



2010

**Financial Statements and
Supplemental Information**

For the Fiscal Year Ended December 31, 2010

FINANCIAL STATEMENTS AND SUPPLEMENTAL INFORMATION

For the fiscal year ended December 31, 2010

TABLE OF CONTENTS

Business Profile	F-2
Financial Summary	F-3
Frequently Used Terms	F-4
Quarterly Information	F-6
Management's Discussion and Analysis of Financial Condition and Results of Operations	
Functional Earnings	F-7
Forward-Looking Statements	F-8
Overview	F-8
Business Environment and Risk Assessment	F-8
Review of 2010 and 2009 Results	F-11
Liquidity and Capital Resources	F-12
Capital and Exploration Expenditures	F-16
Taxes	F-16
Environmental Matters	F-16
Market Risks, Inflation and Other Uncertainties	F-17
Critical Accounting Policies	F-18
Management's Report on Internal Control Over Financial Reporting	F-22
Report of Independent Registered Public Accounting Firm	F-22
Consolidated Financial Statements	
Statement of Income	F-24
Balance Sheet	F-25
Statement of Cash Flows	F-26
Statement of Changes in Equity	F-27
Statement of Comprehensive Income	F-28
Notes to Consolidated Financial Statements	
1. Summary of Accounting Policies	F-29
2. Accounting Changes	F-31
3. Miscellaneous Financial Information	F-32
4. Cash Flow Information	F-32
5. Additional Working Capital Information	F-32
6. Equity Company Information	F-33
7. Investments, Advances and Long-Term Receivables	F-34
8. Property, Plant and Equipment and Asset Retirement Obligations	F-34
9. Accounting for Suspended Exploratory Well Costs	F-35
10. Leased Facilities	F-37
11. Earnings Per Share	F-37
12. Financial Instruments and Derivatives	F-38
13. Long-Term Debt	F-39
14. Incentive Program	F-44
15. Litigation and Other Contingencies	F-47
16. Pension and Other Postretirement Benefits	F-49
17. Disclosures about Segments and Related Information	F-57
18. Income, Sales-Based and Other Taxes	F-59
19. Acquisition of XTO Energy Inc.	F-61
Supplemental Information on Oil and Gas Exploration and Production Activities	F-63
Operating Summary	F-78
Share Performance Graphs	F-79

BUSINESS PROFILE

Financial	Earnings After Income Taxes		Average Capital Employed		Return on Average Capital Employed		Capital and Exploration Expenditures	
	2010	2009	2010	2009	2010	2009	2010	2009
	<i>(millions of dollars)</i>				<i>(percent)</i>		<i>(millions of dollars)</i>	
Upstream								
United States	\$ 4,272	\$ 2,893	\$ 34,969	\$ 15,865	12.2	18.2	\$ 6,349	\$ 3,585
Non-U.S.	19,825	14,214	68,318	57,336	29.0	24.8	20,970	17,119
Total	\$24,097	\$17,107	\$103,287	\$ 73,201	23.3	23.4	\$27,319	\$20,704
Downstream								
United States	\$ 770	\$ (153)	\$ 6,154	\$ 7,306	12.5	(2.1)	\$ 982	\$ 1,511
Non-U.S.	2,797	1,934	17,976	17,793	15.6	10.9	1,523	1,685
Total	\$ 3,567	\$ 1,781	\$ 24,130	\$ 25,099	14.8	7.1	\$ 2,505	\$ 3,196
Chemical								
United States	\$ 2,422	\$ 769	\$ 4,566	\$ 4,370	53.0	17.6	\$ 279	\$ 319
Non-U.S.	2,491	1,540	14,114	12,190	17.6	12.6	1,936	2,829
Total	\$ 4,913	\$ 2,309	\$ 18,680	\$ 16,560	26.3	13.9	\$ 2,215	\$ 3,148
Corporate and financing	(2,117)	(1,917)	(880)	10,190	–	–	187	44
Total	\$30,460	\$19,280	\$145,217	\$125,050	21.7	16.3	\$32,226	\$27,092

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

Operating	2010	2009		2010	2009
	<i>(thousands of barrels daily)</i>			<i>(thousands of barrels daily)</i>	
Net liquids production			Refinery throughput		
United States	408	384	United States	1,753	1,767
Non-U.S.	2,014	2,003	Non-U.S.	3,500	3,583
Total	2,422	2,387	Total	5,253	5,350
	<i>(millions of cubic feet daily)</i>			<i>(thousands of barrels daily)</i>	
Natural gas production available for sale			Petroleum product sales		
United States	2,596	1,275	United States	2,511	2,523
Non-U.S.	9,552	7,998	Non-U.S.	3,903	3,905
Total	12,148	9,273	Total	6,414	6,428
	<i>(thousands of oil-equivalent barrels daily)</i>			<i>(thousands of metric tons)</i>	
Oil-equivalent production (1)	4,447	3,932	Chemical prime product sales		
			United States	9,815	9,649
			Non-U.S.	16,076	15,176
			Total	25,891	24,825

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

FINANCIAL SUMMARY

	2010 (1)	2009	2008	2007	2006
		<i>(millions of dollars, except per share amounts)</i>			
Sales and other operating revenue (2)	\$370,125	\$301,500	\$459,579	\$390,328	\$365,467
Earnings					
Upstream	\$ 24,097	\$ 17,107	\$ 35,402	\$ 26,497	\$ 26,230
Downstream	3,567	1,781	8,151	9,573	8,454
Chemical	4,913	2,309	2,957	4,563	4,382
Corporate and financing	(2,117)	(1,917)	(1,290)	(23)	434
Net income attributable to ExxonMobil	\$ 30,460	\$ 19,280	\$ 45,220	\$ 40,610	\$ 39,500
Earnings per common share	\$ 6.24	\$ 3.99	\$ 8.70	\$ 7.31	\$ 6.64
Earnings per common share – assuming dilution	\$ 6.22	\$ 3.98	\$ 8.66	\$ 7.26	\$ 6.60
Cash dividends per common share	\$ 1.74	\$ 1.66	\$ 1.55	\$ 1.37	\$ 1.28
Earnings to average ExxonMobil share of equity (percent)	23.7	17.3	38.5	34.5	35.1
Working capital	\$ (3,649)	\$ 3,174	\$ 23,166	\$ 27,651	\$ 26,960
Ratio of current assets to current liabilities (times)	0.94	1.06	1.47	1.47	1.55
Additions to property, plant and equipment	\$ 74,156	\$ 22,491	\$ 19,318	\$ 15,387	\$ 15,462
Property, plant and equipment, less allowances	\$199,548	\$139,116	\$121,346	\$120,869	\$113,687
Total assets	\$302,510	\$233,323	\$228,052	\$242,082	\$219,015
Exploration expenses, including dry holes	\$ 2,144	\$ 2,021	\$ 1,451	\$ 1,469	\$ 1,181
Research and development costs	\$ 1,012	\$ 1,050	\$ 847	\$ 814	\$ 733
Long-term debt	\$ 12,227	\$ 7,129	\$ 7,025	\$ 7,183	\$ 6,645
Total debt	\$ 15,014	\$ 9,605	\$ 9,425	\$ 9,566	\$ 8,347
Fixed-charge coverage ratio (times)	42.2	25.8	54.6	51.6	47.8
Debt to capital (percent)	9.0	7.7	7.4	7.1	6.6
Net debt to capital (percent) (3)	4.5	(1.0)	(23.0)	(24.0)	(20.4)
ExxonMobil share of equity at year end	\$146,839	\$110,569	\$112,965	\$121,762	\$113,844
ExxonMobil share of equity per common share	\$ 29.48	\$ 23.39	\$ 22.70	\$ 22.62	\$ 19.87
Weighted average number of common shares outstanding (millions)	4,885	4,832	5,194	5,557	5,948
Number of regular employees at year end (thousands) (4)	83.6	80.7	79.9	80.8	82.1
CORS employees not included above (thousands) (5)	20.1	22.0	24.8	26.3	24.3

(1) See Note 19: Acquisition of XTO Energy Inc.

(2) Sales and other operating revenue includes sales-based taxes of \$28,547 million for 2010, \$25,936 million for 2009, \$34,508 million for 2008, \$31,728 million for 2007 and \$30,381 million for 2006.

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

(4) 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.

(5) 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 from sales of subsidiaries, investments and property, plant and equipment 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 sales proceeds 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	2010	2009	2008
	<i>(millions of dollars)</i>		
Net cash provided by operating activities	\$ 48,413	\$ 28,438	\$ 59,725
Sales of subsidiaries, investments and property, plant and equipment	3,261	1,545	5,985
Cash flow from operations and asset sales	<u>\$ 51,674</u>	<u>\$ 29,983</u>	<u>\$ 65,710</u>

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	2010	2009	2008
	<i>(millions of dollars)</i>		
Business uses: asset and liability perspective			
Total assets	\$ 302,510	\$ 233,323	\$ 228,052
Less liabilities and noncontrolling interests share of assets and liabilities			
Total current liabilities excluding notes and loans payable	(59,846)	(49,585)	(46,700)
Total long-term liabilities excluding long-term debt	(74,971)	(58,741)	(54,404)
Noncontrolling interests share of assets and liabilities	(6,532)	(5,642)	(6,044)
Add ExxonMobil share of debt-financed equity company net assets	4,875	5,043	4,798
Total capital employed	<u>\$ 166,036</u>	<u>\$ 124,398</u>	<u>\$ 125,702</u>
Total corporate sources: debt and equity perspective			
Notes and loans payable	\$ 2,787	\$ 2,476	\$ 2,400
Long-term debt	12,227	7,129	7,025
ExxonMobil share of equity	146,839	110,569	112,965
Less noncontrolling interests share of total debt	(692)	(819)	(1,486)
Add ExxonMobil share of equity company debt	4,875	5,043	4,798
Total capital employed	<u>\$ 166,036</u>	<u>\$ 124,398</u>	<u>\$ 125,702</u>

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	2010	2009	2008
		<i>(millions of dollars)</i>	
Net income attributable to ExxonMobil	\$ 30,460	\$ 19,280	\$ 45,220
Financing costs (after tax)			
Gross third-party debt	(803)	(303)	(343)
ExxonMobil share of equity companies	(333)	(285)	(325)
All other financing costs – net	35	(483)	1,485
Total financing costs	(1,101)	(1,071)	817
Earnings excluding financing costs	<u>\$ 31,561</u>	<u>\$ 20,351</u>	<u>\$ 44,403</u>
Average capital employed	\$145,217	\$125,050	\$129,683
Return on average capital employed – corporate total	21.7%	16.3%	34.2%

QUARTERLY INFORMATION

	2010					2009				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
Volumes										
Production of crude oil and natural gas liquids, synthetic oil and bitumen	2,414	2,325	2,421	2,526	2,422	2,476	2,346	2,335	2,393	2,387
<i>(thousands of barrels daily)</i>										
Refinery throughput	5,156	5,192	5,364	5,298	5,253	5,381	5,290	5,352	5,379	5,350
Petroleum product sales	6,195	6,304	6,595	6,555	6,414	6,434	6,487	6,301	6,489	6,428
Natural gas production available for sale	11,689	10,025	12,192	14,652	12,148	10,187	8,041	8,155	10,717	9,273
<i>(millions of cubic feet daily)</i>										
Oil-equivalent production (1)	4,362	3,996	4,453	4,968	4,447	4,174	3,686	3,694	4,179	3,932
<i>(thousands of oil-equivalent barrels daily)</i>										
Chemical prime product sales	6,488	6,496	6,558	6,349	25,891	5,527	6,267	6,356	6,675	24,825
<i>(thousands of metric tons)</i>										
Summarized financial data										
Sales and other operating revenue (2)	\$ 87,037	89,693	92,353	101,042	370,125	\$ 62,128	72,167	80,090	87,115	301,500
<i>(millions of dollars)</i>										
Gross profit (3)	\$ 28,537	29,482	30,652	32,943	121,614	\$ 23,562	24,231	27,377	28,580	103,750
Net income attributable to ExxonMobil	\$ 6,300	7,560	7,350	9,250	30,460	\$ 4,550	3,950	4,730	6,050	19,280
Per share data										
Earnings per common share (4)	\$ 1.33	1.61	1.44	1.86	6.24	\$ 0.92	0.82	0.98	1.27	3.99
<i>(dollars per share)</i>										
Earnings per common share — assuming dilution (4)	\$ 1.33	1.60	1.44	1.85	6.22	\$ 0.92	0.81	0.98	1.27	3.98
Dividends per common share	\$ 0.42	0.44	0.44	0.44	1.74	\$ 0.40	0.42	0.42	0.42	1.66
Common stock prices										
High	\$ 70.60	70.00	62.99	73.69	73.69	\$ 82.73	74.83	72.79	76.54	82.73
Low	\$ 63.56	56.92	55.94	61.80	55.94	\$ 61.86	64.50	64.46	66.11	61.86

(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 507,028 registered shareholders of ExxonMobil common stock at December 31, 2010. At January 31, 2011, the registered shareholders of ExxonMobil common stock numbered 505,330.

On January 26, 2011, the Corporation declared a \$0.44 dividend per common share, payable March 10, 2011.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

FUNCTIONAL EARNINGS

	2010	2009	2008
	<i>(millions of dollars, except per share amounts)</i>		
Earnings (U.S. GAAP)			
Upstream			
United States	\$ 4,272	\$ 2,893	\$ 6,243
Non-U.S.	19,825	14,214	29,159
Downstream			
United States	770	(153)	1,649
Non-U.S.	2,797	1,934	6,502
Chemical			
United States	2,422	769	724
Non-U.S.	2,491	1,540	2,233
Corporate and financing	(2,117)	(1,917)	(1,290)
Net income attributable to ExxonMobil	\$30,460	\$19,280	\$45,220
Earnings per common share	\$ 6.24	\$ 3.99	\$ 8.70
Earnings per common share – assuming dilution	\$ 6.22	\$ 3.98	\$ 8.66
<u>Special items included in earnings</u>			
Non-U.S. Upstream			
Gain on German natural gas transportation business sale	\$ –	\$ –	\$ 1,620
Corporate and financing			
Valdez litigation	\$ –	\$ (140)	\$ (460)

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, special items, Upstream, Downstream, Chemical and Corporate and Financing segment earnings, and earnings per share are ExxonMobil's share after excluding amounts attributable to noncontrolling interests.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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 of ExxonMobil's 2010 Form 10-K.

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. Prices for crude oil, natural gas and refined 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 2030, the world's population is projected to grow to approximately 8 billion people, or about 1.5 billion more than in 2005. Coincident with this population increase, the Corporation expects worldwide economic growth to average 2.8 percent per year. This combination of population and economic growth is expected to lead to an increase in primary energy demand of about 35 percent by 2030 versus 2005, 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 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 introduction of new 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 nearly 40 percent from 2005 to 2030. The global growth in transportation demand is likely to account for approximately 80 percent of the growth in oil 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 will grow significantly through 2030. Consistent with this projection, power generation will 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 will grow most significantly and gain the most market share, although coal demand will also grow and retain the largest share through 2030 despite also losing share to nuclear and wind.

Liquid fuels provide the largest share of energy supply today due to their availability, affordability and ease of transport. By 2030, global demand for liquids is expected to grow to approximately 103 million barrels of oil-equivalent per day, an increase of more than 20 percent from 2005. Global demand for liquid fuels will be met by a wide variety of sources. Conventional non-OPEC crude and condensate production is expected to remain relatively flat through 2030. However, growth is expected from a number of supply sources, including biofuels, oil sands and natural gas liquids, as well as crude oil from OPEC countries. While the world's resource base is sufficient to meet projected demand, access to resources and timely investments will remain critical to meeting global needs with reliable, affordable supplies.

Increases in natural gas demand in North America, Europe and Asia Pacific will require new sources of supply. Helping meet these needs will be additional local supplies of unconventional natural gas – the result of recent improvements in technologies used to tap these hard-to-produce resources – as well as imports. The growing need for natural gas imports will have a dramatic impact on the worldwide liquefied natural gas (LNG) market, which is expected to approximately triple in volume from 2005 to 2030.

The world's energy mix is highly diverse and will remain so through 2030. Oil is expected to remain the largest source of energy supply at close to 32 percent. From 2005 to 2030, natural gas is expected to grow the fastest of the major energy types and overtake coal as the second-largest energy source. Nuclear power is projected to grow significantly, on par with coal in terms of absolute growth and surpassing biomass as the fourth-largest source of energy. Hydro and geothermal will also grow, though remain limited by the availability of natural sites. Wind, solar and biofuels are expected to grow at close to 10 percent per year on average, the highest growth rate of all fuels, and are projected to reach approximately 2.5 percent of world energy by 2030.

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 2010-2035 will be approximately \$15 trillion (measured in 2009 dollars) or close to \$580 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 large 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 pursuing the highest quality exploration opportunities, investing in projects that deliver superior returns, maximizing 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 in 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 2015. 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 27 percent of the Corporation's production. By 2015, it is expected to generate about 35 percent of total volumes. The remainder of the Corporation's production is expected to be sourced from Asia, Europe, Africa and Australia, with contributions from both established operations and new projects.

In addition to an evolving geographic mix, 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 recovery processes, unconventional gas production and LNG is expected to grow from about 40 percent to around 55 percent of the Corporation's output between now and 2015. 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 of ExxonMobil's 2010 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 2011-2015. 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 of ExxonMobil's 2010 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Downstream

ExxonMobil's Downstream is a large, diversified business with refining and marketing complexes around the world. The Corporation has a strong presence in mature markets in North America and Europe, as well as 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 36 refineries, located in 21 countries, with distillation capacity of 6.3 million barrels per day and lubricant basestock manufacturing capacity of about 131 thousand barrels per day. ExxonMobil's fuels and lubes marketing business portfolios include operations around the world, with multiple channels to market serving a globally diverse customer base.

The downstream industry environment remains challenging. Although demand for refined products has improved from the lower levels in 2009 due to the recent global economic recession, we expect the challenging business environment to continue, reflecting the increase in global refining capacity and regulatory-related policies. Over the prior 20-year period, inflation-adjusted refining margins have been flat.

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 refining 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 of ExxonMobil's 2010 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 2010, ExxonMobil progressed the transition of the direct served (i.e., dealer, company-operated) retail network in the U.S. to a branded distributor model. This transition was announced in 2008 and will be a multiyear process.

ExxonMobil takes a disciplined approach to managing the Downstream capital employed. The Downstream portfolio is continually evaluated during all parts of the business cycle, and numerous asset divestments have been made over the past decade. 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 2010, ExxonMobil invested over \$1 billion in three refineries to increase the supply of cleaner-burning diesel by about 140 thousand barrels per day. The company completed construction of new units and modification of existing facilities at its Baton Rouge, Louisiana; Baytown, Texas; and Antwerp, Belgium, refineries. In addition, construction has commenced at the Sriracha, Thailand, refinery to produce lower sulfur diesel and gasoline to meet upcoming product specifications in Thailand. Completion is expected in the fourth quarter of 2011. At the Jurong/PAC refinery in Singapore, plans are under way to build a new diesel hydrotreater, which will add a capacity of more than 2 million gallons per day to meet increasing demand in the Asia Pacific region.

Chemical

Worldwide petrochemical demand recovered from the economic downturn in 2008 and the first half of 2009. Tighter industry supply/demand balances throughout the year supported improved industry margins, particularly in the U.S. Asia Pacific commodity margins were lower, reflecting the start-up of significant new industry capacity in the region.

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 business lines, which delivered strong results in 2010. 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.

REVIEW OF 2010 AND 2009 RESULTS

	2010	2009	2008
	<i>(millions of dollars)</i>		
Earnings (U.S. GAAP)	\$30,460	\$19,280	\$45,220

2010

Earnings in 2010 of \$30,460 million increased \$11,180 million from 2009. Earnings for 2010 did not include any special items.

2009

Earnings in 2009 of \$19,280 million decreased \$25,940 million from 2008. Earnings for 2009 included an after-tax special charge of \$140 million for interest related to the Valdez punitive damages award.

Upstream

	2010	2009	2008
	<i>(millions of dollars)</i>		
Upstream			
United States	\$ 4,272	\$ 2,893	\$ 6,243
Non-U.S.	19,825	14,214	29,159
Total	<u>\$24,097</u>	<u>\$17,107</u>	<u>\$35,402</u>

2010

Upstream earnings were \$24,097 million, up \$6,990 million from 2009. Higher realizations increased earnings approximately \$6.5 billion. Higher volumes increased earnings by \$1.2 billion, while all other items, including higher operating costs, decreased earnings by \$690 million. On an oil-equivalent basis, production was up 13 percent compared to 2009. Excluding the impacts of entitlement volumes, OPEC quota effects and divestments, production was up 14 percent. Liquids production of 2,422 kbd (thousands of barrels per day) increased 35 kbd compared with 2009. Excluding the impacts of entitlement volumes, OPEC quota effects and divestments, liquids production increased 2 percent from 2009, as project ramp-ups in Qatar were offset by net field decline. Natural gas production of 12,148 mcf (millions of cubic feet per day) increased 2,875 mcf from 2009, driven by higher volumes from Qatar projects and additional U.S. unconventional gas volumes. Earnings from U.S. Upstream operations for 2010 were \$4,272 million, an increase of \$1,379 million from 2009. Non-U.S. Upstream earnings were \$19,825 million, up \$5,611 million from 2009.

