30	36	10	24	2	(1)	146	247
Income taxes	2,852	25,755	1,123	696	1,027	465	(867)	31,051
Additions to property, plant and equipment	10,887	18,934	400	1,334	241	910	932	33,638
Investments in equity companies	2,963	8,439	210	1,358	253	3,973	(228)	16,968
Total assets	82,900	127,977	18,354	51,132	7,245	19,862	23,582	331,052
As of December 31, 2010								
Earnings after income tax	4,272	19,825	770	2,797	2,422	2,491	(2,117)	30,460
Earnings of equity companies above	1,261	8,415	23	225	171	1,163	(581)	10,677
Sales and other operating revenue *(1)*	8,895	26,046	93,599	206,042	13,402	22,119	22	370,125
Intersegment revenue	8,102	39,066	13,546	52,697	9,694	8,421	282	-
Depreciation and depletion expense	3,506	7,574	681	1,565	421	432	581	14,760
Interest revenue	-	-	-	-	-	-	118	118
Interest expense	20	25	1	19	1	4	189	259
Income taxes	2,219	18,627	360	560	736	347	(1,288)	21,561
Additions to property, plant and equipment	52,300	16,937	888	1,332	247	1,733	719	74,156
Investments in equity companies	2,636	9,625	254	1,240	285	3,586	(197)	17,429
Total assets	76,725	115,646	18,378	47,402	7,148	19,087	18,124	302,510

(1) Sales and other operating revenue includes sales-based taxes of $32,409 million for 2012, $33,503 million for 2011 and $28,547 million for 2010. See Note 1, Summary of Accounting Policies.

Geographic

Sales and other operating revenue *(1)*	2012	2011	2010
		(millions of dollars)	
United States	151,298	150,343	115,906
Non-U.S.	301,825	316,686	254,219
Total	453,123	467,029	370,125
Significant non-U.S. revenue sources include:			
Canada	34,325	34,626	27,243
United Kingdom	34,134	34,833	24,637
Belgium	23,567	26,926	21,139
France	19,601	18,510	13,920
Italy	18,228	16,288	14,132
Germany	16,451	17,034	14,301
Singapore	14,606	14,400	11,088
Japan	14,162	31,925	27,143

(1) Sales and other operating revenue includes sales-based taxes of $32,409 million for 2012, $33,503 million for 2011 and $28,547 million for 2010. See Note 1, Summary of Accounting Policies.

Long-lived assets	2012	2011	2010
		(millions of dollars)	
United States	94,336	91,146	86,021
Non-U.S.	132,613	123,518	113,527
Total	226,949	214,664	199,548
Significant non-U.S. long-lived assets include:			
Canada	31,979	24,458	20,879
Australia	13,415	9,474	6,570
Nigeria	12,216	11,806	11,429
Singapore	9,700	9,285	8,610
Angola	8,238	10,395	8,570
Kazakhstan	7,785	7,022	5,938
Norway	7,040	6,039	6,988
United Kingdom	5,472	5,008	6,177

19. Income, Sales-Based and Other Taxes

	2012			2011			2010		
	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	1,791	25,650	27,441	1,547	28,849	30,396	1,224	21,093	22,317
Deferred - net	1,097	1,816	2,913	1,577	(1,417)	160	49	(1,191)	(1,142)
U.S. tax on non-U.S. operations	89	-	89	15	-	15	46	-	46
Total federal and non-U.S.	2,977	27,466	30,443	3,139	27,432	30,571	1,319	19,902	21,221
State	602	-	602	480	-	480	340	-	340
Total income tax expense	3,579	27,466	31,045	3,619	27,432	31,051	1,659	19,902	21,561
Sales-based taxes	5,785	26,624	32,409	5,652	27,851	33,503	6,182	22,365	28,547
All other taxes and duties									
Other taxes and duties	1,406	34,152	35,558	1,539	38,434	39,973	776	35,342	36,118
Included in production and manufacturing expenses	1,242	1,308	2,550	1,342	1,425	2,767	1,001	1,237	2,238
Included in SG&A expenses	154	595	749	181	623	804	201	570	771
Total other taxes and duties	2,802	36,055	38,857	3,062	40,482	43,544	1,978	37,149	39,127
Total	12,166	90,145	102,311	12,333	95,765	108,098	9,819	79,416	89,235

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 net charges of $244 million in 2012 and $175 million in 2010 and a net credit of $330 million in 2011 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 2012, 2011 and 2010 is as follows:

	2012	2011	2010
		(millions of dollars)	
Income before income taxes			
United States	11,222	11,511	7,711
Non-U.S.	67,504	61,746	45,248
Total	78,726	73,257	52,959
Theoretical tax	27,554	25,640	18,536
Effect of equity method of accounting	(5,254)	(5,351)	(3,737)
Non-U.S. taxes in excess of theoretical U.S. tax	8,434	10,385	7,293
U.S. tax on non-U.S. operations	89	15	46
State taxes, net of federal tax benefit	391	312	221
Other U.S.	(169)	50	(798)
Total income tax expense	31,045	31,051	21,561
Effective tax rate calculation			
Income taxes	31,045	31,051	21,561
ExxonMobil share of equity company income taxes	5,859	5,603	4,058
Total income taxes	36,904	36,654	25,619
Net income including noncontrolling interests	47,681	42,206	31,398
Total income before taxes	84,585	78,860	57,017
Effective income tax rate	44%	46%	45%

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:	**2012**	**2011**
	(millions of dollars)	
Property, plant and equipment	48,720	45,951
Other liabilities	3,680	4,281
Total deferred tax liabilities	52,400	50,232
Pension and other postretirement benefits	(8,041)	(7,930)
Asset retirement obligations	(5,826)	(5,302)
Tax loss carryforwards	(2,989)	(3,166)
Other assets	(6,135)	(7,079)
Total deferred tax assets	(22,991)	(23,477)
Asset valuation allowances	1,615	1,304
Net deferred tax liabilities	31,024	28,059

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	**2012**	**2011**
	(millions of dollars)	
Other current assets	(3,540)	(4,549)
Other assets, including intangibles, net	(3,269)	(4,218)
Accounts payable and accrued liabilities	263	208
Deferred income tax liabilities	37,570	36,618
Net deferred tax liabilities	31,024	28,059

The Corporation had $43 billion of indefinitely reinvested, undistributed earnings from subsidiary companies outside the U.S. Unrecognized deferred taxes on remittance of these funds are not expected to be material.

