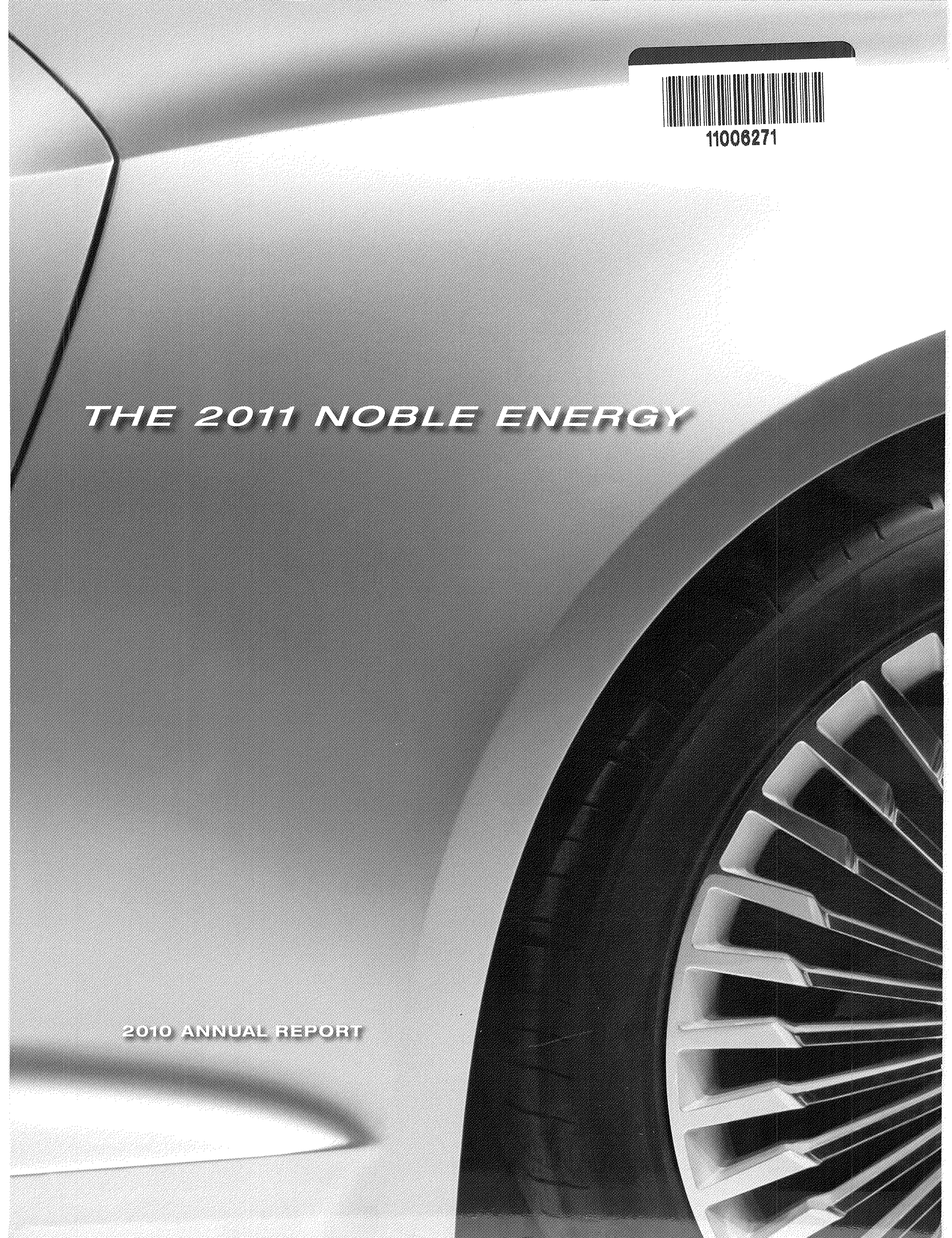
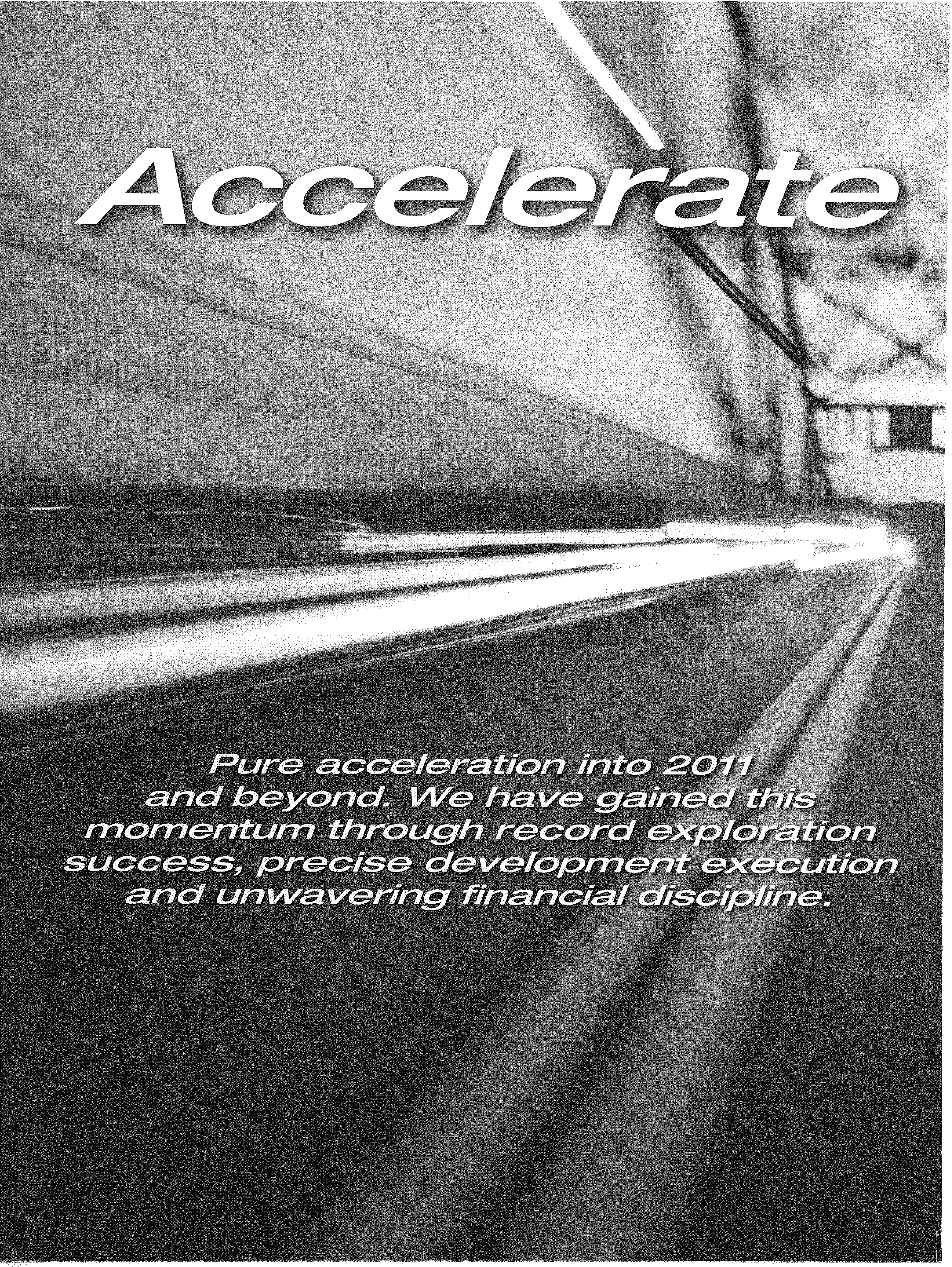

THE 2011 NOBLE ENERGY
2010 ANNUAL REPORT



Accelerate

Pure acceleration into 2011 and beyond. We have gained this momentum through record exploration success, precise development execution and unwavering financial discipline.

To Our Shareholders

At Noble Energy, a long-term strategy and significant exploration success have us on the verge of transformational growth. We are far along towards our goals, despite the considerable economic and industry challenges of the last few years. In 2010, we maintained a strong base of production and made significant progress on our lineup of major projects. Our financial position improved throughout the year, and we are well poised to fuel our future plans. The Company's outlook is highly transparent and very positive.

Noble Energy's portfolio includes four core areas, each with a strong base of production, major projects under development, and additional exploration opportunities. Across our core areas, we have at least one major project planned for start up every year over the next half-decade. In addition to geographic diversity, our production mix gives us exposure to multiple markets, with about 40 percent of our volumes being liquids, 30 percent international natural gas and 30 percent U.S. natural gas.

Our strong position has come from purposeful preparation and focus on best-in-class processes and expertise. The results have been highly rewarding. Investments that we have made in recent years are paying off, and we believe our shareholders will reap the benefits.

Driven by an enduring strategy

For many years, we've stayed the course on our growth plan. We now find ourselves far along on a carefully designed journey of accomplishment.

Onshore United States

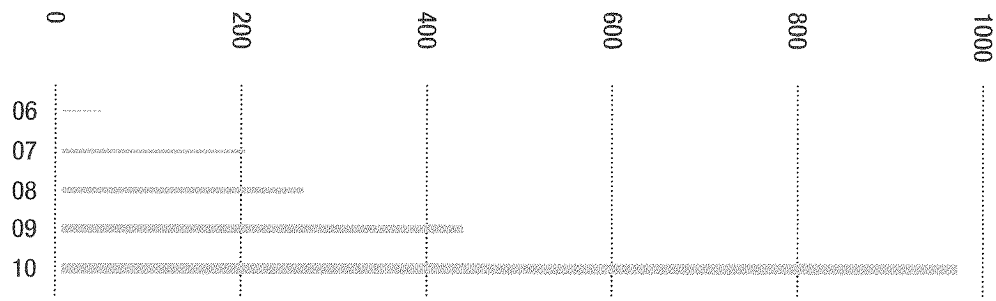
NOBLE ENERGY'S ONSHORE FOCUS is in the Denver-Julesburg (DJ) basin. Our legacy vertical well program in the Wattenberg field continues with high levels of activity, delivering strong performance and results.

In early 2010, we made a timely acquisition of Petro-Canada's Rocky Mountain assets. The acquisition added over 340,000 net acres and about 10,000 barrels of oil equivalent per day of production to Noble Energy, with more than half of these assets in the DJ basin. Today, we have a leading position in the basin, which includes more than 830,000 net acres. Our strategy is to apply best-in-class technology and operating practices in order to fully exploit this resource-rich region.

In the emerging horizontal Niobrara play, we drilled a number of wells testing the potential for increased hydrocarbon recoveries, both inside the Wattenberg field and to the north. In Wattenberg, we have seen great results from the initial horizontal wells, with recoveries and returns far exceeding those of vertical wells. The horizontal technology is allowing us to expand the limits of Wattenberg, making areas of the field economic which were not under vertical development.

Our horizontal Niobrara testing outside of Wattenberg, in northern Colorado and southern Wyoming, is still in the early phases. Throughout the

Net Exploration Resources Discovered (MMBoe)



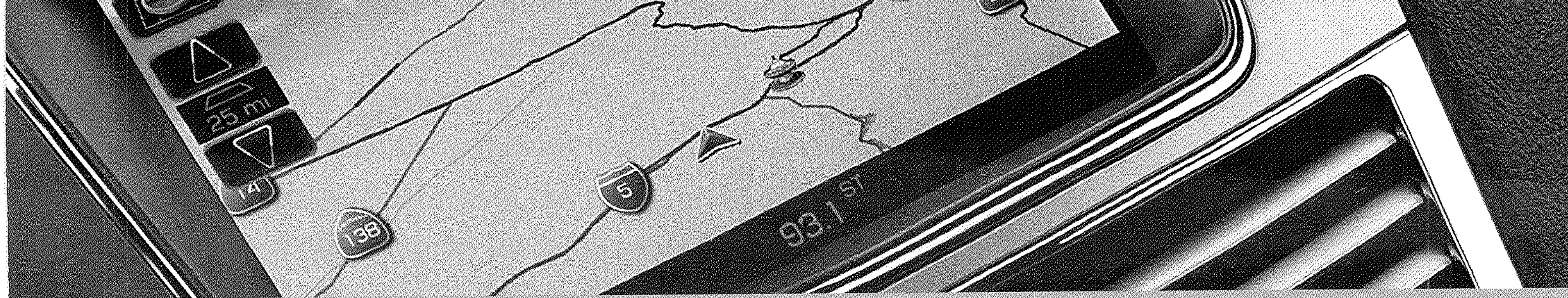
DJ basin, we are utilizing 3D seismic imaging to optimally target well locations and state-of-the-art completion techniques. In 2011, we expect to accelerate our total horizontal Niobrara program, drilling more than twice the number of wells we drilled in 2010.