2009

Upstream earnings for 2009 were \$17,107 million, down \$18,295 million from 2008, including the absence of an after-tax special gain in 2008 of \$1,620 million from the sale of a natural gas transportation business in Germany. Lower crude oil and natural gas realizations reduced earnings \$15.2 billion. Volume and mix effects increased earnings \$700 million. Higher operating expenses and increased exploration activities decreased earnings \$1.4 billion. Lower gains on asset divestments

reduced earnings approximately \$900 million. Oil-equivalent production increased slightly versus 2008, including impacts from entitlement effects, quotas and divestments. Excluding these items, oil-equivalent production was up about 2 percent. Liquids production of 2,387 kbd decreased 18 kbd. Production increases from new projects in the U.S., Qatar and Africa along with higher volumes in Kazakhstan were offset by field decline. Natural gas production of 9,273 mcf increased 178 mcf from 2008. Higher volumes from projects in Qatar were partially offset by field decline. Earnings from U.S. Upstream operations for 2009 were \$2,893 million, a decrease of \$3,350 million. Earnings outside the U.S. for 2009 of \$14,214 million declined \$14,945 million.

Downstream

	2010	2009	2008
	<i>(millions of dollars)</i>		
Downstream			
United States	\$ 770	\$ (153)	\$1,649
Non-U.S.	2,797	1,934	6,502
Total	<u>\$3,567</u>	<u>\$1,781</u>	<u>\$8,151</u>

2010

Downstream earnings of \$3,567 million were \$1,786 million higher than 2009. Higher industry refining margins increased earnings by \$1.2 billion. Positive volume and mix effects increased earnings by \$420 million, while all other items, including lower operating expenses, increased earnings by \$210 million. Petroleum product sales of 6,414 kbd decreased 14 kbd. U.S. Downstream earnings were \$770 million, up \$923 million from 2009. Non-U.S. Downstream earnings were \$2,797 million, \$863 million higher than 2009.

2009

Downstream earnings were \$1,781 million, down \$6.4 billion from 2008. Weaker margins reduced earnings \$5.1 billion. Lower divestment activity reduced earnings about \$1.0 billion. Volumes decreased earnings approximately \$300 million. Petroleum product sales of 6,428 kbd decreased 333 kbd, mainly reflecting asset divestments and lower demand. Refinery throughput was 5,350 kbd, down 66 kbd from 2008. Earnings from the U.S. Downstream were \$1,802 million lower than in 2008. Non-U.S. Downstream earnings were \$1,934 million, down \$4,568 million from 2008.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Chemical

	2010	2009	2008
	<i>(millions of dollars)</i>		
Chemical			
United States	\$2,422	\$ 769	\$ 724
Non-U.S.	2,491	1,540	2,233
Total	<u>\$4,913</u>	<u>\$2,309</u>	<u>\$2,957</u>

2010

Chemical earnings were a record \$4,913 million, up \$2,604 million from 2009. Improved margins increased earnings by \$2.0 billion while higher volumes increased earnings \$380 million. Prime product sales of 25,891 kt were up 1,066 kt from 2009. Prime product sales are total chemical product sales, including ExxonMobil's share of equity-company volumes and finished product transfers to the Downstream business. U.S. Chemical earnings of \$2,422 million increased \$1,653 million. Non-U.S. Chemical earnings of \$2,491 million increased \$951 million.

2009

Earnings declined \$648 million versus 2008 to a total of \$2,309 million. Weaker margins reduced earnings by \$340 million, mostly in commodities. Lower volumes decreased earnings \$190 million. All other items, including unfavorable foreign exchange impacts, reduced earnings \$115 million. Prime product sales of 24,825 kt decreased 157 kt from 2008. U.S. Chemical earnings of \$769 million increased \$45 million. Non-U.S. Chemical earnings were \$1,540 million, down \$693 million.

Corporate and Financing

	2010	2009	2008
	<i>(millions of dollars)</i>		
Corporate and financing	\$(2,117)	\$(1,917)	\$(1,290)

2010

Corporate and financing expenses were \$2,117 million, up \$200 million from 2009 mainly due to a tax charge related to the U.S. health care legislation during the first quarter of 2010 and financing activities, partially offset by the absence of a 2009 charge for interest related to the Valdez punitive damages award.

2009

Corporate and financing expenses of \$1,917 million in 2009 increased \$627 million, primarily due to lower interest income.

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

	2010	2009	2008
	<i>(millions of dollars)</i>		
Net cash provided by/(used in)			
Operating activities	\$ 48,413	\$ 28,438	\$ 59,725
Investing activities	(24,204)	(22,419)	(15,499)
Financing activities	(26,924)	(27,283)	(44,027)
Effect of exchange rate changes	(153)	520	(2,743)
Increase/(decrease) in cash and cash equivalents	<u>\$ (2,868)</u>	<u>\$(20,744)</u>	<u>\$(2,544)</u>
	<i>(Dec. 31)</i>		
Cash and cash equivalents	\$ 7,825	\$ 10,693	\$ 31,437
Cash and cash equivalents – restricted	628	–	–
Total cash and cash equivalents	<u>\$ 8,453</u>	<u>\$ 10,693</u>	<u>\$ 31,437</u>

Total cash and cash equivalents were \$8.5 billion at the end of 2010, \$2.2 billion lower than the prior year. Higher earnings and reduced share purchases were offset by a higher level of capital spending and increased level of debt repurchases. Included in total cash and cash equivalents at year-end 2010 was \$0.6 billion of restricted cash.

Cash and cash equivalents were \$10.7 billion at the end of 2009, \$20.7 billion lower than the prior year, reflecting lower earnings and a higher level of capital spending partially offset by a lower level of purchases of ExxonMobil shares. Cash flows from operating, investing and financing activities are discussed below. 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. The management of cash that may be temporarily available as surplus to the Corporation's immediate needs is carefully controlled to ensure it is secure and readily available to meet the Corporation's cash requirements and to optimize returns on the cash balances.

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 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 2010 were \$32.2 billion, reflecting the Corporation's continued active investment program. The Corporation expects annual expenditures to range from \$33 billion to \$37 billion for the next several years. Actual spending could vary depending on the progress of individual projects. 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

2010

Cash provided by operating activities totaled \$48.4 billion in 2010, \$20.0 billion higher than 2009. The major source of funds was net income including noncontrolling interests of \$31.4 billion, adjusted for the noncash provision of \$14.8 billion for depreciation and depletion, both of which increased. The net effects of changes in prices and the timing of collection of accounts receivable and of payments of accounts and other payables and of income taxes payable increased cash provided by operating activities in 2010 compared to a decrease in 2009, and resulted in net working capital of \$(3.6) billion as total current liabilities of \$62.6 billion exceeded total current assets of \$59.0 billion at year-end 2010.

2009

Cash provided by operating activities totaled \$28.4 billion in 2009, \$31.3 billion lower than 2008. The major source of funds was net income including noncontrolling interests of \$19.7 billion, adjusted for the noncash provision of \$11.9 billion for depreciation and depletion, both of which declined. Pension fund contributions in 2009 of \$4.5 billion increased from \$1.0 billion in 2008. The net effects of changes in prices and the timing of collection of accounts receivable and of payments of accounts and other payables and of income taxes payable reduced cash provided by operating activities in 2009 compared to an increase in 2008.

Cash Flow from Investing Activities

2010

Cash used in investment activities netted to \$24.2 billion in 2010, \$1.8 billion higher than in 2009. Spending for property, plant and equipment of \$26.9 billion increased \$4.4 billion from 2009. Proceeds from the sale of subsidiaries, investments and property, plant and equipment of \$3.3 billion in 2010 compared to \$1.5 billion in 2009, the increase reflecting the sale of some U.S. service stations and Upstream Gulf of Mexico and other producing properties.

2009

Cash used in investing activities netted to \$22.4 billion in 2009, \$6.9 billion higher than in 2008. Spending for property, plant and equipment of \$22.5 billion in 2009 increased \$3.2 billion from 2008. Proceeds from the sales of subsidiaries, investments and property, plant and equipment of \$1.5 billion in 2009 compared to \$6.0 billion in 2008, the decrease reflecting the absence of the sale of the natural gas transportation business in Germany and lower sales of Downstream assets and investments.

Cash Flow from Financing Activities

2010

Cash used in financing activities was \$26.9 billion in 2010, \$0.4 billion lower than 2009. Dividend payments on common shares increased to \$1.74 per share from \$1.66 per share and totaled \$8.5 billion, a pay-out of 28 percent. Total debt increased to \$15.0 billion at year end, an increase of \$5.4 billion from 2009, primarily as a result of debt assumed with the XTO merger.

ExxonMobil share of equity increased \$36.3 billion to \$146.8 billion. The addition to equity for earnings of \$30.5 billion and the issuance of stock for the XTO merger of \$24.7 billion was partially offset by reductions to equity for distributions to ExxonMobil shareholders of \$8.5 billion of dividends and \$11.2 billion of purchases of shares of ExxonMobil stock to reduce shares outstanding.

During 2010, Exxon Mobil Corporation issued 416 million shares for the XTO merger. Exxon Mobil Corporation purchased 199 million shares of its common stock for the treasury at a gross cost of \$13.1 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 increased by 5.3 percent from 4,727 million at the end of 2009 to 4,979 million at the end of 2010. Purchases were made in both the open market and negotiated transactions. Purchases may be increased, decreased or discontinued at any time without prior notice.

2009

Cash used in financing activities was \$27.3 billion in 2009, \$16.7 billion lower than 2008, reflecting a lower level of purchases of ExxonMobil shares. Dividend payments on common shares increased to \$1.66 per share from \$1.55 per share and totaled \$8.0 billion, a pay-out of 42 percent. Total consolidated short-term and long-term debt increased

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

\$0.2 billion to \$9.6 billion at year-end 2009.

ExxonMobil share of equity decreased \$2.4 billion in 2009, to \$110.6 billion. The addition to equity for earnings of \$19.3 billion was more than offset by reductions for distributions to ExxonMobil shareholders of \$8.0 billion of dividends and \$18.0 billion of purchases of shares of ExxonMobil stock to reduce shares outstanding. Equity, and net assets and liabilities, increased \$3.3 billion, representing the foreign exchange translation effects of generally stronger foreign currencies at the end of 2009 on ExxonMobil's operations outside the United States. The change in the funded status of the postretirement benefits reserves in 2009 increased equity by \$1.2 billion.

During 2009, Exxon Mobil Corporation purchased 277 million shares of its common stock for the treasury at a gross cost of \$19.7 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 5.0 percent from 4,976 million at the end of 2008 to 4,727 million at the end of 2009. 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, 2010. It combines data from the Consolidated Balance Sheet and from individual notes to the Consolidated Financial Statements.

Commitments	Note Reference Number	Payments Due by Period			Total
		2011	2012-2015	2016 and Beyond	
		<i>(millions of dollars)</i>			
Long-term debt (1)	13	\$ -	\$ 5,464	\$ 6,763	\$ 12,227
– Due in one year (2)	5	345	-	-	345
Asset retirement obligations (3)	8	775	2,196	6,643	9,614
Pension and other postretirement obligations (4)	16	2,541	4,130	13,231	19,902
Operating leases (5)	10	2,095	3,943	1,738	7,776
Unconditional purchase obligations (6)	15	287	748	487	1,522
Take-or-pay obligations (7)		1,704	6,275	8,832	16,811
Firm capital commitments (8)		14,851	12,329	948	28,128

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 \$4.1 billion as of December 31, 2010, 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 18, Income, Sales-Based and Other Taxes.

Notes:

- (1) Includes capitalized lease obligations of \$304 million.
- (2) The amount due in one year is included in notes and loans payable of \$2,787 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 2011 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 \$1,522 million mainly pertain to pipeline throughput agreements and include \$996 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 \$16,811 million mainly pertain to manufacturing supply, pipeline and terminaling agreements and include \$507 million of obligations to equity companies.
- (8) Firm commitments related to capital projects, shown on an undiscounted basis, totaled approximately \$28.1 billion. These commitments were primarily associated with Upstream projects outside the U.S., of which \$17.2 billion was associated with projects in Australia, Africa, Malaysia and Canada. 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, 2010, for \$8,771 million, primarily relating to guarantees for notes, loans and performance under contracts (note 15). Included in this amount were guarantees by consolidated affiliates of \$5,290 million, representing ExxonMobil's share of obligations of certain equity companies. The below-mentioned 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.

	Dec. 31, 2010		
	Equity Company Obligations	Other Third-Party Obligations	Total
	<i>(millions of dollars)</i>		
Guarantees	\$ 5,290	\$ 3,481	\$ 8,771

Financial Strength

On December 31, 2010, unused credit lines for short-term financing totaled approximately \$5.6 billion (note 5).

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

	2010	2009	2008
Fixed-charge coverage ratio (times)	42.2	25.8	54.6
Debt to capital (percent)	9.0	7.7	7.4
Net debt to capital (percent)	4.5	(1.0)	(23.0)

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

Litigation. As discussed in note 15, 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 materially 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.

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

On September 6, 2007, affiliates of ExxonMobil filed a Request for Arbitration with the International Centre for Settlement of Investment Disputes (ICSID) 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 is currently scheduled for the first quarter of 2012. An affiliate of ExxonMobil has also filed an arbitration under the rules of the International Chamber of Commerce (ICC) against PdVSA and a PdVSA affiliate for breach of their contractual obligations under certain Cerro Negro Project agreements. A hearing on the merits of the ICC arbitration concluded in September 2010 and the parties have filed post-hearing briefs. At this time, the net impact of this matter on the Corporation's consolidated financial results cannot be reasonably estimated. However, the Corporation does not expect the resolution to have a material effect upon the Corporation's operations or financial condition. ExxonMobil's remaining net book investment in Cerro Negro producing assets is about \$750 million.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

CAPITAL AND EXPLORATION EXPENDITURES

	2010		2009	
	U.S.	Non-U.S.	U.S.	Non-U.S.
	<i>(millions of dollars)</i>			
Upstream (1)	\$6,349	\$20,970	\$3,585	\$17,119
Downstream	982	1,523	1,511	1,685
Chemical	279	1,936	319	2,829
Other	187	—	44	—
Total	<u>\$7,797</u>	<u>\$24,429</u>	<u>\$5,459</u>	<u>\$21,633</u>

(1) Exploration expenses included.

Capital and exploration expenditures in 2010 were \$32.2 billion, reflecting the Corporation's continued active investment program. The Corporation expects annual expenditures to range from \$33 billion to \$37 billion for the next several years. Actual spending could vary depending on the progress of individual projects.

Upstream spending of \$27.3 billion in 2010 was up 32 percent from 2009, reflecting unconventional gas activities in the U.S. and continued progress on world-class projects in Canada, Australia and Papua New Guinea. 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 69 percent of total proved reserves at year-end 2010, 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 \$2.5 billion in 2010, a decrease of \$0.7 billion from 2009, due to completion of environmental-related refining projects, primarily in the U.S. The Chemical capital expenditures of \$2.2 billion were \$0.9 billion lower in 2010 as investments in Asia to meet demand growth progressed toward completion.

TAXES

	2010	2009	2008
	<i>(millions of dollars)</i>		
Income taxes	\$ 21,561	\$ 15,119	\$ 36,530
Effective income tax rate	45%	47%	46%
Sales-based taxes	28,547	25,936	34,508
All other taxes and duties	39,127	37,571	45,223
Total	<u>\$ 89,235</u>	<u>\$ 78,626</u>	<u>\$116,261</u>

2010

Income, sales-based and all other taxes and duties totaled \$89.2 billion in 2010, an increase of \$10.6 billion or 13 percent from 2009. Income tax expense, both current and deferred, was \$21.6 billion, \$6.4 billion higher than 2009, reflecting higher pre-tax income in 2010. A lower share of pre-tax income from the Upstream segment in 2010 decreased the effective tax rate to 45 percent compared to 47 percent in 2009. Sales-based and all other taxes and duties of \$67.7 billion in 2010 increased \$4.2 billion, reflecting higher prices.

2009

Income, sales-based and all other taxes and duties totaled \$78.6 billion in 2009, a decrease of \$37.6 billion or 32 percent from 2008. Income tax expense, both current and deferred, was \$15.1 billion, \$21.4 billion lower than 2008, reflecting lower pre-tax income in 2009. A higher share of total income from the Upstream segment in 2009 increased the effective income tax rate to 47 percent compared to 46 percent in 2008. Sales-based and all other taxes and duties of \$63.5 billion in 2009 decreased \$16.2 billion from 2008, reflecting lower prices and foreign exchange effects.

ENVIRONMENTAL MATTERS

Environmental Expenditures

	2010	2009
	<i>(millions of dollars)</i>	
Capital expenditures	\$1,947	\$2,481
Other expenditures	2,593	2,610
Total	<u>\$4,540</u>	<u>\$5,091</u>

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. ExxonMobil's 2010 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were about \$4.5 billion. The total cost for such activities is expected to remain in this range in 2011 and 2012 (with capital expenditures approximately 40 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 2010 for environmental liabilities were \$448 million (\$504 million in 2009) and the balance sheet reflects accumulated liabilities of \$948 million as of December 31, 2010, and \$943 million as of December 31, 2009.

Asset Retirement Obligations

The fair values of asset retirement obligations are recorded as liabilities on a discounted basis when they are incurred, which is typically at the time assets are installed, with an offsetting amount booked as additions to property, plant and equipment (\$1,094 million for 2010). Over time, the liabilities are accreted for the increase in their present value, with this effect included in expenses (\$563 million in 2010). Consolidated company expenditures for asset retirement obligations in 2010 were \$638 million and the obligations recorded on the balance sheet at December 31, 2010, totaled \$9,614 million.

MARKET RISKS, INFLATION AND OTHER UNCERTAINTIES

Worldwide Average Realizations (1)	2010	2009	2008
Crude oil and NGL (\$/barrel)	\$74.04	\$57.86	\$90.96
Natural gas (\$/kcf)	4.31	4.00	7.54

(1) Consolidated subsidiaries.

Crude oil, natural gas, petroleum product and chemical prices have fluctuated in response to changing market forces. The impacts of these price fluctuations on earnings from Upstream, Downstream and Chemical operations have varied. In the Upstream, a \$1 per barrel change in the weighted-average realized price of oil would have approximately a \$375 million annual after-tax effect on Upstream consolidated plus equity company earnings. Similarly, a \$0.10 per kcf change in the worldwide average gas realization would have approximately a \$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 40 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. Investment opportunities are tested against a variety of market conditions, including low-price scenarios.

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 12. 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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. The Corporation makes limited use of commodity forwards, swaps and futures contracts to mitigate the impact of changes in commodity prices. A substantial portion of the commodity futures contracts and swap agreements acquired as part of the XTO merger settled during 2010 and the majority of the remainder will settle by year-end 2011.

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 POLICIES

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 following summary provides further information about the critical accounting policies and the judgments that are made by the Corporation in the application of those policies.

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. Consistent with the definitions in 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. Unproved reserves are those with less than reasonable certainty of recoverability and include probable reserves. Probable reserves are reserves that are more likely to be recovered than not.

The estimation of proved reserves, which is based on the requirement of reasonable certainty, is an ongoing process based on rigorous technical evaluations, commercial and market 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 reserves estimation process include:

- rigorous peer-reviewed technical evaluations and analysis of well and field performance information (such as flow rates and reservoir pressure declines) and
- a requirement that management make significant funding commitments toward the development of the reserves prior to reporting as proved.

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 69 percent of total proved reserves at year-end 2010 (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. Over time, these undeveloped reserves will be reclassified to the developed category as new wells are drilled, existing wells are recompleted and/or facilities to collect and deliver the production from existing and future wells are installed. Major development projects typically take two to four years from the time of recording proved reserves to the start of production from these reserves.

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 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.

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 uses this accounting policy instead of the “full cost” method because it provides a more timely accounting of the success or failure of the Corporation’s exploration and production activities. If the full cost method were used, all costs would be capitalized and depreciated on a country-by-country basis. The capitalized costs would be subject to an impairment test by country. The full cost method would tend to delay the expense recognition of unsuccessful projects.

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. In general, analyses are 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 would be impaired if the undiscounted cash flows were less than its carrying value. Impairments are measured by the amount by which the carrying value exceeds its 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 monitor the performance of assets against corporate objectives. They also 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. 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 historical and forecast operating losses.

In general, the Corporation does not view temporarily low oil and gas prices 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

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

for capital investment decisions. Volumes are based on individual 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 one used in the supplemental oil and gas disclosure and could be lower or higher for any given year.

Suspended Exploratory Well Costs

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. Assessing whether a project has made sufficient progress is a subjective area and requires careful consideration of the relevant facts and circumstances. The facts and circumstances that support continued capitalization of suspended wells as of year-end 2010 are disclosed in note 9 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 percentage interest in the underlying net assets of other significant affiliates that it does not control, but 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." The accounting for these non-consolidated companies is referred to as the equity method of accounting.

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.

Additional disclosures of summary balance sheet and income information for those subsidiaries accounted for under the equity method of accounting can be found in note 6.

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 busi-

ness results according to their percentage 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 percentage share of all assets and liabilities in these partially owned companies rather than only its percentage in the net equity. This method of accounting for investments in partially owned companies is not permitted by 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 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 approximately 100 defined benefit (pension) plans in about 50 countries. The funding arrangement for each plan depends on the prevailing practices and regulations of the countries where the Corporation operates. Pension and Other Postretirement Benefits (note 16) 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 United States, 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 2010 was 7.5 percent. The 10-year and 20-year actual returns on U.S. pension plan assets are 4 percent and 10 percent, respectively. The Corporation establishes the long-term expected rate of return by developing a forward-looking, long-term return assumption for each pension fund asset class, taking into account factors such as the expected real return for the specific asset class and inflation. A single, long-term rate of return is then calculated as the weighted average of the target asset allocation 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 \$140 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 15.

GAAP requires that liabilities for contingencies be recorded when it is probable that a liability has been incurred by the date of the balance sheet and that 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.

