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2012

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2012

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number 1-2256

EXXON MOBIL CORPORATION

(Exact name of registrant as specified in its charter)

NEW JERSEY	**13-5409005**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification Number)**

5959 LAS COLINAS BOULEVARD, IRVING, TEXAS 75039-2298

(Address of principal executive offices) (Zip Code)

(972) 444-1000

(Registrant's telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, without par value (4,480,449,635 shares outstanding at January 31, 2013)	**New York Stock Exchange**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act o during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File requ be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was requ submit and post such files). Yes ☑ No ☐

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

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

Large accelerated filer ☑ Accelerated filer ☐

Non-accelerated filer ☐ Smaller reporting company ☐

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

The aggregate market value of the voting stock held by non-affiliates of the registrant on June 30, 2012, the last business day of the registrant's most re completed second fiscal quarter, based on the closing price on that date of $85.57 on the New York Stock Exchange composite tape, was in exc $394 billion.

Documents Incorporated by Reference: Proxy Statement for the 2013 Annual Meeting of Shareholders (Part III)

EXXON MOBIL CORPORATION
FORM 10-K
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2012

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PART I

PART I

ITEM 1. BUSINESS

Exxon Mobil Corporation was incorporated in the State of New Jersey in 1882. Divisions and affiliated companies of ExxonMobil operate or r products in the United States and most other countries of the world. Their principal business is energy, involving exploration for, and producti crude oil and natural gas, manufacture of petroleum products and transportation and sale of crude oil, natural gas and petroleum pro ExxonMobil is a major manufacturer and marketer of commodity petrochemicals, including olefins, aromatics, polyethylene and polypro plastics and a wide variety of specialty products. ExxonMobil also has interests in electric power generation facilities. Affiliates of Exxon conduct extensive research programs in support of these businesses.

Exxon Mobil Corporation has several divisions and hundreds of affiliates, many with names that include *ExxonMobil*, *Exxon*, *Esso, Mo* *XTO*. For convenience and simplicity, in this report the terms *ExxonMobil*, *Exxon*, *Esso, Mobil* and *XTO*, as well as terms like *Corpor* *Company*, *our*, *we* and *its*, are sometimes used as abbreviated references to specific affiliates or groups of affiliates. The precise meaning de on the context in question.

Throughout ExxonMobil's businesses, new and ongoing measures are taken to prevent and minimize the impact of our operations on air, and ground. These include a significant investment in refining infrastructure and technology to manufacture clean fuels as well as proje monitor and reduce nitrogen oxide, sulfur oxide, and greenhouse gas emissions and expenditures for asset retirement obligations. Using defi and guidelines established by the American Petroleum Institute, ExxonMobil's 2012 worldwide environmental expenditures for all such preve and remediation steps, including ExxonMobil's share of equity company expenditures, were $5.5 billion, of which $3.5 billion were inclu expenses with the remainder in capital expenditures. The total cost for such activities is expected to have a modest increase in 2013 and 2014 capital expenditures approximately 45 percent of the total).

The energy and petrochemical industries are highly competitive. There is competition within the industries and also with other indust supplying the energy, fuel and chemical needs of both industrial and individual consumers. The Corporation competes with other firms in the s purchase of needed goods and services in many national and international markets and employs all methods of competition which are lawf appropriate for such purposes.

Operating data and industry segment information for the Corporation are contained in the Financial Section of this report under the follo "Quarterly Information", "Note 18: Disclosures about Segments and Related Information" and "Operating Summary". Information on oil ar reserves is contained in the "Oil and Gas Reserves" part of the "Supplemental Information on Oil and Gas Exploration and Production Acti portion of the Financial Section of this report.

ExxonMobil has a long-standing commitment to the development of proprietary technology. We have a wide array of research programs de to meet the needs identified in each of our business segments. Information on Company-sponsored research and development spending is con in "Note 3: Miscellaneous Financial Information" of the Financial Section of this report. ExxonMobil held approximately 11 thousand active p worldwide at the end of 2012. For technology licensed to third parties, revenues totaled approximately $176 million in 2012. Although technol an important contributor to the overall operations and results of our Company, the profitability of each business segment is not dependent c individual patent, trade secret, trademark, license, franchise or concession.

The number of regular employees was 76.9 thousand, 82.1 thousand and 83.6 thousand at years ended 2012, 2011 and 2010, respectively. R employees are defined as active executive, management, professional, technical and wage employees who work full time or part time f Corporation and are covered by the Corporation's benefit plans and programs. Regular employees do not include employees of the com operated retail sites (CORS). The number of CORS employees was 11.1 thousand, 17.0 thousand and 20.1 thousand at years ended 2012, 201 2010, respectively.

Information concerning the source and availability of raw materials used in the Corporation's business, the extent of seasonality in the bus the possibility of renegotiation of profits or termination of contracts at the election of governments and risks attendant to foreign operations m found in "Item 1A–Risk Factors" and "Item 2–Properties" in this report.

ExxonMobil maintains a website at exxonmobil.com. Our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on 8-K and any amendments to those reports filed or furnished pursuant to Section 13(a) of the Securities Exchange Act of 1934 are made ava through our website as soon as reasonably practical after we electronically file or furnish the reports to the Securities and Exchange Commi Also available on the Corporation's website are the Company's Corporate Governance Guidelines and Code of Ethics and Business Conduct, a as the charters of the audit, compensation and nominating committees of the Board of Directors. Information on our website is not incorporate this report.

ITEM 1A. RISK FACTORS

ExxonMobil's financial and operating results are subject to a variety of risks inherent in the global oil, gas, and petrochemical businesses. Ma these risk factors are not within the Company's control and could adversely affect our business, our financial and operating results or our fin condition. These risk factors include:

Supply and Demand

The oil, gas, and petrochemical businesses are fundamentally commodity businesses. This means ExxonMobil's operations and earnings m significantly affected by changes in oil, gas and petrochemical prices and by changes in margins on refined products. Oil, gas, petrochemica product prices and margins in turn depend on local, regional and global events or conditions that affect supply and demand for the re commodity.

Economic conditions. The demand for energy and petrochemicals correlates closely with general economic growth rates. The occurren recessions or other periods of low or negative economic growth will typically have a direct adverse impact on our results. Other factors that general economic conditions in the world or in a major region, such as changes in population growth rates, periods of civil unrest, gover austerity programs, or currency exchange rate fluctuations, can also impact the demand for energy and petrochemicals. Sovereign debt downg defaults, inability to access debt markets due to credit or legal constraints, liquidity crises, the breakup or restructuring of fiscal, moneta political systems such as the European Union, and other events or conditions that impair the functioning of financial markets and institution pose risks to ExxonMobil, including risks to the safety of our financial assets and to the ability of our partners and customers to fulfill commitments to ExxonMobil.

Other demand-related factors. Other factors that may affect the demand for oil, gas and petrochemicals, and therefore impact our results, in technological improvements in energy efficiency; seasonal weather patterns, which affect the demand for energy associated with heatin cooling; increased competitiveness of alternative energy sources that have so far generally not been competitive with oil and gas without the b of government subsidies or mandates; and changes in technology or consumer preferences that alter fuel choices, such as toward alternative vehicles.

Other supply-related factors. Commodity prices and margins also vary depending on a number of factors affecting supply. For example, inc supply from the development of new oil and gas supply sources and technologies to enhance recovery from existing sources tend to r commodity prices to the extent such supply increases are not offset by commensurate growth in demand. Similarly, increases in industry refin petrochemical manufacturing capacity tend to reduce margins on the affected products. World oil, gas, and petrochemical supply levels can a affected by factors that reduce available supplies, such as adherence by member countries to OPEC production quotas and the occurrence of hostile actions, natural disasters, disruptions in competitors' operations, or unexpected unavailability of distribution channels that may d supplies. Technological change can also alter the relative costs for competitors to find, produce, and refine oil and gas and to manuf petrochemicals.

Other market factors. ExxonMobil's business results are also exposed to potential negative impacts due to changes in interest rates, inf currency exchange rates, and other local or regional market conditions. We generally do not use financial instruments to hedge market exposur

Government and Political Factors

ExxonMobil's results can be adversely affected by political or regulatory developments affecting our operations.

Access limitations. A number of countries limit access to their oil and gas resources, or may place resources off-limits from development altog Restrictions on foreign investment in the oil and gas sector tend to increase in times of high commodity prices, when national government have less need of outside sources of private capital. Many countries also restrict the import or export of certain products based on point of origi

Restrictions on doing business. As a U.S. company, ExxonMobil is subject to laws prohibiting U.S. companies from doing business in c countries, or restricting the kind of business that may be conducted. Such restrictions may provide a competitive advantage to our nor competitors unless their own home countries impose comparable restrictions.

Lack of legal certainty. Some countries in which we do business lack well-developed legal systems, or have not yet adopted clear regu frameworks for oil and gas development. Lack of legal certainty exposes our operations to increased risk of adverse or unpredictable actic government officials, and also makes it more difficult for us to enforce our contracts. In some cases these risks can be partially offset by agree to arbitrate disputes in an international forum, but the adequacy of this remedy may still depend on the local legal system to enforce an award.

Regulatory and litigation risks. Even in countries with well-developed legal systems where ExxonMobil does business, we remain expo: changes in law (including changes that result from international treaties and accords) that could adversely affect our results, such as:

- increases in taxes or government royalty rates (including retroactive claims);
- price controls;
- changes in environmental regulations or other laws that increase our cost of compliance or reduce or delay available bu opportunities (including changes in laws related to offshore drilling operations, water use, or hydraulic fracturing);
- adoption of regulations mandating the use of alternative fuels or uncompetitive fuel components;
- adoption of government payment transparency regulations that could require us to disclose competitively sensitive comm information, or that could cause us to violate the non-disclosure laws of other countries; and
- government actions to cancel contracts, re-denominate the official currency, renounce or default on obligations, renegotiate unilaterally, or expropriate assets.

Legal remedies available to compensate us for expropriation or other takings may be inadequate.

We also may be adversely affected by the outcome of litigation or other legal proceedings, especially in countries such as the United Sta which very large and unpredictable punitive damage awards may occur.

Security concerns. Successful operation of particular facilities or projects may be disrupted by civil unrest, acts of sabotage or terrorism, and local security concerns. Such concerns may require us to incur greater costs for security or to shut down operations for a period of time.

Climate change and greenhouse gas restrictions. Due to concern over the risk of climate change, a number of countries have adopted, considering the adoption of, regulatory frameworks to reduce greenhouse gas emissions. These include adoption of cap and trade regimes, c taxes, restrictive permitting, increased efficiency standards, and incentives or mandates for renewable energy. These requirements could mal products more expensive, lengthen project implementation times, and reduce demand for hydrocarbons, as well as shift hydrocarbon demand t relatively lower-carbon sources such as natural gas. Current and pending greenhouse gas regulations may also increase our compliance costs, sı for monitoring or sequestering emissions.

Government sponsorship of alternative energy. Many governments are providing tax advantages and other subsidies to support alternative e sources or are mandating the use of specific fuels or technologies. Governments are also promoting research into new technologies to reduce th and increase the scalability of alternative energy sources. We are conducting our own research efforts into alternative energy, such as th sponsorship of the Global Climate and Energy Project at Stanford University and research into fuel-producing algae. Our future results may d in part on the success of our research efforts and on our ability to adapt and apply the strengths of our current business model to providing the e products of the future in a cost-competitive manner. See “Management Effectiveness” below.

Management Effectiveness

In addition to external economic and political factors, our future business results also depend on our ability to manage successfully those facto: are at least in part within our control. The extent to which we manage these factors will impact our performance relative to competition. For pı in which we are not the operator, we depend on the management effectiveness of one or more co-venturers whom we do not control.

Exploration and development program. Our ability to maintain and grow our oil and gas production depends on the success of our explo and development efforts. Among other factors, we must continuously improve our ability to identify the most promising resource prospec apply our project management expertise to bring discovered resources on line on schedule and within budget.

Project management. The success of ExxonMobil’s Upstream, Downstream, and Chemical businesses depends on complex, long-term, c intensive projects. These projects in turn require a high degree of project management expertise to maximize efficiency. Specific factors th affect the performance of major projects include our ability to: negotiate successfully with joint venturers, partners, governments, sup customers, or others; model and optimize reservoir performance; develop markets for project outputs, whether through long-term contracts development of effective spot markets; manage changes in operating conditions and costs, including costs of third party equipment or service as drilling rigs and shipping; prevent, to the extent possible, and respond effectively to unforeseen technical difficulties that could delay p startup or cause unscheduled project downtime; and influence the performance of project operators where ExxonMobil does not perform that rı

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

Operational efficiency. An important component of ExxonMobil’s competitive performance, especially given the commodity-based nature of of our businesses, is our ability to operate efficiently, including our ability to manage expenses and improve production yields on an ongoing This requires continuous management focus, including technology improvements, cost control, productivity enhancements, regular reapprai our asset portfolio, and the recruitment, development and retention of high caliber employees.

Research and development. To maintain our competitive position, especially in light of the technological nature of our businesses and the ne continuous efficiency improvement, ExxonMobil’s research and development organizations must be successful and able to adapt to a cha market and policy environment.

Safety, business controls, and environmental risk management. Our results depend on management’s ability to minimize the inherent risks gas, and petrochemical operations, to control effectively our business activities and to minimize the potential for human error. We apply riɡ management systems and continuous focus to workplace safety and to avoiding spills or other adverse environmental events. For example, we to minimize spills through a combined program of effective operations integrity management, ongoing upgrades, key equipment replacement comprehensive inspection and surveillance. Similarly, we are implementing cost-effective new technologies and adopting new operating practi reduce air emissions, not only in response to government requirements but also to address community priorities. We also maintain a disci framework of internal controls and apply a controls management system for monitoring compliance with this framework. Substantial liabiliti other adverse impacts could result if our management systems and controls do not function as intended. The ability to insure against such r limited by the capacity of the applicable insurance markets, which may not be sufficient.

Business risks also include the risk of cybersecurity breaches. If our systems for protecting against cybersecurity risks prove not to be suff ExxonMobil could be adversely affected such as by having its business systems compromised, its proprietary information altered, lost or stol its business operations disrupted.

Preparedness. Our operations may be disrupted by severe weather events, natural disasters, human error, and similar events. For exa hurricanes may damage our offshore production facilities or coastal refining and petrochemical plants in vulnerable areas. Our ability to mitiga adverse impacts of these events depends in part upon the effectiveness of our rigorous disaster preparedness and response planning, as w business continuity planning.

Projections, estimates and descriptions of ExxonMobil’s plans and objectives included or incorporated in Items 1, 1A, 2, 7 and 7A of this are forward-looking statements. Actual future results, including project completion dates, production rates, capital expenditures, costs and bu plans could differ materially due to, among other things, the factors discussed above and elsewhere in this report.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Information with regard to oil and gas producing activities follows:

1. Disclosure of Reserves

A. Summary of Oil and Gas Reserves at Year-End 2012

The table below summarizes the oil-equivalent proved reserves in each geographic area and by product type for consolidated subsidiaries and companies. The Corporation has reported proved reserves on the basis of the average of the first-day-of-the-month price for each month duri last 12-month period. Gas is converted to an oil-equivalent basis at six million cubic feet per one thousand barrels. No major discovery or favorable or adverse event has occurred since December 31, 2012, that would cause a significant change in the estimated proved reserves as date.

	Crude Oil	Natural Gas Liquids	Bitumen	Synthetic Oil	Natural Gas	Oil-Equiva Basis
	(million bbls)	*(million bbls)*	*(million bbls)*	*(million bbls)*	*(billion cubic ft)*	*(million b*
Proved Reserves						
Developed						
Consolidated Subsidiaries						
United States	1,228	261	-	-	14,471	
Canada/South America *(1)*	108	16	543	599	670	
Europe	230	38	-	-	2,526	
Africa	817	187	-	-	814	
Asia	922	158	-	-	5,150	
Australia/Oceania	63	53	-	-	1,012	
Total Consolidated	3,368	713	543	599	24,643	
Equity Companies						
United States	258	6	-	-	126	
Europe	28	-	-	-	7,057	
Asia	1,009	414	-	-	18,431	
Total Equity Company	1,295	420	-	-	25,614	
Total Developed	4,663	1,133	543	599	50,257	1
Undeveloped						
Consolidated Subsidiaries						
United States	677	244	-	-	11,744	
Canada/South America *(1)*	162	1	3,017	-	255	
Europe	59	18	-	-	723	
Africa	476	21	-	-	115	
Asia	682	-	-	-	695	
Australia/Oceania	100	34	-	-	6,556	
Total Consolidated	2,156	318	3,017	-	20,088	
Equity Companies						
United States	82	2	-	-	29	
Europe	-	-	-	-	2,478	
Asia	251	52	-	-	1,239	
Total Equity Company	333	54	-	-	3,746	
Total Undeveloped	2,489	372	3,017	-	23,834	
Total Proved Reserves	7,152	1,505	3,560	599	74,091	2

(1) South America includes proved developed reserves of 0.4 million barrels of crude oil and natural gas liquids and 57 billion cubic feet of n gas and proved undeveloped reserves of 0.6 million barrels of crude oil and natural gas liquids and 65 billion cubic feet of natural gas.

In the preceding reserves information, consolidated subsidiary and equity company reserves are reported separately. However, the Corpo operates its business with the same view of equity company reserves as it has for reserves from consolidated subsidiaries.

The Corporation's overall volume capacity outlook, based on projects coming on stream as anticipated, is for production capacity to grov the period 2013-2017. However, actual volumes will vary from year to year due to the timing of individual project start-ups, operational ou reservoir performance, regulatory changes, asset sales, weather events, price effects on production sharing contracts and other factors as descri Item 1A—Risk Factors of this report.

The estimation of proved reserves, which is based on the requirement of reasonable certainty, is an ongoing process based on rigorous tec evaluations, commercial and market assessments and detailed analysis of well and reservoir information such as flow rates and reservoir pr declines. Furthermore, the Corporation only records proved reserves for projects which have received significant funding commitmer management made toward the development of the reserves. Although the Corporation is reasonably certain that proved reserves will be proc the timing and amount recovered can be affected by a number of factors including completion of development projects, reservoir perforn regulatory approvals and significant changes in projections of long-term oil and gas price levels.

B. Technologies Used in Establishing Proved Reserves Additions in 2012

Additions to ExxonMobil's proved reserves in 2012 were based on estimates generated through the integration of available and appro geological, engineering and production data, utilizing well-established technologies that have been demonstrated in the field to yield repeatab consistent results.

Data used in these integrated assessments included information obtained directly from the subsurface via wellbores, such as well logs, res core samples, fluid samples, static and dynamic pressure information, production test data, and surveillance and performance information. Th utilized also included subsurface information obtained through indirect measurements including high-quality 2-D and 3-D seismic data, cali with available well control information. The tools used to interpret the data included proprietary seismic processing software, proprietary res modeling and simulation software, and commercially available data analysis packages.

In some circumstances, where appropriate analog reservoirs were available, reservoir parameters from these analogs were used to increa quality of and confidence in the reserves estimates.

C. Qualifications of Reserves Technical Oversight Group and Internal Controls over Proved Reserves

ExxonMobil has a dedicated Global Reserves group that provides technical oversight and is separate from the operating organization. Pr responsibilities of this group include oversight of the reserves estimation process for compliance with Securities and Exchange Commission rules and regulations, review of annual changes in reserves estimates, and the reporting of ExxonMobil's proved reserves. This group also mai the official company reserves estimates for ExxonMobil's proved reserves of crude and natural gas liquids, bitumen, synthetic oil and natural g addition, the group provides training to personnel involved in the reserves estimation and reporting process within ExxonMobil and its affiliate group is managed by and staffed with individuals that have an average of more than 20 years of technical experience in the petroleum inc including expertise in the classification and categorization of reserves under the SEC guidelines. This group includes individuals who hold adv degrees in either Engineering or Geology. Several members of the group hold professional registrations in their field of expertise, and severa served on the Oil and Gas Reserves Committee of the Society of Petroleum Engineers.

The Global Reserves group maintains a central database containing the official company global reserves estimates. Appropriate co including limitations on database access and update capabilities, are in place to ensure data integrity within this central database. An annual r of the system's controls is performed by internal audit. Key components of the reserves estimation process include technical evaluations and an of well and field performance and a rigorous peer review. No changes may be made to the reserves estimates in the central database, incl additions of any new initial reserves estimates or subsequent revisions, unless these changes have been thoroughly reviewed and evaluated b authorized personnel within the operating organization. In addition, changes to reserves estimates that exceed certain thresholds require f review and approval of the appropriate level of management within the operating organization before the changes may be made in the c database. Endorsement by the Global Reserves group for all proved reserves changes is a mandatory component of this review process. Af changes are made, reviews are held with senior management for final endorsement.

2. Proved Undeveloped Reserves

At year-end 2012, approximately 9.9 billion oil-equivalent barrels (GOEB) of ExxonMobil's proved reserves were classified as proved undeve This represents 39 percent of the 25.2 GOEB reported in proved reserves. This compares to the 8.8 GOEB of proved undeveloped reserves re at the end of 2011. The net increase is primarily due to the addition of new projects in

Canada and the United States. During the year, ExxonMobil conducted development activities in over 100 fields that resulted in the trans approximately 0.5 GOEB from proved undeveloped to proved developed reserves by year-end. The largest transfers were related to complet drilling and the initiation of production activities in unconventional fields in the United States and on new pad locations in the Cold Lake fi Canada.

One of ExxonMobil's requirements for reporting proved reserves is that management has made significant funding commitments towa development of the reserves. ExxonMobil has a disciplined investment strategy and many major fields require long lead-time in order developed. Development projects typically take two to four years from the time of first recording of proved reserves to the start of product these reserves. However, the development time for large and complex projects can exceed five years. During 2012, discoveries and exte related to new projects added approximately 1.3 GOEB of proved undeveloped reserves. The largest of these additions were related to pl drilling in the United States. Overall, investments of $24.8 billion were made by the Corporation during 2012 to progress the developm reported proved undeveloped reserves, including $21.7 billion for oil and gas producing activities and an additional $3.1 billion for other non-c gas producing activities such as the construction of support infrastructure and other related facilities that were undertaken to progre development of proved undeveloped reserves. These investments represented 69 percent of the $36.1 billion in total reported Upstream capit exploration expenditures.

Proved undeveloped reserves in Canada, Kazakhstan, the United States, and the Netherlands have remained undeveloped for five years or primarily due to constraints on the capacity of infrastructure and the pace of co-venturer/government funding, as well as the time requi complete development for very large projects. The Corporation is reasonably certain that these proved reserves will be produced; howeve timing and amount recovered can be affected by a number of factors including completion of development projects, reservoir performanc regulatory approvals. Of the proved undeveloped reserves that have been reported for five or more years, 57 percent are contained in four fie Canada, Kazakhstan and the Netherlands. The largest of these is related to the Kearl project in Canada, where construction of the initial develo was completed during 2012 and phased start-up activities were under way. In Kazakhstan, the proved undeveloped reserves are related to the development of the offshore Kashagan field which is included in the North Caspian Production Sharing Agreement and the Tengizchevroi venture which includes a production license in the Tengiz – Korolev field complex. The Tengizchevroil joint venture is producing, and p undeveloped reserves will continue to move to proved developed as approved development phases progress. The fourth field is the Groning field in the Netherlands. Proved undeveloped reserves reported for this field are related to installation of future stages of compression. reserves will move to proved developed when the additional stages of compression are installed to maintain field delivery pressure. The rem of proved undeveloped reserves are contained in over 140 fields in 16 countries.

3. Oil and Gas Production, Production Prices and Production Costs

A. Oil and Gas Production

The table below summarizes production by final product sold and by geographic area for the last three years.