As a final 2010 note for our onshore properties, we took the opportunity to fine-tune our portfolio by selling certain higher-cost non-core assets in the Mid-continent and Illinois basins.

Deepwater Gulf of Mexico

THE DEEPWATER DRILLING MORATORIUM triggered by the Macondo incident impacted all operators in the Gulf of Mexico in 2010. Despite a halt in drilling operations and an uncertain regulatory future, Noble Energy remains well positioned and committed to the region. We are carefully navigating the challenges and remain focused on ensuring that safe operations are always the priority.

Despite significant new permitting and operating requirements, we were successful in securing two completion permits during the moratorium for Santa Cruz and Isabela. This was an enormous accomplishment for our teams and allowed us to continue moving the Galapagos project forward.



Navigating the future

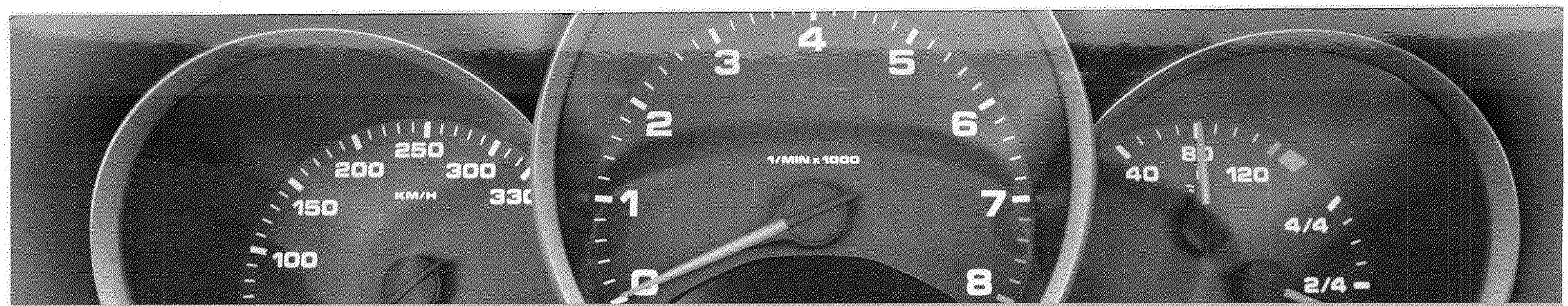
With major projects planned to commence around the globe over the next several years, the route to significant growth is transparent.

Two of our exploration wells, Santiago and Deep Blue, were suspended while drilling as a result of the moratorium. The industry's first post-moratorium drilling permit was issued to Noble Energy for our Santiago prospect, and we are working to permit Deep Blue as well. We look forward to recommencing drilling operations on these wells shortly and are proud to help lead the industry back to drilling in the deepwater Gulf of Mexico. At Gunflint, our largest Gulf discovery to date, appraisal plans and partner unitization continued to move forward throughout 2010. We will be submitting the permit for the first appraisal well at Gunflint in early 2011 and hope to commence drilling later in the year.

Our exploration portfolio in the Gulf of Mexico is extensive, and we are continuing to mature the inventory. Although we are preparing for a resumption of drilling in the Gulf, we would expect our pace of exploration to be slower than before. Certainly the environment for doing business in the Gulf has changed, but I am pleased with the response of the industry and our continued focus on high operating standards.

West Africa

WEST AFRICA IS ANOTHER CORE AREA for Noble Energy, accounting for about a quarter of our current production. In 2010, we made significant



Best-in-class execution

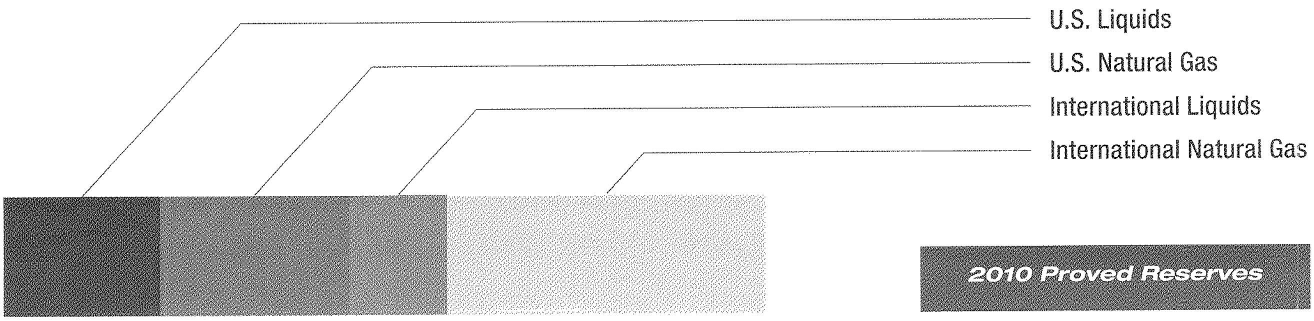
We have intently prepared ourselves for success, and we are delivering on our plans with technical expertise and thorough processes.

progress on our first two operated crude and condensate projects in the region. Aseng, which we sanctioned for development in 2009, is a floating production storage and offloading (FPSO) oil development and will serve as an infrastructure hub for additional liquid discoveries. We have completed the development drilling at Aseng and are targeting production to begin in mid 2012. The project remains on schedule and on budget.

Our second operated project, Alen, is on track to begin production in late 2013. Alen, a gas cycling project, was sanctioned for development in 2010. Between Aseng and Alen, significant growth in crude and condensate production and cash flow is right around the corner. We have 1.5 million gross acres offshore in the Douala basin between our positions in Cameroon and Equatorial Guinea. Our plans are to drill two to three exploration and appraisal wells in 2011, targeting new oil potential in the basin.

Eastern Mediterranean

SIGNIFICANT GAS DISCOVERIES OFFSHORE ISRAEL by Noble Energy and our partners have led an energy evolution in Israel. The journey began in 2000 with the Mari-B natural gas discovery. First production at Mari-B began in 2004 and natural gas now fuels around 40 percent of the country's



electricity generation. In 2010, we made significant investments in two new production wells and additional compression at Mari-B to support Israel's continually growing demand for natural gas. This is low-cost, high-margin production, and we are making sure that it continues.

In 2009 we made a major discovery at Tamar, which is estimated to hold a staggering 8.4 trillion cubic feet (tcf) of gross natural gas resources – enough to fuel Israel for decades to come. Our board sanctioned the development of Tamar in 2010. Utilizing existing onshore facilities and other infrastructure built for Mari-B, Tamar is being progressed to deliver new supplies of natural gas to Israel at the end of 2012 or early in 2013.

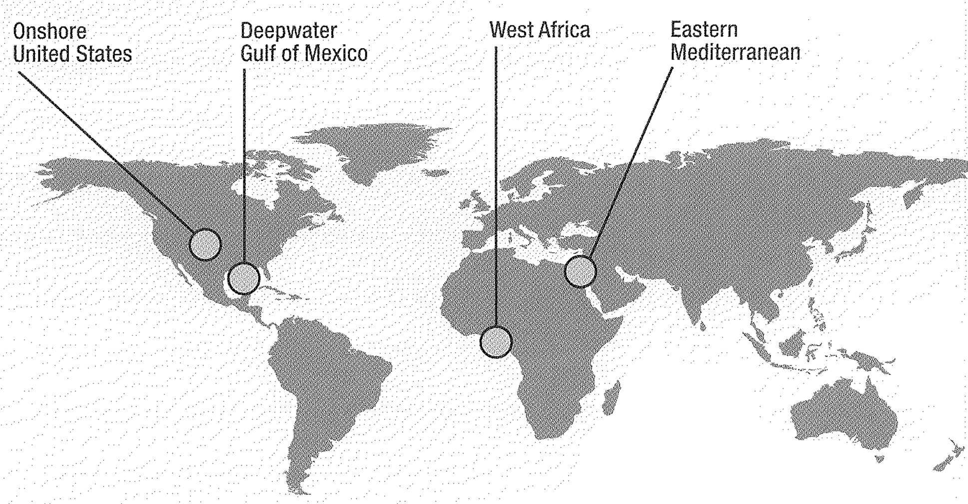
The highlight of 2010 was our most recent discovery at Leviathan, which has the potential to not only be utilized in domestic markets, but will likely result in Israel becoming a natural gas exporter. Although two appraisal wells are planned to further define Leviathan, we have confirmed gross mean estimates of 16 tcf of gas resources – easily the largest discovery in Noble Energy's history. Over the last decade, Leviathan and Tamar are the two biggest deepwater gas discoveries in the world.

Our 2011 plans focus on continuing development of Tamar and further testing the potential of this underexplored basin. We anticipate drilling three to

Our people and partnerships give us the energy to stay in pursuit of our goals. Their focus, dedication, and tireless teamwork propel us toward continued achievement, and we are ever thankful for their efforts.

four exploration and appraisal wells this year in the Eastern Mediterranean, between our positions offshore Israel and Cyprus, with a top priority being the appraisal of the Leviathan discovery.

Core Business Areas



A High-Performance Machine

NOBLE ENERGY is engineered to deliver a high level of performance. We are not gaining ground by small increments; instead, we are accelerating toward significant growth in proven reserves and production, as well as in cash flows and margins. Our proven reserves grew by a third in 2010, as a result of

"We are not gaining ground by small increments; instead, we are accelerating toward significant growth in proven reserves and production, as well as in cash flows and margins."

initial major-project bookings at Tamar and Alen, as well as strong reserve replacement in the U.S. from our vertical and horizontal drilling programs.

We faced a number of big challenges in 2010, and it was the dedication and superior efforts by our employees that resulted in substantial progress for Noble Energy. We continue to attract people of the highest caliber to our Company, and I am exceedingly grateful for their commitment to success. We remain focused on ensuring safe and reliable operations, minimizing environmental impacts, and supporting the communities in which we work – all while delivering excellent returns to shareholders. On behalf of the Board of Directors and our employees, I want to thank all of our stakeholders for their continued confidence and support of Noble Energy.

Charles D. Davidson

Charles D. Davidson *Chairman of the Board and Chief Executive Officer*

OPERATING & FINANCIAL DATA - 2010 ANNUAL REPORT

OPERATING DATA

		2010	2009	2008	2007	2006
Year-End Proved Reserves						
	Natural Gas (Bcf)	4,361	2,904	3,315	3,307	3,231
	Liquids (MMBbls)	365	336	311	329	296
	Total (MMBoe)	1,092	820	864	880	835
Sales Volumes						
	Natural Gas (Bcf)	287	285	281	251	227
	Liquids (MMBbls) [1]	31	29	32	31	30
	Total (MMBoe)	79	77	79	73	68
Average Sales Price						
	Natural Gas (per Mcf)	$ 3.00	$ 2.54	$ 5.04	$ 5.26	$ 5.55
	Crude Oil and Condensate (per Bbl) [2]	$ 76.46	$ 55.76	$ 82.60	$ 60.61	$ 54.47

FINANCIAL DATA

(In millions, except per share amounts and ratios)

	2010	2009	2008	2007	2006
Revenues	$ 3,022	$ 2,313	$ 3,901	$ 3,272	$ 2,940
Net Income (Loss) [3]	$ 725	$ (131)	$ 1,350	$ 944	$ 678
Earnings (Loss) per Share Diluted	$ 4.10	$ (0.75)	$ 7.58	$ 5.45	$ 3.79
Weighted Average Shares Diluted	177	173	176	173	179
Cash Dividend per Share	$ 0.72	$ 0.72	$ 0.66	$ 0.44	$ 0.28
Net Cash Provided by Operating Activities	$ 1,946	$ 1,508	$ 2,285	$ 2,017	$ 1,730
Capital Expenditures [4]	$ 2,641	$ 1,317	$ 2,264	$ 1,739	$ 1,347
Total Assets	$ 13,282	$ 11,807	$ 12,384	$ 10,831	$ 9,589
Total Debt	$ 2,272	$ 2,037	$ 2,266	$ 1,876	$ 1,801
Stockholders' Equity	$ 6,848	$ 6,157	$ 6,309	$ 4,809	$ 4,114
Total Debt-to-Book-Capital Ratio	25%	25%	26%	28%	30%
Debt per Boe	$ 2.08	$ 2.48	$ 2.62	$ 2.13	$ 2.16

[1] Includes sales from equity method investees

[2] Excludes equity method investees

[3] See Adjusted Net Income and Reconciliation to Net Income (Loss) per the Company's quarterly earnings releases

[4] Excludes corporate acquisitions and non-cash FPSO lease accrual

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

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2010
or

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

For the transition period from to
Commission file number: 001-07964

NOBLE ENERGY, INC.