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. Resolution of the related 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. It is reasonably possible that the total amount of unrecognized tax benefits could increase by up to 25 percent in the next 12 months, with no material impact on near-term earnings. Given the long time periods involved in resolving tax positions, the Corporation does not expect that the recognition of unrecognized tax benefits will have a material impact on the Corporation's effective income tax rate in any given year.

The following table summarizes the movement in unrecognized tax benefits.

Gross unrecognized tax benefits	2012	2011	2010
		(millions of dollars)	
Balance at January 1	4,922	4,148	4,725
Additions based on current year's tax positions	1,662	822	830
Additions for prior years' tax positions	2,559	451	620
Reductions for prior years' tax positions	(535)	(329)	(505)
Reductions due to lapse of the statute of limitations	(79)	-	(534)
Settlements with tax authorities	(855)	(145)	(999)
Foreign exchange effects/other	(11)	(25)	11
Balance at December 31	7,663	4,922	4,148

The additions and reductions in unrecognized tax benefits shown above include effects related to net income and equity, and timing differences for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. The 2012, 2011 and 2010 changes in unrecognized tax benefits did not have a material effect on the Corporation's net income or cash flow.

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

Country of Operation	Open Tax Years
Abu Dhabi	2000 - 2012
Angola	2009 - 2012
Australia:	2000 - 2003
	2005 - 2012
Canada	2005 - 2012
Equatorial Guinea	2007 - 2012
Malaysia	2006 - 2012
Nigeria	1998 - 2012
Norway	2000 - 2012
United Kingdom	2010 - 2012
United States	2005 - 2012

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 $46 million and $62 million in interest expense on income tax reserves in 2012 and 2011, respectively. For 2010, interest expense was a credit of $39 million, reflecting the effect of credits from the net favorable resolution of prior year tax positions. The related interest payable balances were $385 million and $662 million at December 31, 2012, and 2011, respectively.

20. Japan Restructuring

On June 1, 2012, the Corporation completed the restructuring of its Downstream and Chemical holdings in Japan. Under the restructuring, TonenGeneral Sekiyu K. K. (TG), a consolidated subsidiary owned 50 percent by the Corporation, purchased for $3.9 billion the Corporation's shares of a wholly-owned affiliate in Japan, EMG Marketing Godo Kaisha (previously known as ExxonMobil Yugen Kaisha), which resulted in TG acquiring approximately 200 million of its shares owned by the Corporation along with other assets. As a result of the restructuring, the Corporation's effective ownership of TG was reduced to approximately 22 percent and a net gain of $6.5 billion was recognized. The gain is included in "Other income" partially offset by amounts included in "Income taxes" and "Net income attributable to noncontrolling interests."

The gain includes $1.9 billion of the Corporation's share of other comprehensive income recycled into earnings (see note 1 below). The gain also includes remeasurement of TG's shares that the Corporation continues to own to $0.7 billion, based on TG's share price on the Tokyo Stock Exchange. The Corporation accounts for its remaining investment using the equity method.

Summarized balance sheet for the Japan entities subject to the restructuring follows:

	June 1, 2012
	(millions of dollars)
Assets	
Current assets	6,391
Net property, plant and equipment	4,700
Other assets	989
Total assets	12,080
Liabilities	
Current liabilities	7,398
Long-term debt	22
Postretirement benefits reserves	2,066
Other long-term obligations	826
Total liabilities	10,312
Equity	
ExxonMobil share of equity *(1)*	(256)
Noncontrolling interests	2,024
Total equity	1,768
Total liabilities and equity	12,080

(1) The accumulated other comprehensive income associated with the Japan restructuring was recycled into earnings. At June 1, 2012, ExxonMobil's share of accumulated other comprehensive income was a benefit of $1.9 billion, including $2.5 billion related to cumulative translation adjustments offset by $0.6 billion related to postretirement benefits reserves adjustments.

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 $2,832 million in 2012, $2,600 million in 2011, and $249 million in 2010. 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							
2012 - Revenue							
Sales to third parties	6,977	1,804	5,835	3,672	6,536	1,275	26,099
Transfers	6,996	5,457	6,366	16,905	9,241	932	45,897
	13,973	7,261	12,201	20,577	15,777	2,207	71,996
Production costs excluding taxes	4,044	3,079	2,443	2,395	1,606	488	14,055
Exploration expenses	391	292	274	234	513	136	1,840
Depreciation and depletion	4,862	848	1,559	2,879	1,785	264	12,197
Taxes other than income	1,963	89	513	1,702	2,248	446	6,961
Related income tax	1,561	720	5,413	8,091	6,616	281	22,682
Results of producing activities for consolidated subsidiaries	1,152	2,233	1,999	5,276	3,009	592	14,261
Equity Companies							
2012 - Revenue							
Sales to third parties	1,284	-	6,380	-	20,017	-	27,681
Transfers	1,108	-	67	-	5,693	-	6,868
	2,392	-	6,447	-	25,710	-	34,549
Production costs excluding taxes	467	-	369	-	484	-	1,320
Exploration expenses	9	-	17	-	-	-	26
Depreciation and depletion	176	-	152	-	676	-	1,004
Taxes other than income	42	-	3,569	-	6,658	-	10,269
Related income tax	-	-	894	-	8,234	-	9,128
Results of producing activities for equity companies	1,698	-	1,446	-	9,658	-	12,802
Total results of operations	2,850	2,233	3,445	5,276	12,667	592	27,063