Significant 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 materially 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.

GAAP requires recognition and measurement of uncertain tax positions that the Corporation has taken or expects to take in its income tax returns. The benefit of an uncertain tax position can only be 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 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 18.

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. Downstream and Chemical operations use the local currency, except in countries with a history of high inflation (primarily in Latin America) and Singapore, which uses the U.S. dollar because it predominantly sells into the U.S. dollar export market. Upstream operations also use the local currency as the functional currency, except where crude and natural gas production is predominantly sold in the export market in U.S. dollars. Upstream operations using the U.S. dollar as their functional currency are primarily in Asia and Africa.

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, 2010.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2010, as stated in their report included in the Financial Section of this report.



Rex W. Tillerson
Chief Executive Officer



Donald D. Humphreys
Sr. Vice President and Treasurer
(Principal Financial Officer)



Patrick T. Mulva
Vice President and Controller
(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, 2010, and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, 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, 2010, 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 25, 2011

CONSOLIDATED STATEMENT OF INCOME

	Note Reference Number	2010	2009	2008
<i>(millions of dollars)</i>				
Revenues and other income				
Sales and other operating revenue (1)		\$370,125	\$301,500	\$459,579
Income from equity affiliates	6	10,677	7,143	11,081
Other income (2)		2,419	1,943	6,699
Total revenues and other income		<u>\$383,221</u>	<u>\$310,586</u>	<u>\$477,359</u>
Costs and other deductions				
Crude oil and product purchases		\$197,959	\$152,806	\$249,454
Production and manufacturing expenses		35,792	33,027	37,905
Selling, general and administrative expenses		14,683	14,735	15,873
Depreciation and depletion		14,760	11,917	12,379
Exploration expenses, including dry holes		2,144	2,021	1,451
Interest expense		259	548	673
Sales-based taxes (1)	18	28,547	25,936	34,508
Other taxes and duties	18	36,118	34,819	41,719
Total costs and other deductions		<u>\$330,262</u>	<u>\$275,809</u>	<u>\$393,962</u>
Income before income taxes		\$ 52,959	\$ 34,777	\$ 83,397
Income taxes	18	21,561	15,119	36,530
Net income including noncontrolling interests		\$ 31,398	\$ 19,658	\$ 46,867
Net income attributable to noncontrolling interests		938	378	1,647
Net income attributable to ExxonMobil		<u>\$ 30,460</u>	<u>\$ 19,280</u>	<u>\$ 45,220</u>
Earnings per common share (dollars)	11	\$ 6.24	\$ 3.99	\$ 8.70
Earnings per common share – assuming dilution (dollars)	11	\$ 6.22	\$ 3.98	\$ 8.66

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

(2) Other income for 2008 includes a \$62 million gain from the sale of a non-U.S. investment and a related \$143 million foreign exchange loss.

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

CONSOLIDATED BALANCE SHEET

	Note Reference Number	Dec. 31 2010	Dec. 31 2009
<i>(millions of dollars)</i>			
Assets			
Current assets			
Cash and cash equivalents		\$ 7,825	\$ 10,693
Cash and cash equivalents – restricted	3	628	–
Marketable securities		2	169
Notes and accounts receivable, less estimated doubtful amounts	5	32,284	27,645
Inventories			
Crude oil, products and merchandise	3	9,852	8,718
Materials and supplies		3,124	2,835
Other current assets		5,269	5,175
Total current assets		\$ 58,984	\$ 55,235
Investments, advances and long-term receivables	7	35,338	31,665
Property, plant and equipment, at cost, less accumulated depreciation and depletion	8	199,548	139,116
Other assets, including intangibles, net		8,640	7,307
Total assets		\$ 302,510	\$ 233,323
Liabilities			
Current liabilities			
Notes and loans payable	5	\$ 2,787	\$ 2,476
Accounts payable and accrued liabilities	5	50,034	41,275
Income taxes payable		9,812	8,310
Total current liabilities		\$ 62,633	\$ 52,061
Long-term debt	13	12,227	7,129
Postretirement benefits reserves	16	19,367	17,942
Deferred income tax liabilities	18	35,150	23,148
Other long-term obligations		20,454	17,651
Total liabilities		\$ 149,831	\$ 117,931
Commitments and contingencies	15		
Equity			
Common stock without par value (9,000 million shares authorized, 8,019 million shares issued)		\$ 9,371	\$ 5,503
Earnings reinvested		298,899	276,937
Accumulated other comprehensive income			
Cumulative foreign exchange translation adjustment		5,011	4,402
Postretirement benefits reserves adjustment		(9,889)	(9,863)
Unrealized gain/(loss) on cash flow hedges		55	–
Common stock held in treasury (3,040 million shares in 2010 and 3,292 million shares in 2009)		(156,608)	(166,410)
ExxonMobil share of equity		\$ 146,839	\$ 110,569
Noncontrolling interests		5,840	4,823
Total equity		152,679	115,392
Total liabilities and equity		\$ 302,510	\$ 233,323

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

CONSOLIDATED STATEMENT OF CASH FLOWS

	Note Reference Number	2010	2009	2008
<i>(millions of dollars)</i>				
Cash flows from operating activities				
Net income including noncontrolling interests		\$ 31,398	\$ 19,658	\$ 46,867
Adjustments for noncash transactions				
Depreciation and depletion		14,760	11,917	12,379
Deferred income tax charges/(credits)		(1,135)	–	1,399
Postretirement benefits expense in excess of/(less than) net payments		1,700	(1,722)	57
Other long-term obligation provisions in excess of/(less than) payments		160	731	(63)
Dividends received greater than/(less than) equity in current earnings of equity companies		(596)	(483)	921
Changes in operational working capital, excluding cash and debt				
Reduction/(increase) – Notes and accounts receivable		(5,863)	(3,170)	8,641
– Inventories		(1,148)	459	(1,285)
– Other current assets		913	132	(509)
Increase/(reduction) – Accounts and other payables		9,943	1,420	(5,415)
Net (gain) on asset sales	4	(1,401)	(488)	(3,757)
All other items – net		(318)	(16)	490
Net cash provided by operating activities		<u>\$ 48,413</u>	<u>\$ 28,438</u>	<u>\$ 59,725</u>
Cash flows from investing activities				
Additions to property, plant and equipment		\$ (26,871)	\$ (22,491)	\$ (19,318)
Sales of subsidiaries, investments and property, plant and equipment	4	3,261	1,545	5,985
Decrease/(increase) in restricted cash and cash equivalents	3	(628)	–	–
Additional investments and advances		(1,239)	(2,752)	(2,495)
Collection of advances		1,133	724	574
Additions to marketable securities		(15)	(16)	(2,113)
Sales of marketable securities		155	571	1,868
Net cash used in investing activities		<u>\$ (24,204)</u>	<u>\$ (22,419)</u>	<u>\$ (15,499)</u>
Cash flows from financing activities				
Additions to long-term debt		\$ 1,143	\$ 225	\$ 79
Reductions in long-term debt		(6,224)	(68)	(192)
Additions to short-term debt		598	1,336	1,067
Reductions in short-term debt		(2,436)	(1,575)	(1,624)
Additions/(reductions) in debt with three months or less maturity		709	(71)	143
Cash dividends to ExxonMobil shareholders		(8,498)	(8,023)	(8,058)
Cash dividends to noncontrolling interests		(281)	(280)	(375)
Changes in noncontrolling interests		(7)	(113)	(419)
Tax benefits related to stock-based awards		122	237	333
Common stock acquired		(13,093)	(19,703)	(35,734)
Common stock sold		1,043	752	753
Net cash used in financing activities		<u>\$ (26,924)</u>	<u>\$ (27,283)</u>	<u>\$ (44,027)</u>
Effects of exchange rate changes on cash		<u>\$ (153)</u>	<u>\$ 520</u>	<u>\$ (2,743)</u>
Increase/(decrease) in cash and cash equivalents		\$ (2,868)	\$ (20,744)	\$ (2,544)
Cash and cash equivalents at beginning of year		<u>10,693</u>	<u>31,437</u>	<u>33,981</u>
Cash and cash equivalents at end of year		<u>\$ 7,825</u>	<u>\$ 10,693</u>	<u>\$ 31,437</u>

Non-Cash Transactions

The Corporation acquired all the outstanding equity of XTO Energy Inc. in an all-stock transaction valued at \$24,659 million in 2010 (see note 19).

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	Noncontrolling Interests	Total Equity
	<i>(millions of dollars)</i>						
Balance as of December 31, 2007	\$ 4,933	\$ 228,518	\$ 1,989	\$(113,678)	\$ 121,762	\$ 4,282	\$ 126,044
Amortization of stock-based awards	618				618		618
Tax benefits related to stock-based awards	315				315		315
Other	(552)				(552)		(552)
Net income for the year		45,220			45,220	1,647	46,867
Dividends – common shares		(8,058)			(8,058)	(375)	(8,433)
Foreign exchange translation adjustment			(6,964)		(6,964)	(334)	(7,298)
Adjustment for foreign exchange translation loss included in net income			138		138	17	155
Postretirement benefits reserves adjustment (note 16)			(5,853)		(5,853)	(224)	(6,077)
Amortization of postretirement benefits reserves adjustment included in net periodic benefit costs (note 16)			759		759		759
Acquisitions, at cost				(35,734)	(35,734)	(675)	(36,409)
Dispositions				1,314	1,314	220	1,534
Balance as of December 31, 2008	\$ 5,314	\$ 265,680	\$(9,931)	\$(148,098)	\$ 112,965	\$ 4,558	\$ 117,523
Amortization of stock-based awards	685				685		685
Tax benefits related to stock-based awards	140				140		140
Other	(636)				(636)		(636)
Net income for the year		19,280			19,280	378	19,658
Dividends – common shares		(8,023)			(8,023)	(280)	(8,303)
Foreign exchange translation adjustment			3,256		3,256	373	3,629
Postretirement benefits reserves adjustment (note 16)			(196)		(196)	(144)	(340)
Amortization of postretirement benefits reserves adjustment included in net periodic benefit costs (note 16)			1,410		1,410	51	1,461
Acquisitions, at cost				(19,703)	(19,703)	(127)	(19,830)
Dispositions				1,391	1,391	14	1,405
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)
Foreign exchange translation adjustment			584		584	450	1,034
Adjustment for foreign exchange translation loss included in net income			25		25		25
Postretirement benefits reserves adjustment (note 16)			(1,014)		(1,014)	(147)	(1,161)
Amortization of postretirement benefits reserves adjustment included in net periodic benefit costs (note 16)			988		988	52	1,040
Change in fair value of cash flow hedges			184		184		184
Realized (gain)/loss from settled cash flow hedges included in net income			(129)		(129)		(129)
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

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

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY (continued)

Common Stock Share Activity	Issued	Held in Treasury	Outstanding
		<i>(millions of shares)</i>	
Balance as of December 31, 2007	8,019	(2,637)	5,382
Acquisitions		(434)	(434)
Dispositions		28	28
Balance as of December 31, 2008	8,019	(3,043)	4,976
Acquisitions		(277)	(277)
Dispositions		28	28
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

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	2010	2009	2008
		<i>(millions of dollars)</i>	
Net income including noncontrolling interests	\$ 31,398	\$ 19,658	\$ 46,867
Other comprehensive income (net of income taxes)			
Foreign exchange translation adjustment	1,034	3,629	(7,298)
Adjustment for foreign exchange translation loss included in net income	25	–	155
Postretirement benefits reserves adjustment (excluding amortization)	(1,161)	(340)	(6,077)
Amortization of postretirement benefits reserves adjustment included in net periodic benefit costs	1,040	1,461	759
Change in fair value of cash flow hedges	184	–	–
Realized (gain)/ loss from settled cash flow hedges included in net income	(129)	–	–
Comprehensive income including noncontrolling interests	32,391	24,408	34,406
Comprehensive income attributable to noncontrolling interests	1,293	658	1,106
Comprehensive income attributable to ExxonMobil	\$ 31,098	\$ 23,750	\$ 33,300

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 2010 presentation basis.

1. Summary of Accounting Policies

Principles of Consolidation. The Consolidated Financial Statements include the accounts of those subsidiaries owned directly or indirectly with more than 50 percent of the voting rights held by the Corporation and for which other shareholders do not possess the right to participate in significant management decisions. They also include the Corporation's share of the undivided interest in certain upstream assets and liabilities.

Amounts representing the Corporation's percentage interest in the underlying net assets of other subsidiaries and less-than-majority-owned companies in which a significant ownership percentage interest is held 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." The Corporation's share of the cumulative foreign exchange translation adjustment for equity method investments is reported in the Consolidated Statement of Changes in Equity. 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. In all cases, 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). This gross reporting basis is footnoted on the Consolidated Statement of Income.

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. For derivatives designated as cash flow hedges, the Corporation's activity is intended to manage the price risk posed by physical transactions.

The Corporation records all derivatives on the balance sheet at fair value. The change in fair value of derivatives designated as fair value hedges is recognized in earnings, offset by the change in fair value of the hedged item. The change in fair value of derivatives designated as cash flow hedges is recorded in other comprehensive income and recognized in earnings when the hedged transaction is recognized in earnings. The change in fair value of derivatives not designated as hedging instruments is recognized in earnings. Any ineffectiveness between the derivative and the hedged item is recorded in earnings.

Hedge effectiveness is reviewed at least quarterly and is generally based on the most recent relevant correlation between the derivative and the

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

item hedged. Hedge ineffectiveness is calculated based on the difference between the change in fair value of the derivative and change in cash flow or fair value of the items hedged. If it is determined that a derivative is no longer highly effective, hedge accounting is then discontinued and the change in fair value since inception that is on the balance sheet either as other comprehensive income for cash flow hedges, or the underlying hedged item for fair value hedges, is recorded in earnings.

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 or 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.

Acquisition costs of proved properties are amortized using a unit-of-production method, computed on the basis of total proved oil and gas reserves. 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. Other exploratory expenditures, including geophysical costs, other dry hole costs and annual lease rentals, are expensed as incurred.

Unit-of-production depreciation is applied to property, plant and equipment, including capitalized exploratory drilling and development costs, associated with productive depletable extractive properties in the Upstream segment. Unit-of-production rates are 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.

Gains on sales of proved and unproved properties are only recognized when there is no uncertainty about the recovery of costs applicable to any interest retained or where there is no 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.

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 and foreign currency exchange rates. Annual volumes are based on individual 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. Impairments are measured by the amount the carrying value exceeds the fair value.

Goodwill. Goodwill is the excess of the consideration transferred over the value of net assets recognized and represents the future economic benefits arising from other assets acquired that could not be individually identified and separately recognized. Goodwill is evaluated for impairment on at least an annual basis.

Asset Retirement Obligations and Environmental Liabilities.

The Corporation incurs retirement obligations for certain assets at the time they are installed. The fair values of these obligations are recorded as liabilities on a discounted basis. 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 14, Incentive Program, for further details.

2. Accounting Changes

Variable-Interest Entities. Effective January 1, 2010, ExxonMobil adopted the authoritative guidance for variable-interest entities (VIEs). The guidance requires the enterprise to qualitatively assess if it is the primary beneficiary of the VIE and, if so, the VIE must be consolidated. The adoption of the guidance did not have a material impact on the Corporation's financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

3. Miscellaneous Financial Information

Research and development costs totaled \$1,012 million in 2010, \$1,050 million in 2009 and \$847 million in 2008.

Net income included before-tax aggregate foreign exchange transaction losses of \$251 million, and gains of \$54 million and \$54 million in 2010, 2009 and 2008, respectively.

In 2010, 2009 and 2008, net income included gains of \$317 million, \$207 million and \$341 million, respectively, attributable to the combined effects of LIFO inventory accumulations and draw-downs. The aggregate replacement cost of inventories was estimated to exceed their LIFO carrying values by \$21.3 billion and \$17.1 billion at December 31, 2010, and 2009, respectively.

Crude oil, products and merchandise as of year-end 2010 and 2009 consist of the following:

	2010	2009
	<i>(billions of dollars)</i>	
Petroleum products	\$3.5	\$3.2
Crude oil	3.8	3.2
Chemical products	2.1	2.0
Gas/other	0.5	0.3
Total	<u>\$9.9</u>	<u>\$8.7</u>

The December 31, 2010, total cash and cash equivalents balance of \$8,453 million includes \$628 million of restricted funds.

4. 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 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; from the sale of Downstream assets and investments and producing properties in the Upstream in 2009; and from the sale of a natural gas transportation business in Germany and other producing properties in the Upstream and Downstream assets and investments in 2008. These gains are reported in "Other income" on the Consolidated Statement of Income.

	2010	2009	2008
	<i>(millions of dollars)</i>		
Cash payments for interest	\$ 703	\$ 820	\$ 650
Cash payments for income taxes	\$18,941	\$15,427	\$33,941

5. Additional Working Capital Information

	Dec. 31 2010	Dec. 31 2009
	<i>(millions of dollars)</i>	
Notes and accounts receivable		
Trade, less reserves of \$152 million and \$198 million	\$25,439	\$22,186
Other, less reserves of \$34 million and \$31 million	6,845	5,459
Total	<u>\$32,284</u>	<u>\$27,645</u>
Notes and loans payable		
Bank loans	\$ 532	\$ 1,043
Commercial paper	1,346	201
Long-term debt due within one year	345	348
Other	564	884
Total	<u>\$ 2,787</u>	<u>\$ 2,476</u>
Accounts payable and accrued liabilities		
Trade payables	\$30,780	\$24,236
Payables to equity companies	5,450	4,979
Accrued taxes other than income taxes	6,778	5,921
Other	7,026	6,139
Total	<u>\$50,034</u>	<u>\$41,275</u>

On December 31, 2010, unused credit lines for short-term financing totaled approximately \$5.6 billion. Of this total, \$2.8 billion support commercial paper programs under terms negotiated when drawn. The weighted-average interest rate on short-term borrowings outstanding at December 31, 2010, and 2009, was 1.2 percent and 3.6 percent, respectively.

6. 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 marketing and refining operations in North America; natural gas production, natural gas distribution and downstream operations in

Europe; crude production in Kazakhstan; and liquefied natural gas (LNG) operations in Qatar. Also included are several power generation, 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. The share of total equity company revenues from sales to ExxonMobil consolidated companies was 18 percent, 19 percent and 21 percent in the years 2010, 2009 and 2008, respectively.

Equity Company Financial Summary	2010		2009		2008	
	Total	ExxonMobil Share	Total	ExxonMobil Share	Total	ExxonMobil Share
	<i>(millions of dollars)</i>					
Total revenues	\$ 153,020	\$ 48,355	\$ 112,153	\$ 36,570	\$ 148,477	\$ 49,999
Income before income taxes	\$ 48,075	\$ 14,735	\$ 28,472	\$ 9,632	\$ 42,588	\$ 15,082
Income taxes	13,962	4,058	7,775	2,489	12,020	4,001
Income from equity affiliates	\$ 34,113	\$ 10,677	\$ 20,697	\$ 7,143	\$ 30,568	\$ 11,081
Current assets	\$ 48,573	\$ 15,860	\$ 37,376	\$ 12,843	\$ 29,358	\$ 9,920
Long-term assets	90,646	29,805	88,153	27,983	87,442	28,339
Total assets	\$ 139,219	\$ 45,665	\$ 125,529	\$ 40,826	\$ 116,800	\$ 38,259
Current liabilities	\$ 33,160	\$ 10,260	\$ 24,854	\$ 8,085	\$ 26,221	\$ 8,707
Long-term liabilities	59,596	17,976	57,384	16,999	50,895	15,094
Net assets	\$ 46,463	\$ 17,429	\$ 43,291	\$ 15,742	\$ 39,684	\$ 14,458

A list of significant equity companies as of December 31, 2010, together with the Corporation's percentage ownership interest, is detailed below:

	Percentage Ownership Interest		Percentage Ownership Interest
Upstream		Downstream	
Aera Energy LLC	48	Chalmette Refining, LLC	50
BEB Erdgas und Erdoel GmbH	50	Fujian Refining & Petrochemical Co. Ltd.	25
Cameroon Oil Transportation Company S.A.	41	Saudi Aramco Mobil Refinery Company Ltd.	50
Castle Peak Power Company Limited	60		
Golden Pass LNG Terminal LLC	18	Chemical	
Nederlandse Aardolie Maatschappij B.V.	50	Al-Jubail Petrochemical Company	50
Qatar Liquefied Gas Company Limited	10	Infineum Holdings B.V.	50
Qatar Liquefied Gas Company Limited 2	24	Saudi Yanbu Petrochemical Co.	50
Ras Laffan Liquefied Natural Gas Company Limited	25	Toray Tonen Specialty Separator Godo Kaisha	50
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.	69		

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

7. Investments, Advances and Long-Term Receivables

	Dec. 31 2010	Dec. 31 2009
	<i>(millions of dollars)</i>	
Companies carried at equity in underlying assets		
Investments	\$17,429	\$15,742
Advances	9,286	8,669
	<u>\$26,715</u>	<u>\$24,411</u>
Companies carried at cost or less and stock investments carried at fair value	1,557	1,577
	<u>\$28,272</u>	<u>\$25,988</u>
Long-term receivables and miscellaneous investments at cost or less, net of reserves of \$292 million and \$368 million	7,066	5,677
Total	<u>\$35,338</u>	<u>\$31,665</u>

8. Property, Plant and Equipment and Asset Retirement Obligations

Property, Plant and Equipment	Dec. 31, 2010		Dec. 31, 2009	
	Cost	Net	Cost	Net
	<i>(millions of dollars)</i>			
Upstream	\$264,136	\$148,152	\$198,036	\$ 88,319
Downstream	68,652	30,095	68,092	30,499
Chemical	29,524	14,255	28,464	13,511
Other	11,626	7,046	11,314	6,787
Total	<u>\$373,938</u>	<u>\$199,548</u>	<u>\$305,906</u>	<u>\$139,116</u>

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 \$174,390 million at the end of 2010 and \$166,790 million at the end of 2009. Interest capitalized in 2010, 2009 and 2008 was \$532 million, \$425 million and \$510 million, respectively.