(Exact name of registrant as specified in its charter)

Delaware	**73-0785597**
(State of incorporation)	(I.R.S. employer identification number)
100 Glenborough Drive, Suite 100	
Houston, Texas	**77067**
(Address of principal executive offices)	(Zip Code)

(281) 872-3100
(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, $3.33-1/3 par value	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. ☒ 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 of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☒ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ☒ Yes ☐ No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐
(Do not check if a smaller reporting company)

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

Aggregate market value of Common Stock held by nonaffiliates as of June 30, 2010: $10.4 billion.
Number of shares of Common Stock outstanding as of January 31, 2011: 175,746,518.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive proxy statement for the 2011 Annual Meeting of Stockholders to be held on April 26, 2011, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2010, are incorporated by reference into Part III.

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GLOSSARY

In this report, the following abbreviations are used:

Bbl	Barrel
MBbls	Thousand barrels
MMBbls	Million barrels
MBbl/d	Thousand barrels per day
BOE	Barrels of oil equivalent. Natural gas is converted on the basis of six Mcf of gas per one barrel of oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency. Given recent commodity price disparities, the price for a barrel of oil equivalent for natural gas is less than the price for a barrel of oil.
MBoe	Thousand barrels oil equivalent
Boe/d	Barrels oil equivalent per day
MBoe/d	Thousand barrels oil equivalent per day
Mcf	Thousand cubic feet
MMcf	Million cubic feet
Bcf	Billion cubic feet
MMcf/d	Million cubic feet per day
Mcfe	Thousand cubic feet equivalent
MMcfe	Million cubic feet equivalent
Btu	British thermal unit
MMBtu	Million British thermal units
MMgal	Million gallons
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
NGL	Natural gas liquid
FPSO	Floating production, storage and offloading vessel

PART I

Items 1. and 2. Business and Properties

This Annual Report on Form 10-K and the documents incorporated herein by reference contain forward-looking statements based on expectations, estimates and projections as of the date of this filing. These statements by their nature are subject to risks, uncertainties and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. See Item 1A. Risk Factors – Disclosure Regarding Forward-Looking Statements of this Form 10-K.

General

Noble Energy, Inc. (Noble Energy, we or us) is a leading independent energy company engaged in worldwide oil and gas exploration and production. Noble Energy is a Delaware corporation, formed in 1969, that has been publicly traded on the New York Stock Exchange (NYSE) since 1980. In this report, unless otherwise indicated or where the context otherwise requires, information includes that of Noble Energy and its subsidiaries.

Our aim is to achieve growth in earnings and cash flow through exploration success and the development of a high quality, diversified portfolio of assets that is balanced between US and international projects. Exploration success, along with additional capital investment in US and international locations such as Equatorial Guinea and Israel, has resulted in a visible lineup of major development projects which positions us for substantial future reserves growth. Occasional strategic acquisitions of producing and non-producing properties, such as the Central Denver-Julesberg (DJ) Basin asset acquisition in 2010, combined with the divestment of non-core assets, have allowed us to achieve our objective of a well-balanced and diversified asset portfolio. Our portfolio is balanced between short-term and long-term projects, both onshore and offshore. Onshore US assets provide a stable base of production and accommodate flexible capital spending programs that are responsive to ongoing changes in the economic environment. Our long-term development projects, while requiring multi-year capital investment, are expected to offer attractive financial returns and sustained production growth, along with a diversity of production mix among crude oil, US natural gas, and international natural gas.

We have operations in four key areas:

- the Central DJ Basin onshore US;
- the deepwater Gulf of Mexico;
- offshore West Africa; and
- offshore Eastern Mediterranean.

These areas provide:

- most of our crude oil and natural gas production;
- visible growth from major development projects; and
- numerous exploration opportunities.

Our growth is supported by a strong balance sheet and ample liquidity levels. See Item 6. Selected Financial Data for additional financial and operating information for fiscal years 2006-2010.

Major Development Project Inventory Our exploration success has provided us with a number of major development projects on which we are moving forward. Although these projects will require significant capital investments over the next several years, they typically offer long life, sustained cash flows after investment and attractive financial returns. Our major development projects include the following:

- Central DJ Basin (onshore US);
- Galapagos (deepwater Gulf of Mexico);
- Gunflint (deepwater Gulf of Mexico);
- Tamar (offshore Israel);
- Aseng (offshore Equatorial Guinea);
- Alen (offshore Equatorial Guinea);
- Diega/Carmen (offshore Equatorial Guinea); and
- West Africa gas projects (offshore Equatorial Guinea and Cameroon).

These projects are discussed in more detail in the sections below. See also Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Operating Outlook – Major Development Project Inventory.

Proved Oil and Gas Reserves Proved reserves estimates at December 31, 2010 were as follows:

Summary of Oil and Gas Reserves as of Fiscal-Year End
Based on Average Fiscal-Year Prices

	December 31, 2010		
	Proved Reserves		
Reserves Category	Crude Oil, Condensate & NGLs (MMBbls)	Natural Gas (Bcf)	Total (1) (MMBoe)
Proved Developed			
United States	119	1,156	312
Equatorial Guinea	43	597	142
Israel	-	145	24
Other International (2)	21	19	24
Total Proved Developed Reserves	183	1,917	502
Proved Undeveloped			
United States	106	470	184
Equatorial Guinea	69	272	114
Israel	2	1,699	286
Other International (2)	5	3	6
Total Proved Undeveloped Reserves	182	2,444	590
Total Proved Reserves	365	4,361	1,092

(1) Natural gas is converted on the basis of six Mcf of gas per one barrel of oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency.

(2) Other international includes the North Sea and China.

Estimated reserves at the end of 2010 were approximately 1.1 billion barrels of oil equivalent, a 33% increase from 2009. US reserves accounted for 45% of the total, and international reserves accounted for 55%. Our 2010 reserve mix is 33% global liquids, 42% international natural gas, and 25% US natural gas.

See Proved Reserves Disclosures, below, and Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Information (Unaudited) for definitions of proved oil and gas reserves, proved developed oil and gas reserves and proved undeveloped oil and gas reserves.

Crude Oil and Natural Gas Properties and Activities We search for crude oil and natural gas properties, seek to acquire exploration rights in areas of interest and conduct exploration activities. These activities include geophysical and geological evaluation and exploratory drilling, where appropriate, on properties for which we have acquired exploration rights. Our properties consist primarily of interests in developed and undeveloped crude oil and natural gas leases and concessions. We also own natural gas processing plants and natural gas gathering and other crude oil and natural gas related pipeline systems which are primarily used in the processing and transportation of our crude oil, natural gas and NGL production.

Exploration Activities We primarily focus on organic growth from exploration and development drilling, concentrating on basins or plays where we have strategic competitive advantage and which we believe offer superior returns. We have had substantial exploration success onshore US and in the deepwater Gulf of Mexico, West Africa and the Eastern Mediterranean, resulting in a significant portfolio of major development projects. In December 2010, we announced a significant natural gas discovery at the Leviathan prospect, offshore Israel, our largest discovery to date. We have numerous exploration opportunities remaining in these areas and are also engaged in new venture activity in the US and international locations.

Appraisal, Development and Exploitation Activities Our exploration success has delivered numerous development opportunities, as demonstrated in our growing inventory of major development projects. In 2010, we sanctioned the development plans for the Tamar and Alen projects.

Acquisition and Divestiture Activities We maintain an ongoing portfolio management program. Accordingly, we may engage in acquisitions of additional crude oil or natural gas properties and related assets through either direct acquisitions of the assets or acquisitions of entities owning the assets. We may also divest non-core, non-strategic assets in order to optimize our property portfolio.

Central DJ Basin Asset Acquisition On March 1, 2010, we acquired substantially all of the US Rocky Mountain assets of Petro-Canada Resources (USA) Inc. and Suncor Energy (Natural Gas) America Inc. for a total purchase price of $498 million. The acquisition included properties located in the Central DJ Basin, one of our key operating areas. The acquisition added approximately 46 MMBoe of proved reserves at closing date, and approximately 10 MBoe/d to our daily production base, starting from the closing date, and will provide significant growth potential. Included in the purchase were 323,000 total net acres, nearly 183,000 of which are located in the Central DJ Basin. See United States discussion below.

Onshore US Sale In August 2010, we closed the sale of non-core assets in the Mid-Continent and Illinois Basin areas for cash proceeds of $552 million and recorded a gain of $110 million. The sale included approximately 32 MMBoe of proved reserves, at closing date, and approximately 5.7 MBoe/d of production.

Mid-Continent Acquisition In 2008, we acquired producing properties in western Oklahoma for $292 million. Properties acquired cover approximately 15,500 net acres and included approximately 16 MMBoe of proved reserves.

Sale of Argentina Assets In 2008, we closed on the sale of our producing property interest in Argentina for a sales price of $117.5 million. Our crude oil reserves for Argentina totaled 7 MMBbls at December 31, 2007.

Deepwater Horizon Incident In April 2010, the deepwater Gulf of Mexico drilling rig Deepwater Horizon, engaged in drilling operations for another operator, sank after a blowout and fire (Deepwater Horizon Incident or Incident). The resulting leak caused a significant oil spill. Subsequently, the Secretary of the Interior ceased issuing offshore drilling permits pursuant to a series of moratoria, and all deepwater drilling activities in progress were suspended (Deepwater Moratorium). Although the moratoria have been lifted for drilling in water depths greater than 500 feet, the US Department of the Interior has not issued any permits related to the drilling of new exploratory wells as of January 31, 2010. Additionally, the US administration and the Department of the Interior have maintained the ban on new drilling on the Atlantic Coast and in the Eastern Gulf of Mexico.

The Deepwater Horizon Incident is likely to have a significant and lasting effect on the US offshore energy industry, and has resulted in a number of fundamental changes, including heightened regulatory scrutiny, more stringent operating and safety standards and changes in equipment requirements. Other countries, including some in which we currently conduct business, are considering legislative or regulatory changes which could also have an impact on offshore drilling activities. These changes may result in increases in our operating and development costs and extend project development timelines. We are monitoring legislative and regulatory developments and are currently unsure of the full impact of the Incident.

See Deepwater Gulf of Mexico, below, and Item 1A. Risk Factors *Our operations in the deepwater Gulf of Mexico, as well as onshore US and international locations, could be adversely affected by future changes in laws and regulations which may occur as a result of the Deepwater Horizon Incident.*

Termination of Ecuador PSC In November 2010, we announced that we had received notice from the government of Ecuador regarding the termination of the Block 3 production sharing contract (PSC) (100% working interest) with our subsidiary, EDC Ecuador Ltd. as we had not negotiated a service contract on Block 3 in accordance with the terms of a newly enacted hydrocarbon law. The Ecuadorian hydrocarbon law aims to change current production sharing arrangements into service contracts and provided for renegotiation of certain contracts by November 23, 2010. It also allows the Ecuadorian government to nationalize oil and gas fields if a private operator does not comply with local laws.

We are continuing to work with the government of Ecuador to resolve this matter. However, we are uncertain as to the potential outcome of this matter, resolution of which could ultimately lead to a reduction in the value of our investment in Ecuador which, as of December 31, 2010, had a net book value of approximately $66 million.

United States

We have been engaged in crude oil and natural gas exploration, exploitation and development activities throughout onshore US since 1932 and in the Gulf of Mexico since 1968. US operations accounted for 57% of our 2010 total consolidated sales volumes and 45% of total proved reserves at December 31, 2010. Approximately 55% of the proved reserves are natural gas and 45% are crude oil, condensate and NGLs.

Sales of production and estimates of proved reserves for our US operating areas were as follows:

	Year Ended December 31, 2010				December 31, 2010		
	Sales Volumes				Proved Reserves		
	Crude Oil & Condensate	Natural Gas	NGLs	Total	Crude Oil, Condensate & NGLs	Natural Gas	Total
	(MBbl/d)	(MMcf/d)	(MBbl/d)	(MBoe/d)	(MMBbls)	(Bcf)	(MMBoe)
Wattenberg	19	151	10	54	177	851	319
Rocky Mountain/Mid-Continent	5	171	1	36	16	646	123
Deepw ater Gulf of Mexico	11	40	2	19	22	34	28
Gulf Coast and Other Onshore	4	38	1	10	10	95	26
Total	39	400	14	119	225	1,626	496

Wells drilled in 2010 and productive wells at December 31, 2010 for our US operating areas were as follows:

	Year Ended December 31, 2010	December 31, 2010
	Gross Wells Drilled or Participated in	Gross Productive Wells
Wattenberg	491	7,706
Rocky Mountain/Mid-Continent	177	4,346
Deepwater Gulf of Mexico [1]	1	11
Gulf Coast and Other Onshore	20	1,284
Total	689	13,347

[1] Excludes Deep Blue and Santiago exploratory wells where drilling activities were suspended by the Deepwater Moratorium.