Results of Operations	United States	Canada/ South America	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
2011 - Revenue							
Sales to third parties	8,579	1,056	8,050	3,507	6,813	1,061	29,066
Transfers	8,190	7,022	7,694	16,704	9,388	1,213	50,211
	16,769	8,078	15,744	20,211	16,201	2,274	79,277
Production costs excluding taxes	4,107	2,751	2,722	2,608	1,672	497	14,357
Exploration expenses	268	290	599	233	618	73	2,081
Depreciation and depletion	4,664	980	1,928	2,159	1,680	236	11,647
Taxes other than income	2,157	79	631	2,055	2,164	295	7,381
Related income tax	2,445	969	6,842	7,888	6,026	353	24,523
Results of producing activities for consolidated subsidiaries	3,128	3,009	3,022	5,268	4,041	820	19,288
Equity Companies							
2011 - Revenue							
Sales to third parties	1,356	-	5,580	-	18,855	-	25,791
Transfers	1,163	-	103	-	5,666	-	6,932
	2,519	-	5,683	-	24,521	-	32,723
Production costs excluding taxes	482	-	315	-	378	-	1,175
Exploration expenses	10	-	13	-	-	-	23
Depreciation and depletion	151	-	160	-	576	-	887
Taxes other than income	36	-	2,995	-	6,173	-	9,204
Related income tax	-	-	847	-	8,036	-	8,883
Results of producing activities for equity companies	1,840	-	1,353	-	9,358	-	12,551
Total results of operations	4,968	3,009	4,375	5,268	13,399	820	31,839
Consolidated Subsidiaries							
2010 - Revenue							
Sales to third parties	5,334	1,218	6,055	4,227	4,578	696	22,108
Transfers	7,070	5,832	7,120	13,295	6,031	1,123	40,471
	12,404	7,050	13,175	17,522	10,609	1,819	62,579
Production costs excluding taxes	2,794	2,612	2,717	2,215	1,308	462	12,108
Exploration expenses	283	464	394	587	360	56	2,144
Depreciation and depletion	3,350	1,015	2,531	2,580	1,141	219	10,836
Taxes other than income	1,188	86	482	1,742	1,298	204	5,000
Related income tax	2,093	715	4,728	6,068	3,852	262	17,718
Results of producing activities for consolidated subsidiaries	2,696	2,158	2,323	4,330	2,650	616	14,773
Equity Companies							
2010 - Revenue							
Sales to third parties	1,012	-	5,050	-	12,682	-	18,744
Transfers	867	-	68	-	3,817	-	4,752
	1,879	-	5,118	-	16,499	-	23,496
Production costs excluding taxes	481	-	294	-	320	-	1,095
Exploration expenses	4	-	19	-	2	-	25
Depreciation and depletion	157	-	188	-	455	-	800
Taxes other than income	32	-	2,515	-	3,844	-	6,391
Related income tax	-	-	815	-	5,295	-	6,110
Results of producing activities for equity companies	1,205	-	1,287	-	6,583	-	9,075
Total results of operations	3,901	2,158	3,610	4,330	9,233	616	23,848

Oil and Gas Exploration and Production Costs

The amounts shown for net capitalized costs of consolidated subsidiaries are $10,643 million less at year-end 2012 and $6,651 million less at year-end 2011 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 have been included in the capitalized costs for 2012 and 2011 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, 2012							
Property (acreage) costs - Proved	12,081	3,911	198	874	1,610	971	19,645
- Unproved	25,769	1,456	89	430	710	162	28,616
Total property costs	37,850	5,367	287	1,304	2,320	1,133	48,261
Producing assets	70,603	21,947	44,068	37,921	23,230	6,910	204,679
Incomplete construction	4,840	18,726	1,589	5,070	12,654	5,988	48,867
Total capitalized costs	113,293	46,040	45,944	44,295	38,204	14,031	301,807
Accumulated depreciation and depletion	36,346	17,357	34,267	21,285	16,599	4,801	130,655
Net capitalized costs for consolidated subsidiaries	76,947	28,683	11,677	23,010	21,605	9,230	171,152
Equity Companies							
As of December 31, 2012							
Property (acreage) costs - Proved	76	-	5	-	-	-	81
- Unproved	39	-	-	-	-	-	39
Total property costs	115	-	5	-	-	-	120
Producing assets	4,216	-	5,736	-	8,169	-	18,121
Incomplete construction	304	-	118	-	822	-	1,244
Total capitalized costs	4,635	-	5,859	-	8,991	-	19,485
Accumulated depreciation and depletion	1,447	-	4,494	-	3,744	-	9,685
Net capitalized costs for equity companies	3,188	-	1,365	-	5,247	-	9,800
Consolidated Subsidiaries							
As of December 31, 2011							
Property (acreage) costs - Proved	10,969	3,837	96	919	1,567	954	18,342
- Unproved	25,398	1,402	67	430	755	128	28,180
Total property costs	36,367	5,239	163	1,349	2,322	1,082	46,522
Producing assets	65,941	20,393	40,646	32,059	22,675	6,035	187,749
Incomplete construction	4,652	12,385	964	9,831	9,922	4,131	41,885
Total capitalized costs	106,960	38,017	41,773	43,239	34,919	11,248	276,156
Accumulated depreciation and depletion	33,037	16,296	31,706	18,449	14,960	4,384	118,832
Net capitalized costs for consolidated subsidiaries	73,923	21,721	10,067	24,790	19,959	6,864	157,324
Equity Companies							
As of December 31, 2011							
Property (acreage) costs - Proved	76	-	4	-	-	-	80
- Unproved	25	-	-	-	-	-	25
Total property costs	101	-	4	-	-	-	105
Producing assets	3,510	-	5,383	-	8,155	-	17,048
Incomplete construction	183	-	212	-	548	-	943
Total capitalized costs	3,794	-	5,599	-	8,703	-	18,096
Accumulated depreciation and depletion	1,354	-	4,267	-	3,068	-	8,689
Net capitalized costs for equity companies	2,440	-	1,332	-	5,635	-	9,407