	2012	2011	
	(thousands of barrels daily)		
Crude oil and natural gas liquids production			
Consolidated Subsidiaries			
United States	355	357	
Canada/South America *(1)*	59	65	
Europe	203	265	
Africa	487	508	
Asia	362	383	
Australia/Oceania	50	51	
Total Consolidated Subsidiaries	1,516	1,629	
Equity Companies			
United States	63	66	
Europe	4	5	
Asia	410	425	
Total Equity Companies	477	496	
Total crude oil and natural gas liquids production	1,993	2,125	
Bitumen production			
Consolidated Subsidiaries			
Canada/South America	123	120	
Synthetic oil production			
Consolidated Subsidiaries			
Canada/South America	69	67	
Total liquids production	2,185	2,312	
	(millions of cubic feet daily)		
Natural gas production available for sale			
Consolidated Subsidiaries			
United States	3,819	3,917	
Canada/South America *(1)*	362	412	
Europe	1,446	1,701	
Africa	17	7	
Asia	1,445	1,879	
Australia/Oceania	363	331	
Total Consolidated Subsidiaries	7,452	8,247	
Equity Companies			
United States	3	-	
Europe	1,774	1,747	
Asia	3,093	3,168	
Total Equity Companies	4,870	4,915	
Total natural gas production available for sale	12,322	13,162	1
	(thousands of oil-equivalent barrels daily)		
Oil-equivalent production	4,239	4,506	

(1) *South America includes liquids production for 2012, 2011 and 2010 of one thousand barrels daily for each year and natural gas prod available for sale for 2012, 2011 and 2010 of 38 million, 45 million, and 52 million cubic feet daily, respectively.*

B. Production Prices and Production Costs

The table below summarizes average production prices and average production costs by geographic area and by product type for the last three y

	United States	Canada/ S. America	Europe	Africa	Asia	Australia/ Oceania	T
During 2012				*(dollars per unit)*			
Consolidated Subsidiaries							
Average production prices							
Crude oil and NGL, per barrel	84.51	91.45	104.14	110.11	102.19	93.39	1
Natural gas, per thousand cubic feet	2.15	1.98	8.92	2.77	3.91	4.39	
Bitumen, per barrel	-	58.91	-	-	-	-	
Synthetic oil, per barrel	-	92.77	-	-	-	-	
Average production costs, per oil-equivalent barrel - total	11.14	26.94	15.06	13.35	7.27	12.11	
Average production costs, per barrel - bitumen	-	23.71	-	-	-	-	
Average production costs, per barrel - synthetic oil	-	47.45	-	-	-	-	
Equity Companies							
Average production prices							
Crude oil and NGL, per barrel	103.94	-	104.59	-	101.60	-	1
Natural gas, per thousand cubic feet	3.22	-	9.66	-	9.38	-	
Average production costs, per oil-equivalent barrel - total	20.15	-	3.36	-	1.43	-	
Total							
Average production prices							
Crude oil and NGL, per barrel	87.43	91.45	104.15	110.11	101.88	93.39	1
Natural gas, per thousand cubic feet	2.15	1.98	9.33	2.77	7.64	4.39	
Bitumen, per barrel	-	58.91	-	-	-	-	
Synthetic oil, per barrel	-	92.77	-	-	-	-	
Average production costs, per oil-equivalent barrel - total	11.68	26.94	10.34	13.35	3.74	12.11	
Average production costs, per barrel - bitumen	-	23.71	-	-	-	-	
Average production costs, per barrel - synthetic oil	-	47.45	-	-	-	-	
During 2011							
Consolidated Subsidiaries							
Average production prices							
Crude oil and NGL, per barrel	90.65	97.10	102.20	109.69	98.79	96.28	1
Natural gas, per thousand cubic feet	3.45	3.29	9.32	2.83	3.37	3.98	
Bitumen, per barrel	-	64.65	-	-	-	-	
Synthetic oil, per barrel	-	102.80	-	-	-	-	1
Average production costs, per oil-equivalent barrel - total	11.14	23.58	13.58	14.04	6.58	12.85	
Average production costs, per barrel - bitumen	-	19.80	-	-	-	-	
Average production costs, per barrel - synthetic oil	-	47.68	-	-	-	-	
Equity Companies							
Average production prices							
Crude oil and NGL, per barrel	104.44	-	103.23	-	100.14	-	1
Natural gas, per thousand cubic feet	5.08	-	8.61	-	7.78	-	
Average production costs, per oil-equivalent barrel - total	19.96	-	2.92	-	1.09	-	
Total							
Average production prices							
Crude oil and NGL, per barrel	92.80	97.10	102.22	109.69	99.50	96.28	1
Natural gas, per thousand cubic feet	3.45	3.29	8.96	2.83	6.14	3.98	
Bitumen, per barrel	-	64.65	-	-	-	-	
Synthetic oil, per barrel	-	102.80	-	-	-	-	1
Average production costs, per oil-equivalent barrel - total	11.68	23.58	9.85	14.04	3.41	12.85	
Average production costs, per barrel - bitumen	-	19.80	-	-	-	-	
Average production costs, per barrel - synthetic oil	-	47.68	-	-	-	-	

	United States	Canada/ S. America	Europe	Africa	Asia	Australia/ Oceania	T
During 2010				*(dollars per unit)*			
Consolidated Subsidiaries							
Average production prices							
Crude oil and NGL, per barrel	70.22	69.92	73.37	78.08	72.96	68.91	
Natural gas, per thousand cubic feet	3.92	3.41	6.44	2.15	3.19	3.31	
Bitumen, per barrel	-	56.61	-	-	-	-	
Synthetic oil, per barrel	-	78.42	-	-	-	-	
Average production costs, per oil-equivalent barrel - total	9.92	20.07	11.62	9.63	5.65	11.20	
Average production costs, per barrel - bitumen	-	17.81	-	-	-	-	
Average production costs, per barrel - synthetic oil	-	42.79	-	-	-	-	
Equity Companies							
Average production prices							
Crude oil and NGL, per barrel	74.70	-	74.14	-	72.67	-	
Natural gas, per thousand cubic feet	8.30	-	6.91	-	5.42	-	
Average production costs, per oil-equivalent barrel - total	19.11	-	2.41	-	0.98	-	
Total							
Average production prices							
Crude oil and NGL, per barrel	70.98	69.92	73.38	78.08	72.80	68.91	
Natural gas, per thousand cubic feet	3.92	3.41	6.68	2.15	4.56	3.31	
Bitumen, per barrel	-	56.61	-	-	-	-	
Synthetic oil, per barrel	-	78.42	-	-	-	-	
Average production costs, per oil-equivalent barrel - total	10.67	20.07	8.46	9.63	2.91	11.20	
Average production costs, per barrel - bitumen	-	17.81	-	-	-	-	
Average production costs, per barrel - synthetic oil	-	42.79	-	-	-	-	

Average production prices have been calculated by using sales quantities from the Corporation's own production as the divisor. Average produ costs have been computed by using net production quantities for the divisor. The volumes of crude oil and natural gas liquids (NGL) productio for this computation are shown in the oil and gas production table in section 3.A. The volumes of natural gas used in the calculation a production volumes of natural gas available for sale and are also shown in section 3.A. The natural gas available for sale volumes are differen those shown in the reserves table in the "Oil and Gas Reserves" part of the "Supplemental Information on Oil and Gas Exploration and Produ Activities" portion of the Financial Section of this report due to volumes consumed or flared. Gas is converted to an oil-equivalent basis million cubic feet per one thousand barrels.

4. Drilling and Other Exploratory and Development Activities

A. Number of Net Productive and Dry Wells Drilled

	2012	2011
Net Productive Exploratory Wells Drilled		
Consolidated Subsidiaries		
United States	7	12
Canada/South America	2	6
Europe	1	1
Africa	2	1
Asia	1	2
Australia/Oceania	2	1
Total Consolidated Subsidiaries	15	23
Equity Companies		
United States	-	1
Europe	1	1
Asia	-	-
Total Equity Companies	1	2
Total productive exploratory wells drilled	16	25
Net Dry Exploratory Wells Drilled		
Consolidated Subsidiaries		
United States	2	2
Canada/South America	-	-
Europe	2	4
Africa	-	-
Asia	2	5
Australia/Oceania	1	-
Total Consolidated Subsidiaries	7	11
Equity Companies		
United States	-	-
Europe	1	-
Asia	-	-
Total Equity Companies	1	-
Total dry exploratory wells drilled	8	11

	2012	2011
Net Productive Development Wells Drilled		
Consolidated Subsidiaries		
United States	867	1,069
Canada/South America	73	154
Europe	10	7
Africa	39	44
Asia	28	30
Australia/Oceania	-	-
Total Consolidated Subsidiaries	1,017	1,304
Equity Companies		
United States	282	236
Europe	4	10
Asia	7	4
Total Equity Companies	293	250
Total productive development wells drilled	1,310	1,554
Net Dry Development Wells Drilled		
Consolidated Subsidiaries		
United States	5	14
Canada/South America	-	-
Europe	1	1
Africa	-	-
Asia	2	1
Australia/Oceania	-	-
Total Consolidated Subsidiaries	8	16
Equity Companies		
United States	-	-
Europe	-	-
Asia	-	-
Total Equity Companies	-	-
Total dry development wells drilled	8	16
Total number of net wells drilled	1,342	1,606

B. Exploratory and Development Activities Regarding Oil and Gas Resources Extracted by Mining Technologies

Syncrude Operations. Syncrude is a joint venture established to recover shallow deposits of oil sands using open-pit mining methods to extra crude bitumen, and then upgrade it to produce a high-quality, light (32 degrees API), sweet, synthetic crude oil. Imperial Oil Limited is the ow a 25 percent interest in the joint venture. Exxon Mobil Corporation has a 69.6 percent interest in Imperial Oil Limited. In 2012, the company's of net production of synthetic crude oil was about 69 thousand barrels per day and share of net acreage was about 63 thousand acres Athabasca oil sands deposit.

Kearl Project. The Kearl project is a joint venture established to recover shallow deposits of oil sands using open-pit mining methods to extra crude bitumen. Imperial Oil Limited holds a 70.96 percent interest in the joint venture and ExxonMobil Canada Properties holds the other percent. Exxon Mobil Corporation has a 69.6 percent interest in Imperial Oil Limited and a 100 percent interest in ExxonMobil Canada Prop Kearl is comprised of six oil sands leases covering about 48 thousand acres in the Athabasca oil sands deposit.

The Kearl project is located approximately 40 miles north of Fort McMurray, Alberta, Canada, and is expected to be developed in two p Bitumen will be extracted from oil sands produced from open-pit mining operations, and processed through a bitumen extraction and froth trea plant. The product, a blend of bitumen and diluent, is planned to be shipped via pipelines for distribution to North American markets. Dilu natural gas condensate or other light hydrocarbons added to the crude bitumen to facilitate transportation to market by pipeline. At year-end the construction of the initial development of the Kearl project was complete and phased start-up activities were under way. Construction Kearl Expansion project continued during 2012.

5. Present Activities

A. Wells Drilling

	Year-End 2012		Year-End 2011
	Gross	Net	Gross
Wells Drilling			
Consolidated Subsidiaries			
United States	1,099	503	1,276
Canada/South America	138	118	83
Europe	26	10	26
Africa	33	10	34
Asia	108	61	102
Australia/Oceania	23	6	9
Total Consolidated Subsidiaries	1,427	708	1,530
Equity Companies			
United States	17	4	2
Europe	9	3	13
Asia	19	2	32
Total Equity Companies	45	9	47
Total gross and net wells drilling	1,472	717	1,577

B. Review of Principal Ongoing Activities

UNITED STATES

ExxonMobil's year-end 2012 acreage holdings totaled 15.6 million net acres, of which 2.2 million net acres were offshore. ExxonMobil was in areas onshore and offshore in the lower 48 states and in Alaska.

During 2012, 1,142.7 net exploration and development wells were completed in the inland lower 48 states. Development activities focus the San Joaquin Basin of California, the Woodford Shale of Oklahoma, the Bakken oil play in North Dakota and Montana, the Permian Ba West Texas and New Mexico, the Marcellus Shale of Pennsylvania and West Virginia, the Haynesville Shale of Texas and Louisiana, the B Shale of North Texas, the Fayetteville Shale of Arkansas, and the Freestone Trend of East Texas.

ExxonMobil's net acreage in the Gulf of Mexico at year-end 2012 was 2.1 million acres. A total of 2.6 net exploration and development were completed during the year. Development activities continued on the deepwater Hadrian South project and the non-operated Lucius project

Participation in Alaska production and development continued with a total of 15.0 net development wells completed. The Point Thomson p
was funded by ExxonMobil in 2012.

CANADA / SOUTH AMERICA

Canada

Oil and Gas Operations: ExxonMobil's year-end 2012 acreage holdings totaled 5.2 million net acres, of which 1.5 million net acres were offsh
total of 44.1 net exploration and development wells were completed during the year. The Hebron project, located offshore Newfoundlan
funded in 2012. ExxonMobil entered into an agreement in 2012 to acquire Celtic Exploration Ltd.

In Situ Bitumen Operations: ExxonMobil's year-end 2012 in situ bitumen acreage holdings totaled 0.5 million net onshore acres. A total of 31
development wells were completed during the year. The Cold Lake Nabiye Expansion project was funded in 2012.

Argentina

ExxonMobil’s net acreage totaled 1.0 million onshore acres at year-end 2012, and there was 0.5 net development well completed during the ye

Venezuela

ExxonMobil’s acreage holdings and assets were expropriated in 2007. Refer to the relevant portion of “Note 16: Litigation and Other Continge
of the Financial Section of this report for additional information.

EUROPE

Germany

A total of 4.9 million net onshore acres and 0.1 million net offshore acres were held by ExxonMobil at year-end 2012, with 6.1 net exploratic
development wells completed during the year.

Netherlands

ExxonMobil’s net interest in licenses totaled approximately 1.5 million acres at year-end 2012, of which 1.2 million acres are onshore. A total
net exploration and development wells were completed during the year.

Norway

ExxonMobil's net interest in licenses at year-end 2012 totaled approximately 1.0 million acres, all offshore. A total of 6.2 net exploratio
development wells were completed in 2012.

United Kingdom

ExxonMobil’s net interest in licenses at year-end 2012 totaled approximately 0.4 million acres, all offshore. A total of 0.9 net development
were completed during the year. The offshore Fram project was funded in 2012.

AFRICA

Angola

ExxonMobil’s year-end 2012 acreage holdings totaled 0.4 million net offshore acres and 5.4 net exploration and development wells were com
during the year. On Block 15, Kizomba Satellites Phase 1 started up, and Kizomba Satellites Phase 2 was funded in 2012. On the non-op
Block 17, work continued on the Cravo-Lirio-Orquidea-Violeta project. ExxonMobil sold its interest in the non-operated Block 31 in 2012.

Chad

ExxonMobil’s net year-end 2012 acreage holdings consisted of 46 thousand onshore acres, with 26.8 net development wells completed durin
year.

Equatorial Guinea

ExxonMobil’s acreage totaled 0.1 million net offshore acres at year-end 2012.

Nigeria

ExxonMobil’s net acreage totaled 0.9 million offshore acres at year-end 2012, with 7.8 net exploration and development wells completed duri year. The Satellite Field Development Phase 1 and the deepwater Usan projects started up in 2012.

ASIA

Azerbaijan

At year-end 2012, ExxonMobil’s net acreage totaled 9 thousand offshore acres. A total of 0.4 net development wells were completed during the Work continued on the Chirag Oil project.

Indonesia

At year-end 2012, ExxonMobil had 5.5 million net acres, 3.4 million net acres offshore and 2.1 million net acres onshore. A total of 2 exploration wells were completed during the year. Project work continued on the full field development at Banyu Urip.

Iraq

At year-end 2012, ExxonMobil’s onshore acreage was 0.9 million net acres. A total of 21.6 net development wells were completed at the West Phase I oil field during the year. In 2010, a contract was signed with South Oil Company of the Iraqi Ministry of Oil to redevelop and expa West Qurna Phase I oil field. The term of the contract is 20 years with the right to extend for five years. In 2010 initial field rehabilitation act commenced. Field rehabilitation activities continued during 2012, and across the life of this project will include drilling of new wells, workin of existing wells, optimization and debottlenecking of existing facilities, and the establishment of field offices and camps.

Production sharing contracts were negotiated with the regional government of Kurdistan in 2011, and planning of activities continued 2012.

Kazakhstan

ExxonMobil’s net acreage totaled 0.1 million acres onshore and 0.2 million acres offshore at year-end 2012. A total of 0.2 net development were completed during 2012. Working with our partners, construction of the initial phase of the Kashagan field continued during 2012.

Malaysia

ExxonMobil has interests in production sharing contracts covering 0.4 million net acres offshore at year-end 2012. During the year, a total of exploration and development wells were completed. The Damar project was funded in 2012, and work continued on the Tapis and Telok projec

Qatar

Through our joint ventures with Qatar Petroleum, ExxonMobil’s net acreage totaled 65 thousand acres offshore at year-end 2012. During the total of 1.4 net development wells were completed. ExxonMobil participated in 61.8 million tonnes per year gross liquefied natural gas capa year end. Development activities continued on the Barzan project.

Republic of Yemen

ExxonMobil's net acreage in the Republic of Yemen production sharing areas totaled 10 thousand acres onshore at year-end 2012.

Russia

ExxonMobil’s net acreage holdings at year-end 2012 were 85 thousand acres, all offshore. A total of 0.6 net development wells were com Development activities continued on the Arkutun-Dagi project during 2012.

ExxonMobil and Rosneft signed a Strategic Cooperation Agreement in 2011 to jointly participate in exploration and development activi Russia, the United States and other parts of the world. In 2012 ExxonMobil and Rosneft signed a Pilot Development Agreement to evalua development of tight-oil reserves in western Siberia and signed an agreement to establish a joint Arctic Research Center.

Thailand

ExxonMobil’s net onshore acreage in Thailand concessions totaled 21 thousand acres at year-end 2012.

United Arab Emirates

ExxonMobil's net acreage in the Abu Dhabi offshore Upper Zakum oil concession was 81 thousand acres at year-end 2012, with 0 development wells completed during the year.

ExxonMobil's net acreage in the Abu Dhabi onshore oil concession was 0.5 million acres at year-end 2012, of which 0.4 million acr onshore. During the year, a total of 5.6 net development wells were completed.

AUSTRALIA / OCEANIA

Australia

ExxonMobil's year-end 2012 acreage holdings totaled 1.8 million net acres, of which 1.6 million net acres were offshore. During the year, a t 1.1 net exploration wells were completed.

Project construction activity for the co-venturer operated Gorgon liquefied natural gas (LNG) project progressed in 2012. The project cons a subsea infrastructure for offshore production and transportation of the gas, and a 15.6 million tonnes per year LNG facility and a 280 million feet per day domestic gas plant located on Barrow Island, Western Australia.

Papua New Guinea

A total of 0.9 million net onshore acres were held by ExxonMobil at year-end 2012, with 1.3 net exploration and development wells com during the year. Work continued on the Papua New Guinea (PNG) LNG project. The project consists of conditioning facilities in the southern Highlands, a 6.9 million tonnes per year LNG facility near Port Moresby and approximately 434 miles of onshore and offshore pipelines.

WORLDWIDE EXPLORATION

At year-end 2012, exploration activities were under way in several areas in which ExxonMobil has no established production operations and th not included above. A total of 35.3 million net acres were held at year-end 2012, and 2.1 net exploration wells were completed during the y these countries.

6. Delivery Commitments

ExxonMobil sells crude oil and natural gas from its producing operations under a variety of contractual obligations, some of which may speci delivery of a fixed and determinable quantity for periods longer than one year. ExxonMobil also enters into natural gas sales contracts whe source of the natural gas used to fulfill the contract can be a combination of our own production and the spot market. Worldwide, v contractually committed to deliver approximately 3,000 billion cubic feet of natural gas for the period from 2013 through 2015. We expect to the majority of these delivery commitments with production from our proved developed reserves. Any remaining commitments will be fulfille production from our proved undeveloped reserves and spot market purchases as necessary.

7. Oil and Gas Properties, Wells, Operations and Acreage

A. Gross and Net Productive Wells

	Year-End 2012				Year-End 2011			
	Oil		Gas		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	N
Gross and Net Productive Wells								
Consolidated Subsidiaries								
United States	22,690	8,155	39,720	24,197	23,891	8,219	41,453	2
Canada/South America	5,283	4,825	3,485	1,319	5,347	4,870	3,299	
Europe	1,255	346	622	258	1,340	357	647	
Africa	1,231	491	11	4	1,167	465	12	
Asia	792	370	204	150	783	399	224	
Australia/Oceania	676	152	40	20	712	171	32	
Total Consolidated Subsidiaries	31,927	14,339	44,082	25,948	33,240	14,481	45,667	2
Equity Companies								
United States	12,777	5,286	2,138	120	11,068	5,200	1	
Europe	71	27	585	185	61	23	593	
Asia	1,200	129	121	29	894	100	121	
Total Equity Companies	14,048	5,442	2,844	334	12,023	5,323	715	
Total gross and net productive wells	45,975	19,781	46,926	26,282	45,263	19,804	46,382	2

There were 37,228 gross and 31,264 net operated wells at year-end 2012 and 37,692 gross and 31,683 net operated wells at year-end 201
number of wells with multiple completions was 1,647 gross in 2012 and 1,775 gross in 2011.

B. Gross and Net Developed Acreage

	Year-End 2012		Year-End 2011	
	Gross	Net	Gross	N
	(thousands of acres)			
Gross and Net Developed Acreage				
Consolidated Subsidiaries				
United States	16,444	10,164	17,255	1
Canada/South America *(1)*	4,545	1,940	4,570	
Europe	3,382	1,515	3,563	
Africa	2,105	780	1,850	
Asia	1,322	525	1,326	
Australia/Oceania	2,018	719	1,955	
Total Consolidated Subsidiaries	29,816	15,643	30,519	1
Equity Companies				
United States	496	202	131	
Europe	4,344	1,357	4,343	
Asia	5,731	640	5,732	
Total Equity Companies	10,571	2,199	10,206	
Total gross and net developed acreage	40,387	17,842	40,725	1

(1) Includes developed acreage in South America of 618 gross and 202 net thousands of acres for 2012 and 2011.

Separate acreage data for oil and gas are not maintained because, in many instances, both are produced from the same acreage.

C. Gross and Net Undeveloped Acreage

	Year-End 2012		Year-End 2011	
	Gross	Net	Gross	N
	(thousands of acres)			
Gross and Net Undeveloped Acreage				
Consolidated Subsidiaries				
United States	8,517	5,077	8,718	
Canada/South America *(1)*	16,669	8,700	19,183	
Europe	35,928	16,123	36,153	1
Africa	12,005	7,707	13,242	
Asia	24,346	20,239	23,883	1
Australia/Oceania	7,460	1,991	5,892	
Total Consolidated Subsidiaries	104,925	59,837	107,071	6
Equity Companies				
United States	351	108	302	
Europe	-	-	-	
Asia	73	5	72	
Total Equity Companies	424	113	374	
Total gross and net undeveloped acreage	105,349	59,950	107,445	6

(1) Includes undeveloped acreage in South America of 8,412 gross and 4,484 net thousands of acres for 2012 and 10,922 gross and 5,6 thousands of acres for 2011.

ExxonMobil's investment in developed and undeveloped acreage is comprised of numerous concessions, blocks and leases. The term conditions under which the Corporation maintains exploration and/or production rights to the acreage are property-specific, contractually d and vary significantly from property to property. Work programs are designed to ensure that the exploration potential of any property is evaluated before expiration. In some instances, the Corporation may elect to relinquish acreage in advance of the contractual expiration date evaluation process is complete and there is not a business basis for extension. In cases where additional time may be required to fully ev acreage, the Corporation has generally been successful in obtaining extensions. The scheduled expiration of leases and concessions for undeve acreage over the next three years is not expected to have a material adverse impact on the Corporation.

D. Summary of Acreage Terms

UNITED STATES

Oil and gas leases have an exploration period ranging from one to ten years, and a production period that normally remains in effect until prod ceases. Under certain circumstances, a lease may be held beyond its exploration term even if production has not commenced. In some instar "fee interest" is acquired where both the surface and the underlying mineral interests are owned outright.

CANADA / SOUTH AMERICA

Canada

Exploration licenses or leases in onshore areas are acquired for varying periods of time with renewals or extensions possible. These licen leases entitle the holder to continue existing licenses or leases upon completing specified work. In general, these license and lease agreemer held as long as there is production on the licenses and leases. Exploration licenses in offshore eastern Canada and the Beaufort Sea are held by commitments of various amounts and rentals. They are valid for a maximum term of nine years. Production licenses in the offshore are valid years, with rights of extension for continued production. Significant discovery licenses in the offshore, relating to currently undeveloped discov do not have a definite term.