Locations of our onshore US operations are shown on the map below:

Central DJ Basin / Wattenberg Our onshore activities are focused in the Central DJ Basin, where we have a significant acreage position of over 830,000 net acres. Included in the Central DJ Basin is Wattenberg (approximately 97% operated working interest), our largest US onshore asset. We have a multi-year project inventory, enhanced in 2010 with the Central DJ Basin asset acquisition, and have added a horizontal drilling program targeting the Niobrara formation.

Wattenberg includes:

- our historical Wattenberg development area, where we have conducted substantial vertical development over the last several years and are now identifying locations for additional horizontal wells;
- the northern and eastern edges of our historical Wattenberg development area where we are focusing on expanding the economic limits of the area. Expansion of this area has resulted in increases in our crude oil and NGL production volumes. Most of our recent horizontal drilling has been in this area; and
- Northern Colorado from the edge of our historical Wattenberg development area to the Wyoming border.

During 2010, we drilled a total of 463 successful development wells in the Codell/Niobrara, J-Sand, and Lyons formations in historical Wattenberg. Seventeen of these wells were drilled horizontally into the Niobrara formation and one was drilled horizontally into the Codell formation.

Historical Wattenberg contributed 52.7 MBoe/d of production and represented approximately 25% of total consolidated sales volumes in 2010, with over 50% being liquids, and approximately 314 MMBoe or 29% of total proved reserves at December 31, 2010.

We also drilled 24 successful development wells in the J-Sand formation and four successful horizontal exploratory wells in the Niobrara formation in Northern Colorado.

Our 2010 Wattenberg drilling program resulted in additions to proved reserves of approximately 36 MMBoe, approximately 64% of which are liquids.

We have also started a horizontal drilling program on acreage in Southeastern Wyoming.

At year-end, we were running six vertical rigs, two horizontal rigs and 23 completion units and are evaluating processing and transportation infrastructure needs as well as optimum well completion techniques. We expect to add three horizontal rigs and drill approximately 80 horizontal and 500 vertical wells in the Central DJ Basin in 2011.

Piceance Basin We currently hold interests in approximately 20,000 net acres in the Piceance Basin in western Colorado (approximately 87% operated working interest), providing an inventory of future projects. Multiple wells are drilled from individual drilling pads to reduce rig mobilization costs in mountainous terrain and to minimize environmental impact on the surface area. In 2010, we drilled 62 development wells, 100% of which were successful. Successful drilling activity in recent years has led to significant volume growth; production has grown from 2 MMcfe/d in 2005 to 49 MMcfe/d for 2010. We plan to drill approximately 20 wells in 2011.

Wind River Basin At our Iron Horse development in the Wind River Basin (99% operated working interest), located in Central Wyoming, we drilled nine development wells during 2010 with a 100% success rate. We plan to continue our drilling program here during 2011 and expect to drill approximately three new wells.

Mid-Continent Area The Mid-Continent area includes properties in the Texas Panhandle, Oklahoma and Kansas. A significant area of activity has been in the liquid-rich Cleveland Sandstone area of western Oklahoma (89% operated working interest). We drilled or participated in a total of 33 development wells in these areas in 2010. Twelve of the wells were horizontal development wells, 100% of which were successful. We currently have one rig operating and expect to drill approximately six wells in 2011.

Bowdoin, Tri-State and San Juan We also produce in the Bowdoin Field (approximately 70% operated working interest) located in North Central Montana, Tri-State Field (approximately 95% operated working interest) in northeastern Colorado, northwestern Kansas, and southwestern Nebraska, and the San Juan Basin (approximately 82% operated working interest) located in northwestern New Mexico and southwestern Colorado. We have reduced investment in these areas in order to focus our capital spending on the core development fields. During 2010, we drilled 72 development wells and one exploratory well in these areas.

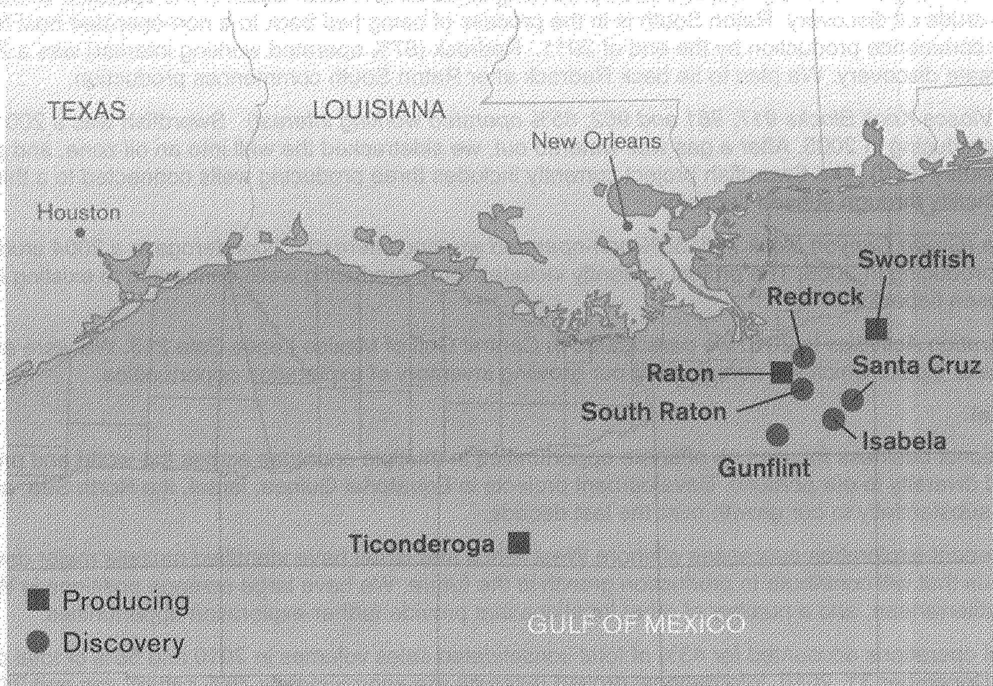
Onshore East Texas and North Louisiana (Haynesville) We hold approximately 17,000 gross acres in the Haynesville/Bossier core area. A majority of our 2010 drilling program targeted the Haynesville/Bossier shale (approximately 60% working interest). We drilled or participated in nine development and two exploratory wells in the Haynesville/Bossier shale with an overall success rate of 100%. The majority of our acreage is now held by production.

Other We drilled or participated in an additional eight development wells and one exploratory well in other onshore US areas in 2010.

Deepwater Gulf of Mexico The deepwater Gulf of Mexico is one of our key operating areas. Our focus is on high-impact opportunities with the potential to provide significant medium and long-term growth. We have three producing fields, multiple ongoing development projects and a substantial inventory of exploration opportunities.

The deepwater Gulf of Mexico accounted for 9% of total consolidated sales volumes in 2010 and 3% of total proved reserves at December 31, 2010. We currently hold leases on 108 deepwater Gulf of Mexico blocks, representing almost 600,000 gross acres (425,000 net acres). We are the operator on approximately 85% of the leases.

Locations of our deepwater Gulf of Mexico developments are shown on the map below:



Deepwater Gulf of Mexico Exploration Program Our deepwater Gulf of Mexico operations resulted from lease acquisition, expansion of our 3-D seismic database, and an active drilling program prior to the Deepwater Moratorium and current permitting environment. We currently have an inventory of 41 identified prospects, with a combination of both large stand-alone prospects as well as a number of smaller, tie-back opportunities.

During 2010, prior to the Deepwater Moratorium, we continued drilling efforts on two significant test wells that had been spud in 2009, Double Mountain (Green Canyon Block 555; 30% non-operated working interest) and Deep Blue (Green Canyon Block 723; 33.75% operated working interest). In April 2010 we announced that the exploration well at the Double Mountain prospect had found noncommercial quantities of hydrocarbons and was plugged and abandoned.

When the Deepwater Moratorium was announced in May 2010, we were required to suspend sidetrack drilling activities at the Deep Blue prospect. We also were required to suspend drilling activities at the Santiago exploratory well (23.25% operated working interest) at the Galapagos project. Once drilling permits are approved, we plan to resume exploration activities at Deep Blue and Santiago and appraisal drilling at Gunflint in 2011.

Our most significant deepwater Gulf of Mexico properties and current development plans are discussed in more detail below.

Gunflint (Mississippi Canyon Block 948; 37.5% operated working interest and Mississippi Canyon Block 949; 43.75% operated working interest) Gunflint is a 2008 crude oil discovery, our largest deepwater Gulf of Mexico discovery to date. Our plans to drill one or two appraisal wells during 2010 were delayed by the Deepwater Moratorium. Once a drilling permit is approved, we plan to conduct appraisal drilling to help define the extent of the reservoir and a potential development scenario.

We are reviewing host platform options including: subsea tieback to existing third-party host, procurement and modification of existing platform, and new construction. If we choose to connect to an existing third-party host, the project could have an accelerated completion schedule, thereby potentially absorbing time lost due to the Deepwater Moratorium and permit-related delay. We are currently targeting 2015 for production start-up.

Galapagos Development Project including Isabela (Mississippi Canyon Block 562, 33% non-operated working interest) and Santa Cruz (Mississippi Canyon Blocks 519/563, 23.25% operated working interest) The Galapagos crude oil development project consists of Isabela, a 2007 discovery, Santa Cruz, a 2009 discovery, and the Santiago exploration well (Mississippi Canyon Block 519, 23.25% operated working interest). In 2009, we approved a phased development plan which includes completion of the wells and connection to the nearby Nakika production platform via subsea tieback. Nakika is partially owned and operated by BP Exploration & Production Inc. (BP). During the last half of 2010, we assumed operatorship of the Isabela well completion from BP and were able to obtain permits to perform completion work at both Isabela and Santa Cruz. Although installation of the Nakika topside equipment is not expected to be complete until 2012, we are working on alternatives which may result in commencement of production in late 2011 or early 2012.

Raton/Raton South/Redrock (Mississippi Canyon Blocks 204, 248 and 292) Raton (67% operated working interest) was a 2006 natural gas discovery and has been producing since 2008. Raton South (79% operated working interest) was a 2008 crude oil discovery. Raton South is in the process of being tied back to a non-operated host facility and is expected to commence production by the end of 2011. Redrock (67% operated working interest) was a 2006 natural gas/condensate discovery. We plan to tie back Redrock after Raton South commences production.

Swordfish (Viosca Knoll Blocks 917, 961 and 962; 85% operated working interest) Swordfish was a 2001 discovery and began producing in 2005. After a gas well watered out, we sidetracked the well into an oil zone, and production began in January 2010. The Swordfish project currently includes three producing wells connected to a third-party production facility through subsea tiebacks.

Ticonderoga (Green Canyon block 768; 50% non-operated working interest) Ticonderoga is a 2004 crude oil discovery and began producing in 2006. The project currently includes three producing wells connected to existing infrastructure through subsea tiebacks.

Other Exploration Activities In 2010 we participated in Central Gulf of Mexico Lease Sale 213. We were awarded 11 new deepwater blocks which will complement our growing inventory of exploration opportunities.

International

Our international business focuses on offshore opportunities in multiple countries across the world and provides balance and diversity to our portfolio. Development projects in Equatorial Guinea, Israel, the North Sea, and China have contributed substantially to our growth over the last decade.

Significant recent exploration successes offshore West Africa and Israel have identified multiple major development projects for us that will contribute to production growth in the future. We have large acreage positions in West Africa, the Eastern Mediterranean, and a number of other locations that provide further exploration opportunities.

International operations accounted for 43% of total consolidated sales volumes in 2010 and 55% of total proved reserves at December 31, 2010. International proved reserves are approximately 76% natural gas and 24% crude oil. Operations in Equatorial Guinea and China are conducted in accordance with the terms of PSCs. In Cameroon, we operate in accordance with the terms of a PSC and a mining concession. Operations in Israel, the North Sea, and other foreign locations are conducted in accordance with concession agreements, permits or licenses.