Asset Retirement Obligations

The Corporation incurs retirement obligations for its upstream 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 Corporation uses estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO; technical assessments of the assets; estimated amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. AROs 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:

	2010	2009
	<i>(millions of dollars)</i>	
Beginning balance	\$8,473	\$5,352
Accretion expense and other provisions	563	372
Reduction due to property sales	(183)	(18)
Payments made	(638)	(448)
Liabilities incurred	1,094	156
Foreign currency translation	(45)	535
Revisions	350	2,524
Ending balance	<u>\$9,614</u>	<u>\$8,473</u>

9. Accounting for Suspended Exploratory Well Costs

The Corporation continues capitalization of exploratory well costs beyond one year after the well is completed if (a) the well found a sufficient quantity of reserves to justify its completion as a producing well and (b) sufficient progress is being made in assessing the reserves and the economic and operating viability of the 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:

	2010	2009	2008
	<i>(millions of dollars)</i>		
Balance beginning at January 1	\$2,005	\$1,585	\$1,291
Additions pending the determination of proved reserves	1,103	624	448
Charged to expense	(104)	(51)	–
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(136)	(200)	(101)
Other	25	47	(53)
Ending balance	<u>\$2,893</u>	<u>\$2,005</u>	<u>\$1,585</u>
Ending balance attributed to equity companies included above	\$ –	\$ 9	\$ 10

Period end capitalized suspended exploratory well costs:

	2010	2009	2008
	<i>(millions of dollars)</i>		
Capitalized for a period of one year or less	\$1,103	\$ 624	\$ 448
Capitalized for a period of between one and five years	1,294	924	636
Capitalized for a period of between five and ten years	278	220	225
Capitalized for a period of greater than ten years	218	237	276
Capitalized for a period greater than one year – subtotal	<u>\$1,790</u>	<u>\$1,381</u>	<u>\$1,137</u>
Total	<u>\$2,893</u>	<u>\$2,005</u>	<u>\$1,585</u>

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.

	2010	2009	2008
Number of projects with first capitalized well drilled in the preceding 12 months	9	18	12
Number of projects that have exploratory well costs capitalized for a period of greater than 12 months	59	57	50
Total	<u>68</u>	<u>75</u>	<u>62</u>

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Of the 59 projects that have exploratory well costs capitalized for a period greater than 12 months as of December 31, 2010, 25 projects have drilling in the preceding 12 months or exploratory activity planned in the next

two years, while the remaining 34 projects are those with completed exploratory activity progressing toward development. The table below provides additional detail for those 34 projects, which total \$692 million.

Country/Project	Dec. 31, 2010	Years Wells Drilled	Comment
<i>(millions of dollars)</i>			
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.
Indonesia			
– Natuna	118	1981 - 1983	Development activity under way, while continuing discussions with the government on contract terms pursuant to recently executed Heads of Agreement.
Kazakhstan			
– Kairan	53	2004 - 2007	Declarations involving field commerciality filed with Kazakhstan government in 2008; progressing commercialization and field development studies.
Nigeria			
– Bolia	15	2002 - 2006	Evaluating development plan, while continuing discussions with the government regarding regional hub strategy.
– Bonga North	34	2004 - 2009	Pursuing alignment with operator and government regarding development plan.
– Bosi	79	2002 - 2006	Development activity under way while continuing discussions with the government regarding development plan.
– Other (5 projects)	16	2001 - 2002	Pursuing development of several additional offshore satellite discoveries which will tie back to existing/planned production facilities.
Norway			
– Gamma	20	2008 - 2009	Evaluating development plan for tieback to existing production facilities.
– H-North	15	2007	Discovery near existing facilities in Fram area; evaluating development options.
– Lavrans	23	1995 - 1999	Development awaiting capacity in existing Kristin production facility; evaluating development concepts for phased ullage scenarios.
– Noatun	19	2008	Evaluating development plan for tieback to existing production facilities.
– Nyk High	20	2008	Evaluating field development alternatives.
– Other (8 projects)	34	1992 - 2009	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			
– Fram	55	2009	Progressing development and commercialization plans.
– Other (3 projects)	21	2001 - 2008	Projects primarily awaiting capacity in existing or planned infrastructure.
United States			
– Julia Unit	78	2007 - 2008	Julia Unit owners are progressing development plans and have agreed to share funding on facilities at the Chevron-operated Jack-Saint Malo platform. Suspension of Production for the Julia Unit is under review by the Bureau of Ocean Energy Management, Regulation and Enforcement.
– Tip Top	31	2009	Evaluating development concept and requisite facility upgrades.
Other			
– Various (2 projects)	8	1979 - 1995	Projects primarily awaiting capacity in existing or planned infrastructure.
Total 2010 (34 projects)	\$692		

10. Leased Facilities

At December 31, 2010, 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 \$7,776 million as indicated in the table. Estimated related rental income from noncancelable subleases is \$62 million.

	Lease Payments Under Minimum Commitments	Related Sublease Rental Income
	<i>(millions of dollars)</i>	
2011	\$ 2,095	\$ 8
2012	1,570	8
2013	1,061	7
2014	731	6
2015	581	6
2016 and beyond	1,738	27
Total	<u>\$ 7,776</u>	<u>\$ 62</u>

Net rental cost under both cancelable and noncancelable operating leases incurred during 2010, 2009 and 2008 were as follows:

	2010	2009	2008
	<i>(millions of dollars)</i>		
Rental cost	\$ 3,762	\$ 4,426	\$ 4,115
Less sublease rental income	90	98	123
Net rental cost	<u>\$ 3,672</u>	<u>\$ 4,328</u>	<u>\$ 3,992</u>

11. Earnings Per Share

	2010	2009	2008
<u>Earnings per common share</u>			
Net income attributable to ExxonMobil <i>(millions of dollars)</i>	\$30,460	\$19,280	\$45,220
Weighted average number of common shares outstanding <i>(millions of shares)</i>	4,885	4,832	5,194
Earnings per common share <i>(dollars)</i>	\$ 6.24	\$ 3.99	\$ 8.70
<u>Earnings per common share – assuming dilution</u>			
Net income attributable to ExxonMobil <i>(millions of dollars)</i>	\$30,460	\$19,280	\$45,220
Weighted average number of common shares outstanding <i>(millions of shares)</i>	4,885	4,832	5,194
Effect of employee stock-based awards	12	16	27
Weighted average number of common shares outstanding – assuming dilution	<u>4,897</u>	<u>4,848</u>	<u>5,221</u>
Earnings per common share – assuming dilution <i>(dollars)</i>	\$ 6.22	\$ 3.98	\$ 8.66
Dividends paid per common share <i>(dollars)</i>	\$ 1.74	\$ 1.66	\$ 1.55

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

12. 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 \$12.8 billion and \$7.7 billion at December 31, 2010, and 2009, respectively, as compared to recorded book values of \$12.2 billion and \$7.1 billion at December 31, 2010, and 2009, respectively. The fair value hierarchy for long-term debt is primarily Level 1 (quoted prices for identical assets in active markets).

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. For derivatives designated as cash flow hedges, the Corporation's activity is intended to manage the price risk posed by physical transactions.

The estimated fair value of derivative instruments outstanding and recorded on the balance sheet was a net asset of \$172 million at year-end 2010 and a net liability of \$5 million at year-end 2009. This is the amount that the Corporation would have received from, or paid to, third parties if these derivatives had been settled in the open market. Assets and liabilities associated with derivatives are predominantly recorded either in "Other current assets" or "Accounts payable and accrued liabilities." The year-end 2010 net asset balance includes the Corporation's outstanding cash flow hedge position, acquired as a result of the XTO merger, of \$219 million. As the current cash flow hedge positions settle, these programs will be discontinued.

The Corporation's fair value measurement of its derivative instruments uses primarily Level 2 inputs (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).

The Corporation recognized a before-tax gain or (loss) related to derivative instruments of \$221 million, \$(73) million and \$154 million during 2010, 2009 and 2008, respectively. Income statement effects associated with derivatives are recorded either in "Sales and other operating revenue" or "Crude oil and product purchases." Of the amount stated above for 2010, cash flow hedges resulted in a before-tax gain of \$218 million. The ineffective portion of derivatives designated as hedges is de minimis.

The principal natural gas futures contracts and swap agreements acquired as part of the XTO merger that are in place as of December 31, 2010, will expire by the end of 2011. The associated volume of natural gas is 250 mcf at a weighted average NYMEX price of \$7.02 per thousand cubic feet. These derivative contracts qualify for cash flow hedge accounting. The Corporation will receive the cash flow related to these derivative contracts at the price indicated above. However, the amount of the income statement gain or loss realized from these contracts will be limited to the change in fair value of the derivative instruments from the acquisition date of XTO.

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 derivative activities described above. The fair value of derivatives outstanding at year-end 2010 and the gain recognized during the year are immaterial.

13. Long-Term Debt

At December 31, 2010, long-term debt consisted of \$11,610 million due in U.S. dollars and \$617 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 \$345 million, which matures within one year and is included in current liabilities. The amounts of long-term debt maturing, together with sinking fund pay-

ments required, in each of the four years after December 31, 2011, in millions of dollars, are: 2012 – \$3,222, 2013 – \$1,019, 2014 – \$622 and 2015 – \$601. At December 31, 2010, the Corporation's unused long-term credit lines were not material.

Summarized long-term debt at year-end 2010 and 2009 are shown in the table below:

	2010	2009
	<i>(millions of dollars)</i>	
SeaRiver Maritime Financial Holdings, Inc. (1)		
Guaranteed debt securities due 2011 (2)	\$ –	\$ 13
Guaranteed deferred interest debentures due 2012		
– Face value net of unamortized discount plus accrued interest	2,389	2,144
XTO Energy Inc. (premium in millions of dollars)		
7.500% senior note due 2012 includes premium of \$15	199	–
5.900% senior note due 2012 includes premium of \$16	233	–
6.250% senior note due 2013 includes premium of \$18	193	–
4.625% senior note due 2013 includes premium of \$9	149	–
5.750% senior note due 2013 includes premium of \$37	359	–
4.900% senior note due 2014 includes premium of \$19	267	–
5.000% senior note due 2015 includes premium of \$13	142	–
5.300% senior note due 2015 includes premium of \$28	262	–
5.650% senior note due 2016 includes premium of \$27	227	–
6.250% senior note due 2017 includes premium of \$80	534	–
5.500% senior note due 2018 includes premium of \$49	420	–
6.500% senior note due 2018 includes premium of \$86	524	–
6.100% senior note due 2036 includes premium of \$29	204	–
6.750% senior note due 2037 includes premium of \$69	329	–
6.375% senior note due 2038 includes premium of \$46	258	–
Mobil Services (Bahamas) Ltd.		
Variable note due 2035 (3)	972	972
Variable note due 2034 (4)	311	311
Mobil Producing Nigeria Unlimited (5)		
Variable notes due 2012-2017	415	621
Esso (Thailand) Public Company Ltd. (6)		
Variable notes due 2012-2017	522	165
Mobil Corporation		
8.625% debentures due 2021	248	248
Industrial revenue bonds due 2012-2040 (7)	2,247	1,685
Other U.S. dollar obligations (8)	454	536
Other foreign currency obligations	65	66
Capitalized lease obligations (9)	304	368
Total long-term debt	<u>\$12,227</u>	<u>\$ 7,129</u>

(1) Additional information is provided for this subsidiary on the following pages.

(2) Average effective interest rate of 1.6% in 2009.

(3) Average effective interest rate of 0.3% in 2010 and 0.3% in 2009.

(4) Average effective interest rate of 0.4% in 2010 and 0.9% in 2009.

(5) Average effective interest rate of 4.6% in 2010 and 5.4% in 2009.

(6) Average effective interest rate of 1.7% in 2010 and 2.2% in 2009.

(7) Average effective interest rate of 0.2% in 2010 and 0.2% in 2009.

(8) Average effective interest rate of 4.7% in 2010 and 5.0% in 2009.

(9) Average imputed interest rate of 8.1% in 2010 and 8.8% in 2009.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Condensed consolidating financial information related to guaranteed securities issued by subsidiaries

Exxon Mobil Corporation has fully and unconditionally guaranteed the deferred interest debentures due 2012 (\$2,389 million long-term debt at December 31, 2010) and the debt securities due 2011 (\$13 million short-term) of SeaRiver Maritime Financial Holdings, Inc.

SeaRiver Maritime Financial Holdings, Inc. is a 100-percent-owned subsidiary of Exxon Mobil Corporation.

The following condensed consolidating financial information is provided for Exxon Mobil Corporation, as guarantor, and for SeaRiver Maritime Financial Holdings, Inc., as issuer, as an alternative to providing separate financial statements for the issuer. The accounts of Exxon Mobil Corporation and SeaRiver Maritime Financial Holdings, Inc. are presented utilizing the equity method of accounting for investments in subsidiaries.

	Exxon Mobil Corporation Parent Guarantor	SeaRiver Maritime Financial Holdings, Inc.	All Other Subsidiaries	Consolidating and Eliminating Adjustments	Consolidated
<i>(millions of dollars)</i>					
Condensed consolidated statement of income for 12 months ended December 31, 2010					
Revenues and other income					
Sales and other operating revenue, including sales-based taxes	\$ 15,382	\$ –	\$ 354,743	\$ –	\$ 370,125
Income from equity affiliates	28,401	(2)	10,589	(28,311)	10,677
Other income	790	–	1,629	–	2,419
Intercompany revenue	39,433	4	332,483	(371,920)	–
Total revenues and other income	84,006	2	699,444	(400,231)	383,221
Costs and other deductions					
Crude oil and product purchases	40,788	–	518,961	(361,790)	197,959
Production and manufacturing expenses	7,627	–	33,400	(5,235)	35,792
Selling, general and administrative expenses	2,871	–	12,482	(670)	14,683
Depreciation and depletion	1,761	–	12,999	–	14,760
Exploration expenses, including dry holes	251	–	1,893	–	2,144
Interest expense	217	246	4,035	(4,239)	259
Sales-based taxes	–	–	28,547	–	28,547
Other taxes and duties	29	–	36,089	–	36,118
Total costs and other deductions	53,544	246	648,406	(371,934)	330,262
Income before income taxes	30,462	(244)	51,038	(28,297)	52,959
Income taxes	2	(90)	21,649	–	21,561
Net income including noncontrolling interests	30,460	(154)	29,389	(28,297)	31,398
Net income attributable to noncontrolling interests	–	–	938	–	938
Net income attributable to ExxonMobil	\$ 30,460	\$ (154)	\$ 28,451	\$ (28,297)	\$ 30,460

	Exxon Mobil Corporation Parent Guarantor	SeaRiver Maritime Financial Holdings, Inc.	All Other Subsidiaries	Consolidating and Eliminating Adjustments	Consolidated
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(millions of dollars)

Condensed consolidated statement of income for 12 months ended December 31, 2009

Revenues and other income					
Sales and other operating revenue, including sales-based taxes	\$ 11,352	\$ –	\$ 290,148	\$ –	\$ 301,500
Income from equity affiliates	19,852	7	7,060	(19,776)	7,143
Other income	813	–	1,130	–	1,943
Intercompany revenue	30,889	4	271,663	(302,556)	–
Total revenues and other income	62,906	11	570,001	(322,332)	310,586
Costs and other deductions					
Crude oil and product purchases	31,419	–	411,689	(290,302)	152,806
Production and manufacturing expenses	7,811	–	30,805	(5,589)	33,027
Selling, general and administrative expenses	2,574	–	12,852	(691)	14,735
Depreciation and depletion	1,571	–	10,346	–	11,917
Exploration expenses, including dry holes	230	–	1,791	–	2,021
Interest expense	1,200	222	5,126	(6,000)	548
Sales-based taxes	–	–	25,936	–	25,936
Other taxes and duties	(29)	–	34,848	–	34,819
Total costs and other deductions	44,776	222	533,393	(302,582)	275,809
Income before income taxes	18,130	(211)	36,608	(19,750)	34,777
Income taxes	(1,150)	(81)	16,350	–	15,119
Net income including noncontrolling interests	19,280	(130)	20,258	(19,750)	19,658
Net income attributable to noncontrolling interests	–	–	378	–	378
Net income attributable to ExxonMobil	\$ 19,280	\$ (130)	\$ 19,880	\$ (19,750)	\$ 19,280

Condensed consolidated statement of income for 12 months ended December 31, 2008

Revenues and other income					
Sales and other operating revenue, including sales-based taxes	\$ 17,481	\$ –	\$ 442,098	\$ –	\$ 459,579
Income from equity affiliates	45,664	9	11,055	(45,647)	11,081
Other income	302	–	6,397	–	6,699
Intercompany revenue	48,414	45	442,305	(490,764)	–
Total revenues and other income	111,861	54	901,855	(536,411)	477,359
Costs and other deductions					
Crude oil and product purchases	48,346	–	669,107	(467,999)	249,454
Production and manufacturing expenses	8,327	–	35,298	(5,720)	37,905
Selling, general and administrative expenses	3,349	–	13,364	(840)	15,873
Depreciation and depletion	1,552	–	10,827	–	12,379
Exploration expenses, including dry holes	192	–	1,259	–	1,451
Interest expense	3,859	207	13,143	(16,536)	673
Sales-based taxes	–	–	34,508	–	34,508
Other taxes and duties	67	–	41,652	–	41,719
Total costs and other deductions	65,692	207	819,158	(491,095)	393,962
Income before income taxes	46,169	(153)	82,697	(45,316)	83,397
Income taxes	949	(56)	35,637	–	36,530
Net income including noncontrolling interests	45,220	(97)	47,060	(45,316)	46,867
Net income attributable to noncontrolling interests	–	–	1,647	–	1,647
Net income attributable to ExxonMobil	\$ 45,220	\$ (97)	\$ 45,413	\$ (45,316)	\$ 45,220

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Condensed consolidating financial information related to guaranteed securities issued by subsidiaries

	Exxon Mobil Corporation Parent Guarantor	SeaRiver Maritime Financial Holdings, Inc.	All Other Subsidiaries	Consolidating and Eliminating Adjustments	Consolidated
	<i>(millions of dollars)</i>				
<u>Condensed consolidated balance sheet for year ended December 31, 2010</u>					
Cash and cash equivalents	\$ 309	\$ –	\$ 7,516	\$ –	\$ 7,825
Cash and cash equivalents – restricted	371	–	257	–	628
Marketable securities	–	–	2	–	2
Notes and accounts receivable – net	2,104	–	30,346	(166)	32,284
Inventories	1,457	–	11,519	–	12,976
Other current assets	239	–	5,030	–	5,269
Total current assets	4,480	–	54,670	(166)	58,984
Investments, advances and long-term receivables	254,781	446	454,489	(674,378)	35,338
Property, plant and equipment – net	18,830	–	180,718	–	199,548
Other long-term assets	224	12	8,404	–	8,640
Intercompany receivables	18,186	2,457	528,405	(549,048)	–
Total assets	\$ 296,501	\$ 2,915	\$ 1,226,686	\$ (1,223,592)	\$ 302,510
Notes and loans payable	\$ 1,042	\$ 13	\$ 1,732	\$ –	\$ 2,787
Accounts payable and accrued liabilities	2,987	–	47,047	–	50,034
Income taxes payable	–	3	9,975	(166)	9,812
Total current liabilities	4,029	16	58,754	(166)	62,633
Long-term debt	295	2,389	9,543	–	12,227
Postretirement benefits reserves	9,660	–	9,707	–	19,367
Deferred income tax liabilities	642	107	34,401	–	35,150
Other long-term liabilities	5,632	–	14,822	–	20,454
Intercompany payables	129,404	382	419,262	(549,048)	–
Total liabilities	149,662	2,894	546,489	(549,214)	149,831
Earnings reinvested	298,899	(848)	132,357	(131,509)	298,899
Other equity	(152,060)	869	542,000	(542,869)	(152,060)
ExxonMobil share of equity	146,839	21	674,357	(674,378)	146,839
Noncontrolling interests	–	–	5,840	–	5,840
Total equity	146,839	21	680,197	(674,378)	152,679
Total liabilities and equity	\$ 296,501	\$ 2,915	\$ 1,226,686	\$ (1,223,592)	\$ 302,510
<u>Condensed consolidated balance sheet for year ended December 31, 2009</u>					
Cash and cash equivalents	\$ 449	\$ –	\$ 10,244	\$ –	\$ 10,693
Marketable securities	–	–	169	–	169
Notes and accounts receivable – net	2,050	–	25,858	(263)	27,645
Inventories	1,202	–	10,351	–	11,553
Other current assets	313	–	4,862	–	5,175
Total current assets	4,014	–	51,484	(263)	55,235
Investments, advances and long-term receivables	199,110	449	439,712	(607,606)	31,665
Property, plant and equipment – net	18,015	–	121,101	–	139,116
Other long-term assets	207	24	7,076	–	7,307
Intercompany receivables	19,637	2,257	442,903	(464,797)	–
Total assets	\$ 240,983	\$ 2,730	\$ 1,062,276	\$ (1,072,666)	\$ 233,323
Notes and loans payable	\$ 43	\$ 13	\$ 2,420	\$ –	\$ 2,476
Accounts payable and accrued liabilities	2,779	–	38,496	–	41,275
Income taxes payable	–	2	8,571	(263)	8,310
Total current liabilities	2,822	15	49,487	(263)	52,061
Long-term debt	279	2,157	4,693	–	7,129
Postretirement benefits reserves	8,673	–	9,269	–	17,942
Deferred income tax liabilities	818	151	22,179	–	23,148
Other long-term liabilities	5,286	–	12,365	–	17,651
Intercompany payables	112,536	382	351,879	(464,797)	–
Total liabilities	130,414	2,705	449,872	(465,060)	117,931
Earnings reinvested	276,937	(694)	109,603	(108,909)	276,937
Other equity	(166,368)	719	497,978	(498,697)	(166,368)
ExxonMobil share of equity	110,569	25	607,581	(607,606)	110,569
Noncontrolling interests	–	–	4,823	–	4,823
Total equity	110,569	25	612,404	(607,606)	115,392
Total liabilities and equity	\$ 240,983	\$ 2,730	\$ 1,062,276	\$ (1,072,666)	\$ 233,323