Argentina

The federal onshore concession terms in Argentina are up to four years for the initial exploration period, up to three years for the second explo period and up to two years for the third exploration period. A 50-percent relinquishment is required after each exploration period. An extensio the third exploration period is possible for up to five years. The total production term is 25 years with a ten-year extension possible, once a fie been developed. Argentine provinces are entitled to modify the concession terms granted within their territories. The concession terms exploration permits granted by Neuquen Province are up to six years for the initial exploration period, up to four years for the second explo period and up to three years for the third exploration period depending on the classification of the area. An extension after the third explo period is possible for up to one year.

EUROPE

Germany

Exploration concessions are granted for an initial maximum period of five years, with an unlimited number of extensions of up to three years Extensions are subject to specific, minimum work commitments. Production licenses are normally granted for 20 to 25 years with multiple pc extensions as long as there is production on the license.

Netherlands

Under the Mining Law, effective January 1, 2003, exploration and production licenses for both onshore and offshore areas are issued for a per explicitly defined in the license. The term is based on the period of time necessary to perform the activities for which the license is issued. Li conditions are stipulated in the license and are based on the Mining Law.

Production rights granted prior to January 1, 2003, remain subject to their existing terms, and differ slightly for onshore and offshore Onshore production licenses issued prior to 1988 were indefinite; from 1988 they were issued for a period as explicitly defined in the li ranging from 35 to 45 years. Offshore production licenses issued before 1976 were issued for a fixed period of 40 years; from 1976 they were issued for a period as explicitly defined in the license, ranging from 15 to 40 years.

Norway

Licenses issued prior to 1972 were for an initial period of six years and an extension period of 40 years, with relinquishment of at least one-fou the original area required at the end of the sixth year and another one-fourth at the end of the ninth year. Licenses issued between 1972 and were for an initial period of up to six years (with extension of the initial period of one year at a time up to ten years after 1985), and an ext period of up to 30 years, with relinquishment of at least one-half of the original area required at the end of the initial period. Licenses issue July 1, 1997, have an initial period of up to ten years and a normal extension period of up to 30 years or in special cases of up to 50 years, an relinquishment of at least one-half of the original area required at the end of the initial period.

United Kingdom

Acreage terms are fixed by the government and are periodically changed. For example, many of the early licenses issued under the firs licensing rounds provided for an initial term of six years with relinquishment of at least one-half of the original area at the end of the initial subject to extension for a further 40 years. At the end of any such 40-year term, licenses may continue in producing areas until cessat production; or licenses may continue in development areas for periods agreed on a case-by-case basis until they become producing areas; or lic terminate in all other areas. The licensing regime was last updated in 2002, and the majority of licenses issued have an initial term of four year a second term extension of four years and a final term of 18 years with a mandatory relinquishment of 50 percent of the acreage after the initia and of all acreage that is not covered by a development plan at the end of the second term.

AFRICA

Angola

Exploration and production activities are governed by production sharing agreements with an initial exploration term of four years and an op second phase of two to three years. The production period is for 25 years, and agreements generally provide for a negotiated extension.

Chad

Exploration permits are issued for a period of five years, and are renewable for one or two further five-year periods. The terms and conditions permits, including relinquishment obligations, are specified in a negotiated convention. The production term is for 30 years and may be exten the discretion of the government.

Equatorial Guinea

Exploration and production activities are governed by production sharing contracts negotiated with the State Ministry of Mines, Industr Energy. The exploration periods are for ten to 15 years with limited relinquishments in the absence of commercial discoveries. The prod period for crude oil is 30 years, while the production period for gas is 50 years. Under the Hydrocarbons Law enacted in 2006, the exploration for new production sharing contracts are four to five years with a maximum of two one-year extensions, unless the Ministry agrees otherwise.

Nigeria

Exploration and production activities in the deepwater offshore areas are typically governed by production sharing contracts (PSCs) wi national oil company, the Nigerian National Petroleum Corporation (NNPC). NNPC holds the underlying Oil Prospecting License (OPL) an resulting Oil Mining Lease (OML). The terms of the PSCs are generally 30 years, including a ten-year exploration period (an initial explo phase plus one or two optional periods) covered by an OPL. Upon commercial discovery, an OPL may be converted to an OML. l relinquishment is required under the PSC at the end of the ten-year exploration period, and OMLs have a 20-year production period that m extended.

Some exploration activities are carried out in deepwater by joint ventures with local companies holding interests in an OPL. OPLs in deep offshore areas are valid for ten years and are non-renewable, while in all other areas the licenses are for five years and also are non-renev Demonstrating a commercial discovery is the basis for conversion of an OPL to an OML.

OMLs granted prior to the 1969 Petroleum Act (i.e., under the Mineral Oils Act 1914, repealed by the 1969 Petroleum Act) were for 30 onshore and 40 years in offshore areas and have been renewed, effective December 1, 2008, for a further period of 20 years, with a further re option of 20 years. Operations under these pre-1969 OMLs are conducted under a joint venture agreement with NNPC rather than a PSC. In 2 Memorandum of Understanding (MOU) was executed defining commercial terms applicable to existing joint venture oil production. The MOU be terminated on one calendar year's notice.

OMLs granted under the 1969 Petroleum Act, which include all deepwater OMLs, have a maximum term of 20 years without distincti onshore or offshore location and are renewable, upon 12 months' written notice, for another period of 20 years. OMLs not held by NNPC ar subject to a mandatory 50-percent relinquishment after the first ten years of their duration.

ASIA

Azerbaijan

The production sharing agreement (PSA) for the development of the Azeri-Chirag-Gunashli field is established for an initial period of 30 starting from the PSA execution date in 1994.

Other exploration and production activities are governed by PSAs negotiated with the national oil company of Azerbaijan. The exploration consists of three or four years with the possibility of a one to three-year extension. The production period, which includes development, is years or 35 years with the possibility of one or two five-year extensions.

Indonesia

Exploration and production activities in Indonesia are generally governed by cooperation contracts, usually in the form of a production s contract (PSC), negotiated with BPMIGAS, a government agency established in 2002 to manage upstream oil and gas activities. In Indonesia's Constitutional Court ruled certain articles of law relating to BPMIGAS to be unconstitutional, but stated that all existing PSCs with BPMIGAS should remain in force until their expiry, and the functions and duties previously performed by BPMIGAS are to be carried the relevant Ministry of the Government of Indonesia until the promulgation of a new oil and gas law. The current PSCs have an exploration of six years, which can be extended up to 10 years, and an exploitation period of 20 years. PSCs generally require the contractor to relinqu percent to 20 percent of the contract area after three years and generally allow the contractor to retain no more than 50 percent to 80 percent original contract area after six years, depending on the acreage and terms.

Iraq

Development and production activities in the state-owned oil and gas fields are governed by contracts with regional oil companies of the Ministry of Oil. An ExxonMobil affiliate entered into a contract with South Oil Company of the Iraqi Ministry of Oil for the rights to particip the development and production activities of the West Qurna Phase I oil and gas field effective March 1, 2010. The term of the contract is 20 with the right to extend for five years. The contract provides for cost recovery plus per-barrel fees for incremental production above specified l

Exploration and production activities in the Kurdistan region of Iraq are governed by production sharing contracts negotiated with the re government of Kurdistan in 2011. The exploration term is for five years with the possibility of two-year extensions. The production period years with the right to extend for five years.

Kazakhstan

Onshore exploration and production activities are governed by the production license, exploration license and joint venture agreements nego with the Republic of Kazakhstan. Existing production operations have a 40-year production period that commenced in 1993.

Offshore exploration and production activities are governed by a production sharing agreement negotiated with the Republic of Kazakhsta exploration period is six years followed by separate appraisal periods for each discovery. The production period for each discovery, which in development, is for 20 years from the date of declaration of commerciality with the possibility of two ten-year extensions.

Malaysia

Exploration and production activities are governed by production sharing contracts (PSCs) negotiated with the national oil company. The recent PSCs governing exploration and production activities have an overall term of 24 to 38 years, depending on water depth, with po extensions to the exploration and/or development periods. The exploration period is five to seven years with the possibility of extensions which time areas with no commercial discoveries will be deemed relinquished. The development period is from four to six years from comm discovery, with the possibility of extensions under special circumstances. Areas from which commercial production has not started by the end development period will be deemed relinquished if no extension is granted. All extensions are subject to the national oil company's prior v approval. The total production period is 15 to 25 years from first commercial lifting, not to exceed the overall term of the contract.

In 2008, the Company reached agreement with the national oil company for a new PSC, which was subsequently signed in 2009. Under th PSC, from 2008 until March 31, 2012, the Company was entitled to undertake new development and production activities in oil fields un existing PSC, subject to new minimum work and spending commitments, including an enhanced oil recovery project in one of the oil fields. the existing PSC expired on March 31, 2012, the producing fields covered by the existing PSC automatically became part of the new PSC, whi a 25-year duration from April 2008.

Qatar

The State of Qatar grants gas production development project rights to develop and supply gas from the offshore North Field to permit the eco development and production of gas reserves sufficient to satisfy the gas and LNG sales obligations of these projects.

Republic of Yemen

The Jannah production sharing agreement has a development period extending 20 years from first commercial declaration, which was made i 1995.

Russia

Terms for ExxonMobil's acreage are fixed by the production sharing agreement (PSA) that became effective in 1996 between the R government and the Sakhalin-1 consortium, of which ExxonMobil is the operator. The term of the PSA is 20 years from the Declarati Commerciality, which would be 2021. The term may be extended thereafter in ten-year increments as specified in the PSA.

Thailand

The Petroleum Act of 1971 allows production under ExxonMobil's concession for 30 years with a ten-year extension at terms generally preva the time.

United Arab Emirates

Exploration and production activities for the major onshore oil fields in the Emirate of Abu Dhabi are governed by a 75-year oil conc agreement executed in 1939 and subsequently amended through various agreements with the government of Abu Dhabi. An interest in the Zakum field, a major offshore field, was acquired effective as of January 2006, for a term expiring March 2026.

AUSTRALIA/OCEANIA

Australia

Exploration and production activities conducted offshore in Commonwealth waters are governed by Federal legislation. Exploration perm granted for an initial term of six years with two possible five-year renewal periods. Retention leases may be granted for resources that a commercially viable at the time of application, but are expected to become commercially viable within 15 years. These are granted for peri five years and renewals may be requested. Prior to July 1998, production licenses were granted initially for 21 years, with a further renewal years and thereafter "indefinitely", i.e., for the life of the field. Effective from July 1998, new production licenses are granted "indefinitely". I case, a production license may be terminated if no production operations have been carried on for five years.

Papua New Guinea

Exploration and production activities are governed by the Oil and Gas Act. Petroleum Prospecting licenses are granted for an initial term of six with a five-year extension possible (an additional extension of three years is possible in certain circumstances). Generally, a 50-p relinquishment of the license area is required at the end of the initial six-year term, if extended. Petroleum Development licenses are granted initial 25-year period. An extension of up to 20 years may be granted at the Minister's discretion. Petroleum Retention licenses may be grant gas resources that are not commercially viable at the time of application, but may become commercially viable within the maximum pc retention time of 15 years. Petroleum Retention licenses are granted for five-year terms, and may be extended, at the Minister's discretion, twi the maximum retention time of 15 years. Extensions of Petroleum Retention licenses may be for periods of less than one year, renewable annu the Minister considers at the time of extension that the resources could become commercially viable in less than five years.

Information with regard to the Downstream segment follows:

ExxonMobil's Downstream segment manufactures and sells petroleum products. The refining and supply operations encompass a global netw manufacturing plants, transportation systems, and distribution centers that provide a range of fuels, lubricants and other products and feedsto our customers around the world.

Refining Capacity At Year-End 2012 *(1)*

		ExxonMobil Share KBD *(2)*	ExxonMo Interest °
United States			
Torrance	California	150	100
Joliet	Illinois	238	100
Baton Rouge	Louisiana	502	100
Baytown	Texas	561	100
Beaumont	Texas	345	100
Other (2 refineries)		155	
Total United States		1,951	
Canada			
Strathcona	Alberta	189	69.6
Dartmouth	Nova Scotia	85	69.6
Nanticoke	Ontario	113	69.6
Sarnia	Ontario	119	69.6
Total Canada		506	
Europe			
Antwerp	Belgium	307	100
Fos-sur-Mer	France	131	82.9
Gravenchon	France	235	82.9
Karlsruhe	Germany	78	25
Augusta	Italy	198	100
Trecate	Italy	126	75.5
Rotterdam	Netherlands	191	100
Slagen	Norway	116	100
Fawley	United Kingdom	258	100
Total Europe		1,640	
Asia Pacific			
Jurong/PAC	Singapore	592	100
Sriracha	Thailand	170	66
Other (7 refineries)		299	
Total Asia Pacific		1,061	
Other Non-U.S.			
Yanbu	Saudi Arabia	200	50
Laffan	Qatar	15	10
Martinique	Martinique	2	14.5
Total Other Non-U.S.		217	
Total Worldwide		5,375	

(1) Capacity data is based on 100 percent of rated refinery process unit stream-day capacities under normal operating conditions, less the i of shutdowns for regular repair and maintenance activities, averaged over an extended period of time.

(2) Thousands of barrels per day (KBD). ExxonMobil share reflects 100 percent of atmospheric distillation capacity in operations of Exxon and majority-owned subsidiaries. For companies owned 50 percent or less, ExxonMobil share is the greater of ExxonMobil's equity inte that portion of distillation capacity normally available to ExxonMobil.

The marketing operations sell products and services throughout the world through our *Exxon*, *Esso* and *Mobil* brands.

Retail Sites At Year-End 2012

United States	
Owned/leased	115
Distributors/resellers	8,921
Total United States	9,036
Canada	
Owned/leased	474
Distributors/resellers	1,308
Total Canada	1,782
Europe	
Owned/leased	3,713
Distributors/resellers	2,361
Total Europe	6,074
Asia Pacific	
Owned/leased	689
Distributors/resellers	256
Total Asia Pacific	945
Latin America	
Owned/leased	156
Distributors/resellers	757
Total Latin America	913
Middle East/Africa	
Owned/leased	446
Distributors/resellers	186
Total Middle East/Africa	632
Worldwide	
Owned/leased	5,593
Distributors/resellers	13,789
Total Worldwide	19,382

Information with regard to the Chemical segment follows:

ExxonMobil's Chemical segment manufactures and sells petrochemicals. The Chemical business supplies olefins, polyolefins, aromatics, and a variety of other petrochemicals.

Chemical Complex Capacity At Year-End 2012 *(1)(2)*

		Ethylene	Polyethylene	Polypropylene	Paraxylene	ExxonMobil Interest
North America						
Baton Rouge	Louisiana	1.0	1.3	0.4	-	100
Baytown	Texas	2.2	-	0.8	0.6	100
Beaumont	Texas	0.9	1.0	-	0.3	100
Mont Belvieu	Texas	-	1.0	-	-	100
Sarnia	Ontario	0.3	0.5	-	-	69.6
Total North America		4.4	3.8	1.2	0.9	
Europe						
Antwerp	Belgium	-	0.4	-	-	100
Fife	United Kingdom	0.4	-	-	-	50
Meerhout	Belgium	-	0.5	-	-	100
Gravenchon	France	0.4	0.4	0.3	-	100
Rotterdam	Netherlands	-	-	-	0.7	100
Total Europe		0.8	1.3	0.3	0.7	
Middle East						
Al Jubail	Saudi Arabia	0.6	0.6	-	-	50
Yanbu	Saudi Arabia	1.0	0.7	0.2	-	50
Total Middle East		1.6	1.3	0.2	-	
Asia Pacific						
Fujian	China	0.2	0.2	0.1	0.2	25
Kawasaki	Japan	0.1	-	-	-	22
Singapore	Singapore	0.9	1.9	0.9	0.9	100
Sriracha	Thailand	-	-	-	0.5	66
Total Asia Pacific		1.2	2.1	1.0	1.6	
All Other		-	-	-	0.2	
Total Worldwide		8.0	8.5	2.7	3.4	

(1) Capacity for ethylene, polyethylene, polypropylene and paraxylene in millions of metric tons per year.

(2) Capacity reflects 100 percent for operations of ExxonMobil and majority-owned subsidiaries. For companies owned 50 percent or capacity is ExxonMobil's interest.

Iran Threat Reduction and Syria Human Rights Act of 2012

The captioned Act was signed by President Obama on August 10, 2012. Among other things, the Act extended the prohibition against U.S. pe doing business with the Government of Iran to include such persons' non-U.S. subsidiaries. Previously, non-U.S. subsidiaries were not cover this restriction. Application of the restriction to non-U.S. subsidiaries took effect on October 10, 2012. The Act also requires registrants to dis in their annual and quarterly reports, activities covered by the Act which occurred anytime during the period covered by the report, even i activities occurred prior to the effective date of the Act and were permitted at the time.

During the period from January to September, 2012, ExxonMobil's majority-owned Canadian affiliate, Imperial Oil Limited (IOL), made s fleet sales of motor fuel with an aggregate total sales price of approximately 11,000 Canadian dollars to the Iranian Embassy in Canada. IOL profits attributable to these sales were less than 500 Canadian dollars. The sales were made without the involvement of any U.S. person and permitted by U.S. laws in effect at the time. No sales occurred after the October 10, 2012, effective date, and we do not expect any such sa occur in the future.

The embassy sales stated above represent an activity described in paragraph (D)(iii) of paragraph (1) of Section 13(r) of the Securitie
Exchange Act of 1934 and therefore are excluded from the required investigation provisions of that statute.

ITEM 3. LEGAL PROCEEDINGS

On October 31, 2012, the Illinois Attorney General and Will County State's Attorney filed a civil complaint and sought a preliminary inju against ExxonMobil Oil Corporation (EMOC) relating to an October 18, 2012, release of oil mist from a pressure relief valve associated wi coker unit at EMOC's Joliet Refinery. The refinery reported the incident promptly to regulatory authorities and took prompt response action State's civil complaint seeks a penalty in excess of $100,000. On November 14, 2012, the parties entered into an Agreed Order resolving so the issues, including the State's demand for injunctive relief. As part of the Agreed Order, EMOC agreed to complete an investigation in incident's cause and to report the findings to the Illinois Environmental Protection Agency (IEPA); submit a work schedule for nec improvements; report all pollutants and quantities involved in the oil release incident; pay all reasonable response, oversight and review relating to the release incurred by the IEPA and the Attorney General, up to and not to exceed $50,000; and reimburse Will County for its reas response costs incurred in the course of providing emergency action relating to the release, up to and not to exceed $20,000.

Regarding a matter previously reported in the Corporation's Form 10-Q for the second quarter of 2012, on December 17, 2012, XTO Energ (XTO) entered into a settlement agreement and stipulated final compliance order with the New Mexico Environment Department (NMED) a from NMED's allegations that XTO violated the New Mexico Air Quality Control Act and air permits for compressor engines at the XTO Va Canyon Compressor Station in Rio Arriba County, New Mexico. Under the settlement, XTO has agreed to pay $90,000 to resolve the a violations.

Refer to the relevant portions of "Note 16: Litigation and Other Contingencies" of the Financial Section of this report for additional inforn on legal proceedings.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

Executive Officers of the Registrant [pursuant to Instruction 3 to Regulation S-K, Item 401(b)] (ages as of March 1, 2013).

Rex W. Tillerson	*Chairman of the Board*	
Held current title since:	January 1, 2006	Age: 60

Mr. Rex W. Tillerson became a Director and President of Exxon Mobil Corporation on March 1, 2004. He became Chairman of the Boar Chief Executive Officer on January 1, 2006. He still holds these positions as of this filing date.

Mark W. Albers	*Senior Vice President*	
Held current title since:	April 1, 2007	Age: 56

Mr. Mark W. Albers became Senior Vice President of Exxon Mobil Corporation on April 1, 2007, a position he still holds as of this filing da

Michael J. Dolan	*Senior Vice President*	
Held current title since:	April 1, 2008	Age: 59

Mr. Michael J. Dolan was President of ExxonMobil Chemical Company and Vice President of Exxon Mobil Corporation September 1, 2 March 31, 2008. He became Senior Vice President of Exxon Mobil Corporation on April 1, 2008, a position he still holds as of this filing da

Andrew P. Swiger	*Senior Vice President*	
Held current title since:	April 1, 2009	Age: 56

Mr. Andrew P. Swiger was President of ExxonMobil Gas & Power Marketing Company and Vice President of Exxon Mobil Corpo October 1, 2006 – March 31, 2009. He became Senior Vice President of Exxon Mobil Corporation on April 1, 2009, a position he still holds this filing date.

S. Jack Balagia	*Vice President and General Counsel*	
Held current title since:	March 1, 2010	Age: 61

Mr. S. Jack Balagia was Assistant General Counsel of Exxon Mobil Corporation April 1, 2004 – March 1, 2010. He became Vice Preside General Counsel of Exxon Mobil Corporation on March 1, 2010, positions he still holds as of this filing date.

William M. Colton	*Vice President - Strategic Planning*	
Held current title since:	February 1, 2009	Age: 59

Mr. William M. Colton was Assistant Treasurer of Exxon Mobil Corporation January 25, 2006 – January 31, 2009. He became Vice Presic Strategic Planning of Exxon Mobil Corporation on February 1, 2009, a position he still holds as of this filing date.

Neil W. Duffin	*President, ExxonMobil Development Company*	
Held current title since:	April 13, 2007	Age: 56

Mr. Neil W. Duffin became President of ExxonMobil Development Company on April 13, 2007, a position he still holds as of this filing dat

Robert S. Franklin	*Vice President*	
Held current title since:	May 1, 2009	Age: 55

Mr. Robert S. Franklin was Executive Assistant to the Chairman, Exxon Mobil Corporation April 16, 2007 – March 31, 2008. He was President, Europe/Russia/Caspian of ExxonMobil Production Company April 1, 2008 – May 1, 2009. He became Vice President of Exxon Corporation and President, ExxonMobil Upstream Ventures on May 1, 2009, positions he still holds as of this filing date.

Stephen M. Greenlee	*Vice President*	
Held current title since:	September 1, 2010	Age: 55

Mr. Stephen M. Greenlee was Vice President of ExxonMobil Exploration Company June 1, 2004 – June 1, 2009. He was Presid ExxonMobil Upstream Research Company June 1, 2009 – August 31, 2010. He became President of ExxonMobil Exploration Company an President of Exxon Mobil Corporation on September 1, 2010, positions he still holds as of this filing date.

Alan J. Kelly	*Vice President*	
Held current title since:	December 1, 2007	Age: 55

Mr. Alan J. Kelly became President of ExxonMobil Lubricants & Petroleum Specialties Company and Vice President of Exxon Corporation on December 1, 2007. On February 1, 2012, the businesses of ExxonMobil Lubricants & Petroleum Specialties Compan ExxonMobil Fuels Marketing Company were consolidated and Mr. Kelly became President of the combined ExxonMobil Fuels, Lubrica Specialties Marketing Company as well as Vice President of Exxon Mobil Corporation, positions he still holds as of this filing date.

Richard M. Kruger	*Vice President*	
Held current title since:	April 1, 2008	Age: 53

Mr. Richard M. Kruger was Executive Vice President of ExxonMobil Production Company October 1, 2006 – March 31, 2008. He be President of ExxonMobil Production Company and Vice President of Exxon Mobil Corporation on April 1, 2008, positions he still holds this filing date.

Patrick T. Mulva	*Vice President and Controller*	
Held current title since:	February 1, 2002 (Vice President) July 1, 2004 (Controller)	Age: 61

Mr. Patrick T. Mulva became Vice President and Controller of Exxon Mobil Corporation on July 1, 2004, positions he still holds as of this date.

Stephen D. Pryor	*Vice President*	
Held current title since:	December 1, 2004	Age: 63

Mr. Stephen D. Pryor was President of ExxonMobil Refining & Supply Company and Vice President of Exxon Mobil Corpo December 1, 2004 – March 31, 2008. He became President of ExxonMobil Chemical Company and Vice President of Exxon Mobil Corpo on April 1, 2008, positions he still holds as of this filing date.

David S. Rosenthal	*Vice President - Investor Relations and Secretary*	
Held current title since:	October 1, 2008	Age: 56

Mr. David S. Rosenthal was Assistant Controller of Exxon Mobil Corporation June 1, 2006 – September 30, 2008. He became Vice Presic Investor Relations and Secretary of Exxon Mobil Corporation on October 1, 2008, positions he still holds as of this filing date.