Sales volumes and estimates of proved reserves for our international operating areas were as follows:

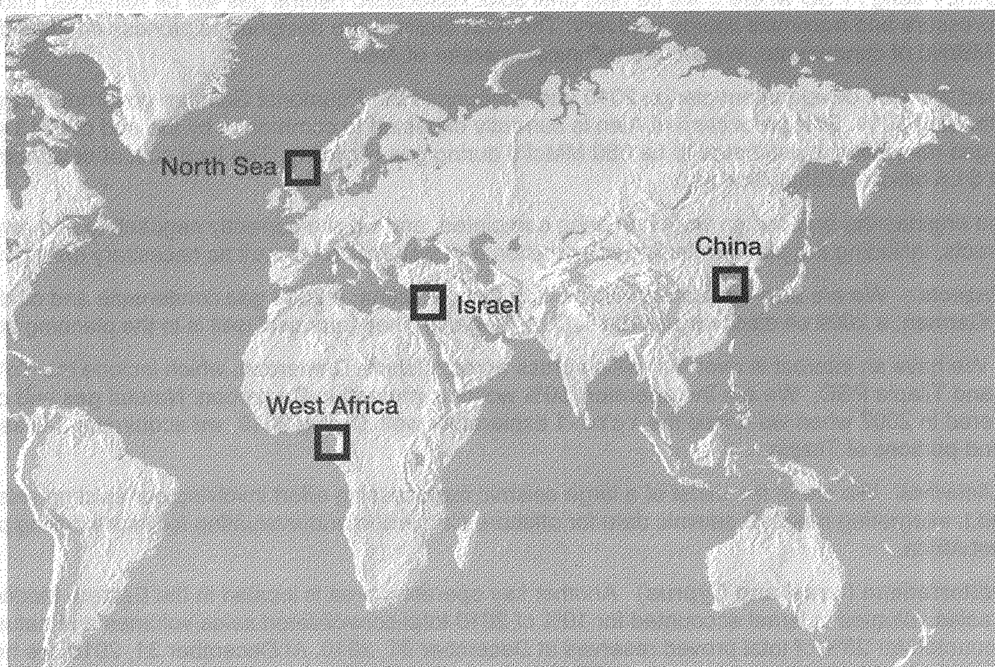
	Year Ended December 31, 2010				December 31, 2010		
	Sales Volumes				Proved Reserves		
	Crude Oil & Condensate	Natural Gas	NGLs	Total	Crude Oil, Condensate & NGLs	Natural Gas	Total
	(MBbl/d)	(MMcf/d)	(MBbl/d)	(MBoe/d)	(MMBbls)	(Bcf)	(MMBoe)
International							
Equatorial Guinea	11	226	-	49	112	869	256
Israel	-	130	-	22	2	1,844	310
North Sea	10	6	-	11	16	17	19
Ecuador [1]	-	25	-	4	-	-	-
China	4	-	-	4	10	5	11
Total International	25	387	-	90	140	2,735	596
Equity Investee	2	-	5	7	-	-	-
Total	27	387	5	97	140	2,735	596
Equity Investee Share of Methanol Sales (MMgal)				129			

[1] Includes production through November 24, 2010. Our Block 3 PSC was terminated by the Ecuadorian government on November 25, 2010. See Termination of Ecuador PSC.

Wells drilled in 2010 and productive wells at December 31, 2010 in our international operating areas were as follows:

	Year Ended December 31, 2010	December 31, 2010
	Gross Wells Drilled or Participated in	Gross Productive Wells
International		
Equatorial Guinea	5	18
Israel	3	6
North Sea	1	26
China	4	20
Total International	13	70

Locations of our international operations are shown on the map below:



West Africa (Equatorial Guinea and Cameroon) West Africa is one of our key operating areas and includes the Alba Field, Block O, and Block I offshore Equatorial Guinea as well as the YoYo mining concession and Tilapia PSC offshore Cameroon. Equatorial Guinea accounted for approximately 24% of 2010 total consolidated sales volumes and 24% of total proved reserves at December 31, 2010. At December 31, 2010, we held approximately 19,000 net developed acres and 233,000 net undeveloped acres in Equatorial Guinea and 563,000 net undeveloped acres in Cameroon.

Alba Field We have a 34% non-operated working interest in the Alba field, offshore Equatorial Guinea, which is one of our most significant assets. Operations include the Alba field and related production and condensate storage facilities, an LPG processing plant where additional condensate is produced, and a methanol plant capable of producing up to 3,000 metric tons per day gross. The LPG processing plant and the methanol plant are located on Bioko Island.

We sell our share of natural gas production from the Alba field to the LPG plant, the methanol plant and an unaffiliated LNG plant. The LPG plant is owned by Alba Plant LLC (Alba Plant), in which we have a 28% interest accounted for by the equity method. The methanol plant is owned by Atlantic Methanol Production Company, LLC (AMPCO), in which we have a 45% interest, also accounted for by the equity method. AMPCO purchases natural gas from the Alba field under a contract that runs through 2026 and subsequently markets the produced methanol to customers in the US and Europe. Alba Plant sells its LPG products and condensate at our marine terminal at prevailing market prices. We sell our share of condensate produced in the Alba field and from the LPG plant under short-term contracts at market-based prices.

Significant development planning has occurred for an Alba field compression project, which is a natural progression for the operations of the field. We are evaluating certain features of project implementation and expect to grant final project approval in 2011 or 2012.

Aseng Project Aseng (formerly Benita) is a crude oil development project on Block I (45% operated working interest) which will include five horizontal wells flowing to an FPSO where the production stream will be separated. The oil will be stored on the FPSO until sold, while the natural gas and water will be reinjected into the reservoir to maintain pressure and maximize oil recoveries. We are the technical operator of Aseng.

During 2010, we concluded field drilling of five production wells and three water injection wells and initiated completions.

The FPSO, currently under construction in Singapore, is designed to act as an oil production hub, as well as a liquids storage and offloading hub, with capabilities to support future subsea oil field developments in the area. It will also have the ability to take on board stabilized condensate from gas condensate fields in the area. It will be capable of processing 120 MBbl/d of liquids, including 80 MBbl/d of oil, and reinjecting 170 MMcf/d of natural gas. Storage will be approximately 1.6 MMBbls of liquids.

First production at Aseng is currently expected to commence mid-year 2012 with net oil production of approximately 17 MBbl/d.

Alen Project Alen (formerly Belinda), located primarily on Block O (45% operated average working interest) offshore Equatorial Guinea is our next West Africa development project. Initial field development will include three production wells and three subsea natural gas injection wells tied to a processing facility. Produced condensate will be separated and piped to the Aseng FPSO where it will be held until sold. Associated natural gas will be reinjected into the reservoir to maintain pressure and maximize liquids recovery. The Alen facilities are designed to process 440 MMcf/d of natural gas and 40 MBbl/d of condensate. We are the technical operator of Alen.

We sanctioned the Alen development plan in 2010 and announced the Equatorial Guinean government's approval of the plan in January 2011. First production at Alen is currently expected to commence by the end of 2013 at 19 MBbl/d, net. Natural gas reinjection is estimated to be 380 MMcf/d during gas-recycling. The total cost of development is estimated at $1.6 billion ($735 million net).

The front-end engineering and design work has been completed, and we are currently negotiating and awarding key project contracts, including the platform facility construction and installation, as well as necessary drilling resources.

Future Oil Projects We are also evaluating future oil projects at Diega, a 2008 gas condensate and oil discovery on Block I, and Carmen, a 2009 oil discovery on Block O. A Diega/Carmen appraisal well is in the planning stages.

Cameroon We have an interest in over 1.1 million gross acres offshore Cameroon, which include the YoYo mining concession and Tilapia PSC. We are the operator (50% working interest) in Cameroon. Natural gas and condensate were discovered in 2007 when we drilled the YoYo -1 exploratory well. During 2010, we acquired a 3-D seismic survey over Yoyo and portions of Tilapia.

Exploration Activities We are in the midst of a large seismic reprocessing effort involving our existing seismic data on Blocks O and I, integrating new 3-D seismic data for offshore Cameroon and evaluating for future drilling potential offshore West Africa.

Eastern Mediterranean (Israel and Cyprus) Another key operating area is located in the Eastern Mediterranean. Natural gas sales volumes in Israel accounted for 10% of 2010 total consolidated sales volumes and natural gas reserves accounted for 28% of total proved reserves at December 31, 2010. At December 31, 2010, we held approximately 29,000 net developed acres and 660,000 net undeveloped acres located between 10 and 90 miles offshore Israel in water depths ranging from 700 feet to 6,500 feet. Our leasehold position in Israel includes four leases and 15 licenses, and we are the operator of the properties. We also hold a license covering approximately 795,000 net undeveloped acres offshore Cyprus adjacent to our Israeli acreage.

Mari-B Field The Mari-B field (47% operated working interest) was the first offshore natural gas production facility in Israel. Natural gas is delivered to a permanent onshore receiving terminal at Ashdod for distribution to purchasers. During 2010 we completed two new wells, allowing us to maintain peak field deliverability of 600 MMcf/d, gross.

Natural gas sales began in 2004 and have increased steadily as Israel's natural gas infrastructure has developed. Our share of the sales volumes has risen from 48 MMcf/d in 2004 to 130 MMcf/d in 2010. Competing imports of natural gas from Egypt to Israel began in 2008. However, during 2010 a higher percentage of the demand for natural gas to produce electricity was met by Mari-B production.

The majority of our natural gas is sold to the Israel Electric Corporation Limited (IEC). We received record sales prices in 2010 as a result of a new sales contract, signed in 2009, under which certain quantities of gas sold receive a price based on a blend of liquids prices and a producer price index.

We currently expect the Mari-B field to produce until the Tamar field begins producing. The Mari-B field will then be used for natural gas storage. We have signed a letter of intent (LOI) with IEC, under which IEC expects to purchase natural gas to establish a natural gas inventory reserve. The Mari-B partners would provide IEC with injection, storage and withdrawal capabilities for this inventory under a related service agreement.

Tamar Project We discovered the Tamar natural gas field (36% operated working interest) offshore Israel in the Levantine Basin in 2009. Tamar is one of the world's largest offshore conventional gas discoveries in recent years. In 2010, we sanctioned the development plan for Tamar and submitted the plan to the Israeli government for approval.

The initial phase of Tamar development will include five subsea wells. The natural gas produced at these wells will flow to a new offshore platform to be constructed near the existing Mari-B platform. The natural gas will then be delivered to an existing pipeline that connects the Mari-B field to the Ashdod onshore terminal. The development will allow for significant expansion as the Israeli natural gas market grows. We expect to commence field development drilling in the first half of 2011, with first production expected by late 2012 or early 2013.

The Israeli natural gas market continues to grow, and the Tamar partners have signed LOIs to sell natural gas from the Tamar field to several purchasers.

Dalit Dalit (36% operated working interest) was our second 2009 natural gas discovery in the Levantine Basin. We are currently working with our partners on a cost-effective development plan.

Leviathan In December 2010, we announced a significant natural gas discovery at the Leviathan prospect (40% operated working interest) in the Levantine Basin offshore Israel. The Leviathan field is the largest discovery in our history and we believe it is the largest deepwater natural gas discovery in the last decade. We are continuing drilling at the Leviathan-1 well in order to evaluate two additional intervals for the existence of crude oil. Results from these deeper tests, which have a low chance of success, are expected during first quarter 2011. As a result of its size, the Leviathan natural gas field will require two or more appraisal wells to further define its boundaries and determine the best development option. See item 1A. Risk Factors – *The magnitude of the Leviathan discovery will present financial and technical challenges for us due to the large-scale development requirements.*

Other Exploration Activities We recently completed a 3-D seismic acquisition offshore Israel and, depending on further results from the Leviathan well, expect to drill between two and four exploratory or appraisal wells in the area in 2011. We are also planning a 2-D seismic acquisition for our Cyprus acreage in 2011.

Potential Change in Israel's Fiscal Regime See Item 1A. Risk Factors – *Our operations may be adversely affected by changes in the fiscal regimes of the countries in which we operate* and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Recent Developments in Israel.

Other International

North Sea We have been conducting business in the North Sea (the Netherlands and the United Kingdom (UK)) since 1996 and currently have interests in 18 licenses with working interests ranging from 7% to 40%. We are the operator of one block.

Most of our production is from the Dumbarton and Lochranza fields (30% non-operated working interest) in blocks 15/20a and 15/20b in the UK sector of the North Sea. We also produce from the MacCulloch, Hanze, Cook and other fields.

The Dumbarton development, which began production in 2007, includes a subsea tie-back to the GP III, an FPSO in which we own a 30% interest. Dumbarton has eight horizontal producing wells and two water injection wells. Two additional producing wells from the nearby Lochranza discovery are tied back to the Dumbarton facilities. During 2010 the Dumbarton field was shut in for approximately two months for facility modifications but has since returned to full production.