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 2012 were $31,146 million, up $392 million from 2011, due primarily to higher exploration and development costs partially offset by lower property acquisition costs. 2011 costs were $30,754 million, down $40,058 million from 2010, due primarily to the absence of the acquisition of XTO Energy Inc. Total equity company costs incurred in 2012 were $1,404 million, up $178 million from 2011, due primarily to higher development 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 2012							
Consolidated Subsidiaries							
Property acquisition costs - Proved	192	2	95	-	43	-	332
- Unproved	1,717	74	24	15	-	31	1,861
Exploration costs	601	405	454	520	554	248	2,782
Development costs	7,172	7,601	2,637	3,081	3,347	2,333	26,171
Total costs incurred for consolidated subsidiaries	9,682	8,082	3,210	3,616	3,944	2,612	31,146
Equity Companies							
Property acquisition costs - Proved	-	-	-	-	-	-	-
- Unproved	14	-	-	-	-	-	14
Exploration costs	45	-	34	-	-	-	79
Development costs	504	-	156	-	651	-	1,311
Total costs incurred for equity companies	563	-	190	-	651	-	1,404
During 2011							
Consolidated Subsidiaries							
Property acquisition costs - Proved	259	-	-	-	96	-	355
- Unproved	2,685	178	-	-	546	-	3,409
Exploration costs	465	372	640	303	518	154	2,452
Development costs	8,166	5,478	1,899	4,316	2,969	1,710	24,538
Total costs incurred for consolidated subsidiaries	11,575	6,028	2,539	4,619	4,129	1,864	30,754
Equity Companies							
Property acquisition costs - Proved	-	-	-	-	-	-	-
- Unproved	23	-	-	-	-	-	23
Exploration costs	19	-	32	-	-	-	51
Development costs	339	-	164	-	649	-	1,152
Total costs incurred for equity companies	381	-	196	-	649	-	1,226
During 2010							
Consolidated Subsidiaries							
Property acquisition costs - Proved	21,633	-	41	3	115	-	21,792
- Unproved	23,509	136	23	-	-	-	23,668
Exploration costs	690	527	550	453	545	228	2,993
Development costs	7,947	4,757	1,227	4,390	2,892	1,146	22,359
Total costs incurred for consolidated subsidiaries	53,779	5,420	1,841	4,846	3,552	1,374	70,812
Equity Companies							
Property acquisition costs - Proved	-	-	-	-	-	-	-
- Unproved	1	-	-	-	-	-	1
Exploration costs	4	-	56	-	2	-	62
Development costs	323	-	225	-	303	-	851
Total costs incurred for equity companies	328	-	281	-	305	-	914

Oil and Gas Reserves

The following information describes changes during the years and balances of proved oil and gas reserves at year-end 2010, 2011, and 2012.

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 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.

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 2012 that were associated with production sharing contract arrangements was 12 percent of liquids, 8 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.

In accordance with the Securities and Exchange Commission's rules, bitumen extracted through mining activities and hydrocarbons from other non-traditional resources are reported as oil and gas reserves beginning in 2009.

The rules in 2009 adopted a reliable technology definition that permits reserves to be added based on technologies that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated.

The changes between 2011 year-end proved reserves and 2012 year-end proved reserves reflect the extensions and discoveries in North America.

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

	Crude Oil and Natural Gas Liquids							Bitumen	Synthetic Oil	
	United States	Canada/ S. Amer.	Europe	Africa	Asia	Australia/ Oceania	Total	Canada/ S. Amer.	Canada/ S. Amer.	Total
	(millions of barrels)									
Net proved developed and undeveloped reserves of consolidated subsidiaries										
January 1, 2010	1,616	172	487	1,907	1,999	288	6,469	2,055	691	9,215
Revisions	57	10	53	89	49	7	265	89	14	368
Improved recovery	4	-	-	-	-	1	5	-	-	5
Purchases	374	-	-	-	4	-	378	-	-	378
Sales	(19)	-	-	(2)	-	-	(21)	-	-	(21)
Extensions/discoveries	43	11	4	34	90	-	182	-	-	182
Production	(123)	(30)	(121)	(229)	(119)	(21)	(643)	(42)	(24)	(709)
December 31, 2010	1,952	163	423	1,799	2,023	275	6,635	2,102	681	9,418
Proportional interest in proved reserves of equity companies										
January 1, 2010	356	-	30	-	2,050	-	2,436	-	-	2,436
Revisions	17	-	3	-	(30)	-	(10)	-	-	(10)
Improved recovery	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-
Sales	-	-	-	-	-	-	-	-	-	-
Extensions/discoveries	3	-	-	-	-	-	3	-	-	3
Production	(25)	-	(2)	-	(147)	-	(174)	-	-	(174)
December 31, 2010	351	-	31	-	1,873	-	2,255	-	-	2,255
Total liquids proved reserves at December 31, 2010	2,303	163	454	1,799	3,896	275	8,890	2,102	681	11,673

Crude Oil, Natural Gas Liquids, Synthetic Oil and Bitumen 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, 2011	1,679	138	350	1,589	1,839	178	5,773	862	2,102	681	9,418
Revisions	29	10	68	52	(55)	5	109	106	53	(4)	264
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	2	-	-	-	-	-	2	14	-	-	16
Sales	(3)	(11)	(24)	-	-	-	(38)	(14)	-	-	(52)
Extensions/discoveries	55	-	3	1	57	-	116	18	995	-	1,129
Production	(102)	(19)	(80)	(179)	(120)	(13)	(513)	(81)	(44)	(24)	(662)
December 31, 2011	1,660	118	317	1,463	1,721	170	5,449	905	3,106	653	10,113
Proportional interest in proved reserves of equity companies											
January 1, 2011	350	-	31	-	1,394	-	1,775	480	-	-	2,255
Revisions	24	-	-	-	(21)	-	3	3	-	-	6
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-	-
Sales	(2)	-	-	-	-	-	(2)	-	-	-	(2)
Extensions/discoveries	-	-	-	-	12	-	12	25	-	-	37
Production	(24)	-	(2)	-	(130)	-	(156)	(25)	-	-	(181)
December 31, 2011	348	-	29	-	1,255	-	1,632	483	-	-	2,115
Total liquids proved reserves at December 31, 2011	2,008	118	346	1,463	2,976	170	7,081	1,388	3,106	653	12,228
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2012	1,660	118	317	1,463	1,721	170	5,449	905	3,106	653	10,113
Revisions	25	33	14	20	(10)	5	87	3	265	(29)	326
Improved recovery	6	-	-	-	1	-	7	-	-	-	7
Purchases	163	-	20	-	-	-	183	36	-	-	219
Sales	(15)	(1)	(8)	(58)	-	-	(82)	(4)	-	-	(86)
Extensions/discoveries	166	138	8	41	9	-	362	164	234	-	760
Production	(100)	(18)	(62)	(173)	(117)	(12)	(482)	(73)	(45)	(25)	(625)
December 31, 2012	1,905	270	289	1,293	1,604	163	5,524	1,031	3,560	599	10,714
Proportional interest in proved reserves of equity companies											
January 1, 2012	348	-	29	-	1,255	-	1,632	483	-	-	2,115
Revisions	(2)	-	1	-	131	-	130	15	-	-	145
Improved recovery	16	-	-	-	-	-	16	-	-	-	16
Purchases	-	-	-	-	-	-	-	-	-	-	-
Sales	-	-	-	-	-	-	-	-	-	-	-
Extensions/discoveries	-	-	-	-	-	-	-	-	-	-	-
Production	(22)	-	(2)	-	(126)	-	(150)	(24)	-	-	(174)
December 31, 2012	340	-	28	-	1,260	-	1,628	474	-	-	2,102
Total liquids proved reserves at December 31, 2012	2,245	270	317	1,293	2,864	163	7,152	1,505	3,560	599	12,816