Robert N. Schleckser *Vice President and Treasurer*

Held current title since: May 1, 2011 Age: 56

Mr. Robert N. Schleckser was Downstream Treasurer, Downstream Business Services May 1, 2005 – January 31, 2009. He was As Treasurer of Exxon Mobil Corporation February 1, 2009 – April 30, 2011. He became Vice President and Treasurer of Exxon Mobil Corpo on May 1, 2011, positions he still holds as of this filing date.

James M. Spellings, Jr. *Vice President and General Tax Counsel*

Held current title since: March 1, 2010 Age: 51

Mr. James M. Spellings, Jr. was Associate General Tax Counsel of Exxon Mobil Corporation April 1, 2007 – March 1, 2010. He becam President and General Tax Counsel of Exxon Mobil Corporation on March 1, 2010, positions he still holds as of this filing date.

Thomas R. Walters *Vice President*

Held current title since: April 1, 2009 Age: 58

Mr. Thomas R. Walters was Executive Vice President of ExxonMobil Development Company April 13, 2007 – April 1, 2009. He b President of ExxonMobil Gas & Power Marketing Company and Vice President of Exxon Mobil Corporation on April 1, 2009 positions h holds as of this filing date.

Jack P. Williams, Jr. *President, XTO Energy Inc.*

Held current title since: June 25, 2010 Age: 49

Mr. Jack P. Williams, Jr. was Vice President, Engineering, ExxonMobil Production Company May 1, 2007 – April 30, 2009. He was President of ExxonMobil Development Company May 1, 2009 – July 1, 2010. He became President of XTO Energy Inc. on June 25, 2 position he still holds as of this filing date.

Darren W. Woods *Vice President*

Held current title since: August 1, 2012 Age: 48

Mr. Darren W. Woods was Vice President, Specialty Elastomers Business, ExxonMobil Chemical Company July 1, 2007 –January 31, 20 was Director, Refining Europe/Africa/Middle East, ExxonMobil Refining & Supply Company February 1, 2008 – June 30, 2010. He wa President, Supply & Transportation, ExxonMobil Refining & Supply Company July 1, 2010 – July 31, 2012. He became Presid ExxonMobil Refining & Supply Company and Vice President of Exxon Mobil Corporation on August 1, 2012, positions he still holds as filing date.

Officers are generally elected by the Board of Directors at its meeting on the day of each annual election of directors, with each such serving until a successor has been elected and qualified.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AN ISSUER PURCHASES OF EQUITY SECURITIES

Reference is made to the "Quarterly Information" portion of the Financial Section of this report.

Issuer Purchases of Equity Securities for Quarter Ended December 31, 2012

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Nun of Shares that I Yet Be Purcha Under the Plan Programs
October 2012	18,265,369	91.68	18,265,369	
November 2012	20,958,452	88.19	20,958,452	
December 2012	19,688,345	87.95	19,688,345	
Total	58,912,166	89.19	58,912,166	(See note 1

Note 1 - On August 1, 2000, the Corporation announced its intention to resume purchases of shares of its common stock for the treasury b offset shares issued in conjunction with company benefit plans and programs and to gradually reduce the number of shares outstanding announcement did not specify an amount or expiration date. The Corporation has continued to purchase shares since this announcement a report purchased volumes in its quarterly earnings releases. In its most recent earnings release dated February 1, 2013, the Corporation state first quarter 2013 share purchases are continuing at a pace consistent with fourth quarter 2012 share reduction spending of $5 billion. Purchase be made in both the open market and through negotiated transactions, and purchases may be increased, decreased or discontinued at any without prior notice.

ITEM 6. SELECTED FINANCIAL DATA

	Years Ended December 31,				
	2012 *(1)*	2011	2010	2009	20
	(millions of dollars, except per share amounts)				
Sales and other operating revenue *(2)*	453,123	467,029	370,125	301,500	45
(2) Sales-based taxes included	*32,409*	*33,503*	*28,547*	*25,936*	*3*
Net income attributable to ExxonMobil	44,880	41,060	30,460	19,280	4
Earnings per common share	9.70	8.43	6.24	3.99	
Earnings per common share - assuming dilution	9.70	8.42	6.22	3.98	
Cash dividends per common share	2.18	1.85	1.74	1.66	
Total assets	333,795	331,052	302,510	233,323	22
Long-term debt	7,928	9,322	12,227	7,129	

(1) See Note 20: Japan Restructuring contained in the Financial Section of this report.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS O OPERATIONS

Reference is made to the section entitled "Management's Discussion and Analysis of Financial Condition and Results of Operations" Financial Section of this report.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Reference is made to the section entitled "Market Risks, Inflation and Other Uncertainties", excluding the part entitled "Inflation and Uncertainties," in the Financial Section of this report. All statements other than historical information incorporated in this Item 7A are for looking statements. The actual impact of future market changes could differ materially due to, among other things, factors discussed in this rep

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Reference is made to the following in the Financial Section of this report:

- Consolidated financial statements, together with the report thereon of PricewaterhouseCoopers LLP dated February 27, 2013, beg with the section entitled "Report of Independent Registered Public Accounting Firm" and continuing through "Note 20: Restructuring";
- "Quarterly Information" (unaudited);
- "Supplemental Information on Oil and Gas Exploration and Production Activities" (unaudited); and
- "Frequently Used Terms" (unaudited).

Financial Statement Schedules have been omitted because they are not applicable or the required information is shown in the consol financial statements or notes thereto.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANC DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Management's Evaluation of Disclosure Controls and Procedures

As indicated in the certifications in Exhibit 31 of this report, the Corporation's chief executive officer, principal financial officer and pri accounting officer have evaluated the Corporation's disclosure controls and procedures as of December 31, 2012. Based on that evaluation, officers have concluded that the Corporation's disclosure controls and procedures are effective in ensuring that information required to be dis by the Corporation in the reports that it files or submits under the Securities Exchange Act of 1934, as amended, is accumulated and commun to them in a manner that allows for timely decisions regarding required disclosures and are effective in ensuring that such information is rec processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms.

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 responsib establishing and maintaining adequate internal control over the Corporation's financial reporting. Management conducted an evaluation effectiveness of internal control over financial reporting based on criteria established in Internal Control - Integrated Framework issued l Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Exxon Corporation's internal control over financial reporting was effective as of December 31, 2012.

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

Changes in Internal Control Over Financial Reporting

There were no changes during the Corporation's last fiscal quarter that materially affected, or are reasonably likely to materially affec Corporation's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

Effective April 1, 2013, the annual salary for Mark W. Albers will increase to $1,110,000 and Michael J. Dolan will increase to $1,200,000. L other ExxonMobil executive officers, Messrs. Albers and Dolan are "at-will" employees of the Corporation and they do not have emplo contracts.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Incorporated by reference to the following from the registrant's definitive proxy statement for the 2013 annual meeting of shareholders (the Proxy Statement"):

- The section entitled "Election of Directors";
- The portion entitled "Section 16(a) Beneficial Ownership Reporting Compliance" of the section entitled "Director and Execu Officer Stock Ownership";
- The portions entitled "Director Qualifications" and "Code of Ethics and Business Conduct" of the section entitled "Corp Governance"; and
- The "Audit Committee" portion and the membership table of the portion entitled "Board Meetings and Committees; Annual Me Attendance" of the section entitled "Corporate Governance".

ITEM 11. EXECUTIVE COMPENSATION

Incorporated by reference to the sections entitled "Director Compensation," "Compensation Committee Report," "Compensation Discussio Analysis" and "Executive Compensation Tables" of the registrant's 2013 Proxy Statement.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required under Item 403 of Regulation S-K is incorporated by reference to the sections "Director and Executive Officer Ownership" and "Certain Beneficial Owners" of the registrant's 2013 Proxy Statement.

Equity Compensation Plan Information

Plan Category	*(a)* Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	*(b)* Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	*(c)* Number of Securit Remaining Availal for Future Issuan Under Equity Compensation Plans [Excluding Securities Reflect in Column (a)]
Equity compensation plans approved by security holders	10,481,088 *(1)(2)*	-	125,413,149 *(2)(*
Equity compensation plans not approved by security holders	-	-	-
Total	10,481,088	-	125,413,149

(1) The number of restricted stock units to be settled in shares.

(2) Does not include options that ExxonMobil assumed in the 2010 merger with XTO Energy Inc. At year-end 2012, the number of securities issued upon exercise of outstanding options under XTO Energy Inc. plans was 2,355,003, and the weighted-average exercise price o options was $78.60. No additional awards may be made under those plans.

(3) Available shares can be granted in the form of restricted stock, options, or other stock-based awards. Includes 124,736,449 shares availal award under the 2003 Incentive Program and 676,700 shares available for award under the 2004 Non-Employee Director Restricted Plan.

(4) Under the 2004 Non-Employee Director Restricted Stock Plan approved by shareholders in May 2004, and the related standing reso adopted by the Board, each non-employee director automatically receives 8,000 shares of restricted stock when first elected to the Board a the director remains in office, an additional 2,500 restricted shares each following year. While on the Board, each non-employee di receives the same cash dividends on restricted shares as a holder of regular common stock, but the director is not allowed to sell the share restricted shares may be forfeited if the director leaves the Board early.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENC

Incorporated by reference to the portions entitled “Related Person Transactions and Procedures” and “Director Independence” of the section en “Corporate Governance” of the registrant’s 2013 Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Incorporated by reference to the portion entitled “Audit Committee” of the section entitled “Corporate Governance” and the section en “Ratification of Independent Auditors” of the registrant’s 2013 Proxy Statement.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) (1) and (2) Financial Statements:
See Table of Contents of the Financial Section of this report.

(a) (3) Exhibits:
See Index to Exhibits of this report.

FINANCIAL SECTION

TABLE OF CONTENTS

BUSINESS PROFILE

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

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

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

	2012	20
	(thousands of barrel	
Refinery throughput		
United States	1,816	
Non-U.S.	3,198	
Total	5,014	
	(thousands of barrel	
Petroleum product sales		
United States	2,569	
Non-U.S.	3,605	
Total	6,174	
	(thousands of metr	
Chemical prime product sales *(2)*		
United States	9,381	
Non-U.S.	14,776	1
Total	24,157	2

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

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

FINANCIAL SUMMARY

	2012	2011	2010	2009	20
	(millions of dollars, except per share amounts)				
Sales and other operating revenue *(1)*	453,123	467,029	370,125	301,500	45
Earnings					
Upstream	29,895	34,439	24,097	17,107	3
Downstream	13,190	4,459	3,567	1,781	
Chemical	3,898	4,383	4,913	2,309	
Corporate and financing	(2,103)	(2,221)	(2,117)	(1,917)	(
Net income attributable to ExxonMobil	44,880	41,060	30,460	19,280	4
Earnings per common share	9.70	8.43	6.24	3.99	
Earnings per common share – assuming dilution	9.70	8.42	6.22	3.98	
Cash dividends per common share	2.18	1.85	1.74	1.66	
Earnings to average ExxonMobil share of equity (percent)	28.0	27.3	23.7	17.3	
Working capital	321	(4,542)	(3,649)	3,174	2
Ratio of current assets to current liabilities (times)	1.01	0.94	0.94	1.06	
Additions to property, plant and equipment	35,179	33,638	74,156	22,491	1
Property, plant and equipment, less allowances	226,949	214,664	199,548	139,116	12
Total assets	333,795	331,052	302,510	233,323	22
Exploration expenses, including dry holes	1,840	2,081	2,144	2,021	
Research and development costs	1,042	1,044	1,012	1,050	
Long-term debt	7,928	9,322	12,227	7,129	
Total debt	11,581	17,033	15,014	9,605	
Fixed-charge coverage ratio (times)	62.4	53.4	42.2	25.8	
Debt to capital (percent)	6.3	9.6	9.0	7.7	
Net debt to capital (percent) *(2)*	1.2	2.6	4.5	(1.0)	
ExxonMobil share of equity at year-end	165,863	154,396	146,839	110,569	11
ExxonMobil share of equity per common share	36.84	32.61	29.48	23.39	
Weighted average number of common shares outstanding (millions)	4,628	4,870	4,885	4,832	
Number of regular employees at year-end (thousands) *(3)*	76.9	82.1	83.6	80.7	
CORS employees not included above (thousands) *(4)*	11.1	17.0	20.1	22.0	

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

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

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

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

FREQUENTLY USED TERMS

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

Cash Flow From Operations and Asset Sales

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

Cash flow from operations and asset sales	**2012**	**2011**	**2(**
		(millions of dollars)	
Net cash provided by operating activities	56,170	55,345	4
Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments	7,655	11,133	
Cash flow from operations and asset sales	63,825	66,478	5

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

Capital employed	**2012**	**2011**	**2(**
		(millions of dollars)	
Business uses: asset and liability perspective			
Total assets	333,795	331,052	30
Less liabilities and noncontrolling interests share of assets and liabilities			
Total current liabilities excluding notes and loans payable	(60,486)	(69,794)	(5
Total long-term liabilities excluding long-term debt	(90,068)	(83,481)	(7
Noncontrolling interests share of assets and liabilities	(6,235)	(7,314)	(
Add ExxonMobil share of debt-financed equity company net assets	5,775	4,943	
Total capital employed	182,781	175,406	16
Total corporate sources: debt and equity perspective			
Notes and loans payable	3,653	7,711	
Long-term debt	7,928	9,322	1
ExxonMobil share of equity	165,863	154,396	14
Less noncontrolling interests share of total debt	(438)	(966)	
Add ExxonMobil share of equity company debt	5,775	4,943	
Total capital employed	182,781	175,406	16

FREQUENTLY USED TERMS

Return on Average Capital Employed

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

Return on average capital employed	**2012**	**2011**	**2(**
		(millions of dollars)	
Net income attributable to ExxonMobil	44,880	41,060	3
Financing costs (after tax)			
Gross third-party debt	(401)	(153)	
ExxonMobil share of equity companies	(257)	(219)	
All other financing costs – net	100	116	
Total financing costs	(558)	(256)	(
Earnings excluding financing costs	45,438	41,316	3
Average capital employed	179,094	170,721	14
Return on average capital employed – corporate total	25.4%	24.2%	

QUARTERLY INFORMATION

	2012					2011				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Ye
Volumes										
Production of crude oil					*(thousands of barrels daily)*					
and natural gas liquids, synthetic oil and bitumen	2,214	2,208	2,116	2,203	2,185	2,399	2,351	2,249	2,250	
Refinery throughput	5,330	4,962	4,929	4,837	5,014	5,180	5,193	5,232	5,250	
Petroleum product sales	6,316	6,171	6,105	6,108	6,174	6,267	6,331	6,558	6,493	
Natural gas production					*(millions of cubic feet daily)*					
available for sale	14,036	11,661	11,061	12,541	12,322	14,525	12,267	12,197	13,677	1
					(thousands of oil-equivalent barrels daily)					
Oil-equivalent production *(1)*	4,553	4,152	3,960	4,293	4,239	4,820	4,396	4,282	4,530	
					(thousands of metric tons)					
Chemical prime product sales	6,337	5,972	5,947	5,901	24,157	6,322	6,181	6,232	6,271	2
Summarized financial data										
Sales and other operating					*(millions of dollars)*					
revenue *(2)*	119,189	112,745	111,554	109,635	453,123	109,251	121,394	120,475	115,909	46
Gross profit *(3)*	35,672	32,715	33,209	31,969	133,565	35,473	37,744	37,121	34,306	14
Net income attributable to										
ExxonMobil	9,450	15,910	9,570	9,950	44,880	10,650	10,680	10,330	9,400	4
Per share data					*(dollars per share)*					
Earnings per common share *(4)*	2.00	3.41	2.09	2.20	9.70	2.14	2.19	2.13	1.97	
Earnings per common share										
– assuming dilution *(4)*	2.00	3.41	2.09	2.20	9.70	2.14	2.18	2.13	1.97	
Dividends per common share	0.47	0.57	0.57	0.57	2.18	0.44	0.47	0.47	0.47	
Common stock prices										
High	87.94	87.67	92.57	93.67	93.67	88.23	88.13	85.41	85.63	
Low	83.19	77.13	82.83	84.70	77.13	73.64	76.72	67.03	69.21	

(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 is traded. The principal market where ExxonMobil common stock (XOM) is traded is the New York Stock Exchange, although the stock is trac other exchanges in and outside the United States.

There were 468,497 registered shareholders of ExxonMobil common stock at December 31, 2012. At January 31, 2013, the regi shareholders of ExxonMobil common stock numbered 466,674.

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

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

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

References in this discussion to total corporate earnings mean net income attributable to ExxonMobil (U.S. GAAP) from the consolidated in statement. Unless otherwise indicated, references to earnings, Upstream, Downstream, Chemical and Corporate and Financing segment ear 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 r including demand growth and energy source mix; capacity increases; production growth and mix; rates of field decline; financing source resolution of contingencies and uncertain tax positions; environmental and capital expenditures; could differ materially depending on a num factors, such as changes in the supply of and demand for crude oil, natural gas, and petroleum and petrochemical products; the outco commercial negotiations; political or regulatory events, and other factors discussed herein and in Item 1A. Risk Factors.

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

OVERVIEW

The following discussion and analysis of ExxonMobil's financial results, as well as the accompanying financial statements and related nc consolidated financial statements to which they refer, are the responsibility of the management of Exxon Mobil Corporation. The Corpora accounting and financial reporting fairly reflect its straightforward business model involving the extracting, manufacturing and marketi hydrocarbons and hydrocarbon-based products. The Corporation's business model involves the production (or purchase), manufacture and s 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 parti in substantial investments to develop new energy supplies. While commodity prices are volatile on a short-term basis and depend on suppl demand, ExxonMobil's investment decisions are based on our long-term business outlook, using a disciplined approach in selecting and pursui most attractive investment opportunities. The corporate plan is a fundamental annual management process that is the basis for setting nea operating and capital objectives in addition to providing the longer-term economic assumptions used for investment evaluation purposes. Vo are based on individual field production profiles, which are also updated annually. Price ranges for crude oil, natural gas, refined product chemical products are based on corporate plan assumptions developed annually by major region and are utilized for investment evaluation pur Potential investment opportunities are tested over a wide range of economic scenarios to establish the resiliency of each opportunity. investments are made, a reappraisal process is completed to ensure relevant lessons are learned and improvements are incorporated into projects.

BUSINESS ENVIRONMENT AND RISK ASSESSMENT

Long-Term Business Outlook

By 2040, the world's population is projected to grow to approximately 8.7 billion people, or about 1.9 billion more than in 2010. Coinciden this population increase, the Corporation expects worldwide economic growth to average close to 3 percent per year. Expanding prosperity ac growing global population is expected to coincide with an increase in primary energy demand of about 35 percent by 2040 versus 2010, ever substantial efficiency gains around the world. This demand increase is expected to be concentrated in developing countries (i.e., those that a member nations of the Organization for Economic Cooperation and Development).

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

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

Demand for electricity around the world is likely to increase approximately 85 percent by 2040, led by growth in developing cou Consistent with this projection, power generation is expected to remain the largest and fastest-growing major segment of global energy de Meeting the expected growth in power demand will require a diverse set of energy sources. Natural gas demand is likely to grow most signifi and become the leading source of generated electricity by 2040, reflecting the efficiency of gas-fired power plants. Today, coal has the larges share in the power sector, but its share is likely to decline

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

significantly by 2040 as policies are gradually adopted to reduce environmental impacts including those related to local air quality and green gas emissions. Nuclear power and renewables, led by wind, are expected to grow significantly over the period.

Liquid fuels provide the largest share of energy supply today due to their broad-based availability, affordability and ease of transport to consumer needs. By 2040, global demand for liquids is expected to grow to approximately 113 million barrels of oil-equivalent per day, an in of about 30 percent from 2010. Global demand for liquid fuels will be met by a wide variety of sources. Conventional crude and cond production is expected to remain relatively flat through 2040. However, growth is expected from a wide variety of sources, including deep resources, oil sands, tight oil, natural gas liquids, and biofuels. The world's resource base is sufficient to meet projected demand through 20 technology advances continue to expand the availability of economic supply options. However, access to resources and timely investment remain critical to meeting global needs with reliable, affordable supplies.

Natural gas is a versatile fuel for a wide variety of applications, and is expected to be the fastest growing major fuel source through 2040. (demand is expected to rise about 65 percent from 2010 to 2040, with demand increases in major regions around the world requiring new sour supply. Helping meet these needs will be significant growth in supplies of unconventional gas – the natural gas found in shale and other formations that was once considered uneconomic to produce. By 2040, unconventional gas is likely to approach one-third of global gas suppli from less than 15 percent in 2010. Growing natural gas demand will also stimulate significant growth in the worldwide liquefied natural gas (market, which is expected to reach about 15 percent of global gas demand by 2040.

The world's energy mix is highly diverse and will remain so through 2040. Oil is expected to remain the largest source of energy with its remaining close to one-third in 2040. Coal is currently the second largest source of energy, but it is likely to lose that position to natural g approximately 2025. The share of natural gas is expected to exceed 25 percent by 2040, while the share of coal falls to less than 20 percent. N power is projected to grow significantly, albeit at a slower pace than otherwise expected in the aftermath of the Fukushima incident in following the earthquake and tsunami in March 2011. Total renewable energy is likely to reach close to 15 percent of total energy by including biomass, hydro and geothermal at a combined share of about 11 percent. Total energy supplied from wind, solar and biofuels is exp to increase close to 450 percent from 2010 to 2040, reaching a combined share of 3 to 4 percent of world energy.

The Corporation anticipates that the world's available oil and gas resource base will grow not only from new discoveries, but also from re increases in previously discovered fields. Technology will underpin these increases. The cost to develop and supply these resources w significant. According to the International Energy Agency, the investment required to meet total oil and gas energy needs worldwide over the p 2012-2035 will be close to $19 trillion (measured in 2011 dollars) or close to $800 billion per year on average.

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

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

Upstream

ExxonMobil continues to maintain a diverse portfolio of exploration and development opportunities, which enables the Corporation to be sel maximizing shareholder value and mitigating political and technical risks. ExxonMobil's fundamental Upstream business strategies guide our exploration, development, production, and gas and power marketing activities. These strategies include identifying and selectively capturi highest quality opportunities, exercising a disciplined approach to investing and cost management, developing and applying high-i technologies, maximizing the profitability of existing oil and gas production, and capitalizing on growing natural gas and power markets. strategies are underpinned by a relentless focus on operational excellence, commitment to innovative technologies, development of our empl and investment in the communities within which we operate.

As future development projects and drilling activities bring new production online, the Corporation expects a shift in the geographic mix production volumes between now and 2017. Oil and natural gas output from North America is expected to increase over the next five years bas current capital activity plans. Currently, this growth area accounts for 32 percent of the Corporation's production. By 2017, it is expected to ge about 35 percent of total volumes. The remainder of the Corporation's production is expected to include contributions from both estab operations and new projects around the globe.

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

In addition to an evolving geographic mix, we expect there will also be continued change in the type of opportunities from which volum produced. Production from diverse resource types utilizing specialized technologies such as arctic technology, deepwater drilling and prod systems, heavy oil and oil sands recovery processes, unconventional gas and oil production and LNG is expected to grow from about 45 perc around 55 percent of the Corporation's output between now and 2017. We do not anticipate that the expected change in the geographic r production volumes, and in the types of opportunities from which volumes will be produced, will have a material impact on the nature and the of the risks disclosed in Item 1A. Risk Factors, or result in a material change in our level of unit operating expenses. The Corporation's c volume capacity outlook, based on projects coming onstream as anticipated, is for production capacity to grow over the period 2013-2017. Hov actual volumes will vary from year to year due to the timing of individual project start-ups and other capital activities, operational outages, res performance, performance of enhanced oil recovery projects, regulatory changes, asset sales, weather events, price effects under production sl contracts and other factors described in Item 1A. Risk Factors. Enhanced oil recovery projects extract hydrocarbons from reservoirs in excess which may be produced through primary recovery, i.e., through pressure depletion or natural aquifer support. They include the injection of gases or chemicals into a reservoir to produce hydrocarbons otherwise unobtainable.

Downstream

ExxonMobil's Downstream is a large, diversified business with refining, logistics, and marketing complexes around the world. The Corporati a presence in mature markets in North America and Europe, as well as in the growing Asia Pacific region. ExxonMobil's fundamental Downs business strategies position the company to deliver long-term growth in shareholder value that is superior to competition across a range of n conditions. These strategies include maintaining best-in-class operations in all aspects of the business, maximizing value from leading technologies, capitalizing on integration across ExxonMobil businesses, selectively investing for resilient, advantaged returns, leading the in in efficiency and effectiveness, and providing quality, valued products and services to customers.