We also participate in the Flyndre (22.5% working interest) and Selkirk (30.5% working interest) projects, both located in the UK sector of the North Sea. We are currently working with our partners on development options.

The North Sea accounted for 5% of 2010 total consolidated sales volumes and 2% of total proved reserves at December 31, 2010. At December 31, 2010, we held approximately 7,000 net developed acres and 41,000 net undeveloped acres.

Ecuador We own and operate the Machala power plant located in Machala, Ecuador. The power plant is fueled by natural gas from the Amistad natural gas field, offshore Ecuador. The government of Ecuador has terminated our PSC for Block 3 offshore Ecuador. See Termination of Ecuador PSC above.

Operations in Ecuador accounted for 2% of 2010 total consolidated sales volumes. Natural gas reserves were an estimated 160 Bcf prior to the termination of our PSC for Block 3. See Item 8. Financial Statements and Supplementary Data – Supplementary Oil and Gas Information (Unaudited).

China We have been engaged in exploration and development activities in China since 1996 under the terms of a 30-year PSC. We have a 57% working interest in the Cheng Dao Xi (CDX) field, which is located in the shallow water of the southern Bohai Bay. During 2010, we continued expansion of production operations under the modified Supplemental Development Plan (SDP). We set the deck of the B platform, drilled four development wells, two of which are horizontal wells, and one injector well. We also recompleted two existing wellbores to uphole zones, one as an injector and one as a producer.

In 2011, we plan to complete the commissioning of the newly installed B platform and commence engineering and design of a third platform (C platform). In addition, we plan to drill and complete six development wells, and recomplete two of the existing wells to uphole zones where additional pay has been identified.

China accounted for 2% of 2010 total consolidated sales volumes and 1% of total proved reserves at December 31, 2010. At December 31, 2010, we held approximately 4,000 net developed acres and no undeveloped acres.

Other International Properties At December 31, 2010, we held undeveloped acreage offshore in other international locations including Nicaragua, India and France. During 2010 we began acquiring 3-D seismic information for Nicaragua and are planning to fund a 2-D seismic survey on the acreage offshore France in the Western Mediterranean Sea in 2011 in return for a working interest in the concession.

Proved Reserves Disclosures

Implementation of the Securities and Exchange Commission's (SEC) Revisions to Oil and Gas Disclosures Effective December 31, 2009, we implemented the SEC's final rules related to the modernization of oil and gas reporting (SEC's reserves rules). Although the SEC's reserves rules allow probable and possible reserves to be disclosed separately, we have elected not to disclose probable and possible reserves in this report. See Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Information (Unaudited) for a description of the most significant revisions to oil and gas reporting disclosures.

Internal Controls Over Reserves Estimates Our policies regarding internal controls over the recording of reserves estimates require reserves to be in compliance with the SEC definitions and guidance and prepared in accordance with generally accepted petroleum engineering principles. Our internal controls over reserve estimates also include the following:

- the Audit Committee of our Board of Directors reviews significant reserves changes on an annual basis;
- each field representing more than 1% of total proved reserves, as well as a rotating group of smaller fields, which combined represent over 80% of our reserves, are audited by Netherland, Sewell & Associates, Inc. (NSAI), a third-party petroleum consulting firm, on an annual basis; and
- NSAI is engaged by and has direct access to the Audit Committee.

In addition, our company-wide short-term incentive plan for 2010 did not include quantitative targets for proved reserves additions.

Responsibility for compliance in reserves estimation is delegated to our Corporate Reservoir Engineering group.

Qualified petroleum engineers in our Houston and Denver offices prepare all reserves estimates for our different geographical regions. These reserves estimates are reviewed and approved by regional management and senior engineering staff with final approval by the Vice President – Strategic Planning, Environmental Analysis & Reserves (Vice President – Reserves) and certain members of senior management.

Our Vice President – Reserves is the technical person primarily responsible for overseeing the preparation of our reserves estimates. Our Vice President – Reserves has a Bachelor of Science degree in Engineering and over 20 years of industry experience with positions of increasing responsibility in engineering and evaluations. The Vice President – Reserves reports directly to our Chief Executive Officer.

We engage NSAI to audit a significant portion of our reserves. See Third-Party Reserves Audit below.

Technologies Used in Reserves Estimation The SEC's updated rules expanded the technologies that a company can use to establish reserves. The SEC now allows use of techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

We used a combination of production and pressure performance, wireline wellbore measurements, simulation studies, offset analogies, seismic data and interpretation, wireline formation tests, geophysical logs and core data to calculate our reserves estimates, including the material additions to the 2010 reserves estimates.

Third-Party Reserves Audit In each of the years 2010, 2009, and 2008, we retained NSAI to perform reserves audits of proved reserves. The reserves audit for 2010 included a detailed review of 13 of our major onshore US, deepwater Gulf of Mexico and international fields, which covered approximately 77% of US proved reserves and 97% of international proved reserves (88% of total proved reserves). The reserves audit for 2009 included a detailed review of 20 of our major fields and covered approximately 86% of total proved reserves. The reserves audit for 2008 included a detailed review of 18 of our major fields and covered approximately 86% of total proved reserves.

In connection with the 2010 reserves audit, NSAI prepared its own estimates of our proved reserves. In order to prepare its estimates of proved reserves, NSAI examined our estimates with respect to reserves quantities, future producing rates, future net revenue, and the present value of such future net revenue. NSAI also examined our estimates with respect to reserves categorization, using the definitions for proved reserves set forth in Regulation S-X Rule 4-10(a) and subsequent SEC staff interpretations and guidance.

In the conduct of the reserves audit, NSAI did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the fields and sales of production. However, if in the course of the examination something came to the attention of NSAI which brought into question the validity or sufficiency of any such information or data, NSAI did not rely on such information or data until it had satisfactorily resolved its questions relating thereto or had independently verified such information or data.

NSAI determined that our estimates of reserves conform to the guidelines of the SEC, including the criteria of "reasonable certainty," as it pertains to expectations about the recoverability of reserves in future years, under existing economic and operating conditions, consistent with the definition in Rule 4-10(a)(24) of Regulation S-X. NSAI issued an unqualified audit opinion on our proved reserves at December 31, 2010, based upon its evaluation. The NSAI opinion concluded that our estimates of proved reserves were, in the aggregate, reasonable and have been prepared in accordance with generally accepted petroleum engineering and evaluation principles. NSAI's report is attached as Exhibit 99.1 to this Annual Report on Form 10-K.

The fields audited by NSAI are chosen in accordance with Company guidelines and result in the audit of a minimum of 80% of our total proved reserves. The fields are chosen by the Vice President – Reserves and are reviewed by senior management and the Audit Committee of our Board of Directors. Our practice is to select fields for audit based on size. This selection process results in the audit of each field representing more than 1% of total proved reserves. As a result, for each of the years 2008 – 2010, our 10 largest fields at the current time were audited. The Aseng field was first audited in 2009 and the Tamar and Alen fields were first audited in 2010, as no reserves had been recorded in prior years.

When compared on a field-by-field basis, some of our estimates are greater and some are less than the estimates of NSAI. Given the inherent uncertainties and judgments that go into estimating proved reserves, differences between internal and external estimates are to be expected. On a quantity basis, the NSAI field estimates ranged from 12 MMBoe above to 14 MMBoe below as compared with our estimates. On a percentage basis, the NSAI field estimates ranged from 9% above our estimates to 9% below our estimates. Differences between our estimates and those of NSAI are reviewed for accuracy but are not further analyzed unless the aggregate variance is greater than 10%. Reserves differences at December 31, 2010 were, in the aggregate, approximately 5 MMBoe, or 0.5%.

Proved Undeveloped Reserves (PUDs) As of December 31, 2010, our PUDs totaled 182 MMBbls of crude oil, condensate and NGLs and 2,444 Bcf of natural gas, for a total of 590 MMBoe.

PUD Locations We have several significant ongoing development projects which are in various stages of completion. PUDs are located as follows at December 31, 2010:

- 146 MMBoe in the Central DJ Basin, including Wattenberg, where we are projecting reasonable levels of increased activity with projected rig counts in line with past levels of operations;
- 20 MMBoe in the deepwater Gulf of Mexico, 91% of which are related to our Galapagos project, which is expected to be producing in late 2011 or early 2012;
- 114 MMBoe in Equatorial Guinea, 54% of which are in the Alba field, 23% of which are in the Aseng field and 23% of which are in the Alen field. The Alba field PUDs represent compression reserves that will be recovered from existing wells and will be reclassified to proved developed during the next five years. The Aseng and Alen field PUDs are scheduled to be reclassified to proved developed reserves beginning in 2012 and 2013, respectively;
- 286 MMBoe (1.7 Tcfe) in the Tamar field, offshore Israel. The Tamar field PUDs are scheduled to be reclassified to proved developed reserves when production begins, currently expected in late 2012 or early 2013; and
- The above fields represent 96% of total PUDs. The remaining 4% are associated with ongoing developments in other US onshore areas and China.

Changes in PUDS Changes in PUDs that occurred during the year were due to:

- recording of approximately 28 MMBoe PUDS from ongoing onshore US development programs, primarily in Wattenberg;
- recording of approximately 25 MMBoe PUDS acquired in the Central DJ Basin asset acquisition;
- recording of approximately 286 MMBoe PUDs due to the sanction of the Tamar project;
- recording of approximately 27 MMBoe PUDS due to the sanction of the Alen project;
- conversion of approximately 21 MMBoe PUDs into proved developed reserves;
- reclassification of approximately 30 MMBoe PUDs, primarily in Wattenberg, that were not scheduled to be developed within five years from proved to probable reserves;
- negative revision of approximately 7 MMBoe due to a change in the likelihood that the Noa field, offshore Israel, will be pursued for development; and
- positive revisions of approximately 12 MMBoe in PUDs primarily due to changes in commodity prices.

Development Costs Costs incurred to advance the development of PUDs were approximately $1.1 billion in 2010 (including $266 million non-cash costs related to an increase in our FPSO lease obligation), $440 million in 2009 (including $29 million non-cash costs related to an increase in our FPSO lease obligation), and $528 million in 2008. A significant portion of costs incurred in 2010 related to our major development projects Aseng, Alen, Tamar and Galapagos, which will be converted to proved developed reserves in future years.

Estimated future development costs relating to the development of PUDs are projected to be approximately $1.6 billion in 2011, $1.3 billion in 2012, and $900 million in 2013. Estimated future development costs include capital spending on major development projects, some of which will take several years to complete. Proved undeveloped reserves related to major development projects will be reclassified to proved developed reserves when production commences.

Drilling Plans All PUD drilling locations are scheduled to be drilled prior to the end of 2015. PUDs associated with projects other than drilling (such as compression projects) are also expected to be converted to proved developed reserves prior to the end of 2015. Initial production from these PUDs is expected to begin during the years 2011 - 2015. All PUDs are scheduled to be developed within 5 years.

For more information see the following:

- Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Proved Reserves for a discussion of changes in proved reserves;
- Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies and Estimates – Reserves for further discussion of our reserves estimation process;
- Item 8. Financial Statements and Supplementary Data – Supplementary Oil and Gas Information (Unaudited) for additional information regarding estimates of crude oil and natural gas reserves, including estimates of proved, proved developed, and proved undeveloped reserves, the standardized measure of discounted future net cash flows, and the changes in the standardized measure of discounted future net cash flows.

Other Reserves Information Since January 1, 2010, no crude oil or natural gas reserves information has been filed with, or included in any report to, any federal authority or agency other than the SEC and the Energy Information Administration (EIA) of the US Department of Energy. We file Form 23, including reserves and other information, with the EIA.