(1) Includes total proved reserves attributable to Imperial Oil Limited of 10 million barrels in 2011 and 9 million barrels in 2012, as well as proved developed reserves of 10 million barrels in 2011 and 9 million barrels in 2012, in which there is a 30.4 percent noncontrolling interest.

Crude Oil, Natural Gas Liquids, Synthetic Oil and Bitumen 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, 2010										
Consolidated subsidiaries	1,478	133	361	1,055	1,306	139	4,472	519	681	5,672
Equity companies	271	-	21	-	1,623	-	1,915	-	-	1,915
Proved undeveloped reserves, as of December 31, 2010										
Consolidated subsidiaries	474	30	62	744	717	136	2,163	1,583	-	3,746
Equity companies	80	-	10	-	250	-	340	-	-	340
Total liquids proved reserves at December 31, 2010	2,303	163	454	1,799	3,896	275	8,890	2,102	681	11,673
Proved developed reserves, as of December 31, 2011										
Consolidated subsidiaries	1,452	109	302	1,050	1,160	126	4,199	519	653	5,371
Equity companies	270	-	28	-	1,457	-	1,755	-	-	1,755
Proved undeveloped reserves, as of December 31, 2011										
Consolidated subsidiaries	567	26	74	625	727	136	2,155	2,587	-	4,742
Equity companies	83	-	1	-	276	-	360	-	-	360
Total liquids proved reserves at December 31, 2011	2,372	135	405	1,675	3,620	262	8,469	3,106	653	12,228
Proved developed reserves, as of December 31, 2012										
Consolidated subsidiaries	1,489	124	268	1,004	1,080	116	4,081	543	599	5,223
Equity companies	264	-	28	-	1,423	-	1,715	-	-	1,715
Proved undeveloped reserves, as of December 31, 2012										
Consolidated subsidiaries	921	163	77	497	682	134	2,474	3,017	-	5,491
Equity companies	84	-	-	-	303	-	387	-	-	387
Total liquids proved reserves at December 31, 2012	2,758	287	373	1,501	3,488	250	8,657 *(4)*	3,560	599	12,816

(1) Includes total proved reserves attributable to Imperial Oil Limited of 57 million barrels in 2010, 55 million barrels in 2011 and 53 million barrels in 2012, as well as proved developed reserves of 56 million barrels in 2010, 55 million barrels in 2011 and 52 million barrels in 2012, and in addition, proved undeveloped reserves of 1 million barrels in both 2010 and 2012, in which there is a 30.4 percent noncontrolling interest.

(2) Includes total proved reserves attributable to Imperial Oil Limited of 1,715 million barrels in 2010, 2,413 million barrels in 2011 and 2,841 million barrels in 2012, as well as proved developed reserves of 519 million barrels in 2010, 519 million barrels in 2011 and 543 million barrels in 2012, and in addition, proved undeveloped reserves of 1,196 million barrels in 2010, 1,894 million barrels in 2011 and 2,298 million barrels in 2012, in which there is a 30.4 percent noncontrolling interest.

(3) Includes total proved reserves attributable to Imperial Oil Limited of 681 million barrels in 2010, 653 million barrels in 2011 and 599 million barrels in 2012, as well as proved developed reserves of 681 million barrels in 2010, 653 million barrels in 2011 and 599 million barrels in 2012, in which there is a 30.4 percent noncontrolling interest.

(4) See previous page 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 2012 Form 10-K.

Natural Gas and Oil-Equivalent Proved Reserves

	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, 2010	11,688	1,368	4,723	920	8,303	7,440	34,442	14,955
Revisions	832	123	(26)	6	(333)	42	644	475
Improved recovery	-	-	-	-	-	-	-	5
Purchases	12,774	-	15	-	-	-	12,789	2,510
Sales	(104)	(2)	-	-	-	-	(106)	(38)
Extensions/discoveries	1,861	3	49	25	25	1	1,964	509
Production	(1,057)	(234)	(719)	(43)	(735)	(132)	(2,920)	(1,196)
December 31, 2010	25,994	1,258	4,042	908	7,260	7,351	46,813	17,220
Proportional interest in proved reserves of equity companies								
January 1, 2010	114	-	11,450	-	22,001	-	33,565	8,030
Revisions	8	-	(4)	-	231	-	235	30
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Sales	-	-	-	-	-	-	-	-
Extensions/discoveries	-	-	24	-	-	-	24	7
Production	(5)	-	(724)	-	(1,093)	-	(1,822)	(478)
December 31, 2010	117	-	10,746	-	21,139	-	32,002	7,589
Total proved reserves at December 31, 2010	26,111	1,258	14,788	908	28,399	7,351	78,815	24,809
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2011	25,994	1,258	4,042	908	7,260	7,351	46,813	17,220
Revisions	(236)	55	310	113	(231)	28	39	271
Improved recovery	-	-	-	-	-	-	-	-
Purchases	303	-	-	-	-	-	303	67
Sales	(32)	(347)	(140)	-	-	-	(519)	(138)
Extensions/discoveries	1,779	42	29	-	192	-	2,042	1,469
Production	(1,554)	(173)	(655)	(39)	(750)	(132)	(3,303)	(1,213)
December 31, 2011	26,254	835	3,586	982	6,471	7,247	45,375	17,676
Proportional interest in proved reserves of equity companies								
January 1, 2011	117	-	10,746	-	21,139	-	32,002	7,589
Revisions	1	-	53	-	(29)	-	25	10
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Sales	(1)	-	(3)	-	-	-	(4)	(3)
Extensions/discoveries	-	-	13	-	627	-	640	144
Production	(5)	-	(640)	-	(1,171)	-	(1,816)	(484)
December 31, 2011	112	-	10,169	-	20,566	-	30,847	7,256
Total proved reserves at December 31, 2011	26,366	835	13,755	982	27,037	7,247	76,222	24,932