ExxonMobil has an ownership interest in 32 refineries, located in 17 countries, with distillation capacity of 5.4 million barrels per da lubricant basestock manufacturing capacity of 126 thousand barrels per day. ExxonMobil's fuels and lubes marketing businesses have signi global reach, with multiple channels to market serving a diverse customer base. Our portfolio of world-renowned brands includes Exxon, M Esso, and Mobil 1.

The downstream industry environment remains challenging. Demand weakness and overcapacity in the refining sector will continue pressure on margins. In the near term, we see variability in refining margins, with some regions seeing stronger margins as refineries rational markets like North America, lower raw material and energy costs driven by the increasing crude and natural gas production strengthened re margins in several areas.

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

ExxonMobil's long-term outlook is that refining margins will remain weak as competition in the industry remains intense and, in the near new capacity additions outpace the growth in global demand. Additionally, as described in more detail in Item 1A. Risk Factors, proposed c policy and other climate-related regulations in many countries, as well as the continued growth in biofuels mandates, could have negative impa the refining business.

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

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

The Downstream portfolio is continually evaluated during all parts of the business cycle, and numerous asset divestments have been mad the past decade. In 2012, we divested our Downstream businesses in Argentina, Uruguay, Paraguay, Central America, Malaysia, and Switze We also restructured and reduced our holdings in Japan. When investing in the Downstream, ExxonMobil remains focused on selective and re projects. These investments capitalize on the Corporation's world-class scale and integration, industry leading efficiency, leading-edge techn and respected brands, enabling ExxonMobil to take advantage of attractive emerging growth opportunities around the globe. In 2012, the co completed the Hydrofiner Conversion Project at the Fawley, United Kingdom, refinery to produce higher-value ultra-low sulfur diesel.

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

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

Chemical

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

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

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

REVIEW OF 2012 AND 2011 RESULTS

	2012	2011	2(
		(millions of dollars)	
Earnings (U.S. GAAP)	44,880	41,060	3

2012

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

2011

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

Upstream

	2012	2011	2(
		(millions of dollars)	
Upstream			
United States	3,925	5,096	
Non-U.S.	25,970	29,343	1
Total	29,895	34,439	2

2012

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

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

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

2011

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

Downstream

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

2012

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

2011

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

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Chemical

	2012	2011	20
		(millions of dollars)	
Chemical			
United States	2,220	2,215	
Non-U.S.	1,678	2,168	
Total	3,898	4,383	

2012

Chemical earnings of $3,898 million were $485 million lower than 2011. Margins decreased earnings by $440 million, while volume e lowered earnings by $100 million. All other items increased earnings by $50 million, as a $630 million gain associated with the Japan restruc and favorable tax impacts were mostly offset by unfavorable foreign exchange effects and higher operating expenses. Prime product sales of 2 kt (thousands of metric tons) were down 849 kt from 2011. U.S. Chemical earnings were $2,220 million, up $5 million from 2011. Nor Chemical earnings were $1,678 million, $490 million lower than last year.

2011

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

Corporate and Financing

	2012	2011	20
		(millions of dollars)	
Corporate and financing	(2,103)	(2,221)	(

2012

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

2011

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

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

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

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

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

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

Although the Corporation has access to significant capacity of long-term and short-term liquidity, internally generated funds cover the majo its financial requirements. Cash that may be temporarily available as surplus to the Corporation's immediate needs is carefully managed th counterparty quality and investment guidelines to ensure it is secure and readily available to meet the Corporation's cash requirements a optimize returns.

To support cash flows in future periods the Corporation will need to continually find and develop new fields, and continue to develop and new technologies and recovery processes to existing fields, in order to maintain or increase production. After a period of production at plateau it is the nature of oil and gas fields eventually to produce at declining rates for the remainder of their economic life. Averaged over a Corporation's existing oil and gas fields and without new projects, ExxonMobil's production is expected to decline at an average of approxima 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 limi the type of reservoir, fluid properties, recovery mechanisms, work activity, and age of the field. Furthermore, the Corporation's net inter 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 opportu and project execution. Over the last decade, this has resulted in net annual additions to proved reserves that have exceeded the amount proc Projects are in progress or planned to increase production capacity. However, these volume increases are subject to a variety of risks incl project start-up timing, operational outages, reservoir performance, crude oil and natural gas prices, weather events, and regulatory changes 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 cor discussion of risks.

The Corporation's financial strength enables it to make large, long-term capital expenditures. Capital and exploration expenditures in 2012 $39.8 billion, reflecting the Corporation's continued active investment program. The Corporation anticipates an investment profile of abou billion per year for the next several years. Actual spending could vary depending on the progress of individual projects and property acquis The Corporation has a large and diverse portfolio of development projects and exploration opportunities, which helps mitigate the overall po and technical risks of the Corporation's Upstream segment and associated cash flow. Further, due to its financial strength, debt capacity and d portfolio of opportunities, the risk associated with failure or delay of any single project would not have a significant impact on the Corpora liquidity or ability to generate sufficient cash flows for operations and its fixed commitments. The purchase and sale of oil and gas properties not had a significant impact on the amount or timing of cash flows from operating activities.

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

Cash Flow from Operating Activities

2012

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

2011

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

Cash Flow from Investing Activities

2012

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

2011

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

Cash Flow from Financing Activities

2012

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

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

During 2012, Exxon Mobil Corporation purchased 244 million shares of its common stock for the treasury at a gross cost of $21.1 billion. purchases were to reduce the number of shares outstanding and to offset shares issued in conjunction with company benefit plans and prog Shares outstanding were reduced by 4.9 percent from 4,734 million to 4,502 million at the end of 2012. Purchases were made in both the market and through negotiated transactions. Purchases may be increased, decreased or discontinued at any time without prior notice.

2011

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

ExxonMobil share of equity increased $7.6 billion to $154.4 billion. The addition to equity for earnings of $41.1 billion was partially off reductions for distributions to ExxonMobil shareholders of $9.0 billion of dividends and $20.0 billion of

purchases of shares of ExxonMobil stock to reduce shares outstanding. The change in the funded status of the postretirement benefits reser 2011 decreased equity by $4.6 billion.

During 2011, Exxon Mobil Corporation purchased 278 million shares of its common stock for the treasury at a gross cost of $22.1 billion. purchases were to reduce the number of shares outstanding and to offset shares issued in conjunction with company benefit plans and prog Shares outstanding were reduced by 4.9 percent from 4,979 million to 4,734 million at the end of 2011. Purchases were made in both the market and through negotiated transactions.

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

Commitments

Set forth below is information about the outstanding commitments of the Corporation's consolidated subsidiaries at December 31, 2012. It con data from the Consolidated Balance Sheet and from individual notes to the Consolidated Financial Statements.

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

This table excludes commodity purchase obligations (volumetric commitments but no fixed or minimum price) which are resold shortly purchase, either in an active, highly liquid market or under long-term, unconditional sales contracts with similar pricing terms. Examples in long-term, noncancelable LNG and natural gas purchase commitments and commitments to purchase refinery products at market prices. Inclus such commitments would not be meaningful in assessing liquidity and cash flow, because these purchases will be offset in the same periods by received from the related sales transactions. The table also excludes unrecognized tax benefits totaling $7.7 billion as of December 31, because the Corporation is unable to make reasonably reliable estimates of the timing of cash settlements with the respective taxing autho Further details on the unrecognized tax benefits can be found in Note 19, Income, Sales-Based and Other Taxes.

Notes:

(1) Includes capitalized lease obligations of $431 million.

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

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

(4) The amount by which the benefit obligations exceeded the fair value of fund assets for certain U.S. and non-U.S. pension and postretirement plans at year end. The payments by period include expected contributions to funded pension plans in 2013 and estimated b 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 properties.

(6) Unconditional purchase obligations (UPOs) are those long-term commitments that are noncancelable or cancelable only under c conditions, and that third parties have used to secure financing for the facilities that will provide the contracted goods or services undiscounted obligations of $1,127 million mainly pertain to pipeline throughput agreements and include $584 million of obligations to companies.

(7) Take-or-pay obligations are noncancelable, long-term commitments for goods and services other than UPOs. The undiscounted obligati $26,209 million mainly pertain to manufacturing supply, pipeline and terminaling agreements and include $187 million of obligations to companies.

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

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

Guarantees

The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2012, for guarantees relating to notes, and performance under contracts (Note 16). Where guarantees for environmental remediation and other similar matters do not include a state the amounts reflect management's estimate of the maximum potential exposure. These guarantees are not reasonably likely to have a material on the Corporation's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditu capital resources.

Financial Strength

On December 31, 2012, unused credit lines for short-term financing totaled approximately $3.5 billion (Note 6).

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

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

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

Litigation and Other Contingencies

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

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

CAPITAL AND EXPLORATION EXPENDITURES

	2012			2011		
	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	T
			(millions of dollars)			
Upstream *(1)*	11,080	25,004	36,084	10,741	22,350	3
Downstream	634	1,628	2,262	518	1,602	
Chemical	408	1,010	1,418	290	1,160	
Other	35	-	35	105	-	
Total	12,157	27,642	39,799	11,654	25,112	3

(1) Exploration expenses included.

Capital and exploration expenditures in 2012 were $39.8 billion, as the Corporation continued to pursue opportunities to find and produc supplies of oil and natural gas to meet global demand for energy. The Corporation anticipates an investment profile of about $38 billion per ye the next several years. Actual spending could vary depending on the progress of individual projects and property acquisitions.

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

TAXES

	2012	2011	2(
		(millions of dollars)	
Income taxes	31,045	31,051	2
Effective income tax rate	*44%*	*46%*	
Sales-based taxes	32,409	33,503	2
All other taxes and duties	38,857	43,544	3
Total	102,311	108,098	8

2012

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

2011

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

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

ENVIRONMENTAL MATTERS

Environmental Expenditures

	2012	2(
	(millions of dollars)	
Capital expenditures	1,989	
Other expenditures	3,523	
Total	5,512	

Throughout ExxonMobil's businesses, new and ongoing measures are taken to prevent and minimize the impact of our operations on air, wat ground. These include a significant investment in refining infrastructure and technology to manufacture clean fuels as well as projects to m and reduce nitrogen oxide, sulfur oxide and greenhouse gas emissions and expenditures for asset retirement obligations. Using definitior guidelines established by the American Petroleum Institute, ExxonMobil's 2012 worldwide environmental expenditures for all such preventativ remediation steps, including ExxonMobil's share of equity company expenditures, were about $5.5 billion. The total cost for such activi expected to have a modest increase in 2013 and 2014 (with capital expenditures approximately 45 percent of the total).

Environmental Liabilities

The Corporation accrues environmental liabilities when it is probable that obligations have been incurred and the amounts can be reasc estimated. This policy applies to assets or businesses currently owned or previously disposed. ExxonMobil has accrued liabilities for pro environmental remediation obligations at various sites, including multiparty sites where the U.S. Environmental Protection Agency has ider ExxonMobil as one of the potentially responsible parties. The involvement of other financially responsible companies at these multiparty sites mitigate ExxonMobil's actual joint and several liability exposure. At present, no individual site is expected to have losses material to ExxonM operations or financial condition. Consolidated company provisions made in 2012 for environmental liabilities were $391 million ($420 mill 2011) and the balance sheet reflects accumulated liabilities of $841 million as of December 31, 2012, and $886 million as of December 31, 201

MARKET RISKS, INFLATION AND OTHER UNCERTAINTIES

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

(1) Consolidated subsidiaries.

Crude oil, natural gas, petroleum product and chemical prices have fluctuated in response to changing market forces. The impacts of these fluctuations on earnings from Upstream, Downstream and Chemical operations have varied. In the Upstream, a $1 per barrel change weighted-average realized price of oil would have approximately a $350 million annual after-tax effect on Upstream consolidated plus company earnings. Similarly, a $0.10 per kcf change in the worldwide average gas realization would have approximately a $200 million a after-tax effect on Upstream consolidated plus equity company earnings. For any given period, the extent of actual benefit or detriment w dependent on the price movements of individual types of crude oil, taxes and other government take impacts, price adjustment lags in long-ter contracts, and crude and gas production volumes. Accordingly, changes in benchmark prices for crude oil and natural gas only provide 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 levels of products sold. Refining margins are a function of the difference between what a refiner pays for its raw materials (primarily crude oi the market prices for the range of products produced. These prices in turn depend on global and regional supply/demand balances, inventory l 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 Corpora businesses. Such conditions, along with the capital-intensive nature of the industry and very long lead times associated with many of our pro underscore the importance of maintaining a strong financial position. Management views the Corporation's financial strength as a comp advantage.

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

In general, segment results are not dependent on the ability to sell and/or purchase products to/from other segments. Instead, where such take place, they are the result of efficiencies and competitive advantages of integrated refinery/chemical complexes. Additionally, intersegmen are at market-based prices. The products bought and sold between segments can also be acquired in worldwide markets that have subst liquidity, capacity and transportation capabilities. About 35 percent of the Corporation's intersegment sales are crude oil produced by the Ups and sold to the Downstream. Other intersegment sales include those between refineries and chemical plants related to raw materials, feedstocl 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, (actions and other factors, industry economics over the long term will continue to be driven by market supply and demand. Accordingl Corporation tests the viability of all of its investments over a broad range of future prices. The Corporation's assessment is that its operation continue to be successful in a variety of market conditions. This is the outcome of disciplined investment and asset management programs.

The Corporation has an active asset management program in which underperforming assets are either improved to acceptable levels or cons for divestment. The asset management program includes a disciplined, regular review to ensure that all assets are contributing to the Corpora strategic objectives. The result is an efficient capital base, and the Corporation has seldom had to write down the carrying value of assets 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 Che businesses reduce the Corporation's enterprise-wide risk from changes in interest rates, currency rates and commodity prices. As a resu Corporation makes limited use of derivative instruments to mitigate the impact of such changes. With respect to derivatives activitie Corporation believes that there are no material market or credit risks to the Corporation's financial position, results of operations or liquidit result of the derivatives described in Note 13. The Corporation does not engage in speculative derivative activities or derivative trading activiti does it use derivatives with leveraged features. Credit risk associated with the Corporation's derivative position is mitigated by several fa including the quality of and financial limits placed on derivative counterparties. The Corporation maintains a system of controls that includ authorization, reporting and monitoring of derivative activity.

The Corporation is exposed to changes in interest rates, primarily on its short-term debt and the portion of long-term debt that carries fl interest rates. The impact of a 100-basis-point change in interest rates affecting the Corporation's debt would not be material to earnings, casl or fair value. Although the Corporation issues long-term debt from time to time and maintains a commercial paper program, internally gen funds are expected to cover the majority of its net near-term financial requirements. However, some joint-venture partners are dependent (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, exp financing and investment transactions. The impacts of fluctuations in exchange rates on ExxonMobil's geographically and functionally d operations are varied and often offsetting in amount. The Corporation makes limited use of currency exchange contracts to mitigate the imp changes in currency values, and exposures related to the Corporation's limited use of the currency exchange contracts are not material.

Inflation and Other Uncertainties

The general rate of inflation in many major countries of operation has remained moderate over the past few years, and the associated impact or energy costs has generally been mitigated by cost reductions from efficiency and productivity improvements. Increased demand for certain se and materials has resulted in higher operating and capital costs in recent years. The Corporation works to counter upward pressure on costs th its economies of scale in global procurement and its efficient project management practices.

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

CRITICAL ACCOUNTING ESTIMATES

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

Oil and Gas Reserves

Evaluations of oil and gas reserves are important to the effective management of upstream assets. They are integral to making investment dec about oil and gas properties such as whether development should proceed. Oil and gas reserve quantities are also used as the basis for calcu unit-of-production depreciation rates and for evaluating impairment.

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

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

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

Proved reserves can be further subdivided into developed and undeveloped reserves. The percentage of proved developed reserves was 61 p of total proved reserves at year-end 2012 (including both consolidated and equity company reserves), and has been over 60 percent for the la years, indicating that proved reserves are consistently moved from undeveloped to developed status.

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

Impact of Oil and Gas Reserves on Depreciation. The calculation of unit-of-production depreciation is a critical accounting estimat measures the depreciation of upstream assets. It is the ratio of actual volumes produced to total proved developed reserves (those proved re recoverable through existing wells with existing equipment and operating methods), applied to the asset cost. The volumes produced and ass are known and, while proved developed reserves have a high probability of recoverability, they are based on estimates that are subject to 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 u 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 Corporati reviewed for impairment whenever events or circumstances indicate that the carrying amounts may not be recoverable. Assets are grouped 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 am Impairment analyses are generally based on proved reserves. Where probable reserves exist, an appropriately risk-adjusted amount of these re may be included in the impairment evaluation. An asset group would be impaired if its undiscounted cash flows were less than the asset's ca value. Impairments are measured by the amount by which the carrying value exceeds fair value.

Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are rec based on the estimated economic chance of success and the length of time that the Corporation expects to hold the properties. Properties that a individually significant are aggregated by groups and amortized based on development risk and average holding period.

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

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

In general, the Corporation does not view temporarily low prices or margins as a trigger event for conducting the impairment tests. The m for crude oil and natural gas have a history of significant price volatility. Although prices will occasionally drop significantly, industry price the long term will continue to be driven by market supply and demand. On the supply side, industry production from mature fields is declinin this is being offset by production from new discoveries and field developments. OPEC production policies also have an impact on wo supplies. The demand side is largely a function of global economic growth. The relative growth/decline in supply versus demand will dete 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 a planning and budgeting process for the crude oil and natural gas markets, petroleum products and chemicals. These are the same price assum that are used for capital investment decisions. Volumes are based on field production profiles, which are updated annually. Cash flow estimat 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 no consolidated financial statements. Future prices used for any impairment tests will vary from the ones used in the supplemental oil ar disclosure and could be lower or higher for any given year.

Asset Retirement Obligations

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

Suspended Exploratory Well Costs

The Corporation continues capitalization of exploratory well costs when the well has found a sufficient quantity of reserves to justify its comp as a producing well and the Corporation is making sufficient progress assessing the reserves and the economic and operating viability of the p Exploratory well costs not meeting these criteria are charged to expense. The facts and circumstances that support continued capitalizat suspended wells as of year-end 2012 are disclosed in Note 10 to the financial statements.

Consolidations

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

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

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

Pension Benefits

The Corporation and its affiliates sponsor over 100 defined benefit (pension) plans in about 50 countries. Pension and Other Postretirement Be (Note 17) provides details on pension obligations, fund assets and pension expense.

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

For funded plans, including those in the U.S., pension obligations are financed in advance through segregated assets or insurance arranger These plans are managed in compliance with the requirements of governmental authorities and meet or exceed required funding levels as mea by relevant actuarial and government standards at the mandated measurement dates. In determining liabilities and required contributions, 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 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 discou for the benefit obligations and the long-term rate for future salary increases. Pension assumptions are reviewed annually by outside actuarie senior management. These assumptions are adjusted as appropriate to reflect changes in market rates and outlook. The long-term expected ear rate on U.S. pension plan assets in 2012 was 7.25 percent. The 10-year and 20-year actual returns on U.S. pension plan assets were both 9 pe The Corporation establishes the long-term expected rate of return by developing a forward-looking, long-term return assumption for each pe fund asset class, taking into account factors such as the expected real return for the specific asset class and inflation. A single, long-term r return is then calculated as the weighted average of the target asset allocation percentages and the long-term return assumption for each asset cl worldwide reduction of 0.5 percent in the long-term rate of return on assets would increase annual pension expense by approximately $150 n before tax.

Differences between actual returns on fund assets and the long-term expected return are not recognized in pension expense in the year th difference occurs. Such differences are deferred, along with other actuarial gains and losses, and are amortized into pension expense ov 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 lav Management has regular litigation reviews, including updates from corporate and outside counsel, to assess the need for accounting recognit disclosure of these contingencies. The status of significant claims is summarized in Note 16.

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

Management judgment is required related to contingent liabilities and the outcome of litigation because both are difficult to predict. Howev Corporation has been successful in defending litigation in the past. Payments have not had a material adverse effect on operations or fin condition. In the Corporation's experience, large claims often do not result in large awards. Large awards are often reversed or substantially re 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 accounting for income tax contingencies and tax disputes because the outcomes are often difficult to predict.

The benefits of uncertain tax positions that the Corporation has taken or expects to take in its income tax returns are recognized in the fin 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 l amount that is greater than 50 percent likely of being realized. A reserve is established for the difference between a position taken or expected taken in an income tax return and the amount recognized in the financial statements. The Corporation’s unrecognized tax benefits and a descr of open tax years are summarized in Note 19.

Foreign Currency Translation

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

Factors considered by management when determining the functional currency for a subsidiary include the currency used for cash flows rela individual assets and liabilities; the responsiveness of sales prices to changes in exchange rates; the history of inflation in the country; whethe are into local markets or exported; the currency used to acquire raw materials, labor, services and supplies; sources of financing; and significa 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 responsib establishing and maintaining adequate internal control over the Corporation's financial reporting. Management conducted an evaluation effectiveness of internal control over financial reporting based on criteria established in *Internal Control – Integrated Framework* issued b Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Exxon Corporation's internal control over financial reporting was effective as of December 31, 2012.