Sales Volumes, Price and Cost Data Sales volumes, price and cost data are as follows:

	Sales Volumes			Average Sales Price			Production Cost [1]
	Crude Oil & Condensate MBbl/d	Natural Gas MMcf/d	NGLs MBbl/d	Crude Oil & Condensate Per Bbl	Natural Gas Per Mcf	NGLs Per Bbl	Per BOE
Year Ended December 31, 2010							
United States							
Wattenberg	19	151	10	$ 75.11	$ 3.95	$43.15	$ 3.62
Other US	20	249	4	74.95	4.31	36.23	7.91
Total US [2]	39	400	14	75.03	4.17	41.21	5.95
Alba Field (Equatorial Guinea) [3]	11	226	-	78.44	0.27	-	2.38
Mari-B Field (Israel)	-	130	-	-	4.03	-	1.15
North Sea	10	6	-	80.24	5.35	-	11.53
Ecuador [4]	-	25	-	-	-	-	-
China	4	-	-	75.15	-	-	7.49
Total Consolidated Operations	64	787	14	76.46	3.00	41.21	$ 4.93
Equity Investee [5]	2	-	5	77.98	-	53.68	
Total	66	787	19	76.50	$3.00	$44.90	
Year Ended December 31, 2009							
United States							
Wattenberg	15	150	6	$ 55.57	$ 3.59	$29.10	$ 3.01
Other US	22	247	4	54.92	3.62	26.37	8.50
Total US [2]	37	397	10	55.19	3.61	$27.96	6.26
Alba Field (Equatorial Guinea) [3]	14	239	-	55.94	0.27	-	2.30
Mari-B Field (Israel)	-	114	-	-	3.47	-	1.36
North Sea	7	5	-	59.51	5.75	-	15.81
Ecuador	-	26	-	-	-	-	-
China	4	-	-	54.40	-	-	6.75
Total Consolidated Operations	62	781	10	55.76	2.54	27.96	$ 5.05
Equity Investee [5]	2	-	6	59.51	-	36.03	
Total	64	781	16	$ 55.87	$ 2.54	$31.20	
Year Ended December 31, 2008							
United States							
Wattenberg	15	146	5	$ 71.41	$ 7.39	$52.19	$ 3.12
Other US	25	249	4	78.02	8.55	47.51	7.91
Total US [2]	40	395	9	75.53	8.12	50.15	6.08
Alba Field (Equatorial Guinea) [3]	15	206	-	88.95	0.27	-	2.17
Mari-B Field (Israel)	-	139	-	-	3.10	-	1.07
North Sea	10	5	-	100.56	10.54	-	12.63
Ecuador	-	22	-	-	-	-	-
China	4	-	-	82.66	-	-	7.03
Total Consolidated Operations	69	767	9	82.60	5.04	50.15	$ 4.90
Equity Investee [5]	2	-	6	96.77	-	58.81	
Total	71	767	15	$ 82.96	$ 5.04	$53.45	

(1) Average production cost includes oil and gas operating costs and workover and repair expense and excludes production and ad valorem taxes.

(2) Average crude oil sales prices reflect reductions of $1.32 per Bbl (2010), $2.13 per Bbl (2009), and $22.06 per Bbl (2008) from hedging activities. Average natural gas sales prices reflect a decrease of $0.01 (2010) and an increase of $0.23 per Mcf (2008) from hedging activities. The effect of hedging activities on the average realized natural gas price for 2009 was de minimis. These price increases/reductions resulted from hedge gains/losses that were previously deferred in Accumulated Other Comprehensive Loss (AOCL). All hedge gains/losses relating to US production had been reclassified to revenues by December 31, 2010.

(3) Average crude oil sales prices reflect reductions of $5.57 per Bbl (2009) and $7.59 per Bbl (2008) from hedging activities. These price reductions resulted from hedge losses that were previously deferred in AOCL. All hedge losses relating to Equatorial Guinea production had been reclassified to revenues by December 31, 2009.

Natural gas is under contract for $0.25 per MMBtu to a methanol plant, an LPG plant and an LNG plant. Sales to these plants are based on a BTU equivalent and then converted to a dry gas equivalent volume. The methanol and LPG plants are owned by affiliated entities accounted for under the equity method of accounting. The volumes produced by the LPG plant are included in the crude oil information.

(4) Includes production through November 24, 2010. Our Block 3 PSC was terminated by the Ecuadorian government on November 25, 2010. Intercompany natural gas sales were eliminated for accounting purposes. Electricity sales are included in other revenues. See Termination of Ecuador PSC above.

(5) Volumes represent sales of condensate and LPG from the LPG plant in Equatorial Guinea.

Revenues from sales of crude oil and natural gas have accounted for 90% or more of consolidated revenues for each of the last three fiscal years.

At December 31, 2010, our operated properties accounted for approximately 64% of our total production. Being the operator of a property improves our ability to directly influence production levels and the timing of projects, while also enhancing our control over operating expenses and capital expenditures.

Productive Wells The number of productive crude oil and natural gas wells in which we held an interest at December 31, 2010 was as follows:

	Crude Oil Wells		Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	6,543	5,759.5	6,804	4,968.1	13,347	10,727.6
Equatorial Guinea	4	1.6	13	4.4	17	6.0
Israel	-	-	6	2.8	6	2.8
North Sea	18	3.8	8	1.0	26	4.8
China	19	10.8	1	0.6	20	11.4
Total	6,584	5,775.7	6,832	4,976.9	13,416	10,752.6

Productive wells are producing wells and wells mechanically capable of production. A gross well is a well in which a working interest is owned. The number of gross wells is the total number of wells in which a working interest is owned. The number of net wells is the sum of the fractional working interests owned in gross wells expressed as whole numbers and fractions thereof. Wells with multiple completions are counted as one well in the table above.

Developed and Undeveloped Acreage Developed and undeveloped acreage (including both leases and concessions) held at December 31, 2010 was as follows:

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
(thousands)				
United States				
Onshore	1,535	1,012	1,815	1,318
Offshore	65	35	562	397
Total United States	1,600	1,047	2,377	1,715
International				
Equatorial Guinea	56	19	573	233
Cameroon	-	-	1,125	563
Israel	62	29	1,592	660
North Sea (1)	52	7	213	41
China	7	4	-	-
Suriname	-	-	3,087	1,389
France (2)	-	-	2,808	2,036
Nicaragua	-	-	1,977	1,977
Cyprus (3)	-	-	1,136	795
India	-	-	694	347
Total International	177	59	13,205	8,041
Total	1,777	1,106	15,582	9,756

(1) The North Sea includes acreage in the UK and the Netherlands.

(2) We are currently funding a 2-D seismic survey over the acreage in return for a working interest in the concession.

(3) A portion of the acreage has been assigned to a partner and the agreement is awaiting government approval.

Developed acreage is comprised of leased acres that are within an area spaced by or assignable to a productive well. Undeveloped acreage is comprised of leased acres with defined remaining terms and not within an area spaced by or assignable to a productive well.

A gross acre is any leased acre in which a working interest is owned. A net acre is comprised of the total of the owned working interest(s) in a gross acre expressed in a fractional format.

Future Acreage Expirations If production is not established or we take no other action to extend the terms of the leases or concessions, undeveloped acreage will expire over the next three years as follows:

	Year Ended December 31,					
	2011		2012		2013	
	Gross	Net	Gross	Net	Gross	Net
(thousands of acres)						
Onshore US	177	140	215	142	978	740
Deepwater Gulf of Mexico	60	31	46	23	37	23
Equatorial Guinea	82	28	-	-	-	-
Suriname	1,080	486	2,007	903	-	-
Total	1,399	685	2,268	1,068	1,015	763

Future deepwater Gulf of Mexico lease expirations are reported according to the original lease terms. We are currently unsure of the impact of the Deepwater Moratorium or lack of permit activity on the expiration dates of these leases and if any extensions will be granted.

Drilling Activity The results of crude oil and natural gas wells drilled and completed for each of the last three years were as follows:

	Net Exploratory Wells			Net Development Wells			
	Productive	Dry	Total	Productive	Dry	Total	Total
Year Ended December 31, 2010							
United States	4.8	1.9	6.7	510.6	1.0	511.6	518.3
Equatorial Guinea	-	-	-	2.0	-	2.0	2.0
Israel (1)	0.4	-	0.4	1.0	-	1.0	1.4
North Sea	-	-	-	0.6	-	0.6	0.6
China	-	-	-	2.3	-	2.3	2.3
Total	5.2	1.9	7.1	516.5	1.0	517.5	524.6
Year Ended December 31, 2009							
United States (1)	4.1	1.6	5.7	532.3	2.0	534.3	540.0
Equatorial Guinea (1)	0.5	-	0.5	-	-	-	0.5
Israel (1)	1.1	-	1.1	-	-	-	1.1
North Sea	-	-	-	1.0	-	1.0	1.0
China	-	-	-	0.6	-	0.6	0.6
Total	5.7	1.6	7.3	533.9	2.0	535.9	543.2
Year Ended December 31, 2008							
United States (1)	15.6	2.0	17.6	868.1	44.0	912.1	929.7
Equatorial Guinea (1)	1.3	-	1.3	-	-	-	1.3
North Sea	-	0.4	0.4	0.6	0.3	0.9	1.3
Suriname	-	0.5	0.5	-	-	-	0.5
Total	16.9	2.9	19.8	868.7	44.3	913.0	932.8

(1) Includes successful exploratory wells drilled but not yet producing.

A productive well is an exploratory, development or extension well that is not a dry well. A dry well (hole) is an exploratory, development, or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

As defined in the rules and regulations of the SEC, an exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. A development well is part of a development project, which is defined as the means by which petroleum resources are brought to the status of economically producible. The number of wells drilled refers to the number of wells completed at any time during the respective year, regardless of when drilling was initiated. Completion refers to the installation of permanent equipment for production of oil or gas, or, in the case of a dry well, to reporting to the appropriate authority that the well has been abandoned.

In addition to the wells drilled and completed in 2010 included in the table above, at December 31, 2010, we were in the process of drilling or completing 245 gross (204.5 net) wells onshore US, 2 gross (0.6 net) exploratory wells in the deepwater Gulf of Mexico, 1 gross (0.4 net) development well offshore Equatorial Guinea, and 1 gross (0.4 net) exploratory well offshore Israel.

Domestic Marketing Activities Crude oil, natural gas, condensate and NGLs produced in the US are generally sold under short-term contracts at market-based prices adjusted for location and quality. Crude oil and condensate are distributed through pipelines and by trucks to gatherers, transportation companies and refineries.

International Marketing Activities In Equatorial Guinea, natural gas from the Alba Field is sold under a long-term contract for $0.25 per MMBtu to a methanol plant, an LPG plant and an LNG plant. The methanol and LPG plants are owned by affiliated entities accounted for under the equity method of accounting. Our share of crude oil and condensate from the Alba Field is sold to Glencore Energy UK Ltd (Glencore Energy) under a short-term sales contract, subject to renewal, and is transported by tanker.

In Israel, we sell natural gas from the Mari-B field under long-term contracts at negotiated prices. IEC is our largest purchaser. In addition, the Tamar partners have signed LOIs to sell natural gas from the Tamar field, which is currently under development, to several purchasers.

Our North Sea crude oil production is transported by tanker and sold on the spot market.

In China, we sell crude oil into the local market under a long-term contract at market-based prices.

Delivery Commitments Some of our natural gas sales contracts specify the delivery of a fixed and determinable quantity of product. We have commitments to deliver approximately 195 Bcf of natural gas, net to our interest, to various customers in Israel through the year 2022. Approximately 97% of this amount will be delivered by 2015. We expect to fulfill the delivery commitments with proved developed and proved undeveloped reserves from the Mari-B and Tamar fields in Israel and we do not expect any shortfall. See International – Eastern Mediterranean (Israel and Cyprus).

Significant Purchaser Glencore Energy was the largest single non-affiliated purchaser of 2010 production and purchased our share of crude oil and condensate production from the Alba field in Equatorial Guinea. Sales to Glencore Energy accounted for 17% of 2010 crude oil sales, or 11% of 2010 total oil and gas sales. No other single non-affiliated purchaser accounted for 10% or more of oil and gas sales in 2010. We believe that the loss of any one purchaser would not have a material effect on our financial position or results of operations since there are numerous potential purchasers of our production.

Hedging Activities Commodity prices were volatile in 2010 and prices for crude oil and natural gas are affected by a variety of factors beyond our control. We have used derivative instruments, and expect to do so in the future, in order to reduce commodity price uncertainty and increase cash flow predictability relating to the marketing of our crude oil and natural gas. For additional information, see Item 1A. Risk Factors – *Commodity and interest rate hedging transactions may limit our potential gains* and *We are exposed to counterparty credit risk as a result of our receivables, hedging transactions, and cash investments*, Item 7A. Quantitative and Qualitative Disclosures About Market Risk, and Item 8. Financial Statements and Supplementary Data – Note 10. Derivative Instruments and Hedging Activities.

Termination of Contracts The government of Ecuador terminated our Block 3 PSC on November 25, 2010. See Termination of Ecuador PSC, above, and Item 8. Financial Statements and Supplementary Data – Note 3. Acquisitions and Divestitures.