	Exxon Mobil Corporation Parent Guarantor	SeaRiver Maritime Financial Holdings, Inc.	All Other Subsidiaries	Consolidating and Eliminating Adjustments	Consolidated
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(millions of dollars)

Condensed consolidated statement of cash flows for 12 months ended December 31, 2010

Cash provided by/(used in) operating activities	\$ 35,740	\$ 63	\$ 18,307	\$ (5,697)	\$ 48,413
Cash flows from investing activities					
Additions to property, plant and equipment	(2,922)	–	(23,949)	–	(26,871)
Sales of long-term assets	1,484	–	1,777	–	3,261
Decrease/(increase) in restricted cash and cash equivalents	(371)	–	(257)	–	(628)
Net intercompany investing	(13,966)	(200)	13,813	353	–
All other investing, net	(672)	–	706	–	34
Net cash provided by/(used in) investing activities	(16,447)	(200)	(7,910)	353	(24,204)
Cash flows from financing activities					
Additions to short- and long-term debt	–	–	1,741	–	1,741
Reductions in short- and long-term debt	(3)	(13)	(8,644)	–	(8,660)
Additions/(reductions) in debt with three months or less maturity	997	–	(288)	–	709
Cash dividends	(8,498)	–	(5,697)	5,697	(8,498)
Common stock acquired	(13,093)	–	–	–	(13,093)
Net intercompany financing activity	–	–	202	(202)	–
All other financing, net	1,164	150	(286)	(151)	877
Net cash provided by/(used in) financing activities	(19,433)	137	(12,972)	5,344	(26,924)
Effects of exchange rate changes on cash	–	–	(153)	–	(153)
Increase/(decrease) in cash and cash equivalents	\$ (140)	\$ –	\$ (2,728)	\$ –	\$ (2,868)

Condensed consolidated statement of cash flows for 12 months ended December 31, 2009

Cash provided by/(used in) operating activities	\$ 27,424	\$ 72	\$ 28,024	\$ (27,082)	\$ 28,438
Cash flows from investing activities					
Additions to property, plant and equipment	(2,686)	–	(19,805)	–	(22,491)
Sales of long-term assets	228	–	1,317	–	1,545
Decrease/(increase) in restricted cash and cash equivalents	–	–	–	–	–
Net intercompany investing	(1,826)	(209)	1,717	318	–
All other investing, net	–	–	(1,473)	–	(1,473)
Net cash provided by/(used in) investing activities	(4,284)	(209)	(18,244)	318	(22,419)
Cash flows from financing activities					
Additions to short- and long-term debt	–	–	1,561	–	1,561
Reductions in short- and long-term debt	(3)	(13)	(1,627)	–	(1,643)
Additions/(reductions) in debt with three months or less maturity	39	–	(110)	–	(71)
Cash dividends	(8,023)	–	(27,082)	27,082	(8,023)
Common stock acquired	(19,703)	–	–	–	(19,703)
Net intercompany financing activity	–	–	168	(168)	–
All other financing, net	988	150	(392)	(150)	596
Net cash provided by/(used in) financing activities	(26,702)	137	(27,482)	26,764	(27,283)
Effects of exchange rate changes on cash	–	–	520	–	520
Increase/(decrease) in cash and cash equivalents	\$ (3,562)	\$ –	\$ (17,182)	\$ –	\$ (20,744)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Condensed consolidating financial information related to guaranteed securities issued by subsidiaries

	Exxon Mobil Corporation Parent Guarantor	SeaRiver Maritime Financial Holdings, Inc.	All Other Subsidiaries	Consolidating and Eliminating Adjustments	Consolidated
	<i>(millions of dollars)</i>				
<u>Condensed consolidated statement of cash flows for 12 months ended December 31, 2008</u>					
Cash provided by/(used in) operating activities	\$ 47,823	\$ 68	\$ 54,478	\$ (42,644)	\$ 59,725
Cash flows from investing activities					
Additions to property, plant and equipment	(2,154)	-	(17,164)	-	(19,318)
Sales of long-term assets	162	-	5,823	-	5,985
Decrease/(increase) in restricted cash and cash equivalents	-	-	-	-	-
Net intercompany investing	(502)	(155)	476	181	-
All other investing, net	-	-	(2,166)	-	(2,166)
Net cash provided by/(used in) investing activities	(2,494)	(155)	(13,031)	181	(15,499)
Cash flows from financing activities					
Additions to short- and long-term debt	-	-	1,146	-	1,146
Reductions in short- and long-term debt	(4)	(13)	(1,799)	-	(1,816)
Additions/(reductions) in debt with three months or less maturity	-	-	143	-	143
Cash dividends	(8,058)	-	(42,644)	42,644	(8,058)
Common stock acquired	(35,734)	-	-	-	(35,734)
Net intercompany financing activity	-	-	81	(81)	-
All other financing, net	1,085	100	(793)	(100)	292
Net cash provided by/(used in) financing activities	(42,711)	87	(43,866)	42,463	(44,027)
Effects of exchange rate changes on cash	-	-	(2,743)	-	(2,743)
Increase/(decrease) in cash and cash equivalents	\$ 2,618	\$ -	\$ (5,162)	\$ -	\$ (2,544)

14. 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. The maximum number of shares of stock that may be issued under the 2003 Incentive Program is 220 million. Awards that are forfeited or 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 2010, remaining shares available for award under the 2003 Incentive Program were 141,939 thousand.

As under earlier programs, 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. Most of the options and SARs normally first become exercisable one year following the date of grant. All remaining stock options and SARs outstanding were either granted prior to 2002 or were converted XTO stock options as a result of the XTO merger.

Under the terms of the XTO merger agreement, outstanding XTO stock-based awards were converted into ExxonMobil stock-based awards based on the merger exchange ratio. The converted XTO awards, granted under XTO's 1998 or 2004 Stock Incentive Plans, include restricted stock awards, stock options and performance stock

awards. The grant date for the converted XTO awards is considered to be the effective date of the merger for purposes of calculating fair value. Compensation cost for the converted XTO awards is recognized in income over the requisite service period. The maximum term of the XTO awards is ten years under the 1998 plan and seven years under the 2004 plan. No additional awards will be issued under either XTO plan. In connection with the closing of the merger, the Corporation also made new grants of restricted stock under the Corporation's 2003 Incentive Program to certain current or former XTO employees as described in more detail below.

Restricted Stock. Excluding XTO merger-related grants, long-term incentive awards totaling 10,648 thousand of restricted (nonvested) common stock and restricted (nonvested) common stock units were granted in 2010. Awards totaling 10,133 thousand and 10,116 thousand of restricted (nonvested) common stock and restricted (nonvested) common stock units were granted in 2009 and 2008, respectively. These shares are issued to employees from treasury stock. The total compensation expense is recognized over the requisite service period. 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. A small

number of awards granted to certain 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, long-term incentive awards totaling 4,206 thousand of restricted (nonvested) common stock were granted in 2010 in association with the XTO merger. This included the granting of 1,423 thousand of restricted common stock awards under the Corporation's 2003 Incentive Program and 2,783 thousand of converted XTO restricted common stock awards. The majority of the converted XTO awards vest in three installments over a period of three years or three and a half years after the initial grant. The remainder of converted XTO awards that were granted to certain senior XTO employees will vest on the first anniversary of the effective date of the merger. Awards granted to certain former senior executives of XTO in connection with consulting agreements negotiated as part of the merger have vesting periods of one year for 50 percent of the award and of two or three years for the remaining 50 percent of the award, depending on the actual term of the consulting engagements.

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.

In 2002, the Corporation began issuing restricted stock as stock-based compensation in lieu of stock options. Compensation expense for these awards is based on the price of the stock at the date of grant and has been recognized in income over the requisite service period. Prior to 2002, the Corporation issued stock options as stock-based compensation and since these awards vested prior to the effective date of current authoritative guidance, they continue to be accounted for under the prior prescribed method. Under this method, compensation expense for awards granted in the form of stock options is measured at the intrinsic value of the options (the difference between the market price of the stock and the exercise price of the options) on the date of grant. Since these two prices were the same on the date of grant, no compensation expense has been recognized in income for these awards.

The following tables summarize information about restricted stock and restricted stock units for the year ended December 31, 2010.

Restricted stock and units outstanding	2010	
	Shares	Weighted Average Grant-Date Fair Value per Share
	<i>(thousands)</i>	
Issued and outstanding at January 1	43,503	\$ 67.52
2009 award issued in 2010	10,132	\$ 75.40
Merger-related granted and converted XTO awards	4,206	\$ 59.31
Vested	(10,377)	\$ 61.72
Forfeited	(158)	\$ 67.91
Issued and outstanding at December 31	47,306	\$ 69.74

Value of restricted stock and units	2010	2009	2008
Grant price	\$ 66.07	\$ 75.40	\$ 78.24
Value at date of grant:		<i>(millions of dollars)</i>	
Restricted stock and units settled in stock	\$ 672	\$ 711	\$ 735
Merger-related granted and converted XTO awards	250	—	—
Units settled in cash	60	53	56
Total value	\$ 982	\$ 764	\$ 791

As of December 31, 2010, there was \$2,133 million of unrecognized compensation cost related to the nonvested restricted awards. This cost is expected to be recognized over a weighted-average period of 4.3 years. The compensation cost charged against income for the restricted stock and restricted units was \$801 million, \$723 million and \$648 million for 2010, 2009 and 2008, respectively. The income tax benefit recognized in income related to this compensation

expense was \$81 million, \$76 million and \$75 million for the same periods, respectively. The fair value of shares and units vested in 2010, 2009 and 2008 was \$718 million, \$763 million and \$438 million, respectively. Cash payments of \$42 million, \$41 million and \$25 million for vested restricted stock units settled in cash were made in 2010, 2009 and 2008, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Performance Stock. The Corporation granted 157 thousand of converted XTO performance stock awards with a grant-date fair value of \$5 million as a result of the merger. Compensation cost for the performance stock awards is based on the estimated grant-date fair value. Vesting of XTO performance stock awards depended on the achievement of certain XTO stock thresholds. Upon conversion of these awards to ExxonMobil performance stock awards in connection with the merger, the performance thresholds were adjusted to equivalent market price thresholds for common stock of the Corporation. The performance stock awards are subject to forfeiture if the performance criteria are not met within the maximum term. Otherwise, holders of performance stock awards generally have all voting, dividend and other rights of other common stockholders.

The following table provides information about these converted performance stock awards as of December 31, 2010.

Performance stock awards	Dec. 31, 2010	
	Shares (thousands)	
Vesting Price:		
\$108.49		38
\$119.76		38

During 2010, 80 thousand performance share awards vested.

Unrecognized compensation cost was \$1 million at December 31, 2010. Compensation expense recognized in 2010 was \$3 million.

Stock Options. 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. The grant included 893 thousand of unvested options. The converted XTO stock option awards are accounted for under current authoritative guidance, which requires the measurement and recognition of compensation expense based on estimated grant-date fair values. Upon conversion of these stock options to ExxonMobil stock options in connection with the merger, the performance thresholds were adjusted to equivalent market price thresholds

for common stock of the Corporation. 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. As of December 31, 2010, unvested stock options of 574 thousand included 130 thousand options that vest ratably over three years and 444 thousand options that vest at stock prices ranging from \$76.08 to \$126.80.

Changes that occurred in the Corporation's stock options in 2010 are summarized below (shares in thousands):

Stock options	2010		Weighted Average Remaining Contractual Term
	Shares	Avg. Exercise Price	
Outstanding at January 1	41,473	\$40.92	
Merger-related converted XTO awards	12,393	\$55.15	
Exercised	(24,305)	\$43.62	
Forfeited	(52)	\$45.91	
Outstanding at December 31	<u>29,509</u>	\$44.65	2.0 Years
Exercisable at December 31	28,935	\$43.94	1.9 Years

Unrecognized compensation cost related to the nonvested merger-related converted XTO stock options was \$1 million as of December 31, 2010. Compensation expense recognized in 2010 was \$2 million. No compensation expense was recognized for stock options in 2009 and 2008, as all remaining outstanding stock options were granted prior to 2002 and were fully vested. Cash received from stock option exercises was \$1,043 million, \$752 million and \$753 million for 2010, 2009 and 2008, respectively. The cash tax benefit realized for the options exer-

cised was \$89 million, \$164 million and \$273 million for 2010, 2009 and 2008, respectively. The aggregate intrinsic value of stock options exercised in 2010, 2009 and 2008 was \$539 million, \$563 million and \$894 million, respectively. The intrinsic value for the balance of outstanding stock options at December 31, 2010, was \$868 million. The intrinsic value for the balance of exercisable stock options at December 31, 2010, was \$865 million.

Estimated Fair Value of XTO Merger-Related Grants. For restricted stock grants, the fair value was equal to the price of the common stock on the grant date. For the converted XTO stock options and performance stock, the Corporation used a Monte Carlo simulation model to estimate fair value. The Monte Carlo simulation model requires inputs for the risk-free interest rate, dividend yield, volatility, contract term, target vesting price, post-vesting turnover rate and sub-optimal exercise factor. Expected life, derived vesting period and fair value are outputs of this model.

The risk-free interest rate is based on the constant maturity nominal rates of U.S. Treasury securities with remaining lives throughout the contract term on the day of the grant. The dividend yield is the expected common stock annual dividend yield over the expected life of the option or performance stock, expressed as a percentage of the stock price on the date of grant. The volatility factors are based on a combination of both the historical volatilities of ExxonMobil's stock and the implied volatility of traded options on ExxonMobil common stock. Estimates of fair value are not intended to predict actual future events or the value ultimately realized by certain employees who receive stock option grants, and subsequent events are not indicative of the reasonableness of the original fair value estimates.

The total estimated fair value calculated at the time of the merger for the converted XTO stock-based awards was \$352 million.

Fair values were determined using the following assumptions:

Weighted average expected term	2.5 years
Range of risk-free interest rates	0.1% - 2.6%
Weighted average risk-free interest rates	0.9%
Dividend yield	3.0%
Weighted average volatility	28.5%
Range of volatility	22.5% - 33.6%

15. 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. 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 materially adverse effect upon the Corporation's operations, financial condition, or financial statements taken as a whole.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Other Contingencies. The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2010, for \$8,771 million, primarily relating to guarantees for notes, loans and performance under contracts. Included in this amount were guarantees by consolidated affiliates of \$5,290 million, representing ExxonMobil's share of obligations of certain equity companies.

	Dec. 31, 2010		
	Equity Company Obligations	Other Third-Party Obligations	Total
	<i>(millions of dollars)</i>		
Guarantees	\$ 5,290	\$ 3,481	\$ 8,771

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			
	2011	2012-2015	2016 and Beyond	Total
	<i>(millions of dollars)</i>			
Unconditional purchase obligations (1)	\$ 287	\$ 748	\$ 487	\$ 1,522

(1) Undiscounted obligations of \$1,522 million mainly pertain to pipeline throughput agreements and include \$996 million of obligations to equity companies. The present value of these commitments, which excludes imputed interest of \$273 million, totaled \$1,249 million.

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

On September 6, 2007, affiliates of ExxonMobil filed a Request for Arbitration with the International Centre for Settlement of Investment Disputes (ICSID) 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 is currently scheduled for the first quarter of 2012. An affiliate of ExxonMobil has also filed an arbitration under the rules of the International Chamber of Commerce (ICC) against PdVSA and a PdVSA affiliate for breach of their contractual obligations under certain Cerro Negro Project agreements. A hearing on the merits of the ICC arbitration concluded in September 2010 and the parties filed post-hearing briefs. At this time, the net impact of this matter on the Corporation's consolidated financial results cannot be reasonably estimated. However, the Corporation does not expect the resolution to have a material effect upon the Corporation's operations or financial condition. ExxonMobil's remaining net book investment in Cerro Negro producing assets is about \$750 million.

16. 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.		2010	2009
	2010	2009	2010	2009		
Weighted-average assumptions used to determine benefit obligations at December 31	<i>(percent)</i>					
Discount rate	5.50	6.00	4.80	5.20	5.50	6.00
Long-term rate of compensation increase	5.00	5.00	5.20	5.00	5.00	5.00
Change in benefit obligation	<i>(millions of dollars)</i>					
Benefit obligation at January 1	\$13,981	\$13,272	\$23,344	\$19,990	\$6,748	\$6,633
Service cost	468	438	480	421	101	94
Interest cost	798	809	1,175	1,121	395	408
Actuarial loss/(gain)	553	1,126	1,672	1,280	277	(49)
Benefits paid (1) (2)	(873)	(1,665)	(1,281)	(1,174)	(394)	(480)
Foreign exchange rate changes	–	–	169	1,676	26	60
Plan amendments, other	80	1	163	30	178	82
Benefit obligation at December 31	<u>\$15,007</u>	<u>\$13,981</u>	<u>\$25,722</u>	<u>\$23,344</u>	<u>\$7,331</u>	<u>\$6,748</u>
Accumulated benefit obligation at December 31	\$12,764	\$11,615	\$22,958	\$20,909	\$ –	\$ –

(1) Benefit payments for funded and unfunded plans.

(2) For 2010 and 2009, other postretirement benefits paid are net of \$15 million and \$28 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 obli-

gation assumes an initial health care cost trend rate of 6.0 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 \$57 million and the postretirement benefit obligation by \$599 million. A one-percentage-point decrease in the health care cost trend rate would decrease service and interest cost by \$45 million and the postretirement benefit obligation by \$494 million.

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.		2010	2009
	2010	2009	2010	2009		
Change in plan assets	<i>(millions of dollars)</i>					
Fair value at January 1	\$10,277	\$ 6,634	\$15,401	\$11,260	\$ 514	\$ 443
Actual return on plan assets	1,235	2,013	1,482	2,201	63	93
Foreign exchange rate changes	–	–	99	1,300	–	–
Company contribution	–	3,070	1,184	1,456	38	36
Benefits paid (1)	(677)	(1,440)	(873)	(795)	(59)	(57)
Other	–	–	(528)	(21)	2	(1)
Fair value at December 31	<u>\$10,835</u>	<u>\$10,277</u>	<u>\$16,765</u>	<u>\$15,401</u>	<u>\$ 558</u>	<u>\$ 514</u>

(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.	
	2010	2009	2010	2009
Assets in excess of/(less than) benefit obligation	<i>(millions of dollars)</i>			
Balance at December 31				
Funded plans	\$ (2,349)	\$ (1,940)	\$ (2,769)	\$ (2,085)
Unfunded plans	(1,823)	(1,764)	(6,188)	(5,858)
Total	<u>\$ (4,172)</u>	<u>\$ (3,704)</u>	<u>\$ (8,957)</u>	<u>\$ (7,943)</u>

The authoritative guidance for defined benefit pension and other post-retirement 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.			
	2010	2009	2010	2009	2010	2009
Assets in excess of/(less than) benefit obligation	<i>(millions of dollars)</i>					
Balance at December 31 ⁽¹⁾	<u>\$ (4,172)</u>	<u>\$ (3,704)</u>	<u>\$ (8,957)</u>	<u>\$ (7,943)</u>	<u>\$ (6,773)</u>	<u>\$ (6,234)</u>
Amounts recorded in the consolidated balance sheet consist of:						
Other assets	\$ 1	\$ 1	\$ 400	\$ 961	\$ -	\$ -
Current liabilities	(257)	(235)	(336)	(348)	(343)	(318)
Postretirement benefits reserves	(3,916)	(3,470)	(9,021)	(8,556)	(6,430)	(5,916)
Total recorded	<u>\$ (4,172)</u>	<u>\$ (3,704)</u>	<u>\$ (8,957)</u>	<u>\$ (7,943)</u>	<u>\$ (6,773)</u>	<u>\$ (6,234)</u>

Amounts recorded in accumulated other comprehensive income consist of:

Net actuarial loss/(gain)	\$ 5,028	\$ 5,830	\$ 7,795	\$ 7,036	\$ 1,985	\$ 1,878
Prior service cost	83	5	674	622	154	181
Total recorded in accumulated other comprehensive income	<u>\$ 5,111</u>	<u>\$ 5,835</u>	<u>\$ 8,469</u>	<u>\$ 7,658</u>	<u>\$ 2,139</u>	<u>\$ 2,059</u>

⁽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 and the long-term return assumption for each asset class.