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

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

pwc

To the Shareholders of Exxon Mobil Corporation:

In our opinion, the accompanying Consolidated Balance Sheets and the related Consolidated Statements of Income, Comprehensive In Changes in Equity and Cash Flows present fairly, in all material respects, the financial position of Exxon Mobil Corporation and its subsidia December 31, 2012, and 2011, and the results of their operations and their cash flows for each of the three years in the period ended Decemb 2012, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Corporation maint in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal C – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Corpora management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessm the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Fin Reporting. Our responsibility is to express opinions on these financial statements and on the Corporation's internal control over financial rep based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial state are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our au the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, ass the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reaso basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of fin reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principl company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records tl reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assuranc transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principle that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the com and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the comp 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 c evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or tl degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Dallas, Texas
February 27, 2013

CONSOLIDATED STATEMENT OF INCOME

	Note Reference Number	2012	2011	201
			(millions of dollars)	
Revenues and other income				
Sales and other operating revenue *(1)*		453,123	467,029	37
Income from equity affiliates	7	15,010	15,289	1
Other income		14,162	4,111	
Total revenues and other income		482,295	486,429	38
Costs and other deductions				
Crude oil and product purchases		265,149	266,534	19
Production and manufacturing expenses		38,521	40,268	3
Selling, general and administrative expenses		13,877	14,983	1
Depreciation and depletion		15,888	15,583	1
Exploration expenses, including dry holes		1,840	2,081	
Interest expense		327	247	
Sales-based taxes *(1)*	19	32,409	33,503	2
Other taxes and duties	19	35,558	39,973	3
Total costs and other deductions		403,569	413,172	33
Income before income taxes		78,726	73,257	5
Income taxes	19	31,045	31,051	2
Net income including noncontrolling interests		47,681	42,206	3
Net income attributable to noncontrolling interests		2,801	1,146	
Net income attributable to ExxonMobil		44,880	41,060	3
Earnings per common share (dollars)	12	9.70	8.43	
Earnings per common share - assuming dilution (dollars)	12	9.70	8.42	

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

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

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	2012	2011	201
		(millions of dollars)	
Net income including noncontrolling interests	47,681	42,206	3
Other comprehensive income (net of income taxes)			
Foreign exchange translation adjustment	920	(867)	
Adjustment for foreign exchange translation (gain)/loss included in net income	(4,352)	-	
Postretirement benefits reserves adjustment (excluding amortization)	(3,574)	(4,907)	(
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	2,395	1,217	
Change in fair value of cash flow hedges	-	28	
Realized (gain)/loss from settled cash flow hedges included in net income	-	(83)	
Total other comprehensive income	(4,611)	(4,612)	
Comprehensive income including noncontrolling interests	43,070	37,594	3
Comprehensive income attributable to noncontrolling interests	1,251	834	
Comprehensive income attributable to ExxonMobil	41,819	36,760	3

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

CONSOLIDATED BALANCE SHEET

	Note Reference Number	Dec. 31 2012	Dec. 2011
		(millions of dollars)	
Assets			
Current assets			
Cash and cash equivalents		9,582	1
Cash and cash equivalents - restricted		341	
Notes and accounts receivable, less estimated doubtful amounts	6	34,987	3
Inventories			
Crude oil, products and merchandise	3	10,836	1
Materials and supplies		3,706	
Other current assets		5,008	
Total current assets		64,460	7
Investments, advances and long-term receivables	8	34,718	3
Property, plant and equipment, at cost, less accumulated depreciation and depletion	9	226,949	21
Other assets, including intangibles, net		7,668	
Total assets		333,795	33
Liabilities			
Current liabilities			
Notes and loans payable	6	3,653	
Accounts payable and accrued liabilities	6	50,728	5
Income taxes payable		9,758	1
Total current liabilities		64,139	7
Long-term debt	14	7,928	
Postretirement benefits reserves	17	25,267	2
Deferred income tax liabilities	19	37,570	3
Long-term obligations to equity companies		3,555	
Other long-term obligations		23,676	2
Total liabilities		162,135	17
Commitments and contingencies	16		
Equity			
Common stock without par value (9,000 million shares authorized, 8,019 million shares issued)		9,653	
Earnings reinvested		365,727	33
Accumulated other comprehensive income		(12,184)	(
Common stock held in treasury (3,517 million shares in 2012 and 3,285 million shares in 2011)		(197,333)	(17
ExxonMobil share of equity		165,863	15
Noncontrolling interests		5,797	
Total equity		171,660	16
Total liabilities and equity		333,795	33

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

CONSOLIDATED STATEMENT OF CASH FLOWS

	Note Reference Number	2012	2011	201
			(millions of dollars)	
Cash flows from operating activities				
Net income including noncontrolling interests		47,681	42,206	3
Adjustments for noncash transactions				
Depreciation and depletion		15,888	15,583	1
Deferred income tax charges/(credits)		3,142	142	(1
Postretirement benefits expense in excess of/(less than) net payments		(315)	544	
Other long-term obligation provisions in excess of/(less than) payments		1,643	(151)	
Dividends received greater than/(less than) equity in current earnings of equity companies		(1,157)	(273)	
Changes in operational working capital, excluding cash and debt				
Reduction/(increase) - Notes and accounts receivable		(1,082)	(7,906)	(
- Inventories		(1,873)	(2,208)	(
- Other current assets		(42)	222	
Increase/(reduction) - Accounts and other payables		3,624	8,880	
Net (gain) on asset sales	5	(13,018)	(2,842)	(
All other items - net		1,679	1,148	
Net cash provided by operating activities		56,170	55,345	4
Cash flows from investing activities				
Additions to property, plant and equipment		(34,271)	(30,975)	(2
Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments	5	7,655	11,133	
Decrease/(increase) in restricted cash and cash equivalents		63	224	
Additional investments and advances		(972)	(3,586)	(
Collection of advances		1,924	1,119	
Additions to marketable securities		-	(1,754)	
Sales of marketable securities		-	1,674	
Net cash used in investing activities		(25,601)	(22,165)	(2
Cash flows from financing activities				
Additions to long-term debt		995	702	
Reductions in long-term debt		(147)	(266)	(
Additions to short-term debt		958	1,063	
Reductions in short-term debt		(4,488)	(1,103)	(
Additions/(reductions) in debt with three months or less maturity		(226)	1,561	
Cash dividends to ExxonMobil shareholders		(10,092)	(9,020)	(
Cash dividends to noncontrolling interests		(327)	(306)	
Changes in noncontrolling interests		204	(16)	
Tax benefits related to stock-based awards		130	260	
Common stock acquired		(21,068)	(22,055)	(1
Common stock sold		193	924	
Net cash used in financing activities		(33,868)	(28,256)	(2
Effects of exchange rate changes on cash		217	(85)	
Increase/(decrease) in cash and cash equivalents		(3,082)	4,839	(
Cash and cash equivalents at beginning of year		12,664	7,825	1
Cash and cash equivalents at end of year		9,582	12,664	

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

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	ExxonMobil Share of Equity					
	Common Stock	Earnings Reinvested	Accumulated Other Comprehensive Income	Common Stock Held in Treasury	ExxonMobil Share of Equity	Non-controlling Interests
	(millions of dollars)					
Balance as of December 31, 2009	5,503	276,937	(5,461)	(166,410)	110,569	4,823
Amortization of stock-based awards	751	-	-	-	751	-
Tax benefits related to stock-based awards	280	-	-	-	280	-
Other	(683)	-	-	-	(683)	10
Net income for the year	-	30,460	-	-	30,460	938
Dividends - common shares	-	(8,498)	-	-	(8,498)	(281)
Other comprehensive income	-	-	638	-	638	355
Acquisitions, at cost	-	-	-	(13,093)	(13,093)	(5)
Issued for XTO merger	3,520	-	-	21,139	24,659	-
Other dispositions	-	-	-	1,756	1,756	-
Balance as of December 31, 2010	9,371	298,899	(4,823)	(156,608)	146,839	5,840
Amortization of stock-based awards	742	-	-	-	742	-
Tax benefits related to stock-based awards	202	-	-	-	202	-
Other	(803)	-	-	-	(803)	(5)
Net income for the year	-	41,060	-	-	41,060	1,146
Dividends - common shares	-	(9,020)	-	-	(9,020)	(306)
Other comprehensive income	-	-	(4,300)	-	(4,300)	(312)
Acquisitions, at cost	-	-	-	(22,055)	(22,055)	(15)
Dispositions	-	-	-	1,731	1,731	-
Balance as of December 31, 2011	9,512	330,939	(9,123)	(176,932)	154,396	6,348
Amortization of stock-based awards	806	-	-	-	806	-
Tax benefits related to stock-based awards	178	-	-	-	178	-
Other	(843)	-	-	-	(843)	(1,441)
Net income for the year	-	44,880	-	-	44,880	2,801
Dividends - common shares	-	(10,092)	-	-	(10,092)	(327)
Other comprehensive income	-	-	(3,061)	-	(3,061)	(1,550)
Acquisitions, at cost	-	-	-	(21,068)	(21,068)	(34)
Dispositions	-	-	-	667	667	-
Balance as of December 31, 2012	9,653	365,727	(12,184)	(197,333)	165,863	5,797

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

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 managem Exxon Mobil Corporation.

The Corporation's principal business is energy, involving the worldwide exploration, production, transportation and sale of crude oil and n gas (Upstream) and the manufacture, transportation and sale of petroleum products (Downstream). The Corporation is also a major worl 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 managem make estimates that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liab Actual results could differ from these estimates. Prior years' data has been reclassified in certain cases to conform to the 2012 presentation basi

1. Summary of Accounting Policies

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

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

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

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

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

Revenue Recognition. The Corporation generally sells crude oil, natural gas and petroleum and chemical products under short-term agreem prevailing market prices. In some cases (e.g., natural gas), products may be sold under long-term agreements, with periodic price adjust Revenues are recognized when the products are delivered, which occurs when the customer has taken title and has assumed the risks and rewa 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 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 recor 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 Stat of Income (included in both revenues and costs).

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

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Level 2 inputs are inputs other than quoted prices included within Level 1 that are directly or indirectly observable for the asset or lia 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 the last-in, first-out method – LIFO). Inventory costs include expenditures and other charges (including depreciation) directly and indirectly in in bringing the inventory to its existing condition and location. Selling expenses and general and administrative expenses are reported as perioc 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 prin determined under either the unit-of-production method or the straight-line method, which is based on estimated asset service life taking obsoles into consideration. Maintenance and repairs, including planned major maintenance, are expensed as incurred. Major renewals and improvemen 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 c acquiring the constructed assets. The project construction phase commences with the development of the detailed engineering design and ends the constructed assets are ready for their intended use. Capitalized interest costs are included in property, plant and equipment and are depre 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, cos accumulated on a field-by-field basis with certain exploratory expenditures and exploratory dry holes being expensed as incurred. Co 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 completio producing well and where the Corporation is making sufficient progress assessing the reserves and the economic and operating viability project. Exploratory well costs not meeting these criteria are charged to expense. Other exploratory expenditures, including geophysical cos annual lease rentals, are expensed as incurred.

Acquisition costs of proved properties are amortized using a unit-of-production method, computed on the basis of total proved oil an reserves.

Capitalized exploratory drilling and development costs associated with productive depletable extractive properties are amortized using un production rates based on the amount of proved developed reserves of oil, gas and other minerals that are estimated to be recoverable from ex 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 cu 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 processin field storage of the oil and gas. The production function normally terminates at the outlet valve on the lease or field production storage Production costs are those incurred to operate and maintain the Corporation's wells and related equipment and facilities. They become part 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 r equipment; repair and maintenance costs on the wells and equipment; materials, supplies and energy costs required to operate the wells and r equipment; and administrative expenses related to the production activity.

Proved oil and gas properties held and used by the Corporation are reviewed for impairment whenever events or changes in circumst indicate that the carrying amounts may not be recoverable. Assets are grouped at the lowest level for which there are identifiable cash flows th 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. flows used in impairment evaluations are developed using annually updated corporate plan investment evaluation assumptions for cru commodity prices, refining and chemical margins and foreign currency exchange rates. Annual volumes are based on field production pr which are also updated annually. Prices for natural gas and other products are based on corporate plan assumptions developed annually by 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 reserves may be included in the impairment evaluation. An asset group would be impaired if the undiscounted cash flows were less than its ca value. Impairments are measured by the amount the carrying value exceeds fair value.

Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are rec based on the estimated economic chance of success and the length of time that the Corporation expects to hold the properties. Properties that a individually significant are aggregated by groups and amortized based on development risk and average holding period. The valuation allow are reviewed at least annually.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

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

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

Liabilities for environmental costs are recorded when it is probable that obligations have been incurred and the amounts can be reaso 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 curre 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 o inflation (primarily in Latin America) and Singapore, which predominantly sells into the U.S. dollar export market. Upstream operations whi relatively self-contained and integrated within a particular country, such as Canada, the United Kingdom, Norway and continental Europe, u local currency. Some Upstream operations, primarily in Asia and Africa, use the U.S. dollar because they predominantly sell crude and natur 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 Compensation expense is measured by the market price of the restricted shares at the date of grant and is recognized in the income statemen the requisite service period of each award. See Note 15, Incentive Program, for further details.

2. Accounting Changes

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

3. Miscellaneous Financial Information

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

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

In 2012, 2011 and 2010, net income included gains of $328 million, $292 million and $317 million, respectively, attributable to the com effects of LIFO inventory accumulations and drawdowns. The aggregate replacement cost of inventories was estimated to exceed their carrying values by $21.3 billion and $25.6 billion at December 31, 2012, and 2011, respectively.

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

	2012
	(billions of dollars)
Petroleum products	3.6
Crude oil	4.0
Chemical products	2.9
Gas/other	0.3
Total	10.8

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

4. Other Comprehensive Income Information

ExxonMobil Share of Accumulated Other Comprehensive Income	**Cumulative Foreign Exchange Translation Adjustment**	**Post-retirement Benefits Reserves Adjustment**	**Unrealized Change in Fair Value on Cash Flow Hedges**	**Total**
		(millions of dollars)		
Balance as of December 31, 2009	4,402	(9,863)	-	(5,4
Current period change excluding amounts reclassified from accumulated other comprehensive income	584	(1,014)	184	(2
Amounts reclassified from accumulated other comprehensive income	25	988	(129)	8
Total change in accumulated other comprehensive income	609	(26)	55	6
Balance as of December 31, 2010	5,011	(9,889)	55	(4,8
Balance as of December 31, 2010	5,011	(9,889)	55	(4,8
Current period change excluding amounts reclassified from accumulated other comprehensive income	(843)	(4,557)	28	(5,3
Amounts reclassified from accumulated other comprehensive income	-	1,155	(83)	1,0
Total change in accumulated other comprehensive income	(843)	(3,402)	(55)	(4,3
Balance as of December 31, 2011	4,168	(13,291)	-	(9,1
Balance as of December 31, 2011	4,168	(13,291)	-	(9,1
Current period change excluding amounts reclassified from accumulated other comprehensive income	842	(3,402)	-	(2,5
Amounts reclassified from accumulated other comprehensive income	(2,600)	2,099	-	(5
Total change in accumulated other comprehensive income	(1,758)	(1,303)	-	(3,0
Balance as of December 31, 2012	2,410	(14,594)	-	(12,1

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

5. Cash Flow Information

The Consolidated Statement of Cash Flows provides information about changes in cash and cash equivalents. Highly liquid investments 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 befo gains from the Japan restructuring, the sale of an Upstream property in Angola, exchanges of Upstream properties, the sale of U.S. service sta and the sale of the Downstream affiliates in Malaysia and Switzerland in 2012; from the sale of some Upstream Canadian, U.K. and other proc properties and assets, and the sale of U.S. service stations in 2011; and from the sale of some Upstream Gulf of Mexico and other proc properties, the sale of U.S. service stations and other Downstream assets and investments and the formation of a Chemical joint venture in These gains are reported in "Other income" on the Consolidated Statement of Income.

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

In 2012, ExxonMobil completed asset exchanges, primarily noncash transactions, of approximately $1 billion. This amount is not included "Sales of subsidiaries, investments, and property, plant and equipment" or the "Additions to property, plant and equipment" lines on the Statem Cash Flows.

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

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

	2012	2011	2(
		(millions of dollars)	
Cash payments for interest	555	557	
Cash payments for income taxes	24,349	27,254	1

6. Additional Working Capital Information

	Dec. 31 2012	De 2(
	(millions of dollars)	
Notes and accounts receivable		
Trade, less reserves of $109 million and $128 million	28,373	3
Other, less reserves of $36 million and $39 million	6,614	
Total	34,987	3
Notes and loans payable		
Bank loans	663	
Commercial paper	1,963	
Long-term debt due within one year	1,025	
Other	2	
Total	3,653	
Accounts payable and accrued liabilities		
Trade payables	33,789	3
Payables to equity companies	6,114	
Accrued taxes other than income taxes	4,130	
Other	6,695	1
Total	50,728	5

On December 31, 2012, unused credit lines for short-term financing totaled approximately $3.5 billion. Of this total, $3.0 billion su commercial paper programs under terms negotiated when drawn. The weighted-average interest rate on short-term borrowings outstand December 31, 2012, and 2011, was 1.7 percent and 1.9 percent, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

7. Equity Company Information

The summarized financial information below includes amounts related to certain less-than-majority-owned companies and majority-c subsidiaries where minority shareholders possess the right to participate in significant management decisions (see Note 1). These compani primarily engaged in crude production, natural gas production, natural gas marketing and refining operations in North America; natur production, natural gas distribution and downstream operations in Europe; refining operations, petrochemical manufacturing, fuel sales and generation in Asia; crude production in Kazakhstan; and liquefied natural gas (LNG) operations in Qatar. Also included are several ref petrochemical manufacturing and chemical ventures. The Corporation's ownership in these ventures is in the form of shares in corporate ventures as well as interests in partnerships. Differences between the company's carrying value of an equity investment and its underlying equ the net assets of the affiliate are assigned to the extent practicable to specific assets and liabilities based on the company's analysis of the f giving rise to the difference. The amortization of this difference, as appropriate, is included in "income from equity affiliates." The share o equity company revenues from sales to ExxonMobil consolidated companies was 16 percent, 19 percent and 18 percent in the years 2012, 201 2010, respectively.

Equity Company Financial Summary	2012 Total	2012 ExxonMobil Share	2011 Total	2011 ExxonMobil Share	2010 Total	2010 ExxonM Sha
			(millions of dollars)			
Total revenues	224,953	67,572	204,635	65,147	153,020	4
Income before income taxes	69,411	20,882	68,908	20,892	48,075	1
Income taxes	20,703	5,868	19,812	5,603	13,962	
Income from equity affiliates	48,708	15,014	49,096	15,289	34,113	1
Current assets	59,612	18,483	52,879	17,317	48,573	1
Long-term assets	111,131	33,798	96,908	30,833	90,646	2
Total assets	170,743	52,281	149,787	48,150	139,219	4
Current liabilities	49,698	14,265	41,016	12,454	33,160	1
Long-term liabilities	68,855	19,715	62,472	18,728	59,596	1
Net assets	52,190	18,301	46,299	16,968	46,463	1

A list of significant equity companies as of December 31, 2012, together with the Corporation's percentage ownership interest, is detailed belo

	Percentage Ownership Interest
Upstream	
Aera Energy LLC	48
BEB Erdgas und Erdoel GmbH & Co. KG	50
Cameroon Oil Transportation Company S.A.	41
Castle Peak Power Company Limited	60
Cross Timbers Energy, LLC	50
Golden Pass LNG Terminal LLC	18
Nederlandse Aardolie Maatschappij B.V.	50
Qatar Liquefied Gas Company Limited	10
Qatar Liquefied Gas Company Limited (2)	24
Ras Laffan Liquefied Natural Gas Company Limited	25
Ras Laffan Liquefied Natural Gas Company Limited (II)	31
Ras Laffan Liquefied Natural Gas Company Limited (3)	30
South Hook LNG Terminal Company Limited	24
Tengizchevroil, LLP	25
Terminale GNL Adriatico S.r.l.	71

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

8. Investments, Advances and Long-Term Receivables

	Dec. 31, 2012	De 2
	(millions of dollars)	
Companies carried at equity in underlying assets		
Investments	18,530	1
Advances	9,959	
Total equity company investments and advances	28,489	2
Companies carried at cost or less and stock investments carried at fair value	437	
Long-term receivables and miscellaneous investments at cost or less, net of reserves of $2,499 million and $469 million	5,792	
Total	34,718	3

9. Property, Plant and Equipment and Asset Retirement Obligations

Property, Plant and Equipment	December 31, 2012		December 31, 2011	
	Cost	Net	Cost	Ne
	(millions of dollars)			
Upstream	313,181	181,795	283,710	16
Downstream	53,737	23,053	67,900	2
Chemical	29,437	14,085	30,405	1
Other	12,959	8,016	11,980	
Total	409,314	226,949	393,995	21

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

Accumulated depreciation and depletion totaled $182,365 million at the end of 2012 and $179,331 million at the end of 2011. Interest capit in 2012, 2011 and 2010 was $506 million, $593 million and $532 million, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Asset Retirement Obligations

The Corporation incurs retirement obligations for certain assets. The fair values of these obligations are recorded as liabilities on a discounted which is typically at the time the assets are installed. In the estimation of fair value, the Corporation uses assumptions and judgments regardin factors as the existence of a legal obligation for an asset retirement obligation; technical assessments of the assets; estimated amounts and tim settlements; discount rates; and inflation rates. Asset retirement obligations incurred in the current period were Level 3 (unobservable input value measurements. The costs associated with these liabilities are capitalized as part of the related assets and depreciated as the reserv 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 and dismantled. These obligations may include the costs of asset disposal and additional soil remediation. However, these sites have indeter lives based on plans for continued operations and as such, the fair value of the conditional legal obligations cannot be measured, sinc impossible to estimate the future settlement dates of such obligations.

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

	2012	
	(millions of dollars)	
Beginning balance	10,578	
Accretion expense and other provisions	709	
Reduction due to property sales	(176)	
Payments made	(816)	
Liabilities incurred	163	
Foreign currency translation	290	
Revisions	1,225	
Ending balance	11,973	1

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

10. Accounting for Suspended Exploratory Well Costs

The Corporation continues capitalization of exploratory well costs when the well has found a sufficient quantity of reserves to justify its comp as a producing well and the Corporation is making sufficient progress assessing the reserves and the economic and operating viability of the p The term "project" as used in this report does not necessarily have the same meaning as under SEC Rule 13q-1 relating to government pa reporting. For example, a single project for purposes of the rule may encompass numerous properties, agreements, investments, develop phases, work efforts, activities, and components, each of which we may also informally describe as a "project."

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

Change in capitalized suspended exploratory well costs:

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

Period end capitalized suspended exploratory well costs:

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

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

Country/Project	Dec. 31, 2012	Years Wells Drilled	Comment
	(millions of dollars)		
Angola			
- Perpetua-Zina-Acacia	15	2008 - 2009	Oil field near Pazflor development, awaiting capacity in existing/planned infrastructure.
Australia			
- East Pilchard	10	2001	Gas field near Kipper/Tuna development, awaiting capacity in existing/planned infrastructure.
- SE Longtom	16	2010	Gas field near Tuna development, awaiting capacity in existing/planned infrastructure.
Indonesia			
- Natuna	118	1981 - 1983	Development activity under way, while continuing discussions with the government on contract terms pursuant to executed Heads of Agreement.
Kazakhstan			
- Kairan	53	2004 - 2007	Evaluating commercialization and field development alternatives, while continuing discussions with the government regarding the development plan.
Malaysia			
- Besar	18	1992 - 2010	Gas field off the east coast of Malaysia; progressing development plan.
- Bindu	2	1995	Awaiting capacity in existing/planned infrastructure.
Nigeria			
- Bolia	15	2002 - 2006	Evaluating development plan, while continuing discussions with the government regarding regional hub strategy.
- Bosi	79	2002 - 2006	Development activity under way, while continuing discussions with the government regarding development plan.
- Bosi Central	16	2006	Development activity under way, while continuing discussions with the government regarding development plan.
- Pegi	32	2009	Awaiting capacity in existing/planned infrastructure.
- Usan South Strip	16	2011	Evaluating development plans to tie into planned infrastructure.
- Other (5 projects)	16	2001 - 2002	Evaluating and pursuing development of several additional discoveries.
Norway			
- Gamma	21	2008 - 2009	Evaluating development plan for tieback to existing production facilities.
- H-North	16	2007	Progressing development and commercialization plans.
- Lavrans	24	1995 - 1999	Development awaiting capacity in existing Kristin production facility; evaluating development concepts for phased ullage scenarios.
- Other (5 projects)	23	2008 - 2010	Evaluating development plans, including potential for tieback to existing production facilities.
Papua New Guinea			
- Juha	28	2007	Working on development plans to tie into planned LNG facilities.
United Kingdom			
- Phyllis	8	2004	Evaluating development plan for tieback to existing production facilities.
United States			
- Tip Top	31	2009	Evaluating development concept and requisite facility upgrades.
Total 2012 (28 projects)	557		

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

11. Leased Facilities

At December 31, 2012, the Corporation and its consolidated subsidiaries held noncancelable operating charters and leases covering d equipment, tankers, service stations and other properties with minimum undiscounted lease commitments totaling $8,181 million as indicated table. Estimated related rental income from noncancelable subleases is $111 million.

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

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

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

12. Earnings Per Share

	2012	2011	
Earnings per common share			
Net income attributable to ExxonMobil *(millions of dollars)*	44,880	41,060	3
Weighted average number of common shares outstanding *(millions of shares)*	4,628	4,870	
Earnings per common share *(dollars)*	9.70	8.43	
Earnings per common share - assuming dilution			
Net income attributable to ExxonMobil *(millions of dollars)*	44,880	41,060	3
Weighted average number of common shares outstanding *(millions of shares)*	4,628	4,870	
Effect of employee stock-based awards	-	5	
Weighted average number of common shares outstanding - assuming dilution	4,628	4,875	
Earnings per common share - assuming dilution *(dollars)*	9.70	8.42	
Dividends paid per common share *(dollars)*	2.18	1.85	

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

13. Financial Instruments and Derivatives

Financial Instruments. The fair value of financial instruments is determined by reference to observable market data and other valuation techı as appropriate. The only category of financial instruments where the difference between fair value and recorded book value is notable is long debt. The estimated fair value of total long-term debt, including capitalized lease obligations, was $8.5 billion and $9.8 billion at Decemb 2012, and 2011, respectively, as compared to recorded book values of $7.9 billion and $9.3 billion at December 31, 2012, and 2011, respec The fair value of long-term debt by hierarchy level at December 31, 2012 is shown below:

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

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

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

The estimated fair value of derivative instruments outstanding and recorded on the balance sheet was a net asset of $2 million at year-end and a net liability of $3 million at year-end 2011. Assets and liabilities associated with derivatives are usually recorded either in "Other c assets" or "Accounts payable and accrued liabilities."

The Corporation's fair value measurement of its derivative instruments use either Level 1 (observable quoted prices on active exchang Level 2 (derivatives that are determined by either market prices on an active market for similar assets or by prices quoted by a broker or market-corroborated prices) inputs.

The Corporation recognized a before-tax gain or (loss) related to derivative instruments of $(23) million, $131 million and $221 million c 2012, 2011 and 2010, respectively. Income statement effects associated with derivatives are usually recorded either in "Sales and other ope revenue" or "Crude oil and product purchases."