(See footnotes on next page)

Natural Gas and Oil-Equivalent Proved Reserves (continued)

	Natural Gas							Oil-Equivalent
	United States	Canada/ South Amer. *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total	**Total All Products *(2)***
	(billions of cubic feet)							*(millions of oil-equivalent barrels)*
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2012	26,254	835	3,586	982	6,471	7,247	45,375	17,676
Revisions	(2,888)	168	168	2	(106)	465	(2,191)	(39)
Improved recovery	-	-	-	-	-	-	-	7
Purchases	503	-	6	-	-	-	509	304
Sales	(181)	(20)	(140)	(12)	-	-	(353)	(145)
Extensions/discoveries	4,045	95	184	-	59	-	4,383	1,490
Production	(1,518)	(153)	(555)	(43)	(579)	(144)	(2,992)	(1,124)
December 31, 2012	26,215	925	3,249	929	5,845	7,568	44,731	18,169
Proportional interest in proved reserves of equity companies								
January 1, 2012	112	-	10,169	-	20,566	-	30,847	7,256
Revisions	49	-	17	-	252	-	318	198
Improved recovery	-	-	-	-	-	-	-	16
Purchases	-	-	-	-	-	-	-	-
Sales	-	-	-	-	-	-	-	-
Extensions/discoveries	-	-	-	-	-	-	-	-
Production	(6)	-	(651)	-	(1,148)	-	(1,805)	(475)
December 31, 2012	155	-	9,535	-	19,670	-	29,360	6,995
Total proved reserves at December 31, 2012	26,370	925	12,784	929	25,515	7,568	74,091	25,164

(1) Includes total proved reserves attributable to Imperial Oil Limited of 576 billion cubic feet in 2010, 422 billion cubic feet in 2011 and 488 billion cubic feet in 2012, as well as proved developed reserves of 507 billion cubic feet in 2010, 360 billion cubic feet in 2011 and 374 billion cubic feet in 2012, and in addition, proved undeveloped reserves of 69 billion cubic feet in 2010, 62 billion cubic feet in 2011 and 114 billion cubic feet in 2012, 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, 2010								
Consolidated subsidiaries	15,344	1,077	3,516	711	6,593	1,174	28,415	10,408
Equity companies	97	-	8,167	-	20,494	-	28,758	6,708
Proved undeveloped reserves, as of December 31, 2010								
Consolidated subsidiaries	10,650	181	526	197	667	6,177	18,398	6,812
Equity companies	20	-	2,579	-	645	-	3,244	881
Total proved reserves at December 31, 2010	26,111	1,258	14,788	908	28,399	7,351	78,815	24,809
Proved developed reserves, as of December 31, 2011								
Consolidated subsidiaries	15,450	658	3,041	853	5,762	1,070	26,834	9,843
Equity companies	83	-	7,588	-	19,305	-	26,976	6,251
Proved undeveloped reserves, as of December 31, 2011								
Consolidated subsidiaries	10,804	177	545	129	709	6,177	18,541	7,833
Equity companies	29	-	2,581	-	1,261	-	3,871	1,005
Total proved reserves at December 31, 2011	26,366	835	13,755	982	27,037	7,247	76,222	24,932
Proved developed reserves, as of December 31, 2012								
Consolidated subsidiaries	14,471	670	2,526	814	5,150	1,012	24,643	9,330
Equity companies	126	-	7,057	-	18,431	-	25,614	5,984
Proved undeveloped reserves, as of December 31, 2012								
Consolidated subsidiaries	11,744	255	723	115	695	6,556	20,088	8,839
Equity companies	29	-	2,478	-	1,239	-	3,746	1,011
Total proved reserves at December 31, 2012	26,370	925	12,784	929	25,515	7,568	74,091	25,164

(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, 2010							
Future cash inflows from sales of oil and gas	221,298	184,671	60,086	137,476	156,337	55,087	814,955
Future production costs	76,992	69,765	15,246	31,189	36,318	16,347	245,857
Future development costs	28,905	22,130	12,155	15,170	13,716	11,652	103,728
Future income tax expenses	44,128	21,798	21,736	46,145	59,477	9,591	202,875
Future net cash flows	71,273	70,978	10,949	44,972	46,826	17,497	262,495
Effect of discounting net cash flows at 10%	39,545	45,607	2,765	18,046	28,883	13,411	148,257
Discounted future net cash flows	31,728	25,371	8,184	26,926	17,943	4,086	114,238
Equity Companies							
As of December 31, 2010							
Future cash inflows from sales of oil and gas	26,110	-	73,222	-	232,334	-	331,666
Future production costs	6,369	-	49,010	-	73,508	-	128,887
Future development costs	2,883	-	2,719	-	2,523	-	8,125
Future income tax expenses	-	-	8,348	-	57,041	-	65,389
Future net cash flows	16,858	-	13,145	-	99,262	-	129,265
Effect of discounting net cash flows at 10%	9,612	-	6,857	-	51,512	-	67,981
Discounted future net cash flows	7,246	-	6,288	-	47,750	-	61,284
Total consolidated and equity interests in standardized measure of discounted future net cash flows	38,974	25,371	14,472	26,926	65,693	4,086	175,522