	Pension Benefits						Other Postretirement Benefits		
	U.S.			Non-U.S.			2010	2009	2008
	2010	2009	2008	2010	2009	2008			
Weighted-average assumptions used to determine net periodic benefit cost for years ended December 31	<i>(percent)</i>								
Discount rate	6.00	6.25	6.25	5.20	5.50	5.40	6.00	6.25	6.25
Long-term rate of return on funded assets	7.50	8.00	9.00	6.70	7.30	7.50	7.50	8.00	9.00
Long-term rate of compensation increase	5.00	5.00	5.00	5.00	4.70	4.50	5.00	5.00	5.00
Components of net periodic benefit cost	<i>(millions of dollars)</i>								
Service cost	\$ 468	\$ 438	\$ 378	\$ 480	\$ 421	\$ 434	\$ 101	\$ 94	\$ 100
Interest cost	798	809	729	1,175	1,121	1,152	395	408	414
Expected return on plan assets	(726)	(656)	(915)	(1,010)	(886)	(1,200)	(37)	(35)	(59)
Amortization of actuarial loss/(gain)	525	694	239	554	648	318	147	176	197
Amortization of prior service cost	2	–	(2)	84	79	93	52	69	76
Net pension enhancement and curtailment/settlement expense	321	485	174	9	2	32	–	–	–
Net periodic benefit cost	\$1,388	\$1,770	\$ 603	\$1,292	\$1,385	\$ 829	\$ 658	\$ 712	\$ 728
Changes in amounts recorded in accumulated other comprehensive income:									
Net actuarial loss/(gain)	\$ 44	\$ (231)	\$5,275	\$1,202	\$ (33)	\$4,837	\$ 251	\$ (107)	\$ 13
Amortization of actuarial (loss)/gain	(846)	(1,179)	(413)	(563)	(650)	(350)	(147)	(176)	(197)
Prior service cost/(credit)	80	–	–	160	69	16	26	–	–
Amortization of prior service (cost)	(2)	–	2	(84)	(79)	(93)	(52)	(69)	(76)
Foreign exchange rate changes	–	–	–	96	608	(997)	2	2	(3)
Total recorded in other comprehensive income	(724)	(1,410)	4,864	811	(85)	3,413	80	(350)	(263)
Total recorded in net periodic benefit cost and other comprehensive income, before tax	\$ 664	\$ 360	\$5,467	\$2,103	\$1,300	\$4,242	\$ 738	\$ 362	\$ 465

Costs for defined contribution plans were \$347 million, \$339 million and \$309 million in 2010, 2009 and 2008, respectively.

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

	Total Pension and Other Postretirement Benefits		
	2010	2009	2008
(Charge)/credit to other comprehensive income, before tax	<i>(millions of dollars)</i>		
U.S. pension	\$ 724	\$ 1,410	\$ (4,864)
Non-U.S. pension	(811)	85	(3,413)
Other postretirement benefits	(80)	350	263
Total (charge)/credit to other comprehensive income, before tax	(167)	1,845	(8,014)
(Charge)/credit to income tax (see note 18)	35	(591)	2,723
(Charge)/credit to investment in equity companies	11	(133)	(27)
(Charge)/credit to other comprehensive income including noncontrolling interests, after tax	\$ (121)	\$ 1,121	\$ (5,318)
Charge/(credit) to equity of noncontrolling interests	95	93	224
(Charge)/credit to other comprehensive income attributable to ExxonMobil	\$ (26)	\$ 1,214	\$ (5,094)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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. The target asset allocation for the U.S. benefit plans is 60% equity securities and 40% debt securities. The target asset allocation for the non-U.S. plans in aggregate is 56% equities, 41% debt and 3% real estate funds. 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% and 3%, respectively.

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

The 2010 fair value of the benefit plan assets, including the level within the fair value hierarchy, is shown in the tables below:

Asset category:	U.S. Pension				Non-U.S. Pension			
	Fair Value Measurement at December 31, 2010, Using:				Fair Value Measurement at December 31, 2010, 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
	<i>(millions of dollars)</i>				<i>(millions of dollars)</i>			
Equity securities								
U.S.	\$ —	\$ 2,648 ⁽¹⁾	\$ —	\$ 2,648	\$ —	\$ 2,443 ⁽¹⁾	\$ —	\$ 2,443
Non-U.S.	—	3,530 ⁽¹⁾	—	3,530	228 ⁽²⁾	6,502 ⁽¹⁾	—	6,730
Private equity	—	—	408 ⁽³⁾	408	—	—	315 ⁽³⁾	315
Debt securities								
Corporate	—	1,152 ⁽⁴⁾	—	1,152	2 ⁽⁵⁾	1,629 ⁽⁴⁾	—	1,631
Government	—	2,847 ⁽⁴⁾	—	2,847	146 ⁽⁵⁾	4,709 ⁽⁴⁾	—	4,855
Asset-backed	—	31 ⁽⁴⁾	—	31	—	98 ⁽⁴⁾	—	98
Private mortgages	—	—	128 ⁽⁶⁾	128	—	—	4 ⁽⁶⁾	4
Real estate funds	—	—	—	—	—	—	417 ⁽⁷⁾	417
Cash	68	—	—	68	63	51 ⁽⁸⁾	—	114
Total at fair value	\$ 68	\$ 10,208	\$ 536	\$10,812	\$ 439	\$15,432	\$ 736	\$16,607
Insurance contracts at contract value				23				158
Total plan assets				<u>\$10,835</u>				<u>\$16,765</u>

(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 based on proprietary credit spread matrices developed using market data and monthly surveys of active mortgage bankers.

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

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

Asset category:	Other Postretirement			Total
	Fair Value Measurement at December 31, 2010, Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	
	<i>(millions of dollars)</i>			
Equity securities				
U.S.	\$ –	\$ 180 ⁽¹⁾	\$ –	\$ 180
Non-U.S.	–	191 ⁽¹⁾	–	191
Private equity	–	–	5 ⁽²⁾	5
Debt securities				
Corporate	–	49 ⁽³⁾	–	49
Government	–	117 ⁽³⁾	–	117
Asset-backed	–	13 ⁽³⁾	–	13
Private mortgages	–	–	2 ⁽⁴⁾	2
Cash	1	–	–	1
Total at fair value	\$ 1	\$ 550	\$ 7	\$ 558

(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.

(4) For private mortgages, fair value is based on proprietary credit spread matrices developed using market data and monthly surveys of active mortgage bankers.

The change in the fair value in 2010 of Level 3 assets that use significant unobservable inputs to measure fair value is shown in the table below:

	2010					Other Postretirement	
	U.S.		Pension			Other Postretirement	
	Private Equity	Private Mortgages	Private Equity	Private Mortgages	Real Estate	Private Equity	Private Mortgages
	<i>(millions of dollars)</i>						
Fair value at January 1	\$349	\$280	\$239	\$ 5	\$413	\$ 4	\$ 3
Net realized gains/(losses)	–	36	(1)	(1)	–	–	1
Net unrealized gains/(losses)	47	(3)	26	1	(4)	1	–
Net purchases/(sales)	12	(185)	51	(1)	8	–	(2)
Fair value at December 31	\$408	\$128	\$315	\$ 4	\$417	\$ 5	\$ 2

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The 2009 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, 2009, Using:				Fair Value Measurement at December 31, 2009, Using:			
Asset category:	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
	<i>(millions of dollars)</i>				<i>(millions of dollars)</i>			
Equity securities								
U.S.	\$ —	\$ 2,503 ⁽¹⁾	\$ —	\$ 2,503	\$ —	\$ 2,244 ⁽¹⁾	\$ —	\$ 2,244
Non-U.S.	—	3,341 ⁽¹⁾	—	3,341	227 ⁽²⁾	5,946 ⁽¹⁾	—	6,173
Private equity	—	—	349 ⁽³⁾	349	—	—	239 ⁽³⁾	239
Debt securities								
Corporate	—	1,040 ⁽⁴⁾	—	1,040	2 ⁽⁵⁾	1,637 ⁽⁴⁾	—	1,639
Government	—	2,570 ⁽⁴⁾	—	2,570	70 ⁽⁵⁾	4,217 ⁽⁴⁾	—	4,287
Asset-backed	—	30 ⁽⁴⁾	—	30	—	119 ⁽⁴⁾	—	119
Private mortgages	—	—	280 ⁽⁶⁾	280	—	—	5 ⁽⁶⁾	5
Real estate funds	—	—	—	—	—	—	413 ⁽⁷⁾	413
Cash	140	—	—	140	79	55 ⁽⁸⁾	—	134
Total at fair value	\$140	\$ 9,484	\$ 629	\$10,253	\$ 378	\$14,218	\$ 657	\$15,253
Insurance contracts at contract value				24				148
Total plan assets				<u>\$10,277</u>				<u>\$15,401</u>

(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 based on proprietary credit spread matrices developed using market data and monthly surveys of active mortgage bankers.

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

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

Asset category:	Other Postretirement			Total
	Fair Value Measurement at December 31, 2009, Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	
	<i>(millions of dollars)</i>			
Equity securities				
U.S.	\$ –	\$ 166 ⁽¹⁾	\$ –	\$ 166
Non-U.S.	–	181 ⁽¹⁾	–	181
Private equity	–	–	4 ⁽²⁾	4
Debt securities				
Corporate	–	51 ⁽³⁾	–	51
Government	–	95 ⁽³⁾	–	95
Asset-backed	–	11 ⁽³⁾	–	11
Private mortgages	–	–	3 ⁽⁴⁾	3
Cash	3	–	–	3
Total at fair value	\$ 3	\$ 504	\$ 7	\$ 514

(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.

(4) For private mortgages, fair value is based on proprietary credit spread matrices developed using market data and monthly surveys of active mortgage bankers.

The change in the fair value in 2009 of Level 3 assets that use significant unobservable inputs to measure fair value is shown in the table below:

	2009						
	U.S.		Pension			Other Postretirement	
	Private Equity	Private Mortgages	Private Equity	Private Mortgages	Real Estate	Private Equity	Private Mortgages
	<i>(millions of dollars)</i>						
Fair value at January 1	\$346	\$476	\$238	\$ 5	\$409	\$ 4	\$ 6
Net realized gains/(losses)	4	11	(10)	–	(7)	–	–
Net unrealized gains/(losses)	(35)	7	(35)	–	(11)	–	–
Net purchases/(sales)	34	(214)	46	–	22	–	(3)
Fair value at December 31	\$349	\$280	\$239	\$ 5	\$413	\$ 4	\$ 3

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.	
	2010	2009	2010	2009
	<i>(millions of dollars)</i>			
For <u>funded</u> pension plans with an accumulated benefit obligation in excess of plan assets:				
Projected benefit obligation	\$13,184	\$12,217	\$ 9,865	\$13,152
Accumulated benefit obligation	11,383	10,312	9,074	12,260
Fair value of plan assets	10,834	10,276	7,131	10,447
For <u>unfunded</u> pension plans:				
Projected benefit obligation	\$ 1,823	\$ 1,764	\$ 6,188	\$ 5,858
Accumulated benefit obligation	1,381	1,303	5,413	5,180

	Pension Benefits		Other Postretirement
	U.S.	Non-U.S.	Benefits
	<i>(millions of dollars)</i>		
Estimated 2011 amortization from accumulated other comprehensive income:			
Net actuarial loss/(gain) (1)	\$ 835	\$ 615	\$ 159
Prior service cost (2)	9	97	35

(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
	<i>(millions of dollars)</i>			
Contributions expected in 2011	\$ 270	\$ 1,130	\$ -	\$ -
Benefit payments expected in:				
2011	1,454	1,299	440	23
2012	1,483	1,281	456	25
2013	1,512	1,316	474	26
2014	1,451	1,362	489	28
2015	1,392	1,393	502	29
2016 - 2020	6,079	8,325	2,662	163

17. 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 special items, and transfers are at estimated market prices. Earnings for 2009 included a special charge of \$140 million in the corporate and financing segment for interest related to the Valdez punitive damages award. Special items included in 2008 after-tax earnings were a \$1,620 million gain in Non-U.S. Upstream on the sale of a natural gas transportation business in Germany and special charges of \$460 million in the corporate and financing segment related to the Valdez litigation.

Interest expense includes non-debt-related interest expense of \$41 million, \$500 million and \$498 million in 2010, 2009 and 2008, respectively. Higher expenses in 2009 and 2008 primarily reflect interest provisions related to the Valdez litigation.

In corporate and financing activities, interest revenue relates to interest earned on cash deposits and marketable securities.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Upstream		Downstream		Chemical		Corporate and Financing	Corporate Total
	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.		
<i>(millions of dollars)</i>								
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 included 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
As of December 31, 2009								
Earnings after income tax	\$ 2,893	\$ 14,214	\$ (153)	\$ 1,934	\$ 769	\$ 1,540	\$(1,917)	\$ 19,280
Earnings of equity companies included above	1,216	5,269	(102)	188	164	906	(498)	7,143
Sales and other operating revenue (1)	3,406	21,355	76,467	173,404	9,962	16,885	21	301,500
Intersegment revenue	6,718	32,982	10,168	39,190	7,185	6,947	284	–
Depreciation and depletion expense	1,768	6,376	687	1,665	400	457	564	11,917
Interest revenue	–	–	–	–	–	–	179	179
Interest expense	38	27	10	18	4	1	450	548
Income taxes	1,451	15,183	(164)	(22)	281	(182)	(1,428)	15,119
Additions to property, plant and equipment	2,973	13,307	1,449	1,447	294	2,553	468	22,491
Investments in equity companies	2,440	8,864	323	1,190	259	2,873	(207)	15,742
Total assets	24,940	102,372	17,493	45,098	7,044	17,117	19,259	233,323
As of December 31, 2008								
Earnings after income tax	\$ 6,243	\$ 29,159	\$ 1,649	\$ 6,502	\$ 724	\$ 2,233	\$(1,290)	\$ 45,220
Earnings of equity companies included above	1,954	7,597	(2)	518	105	1,411	(502)	11,081
Sales and other operating revenue (1)	6,767	32,346	116,701	265,359	14,136	24,252	18	459,579
Intersegment revenue	9,617	55,069	16,225	65,723	9,925	9,749	273	–
Depreciation and depletion expense	1,391	7,266	656	1,672	410	422	562	12,379
Interest revenue	–	–	–	–	–	–	1,400	1,400
Interest expense	47	63	9	28	3	4	519	673
Income taxes	3,451	30,654	728	1,990	177	10	(480)	36,530
Additions to property, plant and equipment	2,699	10,545	1,550	1,552	413	1,987	572	19,318
Investments in equity companies	2,248	7,787	456	1,382	241	2,384	(40)	14,458
Total assets	23,056	83,750	16,328	42,044	6,856	13,300	42,718	228,052

Geographic

Sales and other operating revenue (1)	2010			2009			2008			
	<i>(millions of dollars)</i>									
United States	\$ 115,906	\$ 89,847	\$ 137,615				United States	\$ 86,021	\$ 37,138	\$ 35,548
Non-U.S.	254,219	211,653	321,964				Non-U.S.	113,527	101,978	85,798
Total	\$370,125	\$301,500	\$459,579				Total	\$ 199,548	\$ 139,116	\$ 121,346

Significant non-U.S. revenue sources include:

Canada	\$ 27,243	\$ 21,151	\$ 33,677
Japan	27,143	22,054	30,126
United Kingdom	24,637	20,293	29,764
Belgium	21,139	16,857	25,399
Germany	14,301	14,839	20,591
Italy	14,132	12,997	17,953
France	13,920	12,042	18,530
Singapore	11,088	8,400	11,059

Significant non-U.S. long-lived assets include:

Canada	\$ 20,879	\$ 15,919	\$ 12,018
Nigeria	11,429	11,046	9,227
Singapore	8,610	7,238	5,113
Angola	8,570	7,320	6,129
Norway	6,988	7,251	5,856
Australia	6,570	4,247	2,857
United Kingdom	6,177	7,609	5,778
Kazakhstan	5,938	4,748	3,535

(1) Sales and other operating revenue includes sales-based taxes of \$28,547 million for 2010, \$25,936 million for 2009 and \$34,508 million for 2008. See note 1, Summary of Accounting Policies.

18. Income, Sales-Based and Other Taxes

	2010			2009			2008		
	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total
	<i>(millions of dollars)</i>								
Income taxes									
Federal and non-U.S.									
Current	\$1,224	\$21,093	\$22,317	\$ (838)	\$ 15,830	\$ 14,992	\$ 3,005	\$31,377	\$ 34,382
Deferred – net	49	(1,191)	(1,142)	650	(665)	(15)	168	1,289	1,457
U.S. tax on non-U.S. operations	46	–	46	32	–	32	230	–	230
Total federal and non-U.S.	1,319	19,902	21,221	(156)	15,165	15,009	3,403	32,666	36,069
State	340	–	340	110	–	110	461	–	461
Total income taxes	1,659	19,902	21,561	(46)	15,165	15,119	3,864	32,666	36,530
Sales-based taxes	6,182	22,365	28,547	6,271	19,665	25,936	6,646	27,862	34,508
All other taxes and duties									
Other taxes and duties	776	35,342	36,118	581	34,238	34,819	1,663	40,056	41,719
Included in production and manufacturing expenses	1,001	1,237	2,238	699	1,318	2,017	915	1,720	2,635
Included in SG&A expenses	201	570	771	197	538	735	209	660	869
Total other taxes and duties	1,978	37,149	39,127	1,477	36,094	37,571	2,787	42,436	45,223
Total	\$9,819	\$79,416	\$89,235	\$ 7,702	\$ 70,924	\$ 78,626	\$13,297	\$102,964	\$116,261

All other taxes and duties include taxes reported in production and manufacturing and selling, general and administrative (SG&A) expenses. The above provisions for deferred income taxes include a net charge of \$175 million in 2010 and net credits of \$9 million in 2009 and \$300 million in 2008 for the effect of changes in tax laws and rates.

Income taxes (charged)/credited directly to equity were:

	2010	2009	2008
	<i>(millions of dollars)</i>		
Cumulative foreign exchange translation adjustment	\$ (42)	\$ (247)	\$ 360
Postretirement benefits reserves adjustment:			
Net actuarial loss/(gain)	553	(94)	3,361
Amortization of actuarial loss/(gain)	(609)	(649)	(317)
Prior service cost	92	20	4
Amortization of prior service cost	(45)	(43)	(51)
Foreign exchange rate changes	44	175	(274)
Total postretirement benefits reserves adjustment	35	(591)	2,723
Other components of equity	246	140	315

The reconciliation between income tax expense and a theoretical U.S. tax computed by applying a rate of 35 percent for 2010, 2009 and 2008 is as follows:

	2010	2009	2008
	<i>(millions of dollars)</i>		
Income before income taxes			
United States	\$ 7,711	\$ 2,576	\$10,152
Non-U.S.	45,248	32,201	73,245
Total	\$52,959	\$34,777	\$83,397
Theoretical tax	\$18,536	\$12,172	\$29,189
Effect of equity method of accounting	(3,737)	(2,500)	(3,878)
Non-U.S. taxes in excess of theoretical U.S. tax	7,293	5,948	10,188
U.S. tax on non-U.S. operations	46	32	230
State taxes, net of federal tax benefit	221	72	300
Other U.S.	(798)	(605)	501
Total income tax expense	\$21,561	\$15,119	\$36,530
<u>Effective tax rate calculation</u>			
Income taxes	\$21,561	\$15,119	\$36,530
ExxonMobil share of equity company income taxes	4,058	2,489	4,001
Total income taxes	25,619	17,608	40,531
Net income including noncontrolling interests	31,398	19,658	46,867
Total income before taxes	\$57,017	\$37,266	\$87,398
Effective income tax rate	45%	47%	46%

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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:	2010	2009
	<i>(millions of dollars)</i>	
Property, plant and equipment	\$ 42,657	\$ 29,931
Other liabilities	4,278	4,102
Total deferred tax liabilities	<u>\$ 46,935</u>	<u>\$ 34,033</u>
Pension and other postretirement benefits	\$ (5,634)	\$ (5,442)
Asset retirement obligations	(4,461)	(3,978)
Tax loss carryforwards	(3,243)	(3,693)
Other assets	(6,070)	(4,700)
Total deferred tax assets	<u>\$ (19,408)</u>	<u>\$ (17,813)</u>
Asset valuation allowances	1,183	1,495
Net deferred tax liabilities	<u>\$ 28,710</u>	<u>\$ 17,715</u>

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	2010	2009
	<i>(millions of dollars)</i>	
Other current assets	\$ (3,359)	\$ (3,322)
Other assets, including intangibles, net	(3,527)	(2,263)
Accounts payable and accrued liabilities	446	152
Deferred income tax liabilities	35,150	23,148
Net deferred tax liabilities	<u>\$28,710</u>	<u>\$17,715</u>

The Corporation had \$35 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 20 percent or decrease by up to 5 percent in the next 12 months. 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	2010	2009	2008
	<i>(millions of dollars)</i>		
Balance at January 1	\$ 4,725	\$ 4,976	\$ 5,232
Additions based on current year's tax positions	830	547	656
Additions for prior years' tax positions	620	262	294
Reductions for prior years' tax positions	(505)	(594)	(328)
Reductions due to lapse of the statute of limitations	(534)	–	(27)
Settlements with tax authorities	(999)	(592)	(681)
Foreign exchange effects/other	11	126	(170)
Balance at December 31	<u>\$ 4,148</u>	<u>\$ 4,725</u>	<u>\$ 4,976</u>

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 2010, 2009 and 2008 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 - 2010
Angola	2007 - 2010
Australia	2000 - 2010
Canada	1994 - 2010
Equatorial Guinea	2005 - 2010
Germany	1999 - 2010
Japan	2003 - 2010
Malaysia	2004 - 2010
Nigeria	1998 - 2010
Norway	2000 - 2010
United Kingdom	2004 - 2010
United States:	1991 - 1996
	1998 - 2000
	2004 - 2010

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

In 2010, the Corporation's resolution of certain tax positions with tax jurisdictions resulted in a decrease in the total amount of unrecognized tax benefits and the related interest payable. For 2010, net interest expense was a credit of \$39 million, reflecting the effect of credits from the net favorable resolution of these prior year tax positions. The Corporation incurred approximately \$135 million and \$137 million in interest expense on income tax reserves in 2009 and 2008, respectively. The related interest payable balances were \$636 million and \$771 million at December 31, 2010, and 2009, respectively.