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

14. Long-Term Debt

At December 31, 2012, long-term debt consisted of $7,325 million due in U.S. dollars and $603 million representing the U.S. dollar equival year-end exchange rates of amounts payable in foreign currencies. These amounts exclude that portion of long-term debt, totaling $1,025 m which matures within one year and is included in current liabilities. The amounts of long-term debt maturing in each of the four years December 31, 2013, in millions of dollars, are: 2014 – $907; 2015 – $710; 2016 – $454; and 2017 – $814. At December 31, 201 Corporation's unused long-term credit lines were not material.

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

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

(1) Includes premiums of $326 million.

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

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

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

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

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

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

15. Incentive Program

The 2003 Incentive Program provides for grants of stock options, stock appreciation rights (SARs), restricted stock and other forms of a Awards may be granted to eligible employees of the Corporation and those affiliates at least 50 percent owned. Outstanding awards are subj certain forfeiture provisions contained in the program or award instrument. Options and SARs may be granted at prices not less than 100 perc market value on the date of grant and have a maximum life of 10 years. The maximum number of shares of stock that may be issued under the Incentive Program is 220 million. Awards that are forfeited, expire or are settled in cash, do not count against this maximum limit. The Incentive Program does not have a specified term. New awards may be made until the available shares are depleted, unless the Board terminat plan early. At the end of 2012, remaining shares available for award under the 2003 Incentive Program were 124,736 thousand.

Restricted Stock. Awards totaling 10,017 thousand, 10,533 thousand, and 10,648 thousand (excluding XTO merger-related grants) of rest (nonvested) common stock and restricted (nonvested) common stock units were granted in 2012, 2011 and 2010, respectively. Compen expense for these awards is based on the price of the stock at the date of grant and is recognized in income over the requisite service period. shares are issued to employees from treasury stock. The units that are settled in cash are recorded as liabilities and their changes in fair val recognized over the vesting period. During the applicable restricted periods, the shares may not be sold or transferred and are subject to forf The majority of the awards have graded vesting periods, with 50 percent of the shares in each award vesting after three years and the remaini percent vesting after seven years. Awards granted to a small number of senior executives have vesting periods of five years for 50 percent award and of 10 years or retirement, whichever occurs later, for the remaining 50 percent of the award.

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

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

The following tables summarize information about restricted stock and restricted stock units for the year ended December 31, 2012.

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

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

As of December 31, 2012, there was $2,179 million of unrecognized compensation cost related to the nonvested restricted awards. This c expected to be recognized over a weighted-average period of 4.5 years. The compensation cost charged against income for the restricted stoc restricted units was $854 million, $793 million and $801 million for 2012, 2011 and 2010, respectively. The income tax benefit recogni: income related to this compensation expense was $79 million, $73 million and $81 million for the same periods, respectively. The fair va shares and units vested in 2012, 2011 and 2010 was $926 million, $801 million and $718 million, respectively. Cash payments of $66 millio: million and $42 million for vested restricted stock units settled in cash were made in 2012, 2011 and 2010, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

16. Litigation and Other Contingencies

Litigation. A variety of claims have been made against ExxonMobil and certain of its consolidated subsidiaries in a number of pending lav Management has regular litigation reviews, including updates from corporate and outside counsel, to assess the need for accounting recognit disclosure of these contingencies. The Corporation accrues an undiscounted liability for those contingencies where the incurrence of a l 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 estimate than any other amount, then the minimum of the range is accrued. The Corporation does not record liabilities when the likelihood th liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably pc or remote. For contingencies where an unfavorable outcome is reasonably possible and which are significant, the Corporation discloses the nat the contingency and, where feasible, an estimate of the possible loss. For purposes of our contingency disclosures, "significant" includes m matters as well as other matters which management believes should be disclosed. ExxonMobil will continue to defend itself vigorously in matters. Based on a consideration of all relevant facts and circumstances, the Corporation does not believe the ultimate outcome of any cu pending lawsuit against ExxonMobil will have a material adverse effect upon the Corporation's operations, financial condition, or fin statements taken as a whole.

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

Other Contingencies. The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2012, for guar relating to notes, loans and performance under contracts. Where guarantees for environmental remediation and other similar matters do not inc stated cap, the amounts reflect management's estimate of the maximum potential exposure.

	Dec. 31, 2012		
	Equity Company Obligations *(1)*	**Other Third-Party Obligations**	**Total**
		(millions of dollars)	
Guarantees			
Debt-related	2,423	53	
Other	2,729	4,994	
Total	5,152	5,047	1

(1) ExxonMobil share.

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Payments Due by Period			
	2013	**2014-2017**	**2018 and Beyond**	**T**
	(millions of dollars)			
Unconditional purchase obligations *(1)*	184	624	319	

(1) Undiscounted obligations of $1,127 million mainly pertain to pipeline throughput agreements and include $584 million of obligations to companies. The present value of these commitments, which excludes imputed interest of $198 million, totaled $929 million.

In accordance with a nationalization decree issued by Venezuela's president in February 2007, by May 1, 2007, a subsidiary of the Venez National Oil Company (PdVSA) assumed the operatorship of the Cerro Negro Heavy Oil Project. This Project had been operated and own ExxonMobil affiliates holding a 41.67 percent ownership interest in the Project. The decree also required conversion of the Cerro Negro Proje 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 Exxon refused to accept the terms for the formation of the mixed enterprise within a specified period of time, the government would "directly assur activities" carried out by the joint venture. ExxonMobil refused to accede to the terms proffered by the government, and on June 27, 200 government expropriated ExxonMobil's 41.67 percent interest in the Cerro Negro Project. ExxonMobil's remaining net book investment in Negro producing assets is about $750 million.

On September 6, 2007, affiliates of ExxonMobil filed a Request for Arbitration with the International Centre for Settlement of Inves Disputes (ICSID) invoking ICSID jurisdiction under Venezuela's Investment Law and the Netherlands-Venezuela Bilateral Investment Treaty ICSID Tribunal issued a decision on June 10, 2010, finding that it had jurisdiction to proceed on the basis of the Netherlands-Venezuela Bi Investment Treaty. The ICSID arbitration proceeding is continuing and a hearing on the merits was held in February 2012. At this time, t impact of these matters on the Corporation's consolidated financial results cannot be reasonably estimated. Regardless, the Corporation do expect the resolution to have a material effect upon the Corporation's operations or financial condition.

An affiliate of ExxonMobil is one of the Contractors under a Production Sharing Contract (PSC) with the Nigerian National Petr Corporation (NNPC) covering the Erha block located in the offshore waters of Nigeria. ExxonMobil's affiliate is the operator of the block and a 56.25 percent interest under the PSC. The Contractors are in dispute with NNPC regarding NNPC's lifting of crude oil in excess of its entitl under the terms of the PSC. In accordance with the terms of the PSC, the Contractors initiated arbitration in Abuja, Nigeria, under the Ni Arbitration and Conciliation Act. On October 24, 2011, a three-member arbitral Tribunal issued an award upholding the Contractors' position material respects and awarding damages to the Contractors jointly in an amount of approximately $1.8 billion plus $234 million in accrued in The Contractors petitioned a Nigerian federal court for enforcement of the award, and NNPC petitioned the same court to have the awa aside. On May 22, 2012, the court set aside the award. The Contractors have appealed that judgment. At this time, the net impact of this mat the Corporation's consolidated financial results cannot be reasonably estimated. However, regardless of the outcome of enforcement procee the Corporation does not expect the proceedings to have a material effect upon the Corporation's operations or financial condition.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

17. Pension and Other Postretirement Benefits

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

	Pension Benefits				Other Postretireme	
	U.S.		Non-U.S.		Benefits	
	2012	2011	2012	2011	2012	2(
			(percent)			
Weighted-average assumptions used to determine benefit obligations at December 31						
Discount rate	4.00	5.00	3.80	4.00	4.00	
Long-term rate of compensation increase	5.75	5.75	5.50	5.40	5.75	
			(millions of dollars)			
Change in benefit obligation						
Benefit obligation at January 1	17,035	15,007	29,068	25,722	7,880	
Service cost	665	546	648	574	134	
Interest cost	820	792	1,145	1,267	380	
Actuarial loss/(gain)	2,553	1,954	2,335	3,086	1,035	
Benefits paid *(1) (2)*	(1,294)	(1,264)	(1,330)	(1,470)	(476)	
Foreign exchange rate changes	-	-	651	(303)	13	
Japan restructuring and other divestments	-	-	(3,952)	(16)	-	
Plan amendments, other	-	-	105	208	92	
Benefit obligation at December 31	19,779	17,035	28,670	29,068	9,058	
Accumulated benefit obligation at December 31	15,902	14,081	24,345	25,480	-	

(1) Benefit payments for funded and unfunded plans.

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

For U.S. plans, the discount rate is determined by constructing a portfolio of high-quality, noncallable bonds with cash flows that match esti outflows for benefit payments. For major non-U.S. plans, the discount rate is determined by using bond portfolios with an average ma approximating that of the liabilities or spot yield curves, both of which are constructed using high-quality, local-currency-denominated bonds.

The measurement of the accumulated postretirement benefit obligation assumes an initial health care cost trend rate of 5.0 percent that decli 4.5 percent by 2015. A one-percentage-point increase in the health care cost trend rate would increase service and interest cost by $74 millic the postretirement benefit obligation by $871 million. A one-percentage-point decrease in the health care cost trend rate would decrease servic interest cost by $57 million and the postretirement benefit obligation by $700 million.

	Pension Benefits				Other Postretireme	
	U.S.		Non-U.S.		Benefits	
	2012	2011	2012	2011	2012	2(
			(millions of dollars)			
Change in plan assets						
Fair value at January 1	10,656	10,835	17,117	16,765	538	
Actual return on plan assets	1,457	505	1,541	123	65	
Foreign exchange rate changes	-	-	462	(192)	-	
Company contribution	1,560	370	1,604	1,623	38	
Benefits paid *(1)*	(1,041)	(1,054)	(922)	(1,046)	(60)	
Japan restructuring and other divestments	-	-	(1,696)	(7)	-	
Other	-	-	(16)	(149)	-	
Fair value at December 31	12,632	10,656	18,090	17,117	581	

(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 l certain smaller U.S. pension plans and a number of non-U.S. pension plans are not funded because local tax conventions and regulatory practi not encourage funding of these plans. All defined benefit pension obligations, regardless of the funding status of the underlying plans, are supported by the financial strength of the Corporation or the respective sponsoring affiliate.

	Pension Benefits			
	U.S.		Non-U.S.	
	2012	2011	2012	2(
	(millions of dollars)			
Assets in excess of/(less than) benefit obligation				
Balance at December 31				
Funded plans	(4,438)	(4,141)	(3,247)	(:
Unfunded plans	(2,709)	(2,238)	(7,333)	((
Total	(7,147)	(6,379)	(10,580)	(1

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

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

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

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

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

	Total Pension and Other Postretirement Benefits		
	2012	2011	2(
	(millions of dollars)		
(Charge)/credit to other comprehensive income, before tax			
U.S. pension	(969)	(1,438)	
Non-U.S. pension	253	(3,446)	
Other postretirement benefits	(807)	(271)	
Total (charge)/credit to other comprehensive income, before tax	(1,523)	(5,155)	
(Charge)/credit to income tax (see Note 4)	393	1,495	
(Charge)/credit to investment in equity companies	(49)	(30)	
(Charge)/credit to other comprehensive income including noncontrolling interests, after tax	(1,179)	(3,690)	
Charge/(credit) to equity of noncontrolling interests	(124)	288	
(Charge)/credit to other comprehensive income attributable to ExxonMobil	(1,303)	(3,402)	

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

Studies are periodically conducted to establish the preferred target asset allocation percentages. The target asset allocation for the U.S. b plans is 50 percent equity securities and 50 percent debt securities. The target asset allocation for the non-U.S. plans in aggregate is 50 p equity securities and 50 percent debt securities. The equity targets for the U.S. and non-U.S. plans include an allocation to private (partnerships that primarily focus on early-stage venture capital of 5 percent and 3 percent, respectively.

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The 2012 fair value of the benefit plan assets, including the level within the fair value hierarchy, is shown in the tables below:

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

(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 treate Level 2 input. The fair value of the securities owned by the funds is based on observable quoted prices on active exchanges, which are L 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 Public Offerings.

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

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

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

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

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Other Postretirement			
	Fair Value Measurement at December 31, 2012, Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	T
	(millions of dollars)			
Asset category:				
Equity securities				
U.S.	-	166 *(1)*	-	
Non-U.S.	-	160 *(1)*	-	
Private equity	-	-	7 *(2)*	
Debt securities				
Corporate	-	91 *(3)*	-	
Government	-	136 *(3)*	-	
Asset-backed	-	14 *(3)*	-	
Cash	-	7	-	
Total at fair value	-	574	7	

(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 trea 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 L inputs.

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

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

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The 2011 fair value of the benefit plan assets, including the level within the fair value hierarchy, is shown in the tables below:

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

(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 treate Level 2 input. The fair value of the securities owned by the funds is based on observable quoted prices on active exchanges, which are L 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 Public Offerings.

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

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

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

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

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Other Postretirement			
	Fair Value Measurement at December 31, 2011, Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	T
		(millions of dollars)		
Asset category:				
Equity securities				
U.S.	-	166 (1)	-	
Non-U.S.	-	155 (1)	-	
Private equity	-	-	7 (2)	
Debt securities				
Corporate	-	77 (3)	-	
Government	-	120 (3)	-	
Asset-backed	-	12 (3)	-	
Cash	-	1	-	
Total at fair value	-	531	7	

(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 treate Level 2 input. The fair value of the securities owned by the funds is based on observable quoted prices on active exchanges, which are L inputs.

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

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

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

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

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.	
	2012	2011	2012	20
	(millions of dollars)			
For funded pension plans with an accumulated benefit obligation in excess of plan assets:				
Projected benefit obligation	17,070	14,797	9,422	1
Accumulated benefit obligation	14,171	12,606	8,184	1
Fair value of plan assets	12,631	10,655	7,048	1
For unfunded pension plans:				
Projected benefit obligation	2,709	2,238	7,333	
Accumulated benefit obligation	1,731	1,475	6,103	

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

(1) The Corporation amortizes the net balance of actuarial losses/(gains) as a component of net periodic benefit cost over the average rem 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 pensic other postretirement benefit plans.

	Pension Benefits		Other Postretirement Benefits	
	U.S.	Non-U.S.	Gross	Medicare Subsidy Rec
	(millions of dollars)			
Contributions expected in 2013	100	1,250	-	
Benefit payments expected in:				
2013	1,643	1,237	453	
2014	1,611	1,237	469	
2015	1,597	1,294	482	
2016	1,558	1,329	494	
2017	1,510	1,384	506	
2018 - 2022	6,716	7,319	2,633	

18. Disclosures about Segments and Related Information

The Upstream, Downstream and Chemical functions best define the operating segments of the business that are reported separately. The factor to identify these reportable segments are based on the nature of the operations that are undertaken by each segment. The Upstream segm organized and operates to explore for and produce crude oil and natural gas. The Downstream segment is organized and operates to manufactu sell petroleum products. The Chemical segment is organized and operates to manufacture and sell petrochemicals. These segments are b 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 bu activities from which revenues are earned and expenses are incurred; (2) whose operating results are regularly reviewed by the Corporation's operating decision maker to make decisions about resources to be allocated to the segment and assess its performance; and (3) for which di financial information is available.

Earnings after income tax include transfers at estimated market prices.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

In corporate and financing activities, interest revenue relates to interest earned on cash deposits and marketable securities. Interest ex includes non-debt-related interest expense of $202 million, $165 million and $41 million in 2012, 2011 and 2010, respectively.

	Upstream		Downstream		Chemical		Corporate and Financing	Corp
	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.		T
				(millions of dollars)				
As of December 31, 2012								
Earnings after income tax	3,925	25,970	3,575	9,615	2,220	1,678	(2,103)	4
Earnings of equity companies above	1,759	11,900	6	387	183	1,267	(492)	1
Sales and other operating revenue *(1)*	11,472	28,854	125,088	248,959	14,723	24,003	24	45
Intersegment revenue	8,764	47,507	20,963	62,130	12,409	9,750	258	
Depreciation and depletion expense	5,104	7,340	594	1,280	376	508	686	1
Interest revenue	-	-	-	-	-	-	117	
Interest expense	37	13	3	36	-	(1)	239	
Income taxes	2,025	25,362	1,811	1,892	755	232	(1,032)	3
Additions to property, plant and equipment	9,697	21,769	480	1,153	338	659	1,083	3
Investments in equity companies	4,020	9,147	195	2,069	233	3,143	(277)	1
Total assets	86,146	140,848	18,451	40,956	7,238	18,886	21,270	33
As of December 31, 2011								
Earnings after income tax	5,096	29,343	2,268	2,191	2,215	2,168	(2,221)	4
Earnings of equity companies above	2,045	11,768	7	353	198	1,365	(447)	1
Sales and other operating revenue *(1)*	14,023	32,419	120,844	257,779	15,466	26,476	22	46
Intersegment revenue	9,807	49,910	18,489	73,549	12,226	10,563	262	
Depreciation and depletion expense	4,879	7,021	650	1,560	380	458	635	1
Interest revenue	-	-	-	-	-	-	135	
Interest expense	30	36	10	24	2	(1)	146	
Income taxes	2,852	25,755	1,123	696	1,027	465	(867)	3
Additions to property, plant and equipment	10,887	18,934	400	1,334	241	910	932	3
Investments in equity companies	2,963	8,439	210	1,358	253	3,973	(228)	1
Total assets	82,900	127,977	18,354	51,132	7,245	19,862	23,582	33
As of December 31, 2010								
Earnings after income tax	4,272	19,825	770	2,797	2,422	2,491	(2,117)	3
Earnings of equity companies above	1,261	8,415	23	225	171	1,163	(581)	1
Sales and other operating revenue *(1)*	8,895	26,046	93,599	206,042	13,402	22,119	22	37
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	1
Interest revenue	-	-	-	-	-	-	118	
Interest expense	20	25	1	19	1	4	189	
Income taxes	2,219	18,627	360	560	736	347	(1,288)	2
Additions to property, plant and equipment	52,300	16,937	888	1,332	247	1,733	719	7
Investments in equity companies	2,636	9,625	254	1,240	285	3,586	(197)	1
Total assets	76,725	115,646	18,378	47,402	7,148	19,087	18,124	30

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Geographic

Sales and other operating revenue *(1)*	**2012**	**2011**	**20**
		(millions of dollars)	
United States	151,298	150,343	11
Non-U.S.	301,825	316,686	25
Total	453,123	467,029	37
Significant non-U.S. revenue sources include:			
Canada	34,325	34,626	2
United Kingdom	34,134	34,833	2
Belgium	23,567	26,926	2
France	19,601	18,510	1
Italy	18,228	16,288	1
Germany	16,451	17,034	1
Singapore	14,606	14,400	1
Japan	14,162	31,925	2

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

Long-lived assets	**2012**	**2011**	**20**
		(millions of dollars)	
United States	94,336	91,146	8
Non-U.S.	132,613	123,518	11
Total	226,949	214,664	19
Significant non-U.S. long-lived assets include:			
Canada	31,979	24,458	2
Australia	13,415	9,474	
Nigeria	12,216	11,806	1
Singapore	9,700	9,285	
Angola	8,238	10,395	
Kazakhstan	7,785	7,022	
Norway	7,040	6,039	
United Kingdom	5,472	5,008	

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

19. Income, Sales-Based and Other Taxes

	2012			2011			2010		
	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	T
				(millions of dollars)					
Income tax expense									
Federal and non-U.S.									
Current	1,791	25,650	27,441	1,547	28,849	30,396	1,224	21,093	2
Deferred - net	1,097	1,816	2,913	1,577	(1,417)	160	49	(1,191)	(
U.S. tax on non-U.S. operations	89	-	89	15	-	15	46	-	
Total federal and non-U.S.	2,977	27,466	30,443	3,139	27,432	30,571	1,319	19,902	2
State	602	-	602	480	-	480	340	-	
Total income tax expense	3,579	27,466	31,045	3,619	27,432	31,051	1,659	19,902	2
Sales-based taxes	5,785	26,624	32,409	5,652	27,851	33,503	6,182	22,365	2
All other taxes and duties									
Other taxes and duties	1,406	34,152	35,558	1,539	38,434	39,973	776	35,342	3
Included in production and manufacturing expenses	1,242	1,308	2,550	1,342	1,425	2,767	1,001	1,237	
Included in SG&A expenses	154	595	749	181	623	804	201	570	
Total other taxes and duties	2,802	36,055	38,857	3,062	40,482	43,544	1,978	37,149	3
Total	12,166	90,145	102,311	12,333	95,765	108,098	9,819	79,416	8

All other taxes and duties include taxes reported in production and manufacturing and selling, general and administrative (SG&A) expenses above provisions for deferred income taxes include net charges of $244 million in 2012 and $175 million in 2010 and a net credit of $330 mill 2011 for the effect of changes in tax laws and rates.

The reconciliation between income tax expense and a theoretical U.S. tax computed by applying a rate of 35 percent for 2012, 2011 and 201 follows:

	2012	2011	20
		(millions of dollars)	
Income before income taxes			
United States	11,222	11,511	
Non-U.S.	67,504	61,746	4
Total	78,726	73,257	5
Theoretical tax	27,554	25,640	1
Effect of equity method of accounting	(5,254)	(5,351)	(
Non-U.S. taxes in excess of theoretical U.S. tax	8,434	10,385	
U.S. tax on non-U.S. operations	89	15	
State taxes, net of federal tax benefit	391	312	
Other U.S.	(169)	50	
Total income tax expense	31,045	31,051	2
Effective tax rate calculation			
Income taxes	31,045	31,051	2
ExxonMobil share of equity company income taxes	5,859	5,603	
Total income taxes	36,904	36,654	2
Net income including noncontrolling interests	47,681	42,206	3
Total income before taxes	84,585	78,860	5
Effective income tax rate	44%	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 rep purposes and such amounts recognized for tax purposes.

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

Tax effects of temporary differences for:	**2012**	**2**
	(millions of dollars)	
Property, plant and equipment	48,720	4
Other liabilities	3,680	
Total deferred tax liabilities	52,400	5
Pension and other postretirement benefits	(8,041)	(
Asset retirement obligations	(5,826)	(
Tax loss carryforwards	(2,989)	(
Other assets	(6,135)	(
Total deferred tax assets	(22,991)	(2
Asset valuation allowances	1,615	
Net deferred tax liabilities	31,024	2

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

Balance sheet classification	**2012**	**2**
	(millions of dollars)	
Other current assets	(3,540)	(
Other assets, including intangibles, net	(3,269)	(
Accounts payable and accrued liabilities	263	
Deferred income tax liabilities	37,570	3
Net deferred tax liabilities	31,024	2

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Unrecognized Tax Benefits. The Corporation is subject to income taxation in many jurisdictions around the world. Unrecognized tax be reflect the difference between positions taken or expected to be taken on income tax returns and the amounts recognized in the financial state Resolution of the related tax positions through negotiations with the relevant tax authorities or through litigation will take many years to compl 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 reaso possible that the total amount of unrecognized tax benefits could increase by up to 25 percent in the next 12 months, with no material imp near-term earnings. Given the long time periods involved in resolving tax positions, the Corporation does not expect that the recogniti unrecognized tax benefits will have a material impact on the Corporation's effective income tax rate in any given year.

The following table summarizes the movement in unrecognized tax benefits.