(1) Includes discounted future net cash flows attributable to Imperial Oil Limited of $19,834 million in 2010, 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, 2011							
Future cash inflows from sales of oil and gas	264,991	280,991	71,847	179,337	203,007	86,456	1,086,629
Future production costs	105,391	98,135	15,045	36,309	43,442	23,381	321,703
Future development costs	31,452	35,121	11,987	15,384	16,010	10,052	120,006
Future income tax expenses	53,507	34,542	32,004	67,256	79,975	17,287	284,571
Future net cash flows	74,641	113,193	12,811	60,388	63,580	35,736	360,349
Effect of discounting net cash flows at 10%	42,309	79,303	3,525	22,029	38,066	22,873	208,105
Discounted future net cash flows	32,332	33,890	9,286	38,359	25,514	12,863	152,244
Equity Companies							
As of December 31, 2011							
Future cash inflows from sales of oil and gas	37,398	-	88,417	-	324,283	-	450,098
Future production costs	6,862	-	62,377	-	104,040	-	173,279
Future development costs	3,072	-	2,701	-	3,636	-	9,409
Future income tax expenses	-	-	9,035	-	76,825	-	85,860
Future net cash flows	27,464	-	14,304	-	139,782	-	181,550
Effect of discounting net cash flows at 10%	15,941	-	7,131	-	71,918	-	94,990
Discounted future net cash flows	11,523	-	7,173	-	67,864	-	86,560
Total consolidated and equity interests in standardized measure of discounted future net cash flows	43,855	33,890	16,459	38,359	93,378	12,863	238,804
Consolidated Subsidiaries							
As of December 31, 2012							
Future cash inflows from sales of oil and gas	250,382	293,910	66,769	160,261	192,491	104,334	1,068,147
Future production costs	109,325	101,299	17,277	33,398	42,816	26,132	330,247
Future development costs	37,504	44,518	16,505	13,363	13,083	11,435	136,408
Future income tax expenses	43,772	34,692	23,252	63,246	75,261	21,405	261,628
Future net cash flows	59,781	113,401	9,735	50,254	61,331	45,362	339,864
Effect of discounting net cash flows at 10%	36,578	82,629	2,097	18,091	35,310	27,610	202,315
Discounted future net cash flows	23,203	30,772	7,638	32,163	26,021	17,752	137,549
Equity Companies							
As of December 31, 2012							
Future cash inflows from sales of oil and gas	36,043	-	93,563	-	348,026	-	477,632
Future production costs	7,040	-	64,988	-	112,980	-	185,008
Future development costs	3,708	-	2,569	-	10,780	-	17,057
Future income tax expenses	-	-	9,937	-	78,539	-	88,476
Future net cash flows	25,295	-	16,069	-	145,727	-	187,091
Effect of discounting net cash flows at 10%	14,741	-	8,133	-	76,979	-	99,853
Discounted future net cash flows	10,554	-	7,936	-	68,748	-	87,238
Total consolidated and equity interests in standardized measure of discounted future net cash flows	33,757	30,772	15,574	32,163	94,769	17,752	224,787

(1) Includes discounted future net cash flows attributable to Imperial Oil Limited of $27,568 million in 2011 and $24,690 million in 2012, 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	2010		
	Consolidated Subsidiaries	Share of Equity Method Investees	Total Consolidated and Equity Interests
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2009	65,846	49,310	115,156
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	20,093	210	20,303
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	(46,078)	(16,050)	(62,128)
Development costs incurred during the year	20,975	843	21,818
Net change in prices, lifting and development costs	61,612	23,135	84,747
Revisions of previous reserves estimates	14,770	3,605	18,375
Accretion of discount	10,399	5,775	16,174
Net change in income taxes	(33,379)	(5,544)	(38,923)
Total change in the standardized measure during the year	48,392	11,974	60,366
Discounted future net cash flows as of December 31, 2010	114,238	61,284	175,522

Consolidated and Equity Interests	2011		
	Consolidated Subsidiaries	Share of Equity Method Investees	Total Consolidated and Equity Interests
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2010	114,238	61,284	175,522
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	6,608	309	6,917
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	(58,308)	(22,402)	(80,710)
Development costs incurred during the year	22,843	1,153	23,996
Net change in prices, lifting and development costs	79,435	46,304	125,739
Revisions of previous reserves estimates	10,462	3,127	13,589
Accretion of discount	16,802	7,196	23,998
Net change in income taxes	(39,836)	(10,411)	(50,247)
Total change in the standardized measure during the year	38,006	25,276	63,282
Discounted future net cash flows as of December 31, 2011	152,244	86,560	238,804

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

Consolidated and Equity Interests (continued)	2012		
	Consolidated Subsidiaries	Share of Equity Method Investees	Total Consolidated and Equity Interests
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2011	152,244	86,560	238,804
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	7,952	531	8,483
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	(51,752)	(23,022)	(74,774)
Development costs incurred during the year	24,596	1,186	25,782
Net change in prices, lifting and development costs	(31,382)	5,656	(25,726)
Revisions of previous reserves estimates	3,876	7,018	10,894
Accretion of discount	19,676	8,846	28,522
Net change in income taxes	12,339	463	12,802
Total change in the standardized measure during the year	(14,695)	678	(14,017)
Discounted future net cash flows as of December 31, 2012	137,549	87,238	224,787

OPERATING SUMMARY (unaudited)