19. Acquisition of XTO Energy Inc.

Description of the Transaction. On June 25, 2010, ExxonMobil acquired XTO Energy Inc. (XTO) by merging a wholly-owned subsidiary of ExxonMobil with and into XTO (the “merger”), with XTO continuing as the surviving corporation and wholly-owned subsidiary of ExxonMobil. XTO is involved in the exploration for, production of, and transportation and sale of crude oil and natural gas. XTO’s asset base, technical capabilities and operating expertise, together with ExxonMobil’s extensive research and development expertise, project management and operational skills, global scale and financial capacity, should enable effective development of additional supplies of unconventional oil and gas resources.

At the effective time of the merger, each share of XTO common stock was converted into the right to receive 0.7098 shares of common stock of ExxonMobil (the “Exchange Ratio”), with cash being paid in lieu of any fractional shares of ExxonMobil stock. Also at the effective time, each outstanding option to purchase XTO common stock was converted into an option to purchase a number of shares of ExxonMobil stock based on the Exchange Ratio, and each outstanding restricted stock award and performance stock award of XTO was converted into a restricted stock award or performance stock award, as applicable, of ExxonMobil stock based on the Exchange Ratio.

The components of the consideration transferred follow:

	<i>(millions of dollars)</i>
Consideration attributable to stock issued (1) (2)	\$ 24,480
Consideration attributable to converted stock options (2)	179
Total consideration transferred	<u>\$ 24,659</u>

(1) The fair value of the Corporation’s common stock on the acquisition date was \$59.10 per share based on the closing value on the NYSE. The Corporation issued 416 million shares of stock previously held in treasury. The treasury stock issued, based on the average cost, was valued at \$21,139 million. The excess of the fair value of the consideration transferred over the cost of treasury stock issued was \$3,520 million and was included in common stock without par value.

(2) The portion of the fair value of XTO converted stock-based awards attributable to pre-merger employee service was part of consideration. The remaining fair value of the awards will be recognized in future periods over the requisite service period.

Recording of Assets Acquired and Liabilities Assumed. The transaction was accounted for using the acquisition method of accounting, which requires, among other things, that assets acquired and liabilities assumed be recognized at their fair values as of the acquisition date.

The following table summarizes the assets acquired and liabilities assumed:

	<i>(millions of dollars)</i>
Cash and cash equivalents	\$ 47
Notes and accounts receivable	925
Inventories	170
Other current assets (1)	911
Investments, advances and long-term receivables	52
Property, plant and equipment (2)	47,300
Identifiable intangible assets (3)	493
Goodwill (4)	39
Other assets (1)	75
Total assets acquired	<u>\$50,012</u>
Notes and loans payable (5)	\$ 1,026
Accounts payable and accrued liabilities (1) (6)	1,788
Income taxes payable	(199)
Long-term debt (5)	10,574
Postretirement benefits reserves	65
Deferred income tax liabilities (6)	11,204
Other long-term obligations	895
Total liabilities assumed	<u>\$25,353</u>
Net assets acquired	<u>\$24,659</u>

(1) Derivatives were measured using Level 1 inputs for derivatives that are traded directly on the NYMEX and Level 2 inputs for 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.

(2) Property, plant and equipment were measured primarily using an income approach. The fair value measurements of the oil and gas assets were based, in part, on significant inputs not observable in the market and thus represent a Level 3 measurement. The significant inputs included XTO resources, assumed future production profiles, commodity prices (mainly based on observable market inputs), risk adjusted discount rate of 7.0 percent, inflation of 2.0 percent and assumptions on the timing and amount of future development and operating costs. The property, plant and equipment additions were segmented to the Upstream business, with substantially all of the assets in the United States.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

- (3) Identifiable intangible assets and other assets were measured using a combination of an income approach and a market approach (Level 3). Identifiable intangible assets will be amortized over 20 years.
- (4) Goodwill was the excess of the consideration transferred over the net assets recognized and represents the future economic benefits arising from other assets acquired that could not be individually identified and separately recognized. Goodwill was recognized in the Upstream reporting unit. Goodwill is not amortized and is not deductible for tax purposes.
- (5) Long-term debt was recognized mainly at market rates at closing (Level 1).
- (6) Deferred income taxes reflect the temporary differences between the amount of assets and liabilities recognized for financial reporting purposes and such amounts recognized for tax purposes.

XTO Results and Pro Forma Impact of Merger. The following table presents revenues and earnings for XTO for the periods presented:

	Acquisition Date Through December 31, 2010 <i>(millions of dollars)</i>
Revenues	\$ 4,448
Upstream earnings	\$ 262

Transaction-related costs were expensed as incurred. The Corporation recognized \$18 million in transaction costs related to the merger in 2010.

The following table presents unaudited pro forma information for the Corporation as if the merger of XTO had occurred at the beginning of each year presented:

	2010	2009
	<i>(millions of dollars, except per share amounts)</i>	
Revenues	\$ 373,273	\$ 307,456
Net income attributable to ExxonMobil	\$ 30,668	\$ 19,672
Earnings per common share	\$ 6.03	\$ 3.75
Earnings per common share – assuming dilution	\$ 6.01	\$ 3.74

The historical financial information was adjusted to give effect to the pro forma events that were directly attributable to the merger and factually supportable. The unaudited pro forma consolidated results are not necessarily indicative of what the consolidated results of operations actually would have been had the merger been completed on January 1, 2010, or on January 1, 2009. In addition, the unaudited pro forma consolidated results do not purport to project the future results of operations of the combined company. The unaudited pro forma consolidated

results reflect pro forma adjustments for the elimination of deferred gains and losses recognized in earnings for derivatives outstanding at the beginning of the year presented, depreciation expense related to the fair value adjustment to property, plant and equipment acquired, additional amortization expense related to the fair value of identifiable intangible assets acquired, capitalization of interest expense and applicable income tax impacts.

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 \$249 million in 2010,

\$536 million in 2009, and \$3,834 million in 2008. Oil sands mining operations were in the excluded amounts for 2008. However, beginning in 2009, oil sands mining operations are included in the results of operations in accordance with revised Securities and Exchange Commission and Financial Accounting Standards Board rules. The amounts included for oil sands mining operations in the results of operations for 2009 are shown in footnote 1 on page F-64.

Results of Operations – Consolidated Subsidiaries	United States	Canada/ South America	Europe	Africa	Asia	Australia/ Oceania	Total
	<i>(millions of dollars)</i>						
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
	<u>\$12,404</u>	<u>\$7,050</u>	<u>\$13,175</u>	<u>\$17,522</u>	<u>\$10,609</u>	<u>\$1,819</u>	<u>\$62,579</u>
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	<u>\$ 2,696</u>	<u>\$2,158</u>	<u>\$ 2,323</u>	<u>\$ 4,330</u>	<u>\$ 2,650</u>	<u>\$ 616</u>	<u>\$14,773</u>
 <u>Results of Operations – Equity Companies</u>							
2010 – Revenue							
Sales to third parties	\$ 1,012	\$ –	\$ 5,050	\$ –	\$12,682	\$ –	\$18,744
Transfers	867	–	68	–	3,817	–	4,752
	<u>\$ 1,879</u>	<u>\$ –</u>	<u>\$ 5,118</u>	<u>\$ –</u>	<u>\$16,499</u>	<u>\$ –</u>	<u>\$23,496</u>
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	<u>\$ 1,205</u>	<u>\$ –</u>	<u>\$ 1,287</u>	<u>\$ –</u>	<u>\$ 6,583</u>	<u>\$ –</u>	<u>\$ 9,075</u>
Total results of operations	<u>\$ 3,901</u>	<u>\$2,158</u>	<u>\$ 3,610</u>	<u>\$ 4,330</u>	<u>\$ 9,233</u>	<u>\$ 616</u>	<u>\$23,848</u>

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

Results of Operations – Consolidated Subsidiaries	United States	Canada/ South America ⁽¹⁾	Europe	Africa	Asia	Australia/ Oceania	Total
<i>(millions of dollars)</i>							
2009 – Revenue							
Sales to third parties	\$ 1,859	\$1,345	\$ 5,900	\$ 3,012	\$ 2,637	\$ 586	\$15,339
Transfers	5,652	4,538	5,977	11,868	5,433	1,066	34,534
	\$ 7,511	\$5,883	\$11,877	\$14,880	\$ 8,070	\$1,652	\$49,873
Production costs excluding taxes	2,255	2,428	2,675	2,027	1,247	386	11,018
Exploration expenses	219	339	375	662	393	33	2,021
Depreciation and depletion	1,670	948	2,078	2,293	816	195	8,000
Taxes other than income	730	78	593	1,343	991	252	3,987
Related income tax	1,127	597	4,277	4,667	2,822	237	13,727
Results of producing activities for consolidated subsidiaries	\$ 1,510	\$1,493	\$ 1,879	\$ 3,888	\$ 1,801	\$ 549	\$11,120
Results of Operations – Equity Companies							
2009 – Revenue							
Sales to third parties	\$ 818	\$ –	\$ 4,889	\$ –	\$ 6,148	\$ –	\$11,855
Transfers	686	–	53	–	2,960	–	3,699
	\$ 1,504	\$ –	\$ 4,942	\$ –	\$ 9,108	\$ –	\$15,554
Production costs excluding taxes	481	–	248	–	251	–	980
Exploration expenses	1	–	12	–	–	–	13
Depreciation and depletion	163	–	168	–	366	–	697
Taxes other than income	37	–	2,233	–	2,120	–	4,390
Related income tax	–	–	902	–	3,121	–	4,023
Results of producing activities for equity companies	\$ 822	\$ –	\$ 1,379	\$ –	\$ 3,250	\$ –	\$ 5,451
Total results of operations	\$ 2,332	\$1,493	\$ 3,258	\$ 3,888	\$ 5,051	\$ 549	\$16,571
Results of Operations							
2008 – Revenue							
Sales to third parties	\$ 3,980	\$4,591	\$11,239	\$ 2,284	\$ 4,294	\$ 808	\$27,196
Transfers	8,525	3,518	10,859	18,361	9,417	1,692	52,372
	\$12,505	\$8,109	\$22,098	\$20,645	\$13,711	\$2,500	\$79,568
Production costs excluding taxes	2,143	1,686	2,623	1,603	1,100	332	9,487
Exploration expenses	189	232	180	439	292	109	1,441
Depreciation and depletion	1,303	906	2,510	2,471	965	179	8,334
Taxes other than income	1,983	58	971	1,815	2,333	665	7,825
Related income tax	3,191	1,501	10,715	8,119	5,357	399	29,282
Results of producing activities for consolidated subsidiaries	\$ 3,696	\$3,726	\$ 5,099	\$ 6,198	\$ 3,664	\$ 816	\$23,199
Proportional interest in results of producing activities of equity companies	\$ 1,885	\$ –	\$ 1,918	\$ –	\$ 4,566	\$ –	\$ 8,369

(1) The impact of including synthetic oil reserves and bitumen mining operations in the results of operations for 2009 was \$1,447 million in revenue and \$279 million in earnings. Cold Lake bitumen operations had no net impact as they had already been included in the results of operations in previous years as an oil and gas operation.

Oil and Gas Exploration and Production Costs

The amounts shown for net capitalized costs of consolidated subsidiaries are \$4,729 million less at year-end 2010 and \$2,910 million less at year-end 2009 than the amounts reported as investments in property, plant and equipment for the Upstream in note 8. 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 2010 and 2009 in accordance with revised Financial Accounting Standards Board rules.

Capitalized Costs – Consolidated Subsidiaries	United States	Canada/ South America	Europe	Africa	Asia	Australia/ Oceania	Total
<i>(millions of dollars)</i>							
As of December 31, 2010							
Property (acreage) costs – Proved	\$ 8,031	\$ 4,166	\$ 199	\$ 929	\$ 1,451	\$ 905	\$ 15,681
– Unproved	24,697	1,260	75	418	229	211	26,890
Total property costs	\$32,728	\$ 5,426	\$ 274	\$ 1,347	\$ 1,680	\$ 1,116	\$ 42,571
Producing assets	60,231	22,115	43,592	28,354	22,264	5,842	182,398
Incomplete construction	4,029	8,109	1,126	9,180	7,658	2,543	32,645
Total capitalized costs	\$96,988	\$35,650	\$44,992	\$38,881	\$31,602	\$9,501	\$257,614
Accumulated depreciation and depletion	29,199	17,561	33,484	16,318	13,412	4,217	114,191
Net capitalized costs for consolidated subsidiaries	\$67,789	\$ 18,089	\$ 11,508	\$ 22,563	\$ 18,190	\$ 5,284	\$ 143,423
Capitalized Costs – Equity Companies							
As of December 31, 2010							
Property (acreage) costs – Proved	\$ 76	\$ –	\$ 8	\$ –	\$ –	\$ –	\$ 84
– Unproved	2	–	–	–	–	–	2
Total property costs	\$ 78	\$ –	\$ 8	\$ –	\$ –	\$ –	\$ 86
Producing assets	3,446	–	5,197	–	7,845	–	16,488
Incomplete construction	116	–	384	–	214	–	714
Total capitalized costs	\$ 3,640	\$ –	\$ 5,589	\$ –	\$ 8,059	\$ –	\$ 17,288
Accumulated depreciation and depletion	1,418	–	4,252	–	2,484	–	8,154
Net capitalized costs for equity companies	\$ 2,222	\$ –	\$ 1,337	\$ –	\$ 5,575	\$ –	\$ 9,134
Capitalized Costs – Consolidated Subsidiaries							
As of December 31, 2009							
Property (acreage) costs – Proved	\$ 3,225	\$ 3,940	\$ 204	\$ 927	\$ 1,257	\$ 816	\$ 10,369
– Unproved	1,233	1,117	52	416	237	198	3,253
Total property costs	\$ 4,458	\$ 5,057	\$ 256	\$ 1,343	\$ 1,494	\$ 1,014	\$ 13,622
Producing assets	40,435	20,357	43,913	26,621	18,806	5,168	155,300
Incomplete construction	3,315	3,701	999	6,872	8,380	1,216	24,483
Total capitalized costs	\$48,208	\$29,115	\$45,168	\$34,836	\$28,680	\$7,398	\$193,405
Accumulated depreciation and depletion	29,934	15,707	32,236	13,919	12,527	3,673	107,996
Net capitalized costs for consolidated subsidiaries	\$18,274	\$ 13,408	\$ 12,932	\$ 20,917	\$ 16,153	\$ 3,725	\$ 85,409
Capitalized Costs – Equity Companies							
As of December 31, 2009							
Property (acreage) costs – Proved	\$ 76	\$ –	\$ 8	\$ –	\$ –	\$ –	\$ 84
– Unproved	1	–	–	–	–	–	1
Total property costs	\$ 77	\$ –	\$ 8	\$ –	\$ –	\$ –	\$ 85
Producing assets	3,224	–	5,574	–	6,869	–	15,667
Incomplete construction	128	–	336	–	885	–	1,349
Total capitalized costs	\$ 3,429	\$ –	\$ 5,918	\$ –	\$ 7,754	\$ –	\$ 17,101
Accumulated depreciation and depletion	1,340	–	4,493	–	2,048	–	7,881
Net capitalized costs for equity companies	\$ 2,089	\$ –	\$ 1,425	\$ –	\$ 5,706	\$ –	\$ 9,220

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

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 2010 were \$70,812 million, up \$50,305 million from 2009, due

primarily to the acquisition of XTO Energy Inc. 2009 costs were \$20,507 million, up \$4,691 million from 2008, due primarily to higher exploration and development costs as well as the inclusion in 2009 of costs incurred related to oil sands mining operations (see footnote 1 below). Total equity company costs incurred in 2010 were \$914 million, down \$105 million from 2009, due primarily to lower development costs.

 Costs incurred in property acquisitions,
 exploration and development activities –
 Consolidated Subsidiaries

	United States	Canada/ South America ⁽¹⁾	Europe	Africa	Asia	Australia/ Oceania	Total
	<i>(millions of dollars)</i>						
During 2010							
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	<u>\$53,779</u>	<u>\$ 5,420</u>	<u>\$ 1,841</u>	<u>\$4,846</u>	<u>\$3,552</u>	<u>\$1,374</u>	<u>\$70,812</u>

 Costs incurred in property acquisitions,
 exploration and development activities –
 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	<u>\$ 328</u>	<u>\$ –</u>	<u>\$ 281</u>	<u>\$ –</u>	<u>\$ 305</u>	<u>\$ –</u>	<u>\$ 914</u>

 Costs incurred in property acquisitions,
 exploration and development activities –
 Consolidated Subsidiaries

During 2009							
Property acquisition costs – Proved	\$ 17	\$ –	\$ –	\$ 600	\$ 59	\$ –	\$ 676
– Unproved	188	353	1	5	62	–	609
Exploration costs	548	498	471	880	529	130	3,056
Development costs	2,482	2,394	3,384	4,596	2,542	768	16,166
Total costs incurred for consolidated subsidiaries	<u>\$ 3,235</u>	<u>\$ 3,245</u>	<u>\$ 3,856</u>	<u>\$6,081</u>	<u>\$3,192</u>	<u>\$ 898</u>	<u>\$20,507</u>

 Costs incurred in property acquisitions,
 exploration and development activities –
 Equity Companies

Property acquisition costs – Proved	\$ –	\$ –	\$ –	\$ –	\$ –	\$ –	\$ –
– Unproved	–	–	–	–	–	–	–
Exploration costs	1	–	54	–	–	–	55
Development costs	305	–	255	–	404	–	964
Total costs incurred for equity companies	<u>\$ 306</u>	<u>\$ –</u>	<u>\$ 309</u>	<u>\$ –</u>	<u>\$ 404</u>	<u>\$ –</u>	<u>\$ 1,019</u>

During 2008

Property acquisition costs – Proved	\$ –	\$ 1	\$ –	\$ –	\$ 60	\$ –	\$ 61
– Unproved	281	125	25	82	13	76	602
Exploration costs	453	306	389	686	307	100	2,241
Development costs	2,255	907	1,634	4,783	2,890	443	12,912
Total costs incurred for consolidated subsidiaries	<u>\$ 2,989</u>	<u>\$ 1,339</u>	<u>\$ 2,048</u>	<u>\$5,551</u>	<u>\$3,270</u>	<u>\$ 619</u>	<u>\$15,816</u>
Proportional interest of costs incurred of equity companies	<u>\$ 484</u>	<u>\$ –</u>	<u>\$ 241</u>	<u>\$ –</u>	<u>\$ 494</u>	<u>\$ –</u>	<u>\$ 1,219</u>

(1) Costs incurred on synthetic oil reserves and bitumen mining operations in 2009 were \$1,872 million, primarily on unproved property acquisition and development costs. Cold Lake bitumen operations had been included in costs incurred in previous years as an oil and gas operation.

Oil and Gas Reserves

The following information describes changes during the years and balances of proved oil and gas reserves at year-end 2008, 2009 and 2010.

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 for 2009 and 2010 as well as the reserves change categories for 2009 and 2010 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. The year-end reserves volumes for 2008 as well as the reserves change categories for 2008 shown in the following tables were calculated using December 31 prices and costs. 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 2010 that were associated with production sharing contract arrangements was 16 percent of liquids, 10 percent of natural gas and 13 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.

Major changes between 2009 year-end proved reserves and 2010 year-end proved reserves included the initial booking of the properties acquired in the XTO Energy Inc. transaction.

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

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

	Crude Oil and Natural Gas Liquids						Total	Bitumen	Synthetic Oil	Total
	United States	Canada/ S. Amer. ⁽¹⁾	Europe	Africa	Asia	Australia/ Oceania		Canada/ S. Amer. ⁽²⁾	Canada/ S. Amer. ⁽³⁾	
	<i>(millions of barrels)</i>									
Net proved developed and undeveloped reserves of consolidated subsidiaries										
January 1, 2008	1,851	939	673	2,058	2,010	213	7,744			
Revisions	(104)	(70)	39	253	351	2	471			
Improved recovery	–	–	–	–	–	–	–			
Purchases	–	–	–	–	–	–	–			
Sales	(4)	(2)	(28)	–	(52)	–	(86)			
Extensions/discoveries	5	29	4	65	28	40	171			
Production	(104)	(84)	(155)	(239)	(118)	(24)	(724)			
December 31, 2008	1,644	812	533	2,137	2,219	231	7,576			
Proportional interest in proved reserves of equity companies										
End of year 2008	327	–	27	–	2,205	–	2,559			
Net proved developed and undeveloped reserves of consolidated subsidiaries										
January 1, 2009	1,644	812	533	2,137	2,219	231	7,576	–	–	7,576
Revisions	82	(610) ⁽⁴⁾	93	(33)	(130)	9	(589)	2,099 ⁽⁴⁾	715	2,225
Improved recovery	–	–	–	–	–	–	–	–	–	–
Purchases	–	–	–	–	–	–	–	–	–	–
Sales	(1)	–	(2)	–	–	–	(3)	–	–	(3)
Extensions/discoveries	3	–	–	53	15	71	142	–	–	142
Production	(112)	(30)	(137)	(250)	(105)	(23)	(657)	(44)	(24)	(725)
December 31, 2009	1,616	172	487	1,907	1,999	288	6,469	2,055	691	9,215
Proportional interest in proved reserves of equity companies										
January 1, 2009	327	–	27	–	2,205	–	2,559	–	–	2,559
Revisions	56	–	5	–	(54)	–	7	–	–	7
Improved recovery	–	–	–	–	15	–	15	–	–	15
Purchases	–	–	–	–	–	–	–	–	–	–
Sales	–	–	–	–	–	–	–	–	–	–
Extensions/discoveries	–	–	–	–	–	–	–	–	–	–
Production	(27)	–	(2)	–	(116)	–	(145)	–	–	(145)
December 31, 2009	356	–	30	–	2,050	–	2,436	–	–	2,436
Total liquids proved reserves at December 31, 2009	1,972	172	517	1,907	4,049	288	8,905	2,055	691	11,651

(1) Includes total proved reserves attributable to Imperial Oil Limited of 694 million barrels in 2008, 63 million barrels in 2009 and 57 million barrels in 2010, as well as proved developed reserves of 488 million barrels in 2008, 62 million barrels in 2009 and 56 million barrels in 2010, and in addition, proved undeveloped reserves of 1 million barrels in 2009 and 1 million barrels in 2010, in which there is a 30.4 percent noncontrolling interest.