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

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

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

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

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

20. Japan Restructuring

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

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

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

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

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

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

The results of operations for producing activities shown below do not include earnings from other activities that ExxonMobil includes Upstream function, such as oil and gas transportation operations, LNG liquefaction and transportation operations, coal and power opera technical service agreements, other nonoperating activities and adjustments for noncontrolling interests. These excluded amounts for consolidated and equity companies totaled $2,832 million in 2012, $2,600 million in 2011, and $249 million in 2010. Oil sands mining oper are included in the results of operations in accordance with Securities and Exchange Commission and Financial Accounting Standards Board ru

Results of Operations	**United States**	**Canada/ South America**	**Europe**	**Africa**	**Asia**	**Australia/ Oceania**	**T**
				(millions of dollars)			
Consolidated Subsidiaries							
2012 - Revenue							
Sales to third parties	6,977	1,804	5,835	3,672	6,536	1,275	2
Transfers	6,996	5,457	6,366	16,905	9,241	932	4
	13,973	7,261	12,201	20,577	15,777	2,207	7
Production costs excluding taxes	4,044	3,079	2,443	2,395	1,606	488	1
Exploration expenses	391	292	274	234	513	136	
Depreciation and depletion	4,862	848	1,559	2,879	1,785	264	1
Taxes other than income	1,963	89	513	1,702	2,248	446	
Related income tax	1,561	720	5,413	8,091	6,616	281	2
Results of producing activities for consolidated subsidiaries	1,152	2,233	1,999	5,276	3,009	592	1
Equity Companies							
2012 - Revenue							
Sales to third parties	1,284	-	6,380	-	20,017	-	2
Transfers	1,108	-	67	-	5,693	-	
	2,392	-	6,447	-	25,710	-	3
Production costs excluding taxes	467	-	369	-	484	-	
Exploration expenses	9	-	17	-	-	-	
Depreciation and depletion	176	-	152	-	676	-	
Taxes other than income	42	-	3,569	-	6,658	-	1
Related income tax	-	-	894	-	8,234	-	
Results of producing activities for equity companies	1,698	-	1,446	-	9,658	-	1
Total results of operations	2,850	2,233	3,445	5,276	12,667	592	2

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

Oil and Gas Exploration and Production Costs

The amounts shown for net capitalized costs of consolidated subsidiaries are $10,643 million less at year-end 2012 and $6,651 million less at end 2011 than the amounts reported as investments in property, plant and equipment for the Upstream in Note 9. This is due to the exclusior capitalized costs of certain transportation and research assets and assets relating to LNG operations. Assets related to oil sands and oil shale n operations have been included in the capitalized costs for 2012 and 2011 in accordance with Financial Accounting Standards Board rules.

Capitalized Costs		United States	Canada/ South America	Europe	Africa	Asia	Australia/ Oceania
					(millions of dollars)		
Consolidated Subsidiaries							
As of December 31, 2012							
Property (acreage) costs	- Proved	12,081	3,911	198	874	1,610	971
	- Unproved	25,769	1,456	89	430	710	162
Total property costs		37,850	5,367	287	1,304	2,320	1,133
Producing assets		70,603	21,947	44,068	37,921	23,230	6,910
Incomplete construction		4,840	18,726	1,589	5,070	12,654	5,988
Total capitalized costs		113,293	46,040	45,944	44,295	38,204	14,031
Accumulated depreciation and depletion		36,346	17,357	34,267	21,285	16,599	4,801
Net capitalized costs for consolidated subsidiaries		76,947	28,683	11,677	23,010	21,605	9,230
Equity Companies							
As of December 31, 2012							
Property (acreage) costs	- Proved	76	-	5	-	-	-
	- Unproved	39	-	-	-	-	-
Total property costs		115	-	5	-	-	-
Producing assets		4,216	-	5,736	-	8,169	-
Incomplete construction		304	-	118	-	822	-
Total capitalized costs		4,635	-	5,859	-	8,991	-
Accumulated depreciation and depletion		1,447	-	4,494	-	3,744	-
Net capitalized costs for equity companies		3,188	-	1,365	-	5,247	-
Consolidated Subsidiaries							
As of December 31, 2011							
Property (acreage) costs	- Proved	10,969	3,837	96	919	1,567	954
	- Unproved	25,398	1,402	67	430	755	128
Total property costs		36,367	5,239	163	1,349	2,322	1,082
Producing assets		65,941	20,393	40,646	32,059	22,675	6,035
Incomplete construction		4,652	12,385	964	9,831	9,922	4,131
Total capitalized costs		106,960	38,017	41,773	43,239	34,919	11,248
Accumulated depreciation and depletion		33,037	16,296	31,706	18,449	14,960	4,384
Net capitalized costs for consolidated subsidiaries		73,923	21,721	10,067	24,790	19,959	6,864
Equity Companies							
As of December 31, 2011							
Property (acreage) costs	- Proved	76	-	4	-	-	-
	- Unproved	25	-	-	-	-	-
Total property costs		101	-	4	-	-	-
Producing assets		3,510	-	5,383	-	8,155	-
Incomplete construction		183	-	212	-	548	-
Total capitalized costs		3,794	-	5,599	-	8,703	-
Accumulated depreciation and depletion		1,354	-	4,267	-	3,068	-
Net capitalized costs for equity companies		2,440	-	1,332	-	5,635	-

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 includ asset retirement obligations established in the current year, as well as increases or decreases to the asset retirement obligation resulting from ch in cost estimates or abandonment date. Total consolidated costs incurred in 2012 were $31,146 million, up $392 million from 2011, due prima higher exploration and development costs partially offset by lower property acquisition costs. 2011 costs were $30,754 million, down $4 million from 2010, due primarily to the absence of the acquisition of XTO Energy Inc. Total equity company costs incurred in 2012 were $ million, up $178 million from 2011, due primarily to higher development costs.

Costs Incurred in Property Acquisitions, Exploration and Development Activities		**United States**	**Canada/ South America**	**Europe**	**Africa**	**Asia**	**Australia/ Oceania**
				(millions of dollars)			
During 2012							
Consolidated Subsidiaries							
Property acquisition costs	- Proved	192	2	95	-	43	-
	- Unproved	1,717	74	24	15	-	31
Exploration costs		601	405	454	520	554	248
Development costs		7,172	7,601	2,637	3,081	3,347	2,333
Total costs incurred for consolidated subsidiaries		9,682	8,082	3,210	3,616	3,944	2,612
Equity Companies							
Property acquisition costs	- Proved	-	-	-	-	-	-
	- Unproved	14	-	-	-	-	-
Exploration costs		45	-	34	-	-	-
Development costs		504	-	156	-	651	-
Total costs incurred for equity companies		563	-	190	-	651	-
During 2011							
Consolidated Subsidiaries							
Property acquisition costs	- Proved	259	-	-	-	96	-
	- Unproved	2,685	178	-	-	546	-
Exploration costs		465	372	640	303	518	154
Development costs		8,166	5,478	1,899	4,316	2,969	1,710
Total costs incurred for consolidated subsidiaries		11,575	6,028	2,539	4,619	4,129	1,864
Equity Companies							
Property acquisition costs	- Proved	-	-	-	-	-	-
	- Unproved	23	-	-	-	-	-
Exploration costs		19	-	32	-	-	-
Development costs		339	-	164	-	649	-
Total costs incurred for equity companies		381	-	196	-	649	-
During 2010							
Consolidated Subsidiaries							
Property acquisition costs	- Proved	21,633	-	41	3	115	-
	- Unproved	23,509	136	23	-	-	-
Exploration costs		690	527	550	453	545	228
Development costs		7,947	4,757	1,227	4,390	2,892	1,146
Total costs incurred for consolidated subsidiaries		53,779	5,420	1,841	4,846	3,552	1,374
Equity Companies							
Property acquisition costs	- Proved	-	-	-	-	-	-
	- Unproved	1	-	-	-	-	-
Exploration costs		4	-	56	-	2	-
Development costs		323	-	225	-	303	-
Total costs incurred for equity companies		328	-	281	-	305	-

Oil and Gas Reserves

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

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

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

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

Revisions can include upward or downward changes in previously estimated volumes of proved reserves for existing fields due to the eval or re-evaluation of (1) already available geologic, reservoir or production data, (2) new geologic, reservoir or production data or (3) chan average prices and year-end costs that are used in the estimation of reserves. This category can also include significant changes in 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 perce of the proved reserves of equity companies, but exclude royalties and quantities due others. Gas reserves exclude the gaseous equivalent of l expected to be removed from the gas on leases, at field facilities and at gas processing plants. These liquids are included in net proved reser crude oil and natural gas liquids.

In the proved reserves tables, consolidated reserves and equity company reserves are reported separately. However, the Corporation does no 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 sp fiscal terms in the agreement. The production and reserves that we report for these types of arrangements typically vary inversely with oil ar price changes. As oil and gas prices increase, the cash flow and value received by the company increase; however, the production volume reserves required to achieve this value will typically be lower because of the higher prices. When prices decrease, the opposite effect gen occurs. The percentage of total liquids and natural gas proved reserves (consolidated subsidiaries plus equity companies) at year-end 2012 tha associated with production sharing contract arrangements was 12 percent of liquids, 8 percent of natural gas and 10 percent on an oil-equi 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 ope methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well. Net proved undeveloped reserv those volumes that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expendi required for recompletion.

Crude oil and natural gas liquids and natural gas production quantities shown are the net volumes withdrawn from ExxonMobil's oil ar reserves. The natural gas quantities differ from the quantities of gas delivered for sale by the producing function as reported in the Ope 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 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 teste have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated.

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

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

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

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

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

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

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

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

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

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

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

(4) *See previous page for natural gas liquids proved reserves attributable to consolidated subsidiaries and equity companies. For additional informat natural gas liquids proved reserves see Item 2. Properties in ExxonMobil's 2012 Form 10-K.*

Natural Gas and Oil-Equivalent Proved Reserves

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

(See footnotes on next page)

Natural Gas and Oil-Equivalent Proved Reserves (continued)

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

(1) Includes total proved reserves attributable to Imperial Oil Limited of 576 billion cubic feet in 2010, 422 billion cubic feet in 2011 an billion cubic feet in 2012, as well as proved developed reserves of 507 billion cubic feet in 2010, 360 billion cubic feet in 2011 and 374 cubic feet in 2012, and in addition, proved undeveloped reserves of 69 billion cubic feet in 2010, 62 billion cubic feet in 2011 and 114 cubic feet in 2012, in which there is a 30.4 percent noncontrolling interest.

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

Natural Gas and Oil-Equivalent Proved Reserves (continued)

	Natural Gas							
	United States	Canada/ South Amer. *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total	**Oil-Equival Total All Products**
	(billions of cubic feet)							*(millions of o equivalent b*
Proved developed reserves, as of December 31, 2010								
Consolidated subsidiaries	15,344	1,077	3,516	711	6,593	1,174	28,415	10,408
Equity companies	97	-	8,167	-	20,494	-	28,758	6,708
Proved undeveloped reserves, as of December 31, 2010								
Consolidated subsidiaries	10,650	181	526	197	667	6,177	18,398	6,812
Equity companies	20	-	2,579	-	645	-	3,244	881
Total proved reserves at December 31, 2010	26,111	1,258	14,788	908	28,399	7,351	78,815	24,809
Proved developed reserves, as of December 31, 2011								
Consolidated subsidiaries	15,450	658	3,041	853	5,762	1,070	26,834	9,843
Equity companies	83	-	7,588	-	19,305	-	26,976	6,251
Proved undeveloped reserves, as of December 31, 2011								
Consolidated subsidiaries	10,804	177	545	129	709	6,177	18,541	7,833
Equity companies	29	-	2,581	-	1,261	-	3,871	1,005
Total proved reserves at December 31, 2011	26,366	835	13,755	982	27,037	7,247	76,222	24,932
Proved developed reserves, as of December 31, 2012								
Consolidated subsidiaries	14,471	670	2,526	814	5,150	1,012	24,643	9,330
Equity companies	126	-	7,057	-	18,431	-	25,614	5,984
Proved undeveloped reserves, as of December 31, 2012								
Consolidated subsidiaries	11,744	255	723	115	695	6,556	20,088	8,839
Equity companies	29	-	2,478	-	1,239	-	3,746	1,011
Total proved reserves at December 31, 2012	26,370	925	12,784	929	25,515	7,568	74,091	25,164

(See footnotes on previous page)

Standardized Measure of Discounted Future Cash Flows

As required by the Financial Accounting Standards Board, the standardized measure of discounted future net cash flows is computed by ap first-day-of-the-month average prices, year-end costs and legislated tax rates and a discount factor of 10 percent to net proved reserves standardized measure includes costs for future dismantlement, abandonment and rehabilitation obligations. The Corporation believe standardized measure does not provide a reliable estimate of the Corporation's expected future cash flows to be obtained from the developme 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 c prescribed assumptions including first-day-of-the-month average prices, which represent discrete points in time and therefore may cause sign 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	To
				(millions of dollars)			
Consolidated Subsidiaries							
As of December 31, 2010							
Future cash inflows from sales of oil and gas	221,298	184,671	60,086	137,476	156,337	55,087	81
Future production costs	76,992	69,765	15,246	31,189	36,318	16,347	24
Future development costs	28,905	22,130	12,155	15,170	13,716	11,652	10
Future income tax expenses	44,128	21,798	21,736	46,145	59,477	9,591	20
Future net cash flows	71,273	70,978	10,949	44,972	46,826	17,497	26
Effect of discounting net cash flows at 10%	39,545	45,607	2,765	18,046	28,883	13,411	14
Discounted future net cash flows	31,728	25,371	8,184	26,926	17,943	4,086	11
Equity Companies							
As of December 31, 2010							
Future cash inflows from sales of oil and gas	26,110	-	73,222	-	232,334	-	33
Future production costs	6,369	-	49,010	-	73,508	-	12
Future development costs	2,883	-	2,719	-	2,523	-	
Future income tax expenses	-	-	8,348	-	57,041	-	6
Future net cash flows	16,858	-	13,145	-	99,262	-	12
Effect of discounting net cash flows at 10%	9,612	-	6,857	-	51,512	-	6
Discounted future net cash flows	7,246	-	6,288	-	47,750	-	6
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	17

(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 p noncontrolling interest.

Standardized Measure of Discounted Future Cash Flows (continued)	United States	Canada/ South America *(1)*	Europe	Africa	Asia	Australia/ Oceania	To
				(millions of dollars)			
Consolidated Subsidiaries							
As of December 31, 2011							
Future cash inflows from sales of oil and gas	264,991	280,991	71,847	179,337	203,007	86,456	1,08
Future production costs	105,391	98,135	15,045	36,309	43,442	23,381	32
Future development costs	31,452	35,121	11,987	15,384	16,010	10,052	12
Future income tax expenses	53,507	34,542	32,004	67,256	79,975	17,287	28
Future net cash flows	74,641	113,193	12,811	60,388	63,580	35,736	36
Effect of discounting net cash flows at 10%	42,309	79,303	3,525	22,029	38,066	22,873	20
Discounted future net cash flows	32,332	33,890	9,286	38,359	25,514	12,863	15
Equity Companies							
As of December 31, 2011							
Future cash inflows from sales of oil and gas	37,398	-	88,417	-	324,283	-	45
Future production costs	6,862	-	62,377	-	104,040	-	17
Future development costs	3,072	-	2,701	-	3,636	-	
Future income tax expenses	-	-	9,035	-	76,825	-	8
Future net cash flows	27,464	-	14,304	-	139,782	-	18
Effect of discounting net cash flows at 10%	15,941	-	7,131	-	71,918	-	9
Discounted future net cash flows	11,523	-	7,173	-	67,864	-	8
Total consolidated and equity interests in standardized measure of discounted future net cash flows	43,855	33,890	16,459	38,359	93,378	12,863	23
Consolidated Subsidiaries							
As of December 31, 2012							
Future cash inflows from sales of oil and gas	250,382	293,910	66,769	160,261	192,491	104,334	1,06
Future production costs	109,325	101,299	17,277	33,398	42,816	26,132	33
Future development costs	37,504	44,518	16,505	13,363	13,083	11,435	13
Future income tax expenses	43,772	34,692	23,252	63,246	75,261	21,405	26
Future net cash flows	59,781	113,401	9,735	50,254	61,331	45,362	33
Effect of discounting net cash flows at 10%	36,578	82,629	2,097	18,091	35,310	27,610	20
Discounted future net cash flows	23,203	30,772	7,638	32,163	26,021	17,752	13
Equity Companies							
As of December 31, 2012							
Future cash inflows from sales of oil and gas	36,043	-	93,563	-	348,026	-	47
Future production costs	7,040	-	64,988	-	112,980	-	18
Future development costs	3,708	-	2,569	-	10,780	-	1
Future income tax expenses	-	-	9,937	-	78,539	-	8
Future net cash flows	25,295	-	16,069	-	145,727	-	18
Effect of discounting net cash flows at 10%	14,741	-	8,133	-	76,979	-	9
Discounted future net cash flows	10,554	-	7,936	-	68,748	-	8
Total consolidated and equity interests in standardized measure of discounted future net cash flows	33,757	30,772	15,574	32,163	94,769	17,752	22

(1) Includes discounted future net cash flows attributable to Imperial Oil Limited of $27,568 million in 2011 and $24,690 million in 2012, in there is a 30.4 percent noncontrolling interest.

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

Consolidated and Equity Interests		**2010**	
	Consolidated Subsidiaries	**Share of Equity Method Investees**	**Total Consolida and Equ Interest**
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2009	65,846	49,310	115,15
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	20,093	210	20,30
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)	(62,12
Development costs incurred during the year	20,975	843	21,81
Net change in prices, lifting and development costs	61,612	23,135	84,74
Revisions of previous reserves estimates	14,770	3,605	18,37
Accretion of discount	10,399	5,775	16,17
Net change in income taxes	(33,379)	(5,544)	(38,92
Total change in the standardized measure during the year	48,392	11,974	60,36
Discounted future net cash flows as of December 31, 2010	114,238	61,284	175,52

Consolidated and Equity Interests		**2011**	
	Consolidated Subsidiaries	**Share of Equity Method Investees**	**Total Consolida and Equ Interest**
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2010	114,238	61,284	175,52
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	6,608	309	6,91
Changes in value of previous-year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of production (lifting) costs	(58,308)	(22,402)	(80,71
Development costs incurred during the year	22,843	1,153	23,99
Net change in prices, lifting and development costs	79,435	46,304	125,73
Revisions of previous reserves estimates	10,462	3,127	13,58
Accretion of discount	16,802	7,196	23,99
Net change in income taxes	(39,836)	(10,411)	(50,24
Total change in the standardized measure during the year	38,006	25,276	63,28
Discounted future net cash flows as of December 31, 2011	152,244	86,560	238,80

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

Consolidated and Equity Interests (continued)	2012		
	Consolidated Subsidiaries	Share of Equity Method Investees	Total Consolida and Equ Interest
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2011	152,244	86,560	238,80
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	7,952	531	8,48
Changes in value of previous-year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of production (lifting) costs	(51,752)	(23,022)	(74,77
Development costs incurred during the year	24,596	1,186	25,78
Net change in prices, lifting and development costs	(31,382)	5,656	(25,72
Revisions of previous reserves estimates	3,876	7,018	10,89
Accretion of discount	19,676	8,846	28,52
Net change in income taxes	12,339	463	12,80
Total change in the standardized measure during the year	(14,695)	678	(14,01
Discounted future net cash flows as of December 31, 2012	137,549	87,238	224,78

OPERATING SUMMARY (unaudited)

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

Operating statistics include 100 percent of operations of majority-owned subsidiaries; for other companies, crude production, gas, petr product and chemical prime product sales include ExxonMobil's ownership percentage and refining throughput includes quantities process 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.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this rep be signed on its behalf by the undersigned, thereunto duly authorized.

EXXON MOBIL CORPORATION

By: /s/ REX W. TILLERSON
(Rex W. Tillerson,
Chairman of the Board)

Dated February 27, 2013

POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints Randall M. Ebner, Leonard M. Fox and Catherine C. Sha each of them, his or her true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him or he in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, a file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commi granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and requisite and necessary to be done, as fully to all intents and purposes as he or she might or could do in person, hereby ratifyin confirming all that said attorneys-in-fact and agents or any of them, or their or his or her substitute or substitutes, may lawfully do or to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following perso behalf of the registrant and in the capacities indicated and on February 27, 2013.

/s/ REX W. TILLERSON (Rex W. Tillerson)	Chairman of the Board (Principal Executive Office
/s/ MICHAEL J. BOSKIN (Michael J. Boskin)	Director
/s/ PETER BRABECK-LETMATHE (Peter Brabeck-Letmathe)	Director
/s/ URSULA M. BURNS (Ursula M. Burns)	Director
/s/ LARRY R. FAULKNER (Larry R. Faulkner)	Director

/s/ JAY S. FISHMAN (Jay S. Fishman)	Director
/s/ HENRIETTA H. FORE (Henrietta H. Fore)	Director
/s/ KENNETH C. FRAZIER (Kenneth C. Frazier)	Director
/s/ WILLIAM W. GEORGE (William W. George)	Director
/s/ SAMUEL J. PALMISANO (Samuel J. Palmisano)	Director
/s/ STEVEN S REINEMUND (Steven S Reinemund)	Director
/s/ EDWARD E. WHITACRE, JR. (Edward E. Whitacre, Jr.)	Director
/s/ ANDREW P. SWIGER (Andrew P. Swiger)	Senior Vice President (Principal Financial Office
/s/ PATRICK T. MULVA (Patrick T. Mulva)	Vice President and Controll (Principal Accounting Offic

INDEX TO EXHIBITS

3(i)	Restated Certificate of Incorporation, as restated November 30, 1999, and as further amended effective June 20, 2001 (incorp by reference to Exhibit 3(i) to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011).
3(ii)	By-Laws, as revised to April 27, 2011 (incorporated by reference to Exhibit 3(ii) to the Registrant's Report on Form 8-K on Ap 2011).
10(iii)(a.1)	2003 Incentive Program, as approved by shareholders May 28, 2003.*
10(iii)(a.2)	Form of restricted stock agreement with executive officers (incorporated by reference to Exhibit 99.2 to the Registrant's Rep Form 8-K of November 28, 2012).*
10(iii)(a.3)	Extended Provisions for Restricted Stock Unit Agreements-Settlement in Shares.*
10(iii)(b.1)	Short Term Incentive Program, as amended (incorporated by reference to Exhibit 99.3 to the Registrant's Report on Form 8 December 1, 2009).*
10(iii)(b.2)	Form of Earnings Bonus Unit instrument granted to executive officers (incorporated by reference to Exhibit 99.1 to the Regis Report on Form 8-K on November 28, 2012).*
10(iii)(c.1)	ExxonMobil Supplemental Savings Plan (incorporated by reference to Exhibit 10(iii)(c.1) to the Registrant's Annual Rep Form 10-K for 2011).*
10(iii)(c.2)	ExxonMobil Supplemental Pension Plan (incorporated by reference to Exhibit 10(iii)(c.2) to the Registrant's Annual Rep Form 10-K for 2011).*
10(iii)(c.3)	ExxonMobil Additional Payments Plan (incorporated by reference to Exhibit 10(iii)(c.3) to the Registrant's Annual Rep Form 10-K for 2011).*
10(iii)(d)	ExxonMobil Executive Life Insurance and Death Benefit Plan (incorporated by reference to Exhibit 10(iii)(d) to the Regis Annual Report on Form 10-K for 2011).*
10(iii)(f.1)	2004 Non-Employee Director Restricted Stock Plan (incorporated by reference to Exhibit 10(iii)(f.1) to the Registrant's Qua Report on Form 10-Q for the quarter ended March 31, 2009).*
10(iii)(f.2)	Standing resolution for non-employee director restricted grants dated September 26, 2007 (incorporated by referen Exhibit 10(iii)(f.2) to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2012).*
10(iii)(f.3)	Form of restricted stock grant letter for non-employee directors (incorporated by reference to Exhibit 10(iii)(f.3) to the Regis Annual Report on Form 10-K for 2009).*
10(iii)(f.4)	Standing resolution for non-employee director cash fees dated October 26, 2011 (incorporated by reference to Exhibit 10(iii)(the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2011).*
10(iii)(g.3)	1984 Mobil Compensation Management Retention Plan (incorporated by reference to Exhibit 10(iii)(g.3) to the Registrant's A Report on Form 10-K for 2011).*
12	Computation of ratio of earnings to fixed charges.
14	Code of Ethics and Business Conduct (incorporated by reference to Exhibit 14 to the Registrant's Annual Report on Form 10- 2008).
21	Subsidiaries of the registrant.
23	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.
31.1	Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Chief Executive Officer.
31.2	Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Principal Financial Officer.
31.3	Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Principal Accounting Officer.

INDEX TO EXHIBITS – (continued)

32.1	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Chief Executive Officer.
32.2	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Principal Financial Officer.
32.3	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Principal Accounting Officer.
101	Interactive data files.

* Compensatory plan or arrangement required to be identified pursuant to Item 15(a)(3) of this Annual Report on Form 10-K.

The registrant has not filed with this report copies of the instruments defining the rights of holders of long-term debt of the registrant a subsidiaries for which consolidated or unconsolidated financial statements are required to be filed. The registrant agrees to furnish a copy o such instrument to the Securities and Exchange Commission upon request.