	2012	2011	2010	2009	2008
Production of crude oil, natural gas liquids, synthetic oil and bitumen					
Net production			*(thousands of barrels daily)*		
United States	418	423	408	384	367
Canada/South America	251	252	263	267	292
Europe	207	270	335	379	428
Africa	487	508	628	685	652
Asia	772	808	730	607	599
Australia/Oceania	50	51	58	65	67
Worldwide	2,185	2,312	2,422	2,387	2,405
Natural gas production available for sale					
Net production			*(millions of cubic feet daily)*		
United States	3,822	3,917	2,596	1,275	1,246
Canada/South America	362	412	569	643	640
Europe	3,220	3,448	3,836	3,689	3,949
Africa	17	7	14	19	32
Asia	4,538	5,047	4,801	3,332	2,870
Australia/Oceania	363	331	332	315	358
Worldwide	12,322	13,162	12,148	9,273	9,095
			(thousands of oil-equivalent barrels daily)		
Oil-equivalent production *(1)*	4,239	4,506	4,447	3,932	3,921
Refinery throughput			*(thousands of barrels daily)*		
United States	1,816	1,784	1,753	1,767	1,702
Canada	435	430	444	413	446
Europe	1,504	1,528	1,538	1,548	1,601
Asia Pacific	998	1,180	1,249	1,328	1,352
Other Non-U.S.	261	292	269	294	315
Worldwide	5,014	5,214	5,253	5,350	5,416
Petroleum product sales *(2)*					
United States	2,569	2,530	2,511	2,523	2,540
Canada	453	455	450	413	444
Europe	1,571	1,596	1,611	1,625	1,712
Asia Pacific and other Eastern Hemisphere	1,381	1,556	1,562	1,588	1,646
Latin America	200	276	280	279	419
Worldwide	6,174	6,413	6,414	6,428	6,761
Gasoline, naphthas	2,489	2,541	2,611	2,573	2,654
Heating oils, kerosene, diesel oils	1,947	2,019	1,951	2,013	2,096
Aviation fuels	473	492	476	536	607
Heavy fuels	515	588	603	598	636
Specialty petroleum products	750	773	773	708	768
Worldwide	6,174	6,413	6,414	6,428	6,761
Chemical prime product sales			*(thousands of metric tons)*		
United States	9,381	9,250	9,815	9,649	9,526
Non-U.S.	14,776	15,756	16,076	15,176	15,456
Worldwide	24,157	25,006	25,891	24,825	24,982

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.

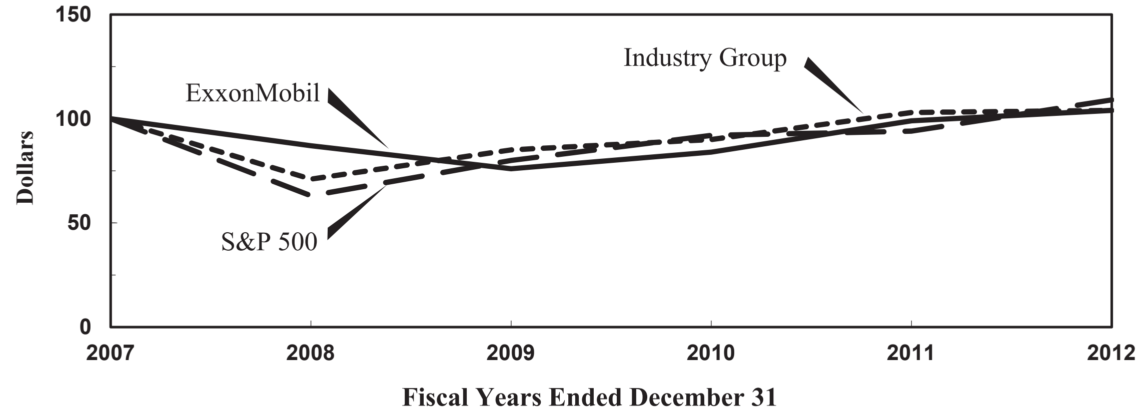
(1) Gas converted to oil-equivalent at 6 million cubic feet = 1 thousand barrels.

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

STOCK PERFORMANCE GRAPHS (unaudited)

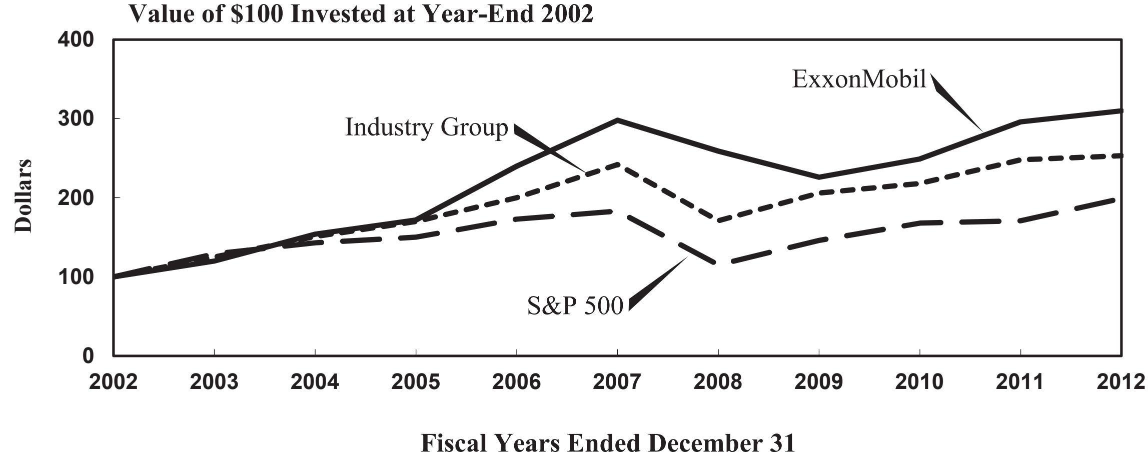
Annual total returns to ExxonMobil shareholders were 10 percent in 2010, 19 percent in 2011, and 5 percent in 2012. Total returns mean share price increase plus dividends paid, with dividends reinvested. The graphs below show the relative investment performance of ExxonMobil common stock, the S&P 500, and an industry competitor group over the last five and 10 years. The industry competitor group consists of three other international integrated oil companies: BP, Chevron, and Royal Dutch Shell.

FIVE-YEAR CUMULATIVE TOTAL RETURNS
Value of $100 Invested at Year-End 2007



ExxonMobil	100	87	76	84	99	104
S&P 500	100	63	80	92	94	109
Industry Group	100	71	85	90	103	104

TEN-YEAR CUMULATIVE TOTAL RETURNS
Value of $100 Invested at Year-End 2002



ExxonMobil	100	120	154	172	240	298	259	226	249	296	310
S&P 500	100	129	143	150	173	183	115	146	168	171	199
Industry Group	100	125	151	170	200	242	171	206	218	248	253

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