(2) Includes total proved reserves attributable to Imperial Oil Limited of 1,661 million barrels in 2009 and 1,715 million barrels in 2010, as well as proved developed reserves of 468 million barrels in 2009 and 519 million barrels in 2010, and in addition, proved undeveloped reserves of 1,193 million barrels in 2009 and 1,196 million barrels in 2010, in which there is a 30.4 percent noncontrolling interest.

(3) Includes total proved reserves attributable to Imperial Oil Limited of 691 million barrels in 2009 and 681 million barrels in 2010, as well as proved developed reserves of 691 million barrels in 2009 and 681 million barrels in 2010, in which there is a 30.4 percent noncontrolling interest.

(4) Total proved reserves of 630 million barrels at December 31, 2008, associated with the Cold Lake field in Canada are reported as bitumen reserves under the amended Securities and Exchange Commission's Rule 4-10 of Regulation S-X.

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

	Crude Oil and Natural Gas Liquids						Bitumen	Synthetic Oil	Total	
	United States	Canada/ S. Amer. ⁽¹⁾	Europe	Africa	Asia	Australia/ Oceania	Canada/ S. Amer. ⁽²⁾	Canada/ S. Amer. ⁽³⁾		
	<i>(millions of barrels)</i>									
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

(See footnotes on previous page)

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

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

	Crude Oil and Natural Gas Liquids							Bitumen	Synthetic Oil	Total
	United States	Canada/ S. Amer. ⁽¹⁾	Europe	Africa	Asia	Australia/ Oceania	Total	Canada/ S. Amer. ⁽²⁾	Canada/ S. Amer. ⁽³⁾	
	<i>(millions of barrels)</i>									
Proved developed reserves, as of January 1, 2008										
Consolidated subsidiaries	1,327	682	518	1,202	1,033	185	4,947			
Equity companies	299	–	8	–	1,181	–	1,488			
Proved developed reserves, as of December 31, 2008										
Consolidated subsidiaries	1,257	580	410	1,284	1,097	165	4,793			
Equity companies	264	–	9	–	1,417	–	1,690			
Proved developed reserves, as of December 31, 2009										
Consolidated subsidiaries	1,211	152	376	1,122	1,268	153	4,282	468	691	5,441
Equity companies	279	–	10	–	1,608	–	1,897	–	–	1,897
Proved undeveloped reserves, as of December 31, 2009										
Consolidated subsidiaries	405	20	111	785	731	135	2,187	1,587	–	3,774
Equity companies	77	–	20	–	442	–	539	–	–	539
Total liquids proved reserves at December 31, 2009	<u>1,972</u>	<u>172</u>	<u>517</u>	<u>1,907</u>	<u>4,049</u>	<u>288</u>	<u>8,905</u>	<u>2,055</u>	<u>691</u>	<u>11,651</u>
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	<u>2,303</u>	<u>163</u>	<u>454</u>	<u>1,799</u>	<u>3,896</u>	<u>275</u>	<u>8,890</u>	<u>2,102</u>	<u>681</u>	<u>11,673</u>

(See footnotes on page F-68)

Natural Gas and Oil-Equivalent Proved Reserves

	Natural Gas							Oil-Equivalent
	United States	Canada/S. Amer. ⁽¹⁾	Europe	Africa	Asia	Australia/Oceania	Total	Total All Products ⁽²⁾
	<i>(billions of cubic feet)</i>							<i>(millions of oil-equivalent barrels)</i>
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2008	13,172	1,559	6,512	1,006	8,604	1,757	32,610	
Revisions	(1,056)	88	(193)	(55)	1,855	(4)	635	
Improved recovery	—	—	—	—	—	—	—	
Purchases	—	—	—	—	—	—	—	
Sales	(12)	(17)	(8)	—	(24)	—	(61)	
Extensions/discoveries	229	16	10	12	7	412	686	
Production	(555)	(263)	(876)	(45)	(585)	(144)	(2,468)	
December 31, 2008	11,778	1,383	5,445	918	9,857	2,021	31,402	
Proportional interest in proved reserves of equity companies								
End of year 2008	112	—	11,839	—	22,526	—	34,477	
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2009	11,778	1,383	5,445	918	9,857	2,021	31,402	12,810
Revisions	320	248	79	45	(980)	40	(248)	2,183
Improved recovery	—	—	—	—	—	—	—	—
Purchases	8	—	—	—	—	—	8	1
Sales	(10)	(2)	(1)	—	—	—	(13)	(5)
Extensions/discoveries	158	—	—	—	11	5,507	5,676	1,088
Production	(566)	(261)	(800)	(43)	(585)	(128)	(2,383)	(1,122)
December 31, 2009	11,688	1,368	4,723	920	8,303	7,440	34,442	14,955
Proportional interest in proved reserves of equity companies								
January 1, 2009	112	—	11,839	—	22,526	—	34,477	8,305
Revisions	8	—	186	—	189	—	383	71
Improved recovery	—	—	—	—	—	—	—	15
Purchases	—	—	—	—	—	—	—	—
Sales	—	—	—	—	—	—	—	—
Extensions/discoveries	—	—	18	—	—	—	18	3
Production	(6)	—	(593)	—	(714)	—	(1,313)	(364)
December 31, 2009	114	—	11,450	—	22,001	—	33,565	8,030
Total proved reserves at December 31, 2009								
	11,802	1,368	16,173	920	30,304	7,440	68,007	22,985

(1) Includes total proved reserves attributable to Imperial Oil Limited of 593 billion cubic feet in 2008, 590 billion cubic feet in 2009 and 576 billion cubic feet in 2010, as well as proved developed reserves of 513 billion cubic feet in 2008, 526 billion cubic feet in 2009 and 507 billion cubic feet in 2010, and in addition, proved undeveloped reserves of 64 billion cubic feet in 2009 and 69 billion cubic feet in 2010, 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.

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

Natural Gas and Oil-Equivalent Proved Reserves (continued)

	Natural Gas						Oil-Equivalent	
	United States	Canada/ S. Amer. ⁽¹⁾	Europe	Africa	Asia	Australia/ Oceania	Total	Total All Products ⁽²⁾
	<i>(billions of cubic feet)</i>						<i>(millions of oil-equivalent barrels)</i>	
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

(See footnotes on previous page)

Natural Gas and Oil-Equivalent Proved Reserves (continued)

	Natural Gas							Oil-Equivalent
	United States	Canada/ S. Amer. ⁽¹⁾	Europe	Africa	Asia	Australia/ Oceania	Total	Total All Products ⁽²⁾ <i>(millions of oil-equivalent barrels)</i>
	<i>(billions of cubic feet)</i>							
Proved developed reserves, as of January 1, 2008								
Consolidated subsidiaries	8,373	1,303	5,064	773	4,562	1,403	21,478	
Equity companies	104	–	9,679	–	9,459	–	19,242	
Proved developed reserves, as of December 31, 2008								
Consolidated subsidiaries	7,835	1,148	4,426	738	5,257	1,346	20,750	
Equity companies	96	–	9,284	–	12,619	–	21,999	
Proved developed reserves, as of December 31, 2009								
Consolidated subsidiaries	7,492	1,200	3,920	739	7,407	1,262	22,020	9,111
Equity companies	90	–	8,862	–	17,799	–	26,751	6,356
Proved undeveloped reserves, as of December 31, 2009								
Consolidated subsidiaries	4,196	168	803	181	896	6,178	12,422	5,844
Equity companies	24	–	2,588	–	4,202	–	6,814	1,674
Total proved reserves at December 31, 2009	11,802	1,368	16,173	920	30,304	7,440	68,007	22,985
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

(See footnotes on page F-71)

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

Standardized Measure of Discounted Future Cash Flows

As required by the Financial Accounting Standards Board, the standardized measure of discounted future net cash flows was computed through 2008 by applying year-end prices, costs and legislated tax rates and a discount factor of 10 percent to net proved reserves. Beginning in 2009, 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 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
<i>(millions of dollars)</i>							
Consolidated Subsidiaries							
As of December 31, 2008							
Future cash inflows							
from sales of oil and gas	\$104,441	\$22,952	\$ 71,879	\$ 74,426	\$ 80,314	\$ 10,437	\$364,449
Future production costs	44,230	13,113	19,485	24,403	22,826	5,334	129,391
Future development costs	19,828	6,156	8,765	16,064	11,496	2,134	64,443
Future income tax expenses	17,857	961	24,729	16,870	26,218	917	87,552
Future net cash flows	\$ 22,526	\$ 2,722	\$ 18,900	\$ 17,089	\$ 19,774	\$ 2,052	\$ 83,063
Effect of discounting net cash flows at 10%	13,107	(239)	7,602	8,052	13,031	941	42,494
Discounted future net cash flows	\$ 9,419	\$ 2,961	\$ 11,298	\$ 9,037	\$ 6,743	\$ 1,111	\$ 40,569
Proportional interest in standardized measure of discounted future net cash flows related to proved reserves of equity companies							
	\$ 2,354	\$ –	\$ 12,507	\$ –	\$ 30,588	\$ –	\$ 45,449
Consolidated Subsidiaries							
As of December 31, 2009							
Future cash inflows							
from sales of oil and gas	\$112,408	\$147,597	\$54,074	\$110,475	\$121,110	\$39,127	\$584,791
Future production costs	47,660	62,241	16,412	28,679	29,769	12,571	197,332
Future development costs	15,544	25,738	12,565	15,155	10,256	11,655	90,913
Future income tax expenses	22,058	14,572	16,065	32,784	46,286	4,739	136,504
Future net cash flows	\$ 27,146	\$ 45,046	\$ 9,032	\$ 33,857	\$ 34,799	\$ 10,162	\$ 160,042
Effect of discounting net cash flows at 10%	15,563	31,980	2,569	14,192	20,698	9,194	94,196
Discounted future net cash flows	\$ 11,583	\$ 13,066	\$ 6,463	\$ 19,665	\$ 14,101	\$ 968	\$ 65,846
Equity Companies							
As of December 31, 2009							
Future cash inflows							
from sales of oil and gas	\$ 19,705	\$ –	\$94,401	\$ –	\$180,253	\$ –	\$294,359
Future production costs	5,847	–	60,869	–	54,493	–	121,209
Future development costs	2,862	–	3,220	–	2,759	–	8,841
Future income tax expenses	–	–	12,003	–	44,733	–	56,736
Future net cash flows	\$ 10,996	\$ –	\$ 18,309	\$ –	\$ 78,268	\$ –	\$ 107,573
Effect of discounting net cash flows at 10%	6,332	–	9,845	–	42,086	–	58,263
Discounted future net cash flows	\$ 4,664	\$ –	\$ 8,464	\$ –	\$ 36,182	\$ –	\$ 49,310
Total consolidated and equity interests in standardized measure of discounted future net cash flows							
	\$ 16,247	\$ 13,066	\$ 14,927	\$ 19,665	\$ 50,283	\$ 968	\$ 115,156

(1) Includes discounted future net cash flows attributable to Imperial Oil Limited of \$1,033 million in 2008 and \$10,088 million in 2009, 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
	<i>(millions of dollars)</i>						
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.

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

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

Consolidated Subsidiaries	2008
	<i>(millions of dollars)</i>
Discounted future net cash flows as of December 31, 2007	\$126,173
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	(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	(62,685)
Development costs incurred during the year	11,649
Net change in prices, lifting and development costs	(178,960)
Revisions of previous reserves estimates	7,652
Accretion of discount	21,463
Net change in income taxes	115,580
Total change in the standardized measure during the year for consolidated subsidiaries	<u>\$ (85,604)</u>
Discounted future net cash flows as of December 31, 2008	<u>\$ 40,569</u>

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

Consolidated and Equity Interests	2009		
	Consolidated Subsidiaries	Share of Equity Method Investees	Total Consolidated and Equity Interests
	<i>(millions of dollars)</i>		
Discounted future net cash flows as of December 31, 2008	\$ 40,569	\$ 45,449	\$ 86,018
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	2,138	280	2,418
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	(35,384)	(10,288)	(45,672)
Development costs incurred during the year	13,549	1,017	14,566
Net change in prices, lifting and development costs	51,627	9,245	60,872
Revisions of previous reserves estimates	8,805	858	9,663
Accretion of discount	6,943	5,214	12,157
Net change in income taxes	(22,401)	(2,465)	(24,866)
Total change in the standardized measure during the year	<u>\$ 25,277</u>	<u>\$ 3,861</u>	<u>\$ 29,138⁽¹⁾⁽²⁾</u>
Discounted future net cash flows as of December 31, 2009	<u>\$ 65,846</u>	<u>\$ 49,310</u>	<u>\$ 115,156</u>

(1) Discounted future net cash flows associated with synthetic oil reserves and bitumen mining operations in 2009 were \$5,268 million. Cold Lake bitumen operations had been included in discounted future net cash flows in previous years as an oil and gas operation.

(2) The estimated impact of adopting the reliable technology definition and changing from year-end price to first-day-of-the-month average prices in the Securities and Exchange Commission's Rule 4-10 of Regulation S-X was de minimis on discounted future net cash flows for consolidated and equity subsidiaries in 2009.

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

Consolidated and Equity Interests (continued)

	2010		
	Consolidated Subsidiaries	Share of Equity Method Investees	Total Consolidated and Equity Interests
	<i>(millions of dollars)</i>		
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	<u>\$ 114,238</u>	<u>\$ 61,284</u>	<u>\$ 175,522</u>

OPERATING SUMMARY (unaudited)

	2010	2009	2008	2007	2006
	<i>(thousands of barrels daily)</i>				
Production of crude oil, natural gas liquids, synthetic oil and bitumen					
Net production					
United States	408	384	367	392	414
Canada/South America	263	267	292	324	354
Europe	335	379	428	480	520
Africa	628	685	652	717	781
Asia	730	607	599	629	535
Australia/Oceania	58	65	67	74	77
Worldwide	2,422	2,387	2,405	2,616	2,681
	<i>(millions of cubic feet daily)</i>				
Natural gas production available for sale					
Net production					
United States	2,596	1,275	1,246	1,468	1,625
Canada/South America	569	643	640	808	935
Europe	3,836	3,689	3,949	3,810	4,086
Africa	14	19	32	26	–
Asia	4,801	3,332	2,870	2,883	2,358
Australia/Oceania	332	315	358	389	330
Worldwide	12,148	9,273	9,095	9,384	9,334
	<i>(thousands of oil-equivalent barrels daily)</i>				
Oil-equivalent production (1)	4,447	3,932	3,921	4,180	4,237
	<i>(thousands of barrels daily)</i>				
Refinery throughput					
United States	1,753	1,767	1,702	1,746	1,760
Canada	444	413	446	442	442
Europe	1,538	1,548	1,601	1,642	1,672
Asia Pacific	1,249	1,328	1,352	1,416	1,434
Other Non-U.S.	269	294	315	325	295
Worldwide	5,253	5,350	5,416	5,571	5,603
	<i>(thousands of metric tons)</i>				
Petroleum product sales (2)					
United States	2,511	2,523	2,540	2,717	2,729
Canada	450	413	444	461	473
Europe	1,611	1,625	1,712	1,773	1,813
Asia Pacific and other Eastern Hemisphere	1,562	1,588	1,646	1,701	1,763
Latin America	280	279	419	447	469
Worldwide	6,414	6,428	6,761	7,099	7,247
Gasoline, naphthas	2,611	2,573	2,654	2,850	2,866
Heating oils, kerosene, diesel oils	1,951	2,013	2,096	2,094	2,191
Aviation fuels	476	536	607	641	651
Heavy fuels	603	598	636	715	682
Specialty petroleum products	773	708	768	799	857
Worldwide	6,414	6,428	6,761	7,099	7,247
	<i>(thousands of metric tons)</i>				
Chemical prime product sales					
United States	9,815	9,649	9,526	10,855	10,703
Non-U.S.	16,076	15,176	15,456	16,625	16,647
Worldwide	25,891	24,825	24,982	27,480	27,350

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.

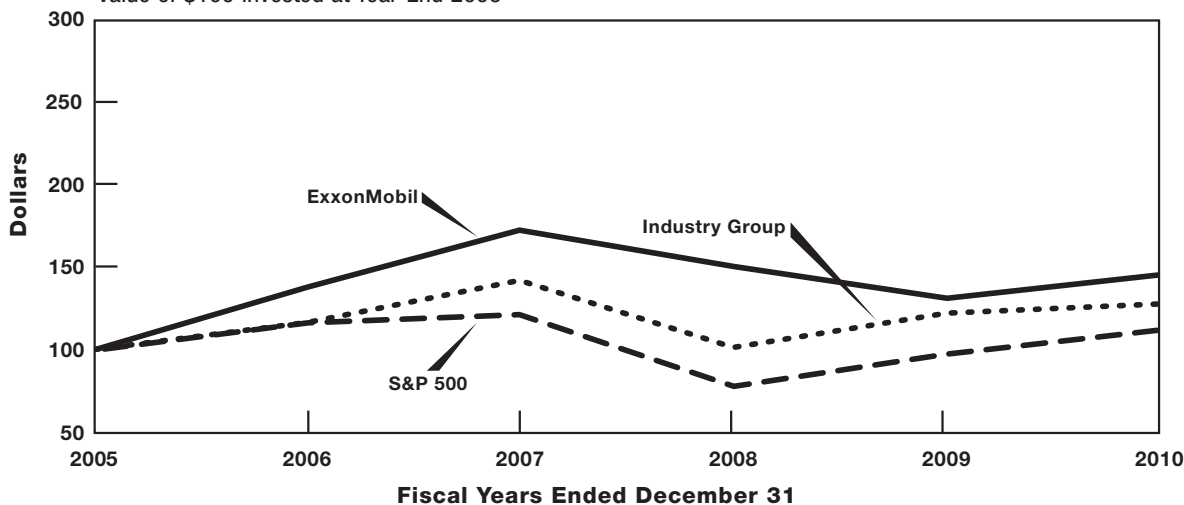
STOCK PERFORMANCE GRAPHS (unaudited)

Annual total returns to ExxonMobil shareholders were negative 13 percent in 2008, negative 13 percent in 2009, and 10 percent in 2010, and have averaged nearly 8 percent per year over the past five years. Total returns mean share price increase plus dividends paid, with dividends reinvested. The graphs below show the relative investment perfor-

mance 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

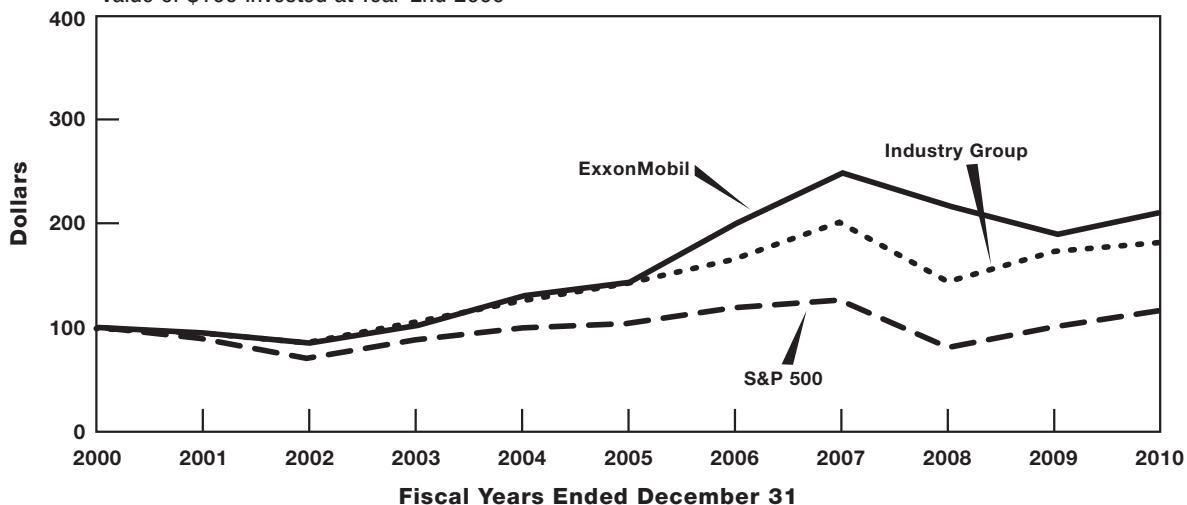
Value of \$100 Invested at Year-End 2005



ExxonMobil	100	139	173	150	131	145
S&P 500	100	116	122	77	97	112
Industry Group	100	117	142	101	121	128

TEN-YEAR CUMULATIVE TOTAL RETURNS

Value of \$100 Invested at Year-End 2000



ExxonMobil	100	92	84	101	130	145	202	251	218	190	210
S&P 500	100	88	69	88	98	103	119	126	79	100	115
Industry Group	100	94	84	105	126	142	167	202	143	173	182

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