Regulations

Government Regulation Exploration for, and production and marketing of, crude oil and natural gas are extensively regulated at the international, federal, state and local levels. Crude oil and natural gas development and production activities are subject to various laws and regulations (and orders of regulatory bodies pursuant thereto) governing a wide variety of matters, including, among others, allowable rates of production, transportation, prevention of waste and pollution and protection of the environment. Laws affecting the crude oil and natural gas industry are under constant review for amendment or expansion and frequently increase the regulatory burden on companies. Our ability to economically produce and sell crude oil and natural gas is affected by a number of legal and regulatory factors, including federal, state and local laws and regulations in the US and laws and regulations of foreign nations. Many of these governmental bodies have issued rules and regulations that are often difficult and costly to comply with, and that carry substantial penalties for failure to comply. These laws, regulations and orders may restrict the rate of crude oil and natural gas production below the rate that would otherwise exist in the absence of such laws, regulations and orders. The regulatory burden on the crude oil and natural gas industry increases our costs of doing business and consequently affects our profitability. See Item 1A. Risk Factors – *We are subject to increasing governmental regulations and environmental risks that may cause us to incur substantial costs.*

Examples of US federal agencies with regulatory authority over our exploration for, and production and sale of, crude oil and natural gas include:

- the Bureau of Land Management (BLM) and the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) (formerly the Minerals Management Service), which under laws such as the Federal Land Policy and Management Act, Endangered Species Act, National Environmental Policy Act and Outer Continental Shelf Lands Act have certain authority over our operations on federal lands, particularly in the Rocky Mountains and deepwater Gulf of Mexico;
- the Office of Natural Resources Revenue, which under the Federal Oil and Gas Royalty Management Act of 1982 has certain authority over our payment of royalties, rentals, bonuses, fines, penalties, assessments, and other revenue;
- the US Environmental Protection Agency (EPA) and the Occupational Safety and Health Administration, which under laws such as the Comprehensive Environmental Response, Compensation and Liability Act, as amended, the Resource Conservation and Recovery Act, as amended, the Oil Pollution Act of 1990, the Clean Air Act, the

Clean Water Act, and the Occupational Safety and Health Act have certain authority over environmental, health and safety matters affecting our operations as discussed below;

- the Federal Energy Regulatory Commission, which under laws such as the Energy Policy Act of 2005 has certain authority over the marketing and transportation of crude oil and natural gas we produce onshore and from the deepwater Gulf of Mexico; and
- the Department of Transportation, which has certain authority over the transportation of products, equipment and personnel necessary to our onshore US and deepwater Gulf of Mexico operations.

Other federal agencies with certain authority over our business include the Internal Revenue Service and the SEC, as well as the NYSE upon which shares of our common stock are traded.

On May 17, 2010, the BLM issued a revised oil and gas leasing policy that requires, among other things, a more detailed environmental review prior to leasing oil and natural gas resources, increased public engagement in the development of master leasing and development plans prior to leasing areas where intensive new oil and gas development is anticipated, and a comprehensive parcel review process.

The EPA has issued the Final Mandatory Reporting of Greenhouse Gases Rule, which requires many suppliers of fossil fuels or industrial chemicals, manufacturers of vehicles and engines, and other facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year to begin collecting greenhouse gas (GHG) emissions data under a new reporting system on January 1, 2010 with the first annual report due March 31, 2011. In November 2010, the EPA issued final regulations requiring the annual reporting of GHG emissions from qualifying facilities in the upstream oil and natural gas sector, including onshore production (Subpart W).

Most of the states within which we operate have separate agencies with authority to regulate related operational and environmental matters. Examples of such regulation on the operational side include the Greater Wattenberg Area Special Well Location Rule 318A, which was adopted by the Colorado Oil and Gas Conservation Commission to address oil and gas well drilling, production, commingling and spacing in Wattenberg, and the same Commission's December 10, 2008 approval of a comprehensive update to statewide rules governing oil and gas operations in Colorado. These rules were reviewed by the Colorado legislature in its 2009 session and became effective in the second quarter of 2009, addressing areas such as public drinking water protection, monitoring and disclosure of chemicals used in drilling operations, erosion management and environment and wildlife protection. On the environmental side, Colorado Regulation Seven and requirements for storm water management plans were adopted by the Colorado Department of Environmental Quality, under delegation from the EPA, to regulate air emissions, water protection and waste handling and disposal relating to our oil and gas exploration and production.

Some of the counties and municipalities within which we operate have adopted regulations or ordinances that impose additional restrictions on our oil and gas exploration and production. An example is Garfield County, Colorado, which provides local land and road use restrictions affecting our Piceance Basin operations and requires us to post bonds to secure any restoration obligations.

Our international operations are subject to legal and regulatory oversight by energy-related ministries of our host countries, each having certain relevant energy or hydrocarbons laws. Examples of these ministries include the Equatorial Guinea Ministry of Mines, Industry and Energy, the Israel Ministry of National Infrastructures, and the UK Department of Energy and Climate Change. An example of a law affecting our international operations is the UK Finance Act of 2006, which increased the income tax rate on our UK operations effective January 1, 2006.

Environmental Matters As a developer, owner and operator of crude oil and natural gas properties, we are subject to various federal, state, local and foreign country laws and regulations relating to the discharge of materials into, and the protection of, the environment. We must take into account the cost of complying with environmental regulations in planning, designing, drilling, operating and abandoning wells. In most instances, the regulatory requirements relate to the handling and disposal of drilling and production waste products, water and air pollution control procedures, and the remediation of petroleum-product contamination. Under state and federal laws, we could be required to remove or remediate previously disposed wastes, including wastes disposed of or released by us or prior owners or operators in accordance with current laws or otherwise, to suspend or cease operations in contaminated areas, or to perform remedial well plugging operations or cleanups to prevent future contamination. The EPA and various state agencies have limited the disposal options for hazardous and non-hazardous wastes. The owner and operator of a site, and persons that treated, disposed of or arranged for the disposal of hazardous substances found at a site, may be liable, without regard to fault or the legality of the original conduct, for the release of a hazardous substance into the environment. The EPA, state environmental agencies and, in some cases, third parties are authorized to take actions in response to threats to human health or the environment and to seek to recover from responsible classes of persons the costs of such action. Furthermore, certain wastes generated by our crude oil and natural gas operations that are currently exempt from treatment as hazardous wastes may in the future be designated as hazardous wastes and, therefore, be subject to considerably more rigorous and costly operating and disposal requirements. See Item 1A. Risk Factors – *We are subject to increasing governmental regulations and environmental risks that may cause us to incur substantial costs.*

Federal and state occupational safety and health laws require us to organize information about hazardous materials used, released or produced in our operations. Certain portions of this information must be provided to employees, state and local governmental authorities and local citizens. We are also subject to the requirements and reporting set forth in federal workplace standards.

Certain state or local laws or regulations and common law may impose liabilities in addition to, or restrictions more stringent than, those described herein.

We have made and will continue to make expenditures in our efforts to comply with environmental requirements. We do not believe that we have, to date, expended material amounts in connection with such activities or that compliance with such requirements will have a material adverse effect on our capital expenditures, earnings or competitive position. Although such requirements do have a substantial impact on the crude oil and natural gas industry, they do not appear to affect us to any greater or lesser extent than other companies in the industry.

Competition

The crude oil and natural gas industry is highly competitive. We encounter competition from other crude oil and natural gas companies in all areas of operations, including the acquisition of seismic and lease rights on crude oil and natural gas properties and for the labor and equipment required for exploration and development of those properties. Our competitors include major integrated crude oil and natural gas companies, state-controlled national oil companies, independent crude oil and natural gas companies, service companies engaging in exploration and production activities, drilling partnership programs, and individuals. Many of our competitors are large, well established companies. Such companies may be able to pay more for seismic and lease rights on crude oil and natural gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. See Item 1A. Risk Factors – *We face significant competition and many of our competitors have resources in excess of our available resources.*

Geographical Data

We have operations throughout the world and manage our operations by country. Information is grouped into five components that are all primarily in the business of crude oil, natural gas and NGL exploration, development and production: United States, West Africa, Eastern Mediterranean, North Sea, and Other International and Corporate. See Item 8. Financial Statements and Supplementary Data – Note 18. Segment Information.

Employees

Our total number of employees increased from 1,630 at December 31, 2009 to 1,772 at December 31, 2010. The 2010 year-end employee count includes 185 foreign nationals working as employees in Ecuador, Israel, the UK, Equatorial Guinea and Cameroon. We regularly use independent contractors and consultants to perform various field and other services.

Offices

Our principal corporate office, including our offices for US and international operations, is located at 100 Glenborough Drive, Suite 100, Houston, Texas 77067-3610. We maintain additional offices in Ardmore, Oklahoma and Denver, Colorado and in China, Cameroon, Ecuador, Equatorial Guinea, Israel, Cyprus, and the UK.

Title to Properties

We believe that our title to the various interests set forth above is satisfactory and consistent with generally accepted industry standards, subject to exceptions that would not materially detract from the value of the interests or materially interfere with their use in our operations. Individual properties may be subject to burdens such as royalty, overriding royalty and other outstanding interests customary in the industry. In addition, interests may be subject to obligations or duties under applicable laws or burdens such as production payments, net profits interest, liens incident to operating agreements and for current taxes, development obligations under crude oil and natural gas leases or capital commitments under PSCs or exploration licenses.

Available Information

Our website address is *www.nobleenergyinc.com.* Available on this website under "Investors – Investors Menu – SEC Filings," free of charge, are our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, Forms 3, 4 and 5 filed on behalf of directors and executive officers and amendments to those reports as soon as reasonably practicable after such materials are electronically filed with or furnished to the SEC.

Also posted on our website under "About Us – Corporate Governance", and available in print upon request made by any stockholder to the Investor Relations Department, are charters for our Audit Committee; Compensation, Benefits and Stock Option Committee; Corporate Governance and Nominating Committee; and Environment, Health and Safety Committee. Copies of the Code of Business Conduct and Ethics, and the Code of Ethics for Chief Executive and Senior Financial Officers (the Codes) are posted on our website under the "Corporate Governance" section. Within the time period required by the SEC and the NYSE, as applicable, we will post on our website any modifications to the Codes and any waivers applicable to senior officers as defined in the applicable Code, as required by the Sarbanes-Oxley Act of 2002.

Item 1A. Risk Factors

Described below are certain risks that we believe are applicable to our business and the oil and gas industry in which we operate. There may be additional risks that are not presently material or known. You should carefully consider each of the following risks and all other information set forth in this Annual Report on Form 10-K.

If any of the events described below occur, our business, financial condition, results of operations, liquidity or access to the capital markets could be materially adversely affected. In addition, the current global economic and political environment intensifies many of these risks.

Crude oil and natural gas prices are volatile and a substantial reduction in these prices could adversely affect our results and the price of our common stock.

Our revenues, operating results and future rate of growth depend highly upon the prices we receive for our crude oil and natural gas production. Historically, the markets for crude oil and natural gas have been volatile and are likely to continue to be volatile in the future. For example, the NYMEX daily average settlement price for the prompt month crude oil contract in 2010 ranged from a high of $89.23 per barrel to a low of $74.12 per barrel. The NYMEX monthly settlement price for the prompt month natural gas contract in 2010 ranged from a high of $5.81 per MMBtu to a low of $3.29 per MMBtu.

The markets and prices for crude oil and natural gas depend on factors beyond our control. These factors include demand for crude oil and natural gas, which fluctuates with changes in economic and market conditions, and other factors, including:

- economic factors impacting global gross domestic product growth rates;
- global demand for crude oil and natural gas;
- global factors impacting supply quantities of crude oil and natural gas;
- the potential long-term impact of an abundance of natural gas from shale on the global natural gas supply;
- actions taken by foreign oil and gas producing nations;
- political conditions and events (including instability or armed conflict) in crude oil or natural gas producing regions;
- the level of global crude oil and natural gas inventories;
- the price and level of imported foreign crude oil and natural gas;
- the price and availability of alternative fuels, including coal, nuclear energy, and biofuels;
- the long-term impact of the use of natural gas as an alternative fuel on the crude oil market;
- the availability of pipeline capacity and infrastructure;
- the availability of crude oil transportation and refining capacity;
- weather conditions;
- demand for electricity as well as natural gas used as fuel for electricity generation; and
- domestic and foreign governmental regulations and taxes.

Significant declines in crude oil and natural gas prices for an extended period may have the following effects on our business:

- reducing our revenues, operating income and cash flows;
- reducing the amount of crude oil and natural gas that we can produce economically;
- limiting our financial condition, liquidity, and/or ability to finance planned capital expenditures and operations;
- limiting our access to sources of capital, such as equity and long-term debt; or
- causing us to delay or postpone some of our capital projects.

In addition, lower commodity prices, including significant declines in the forward commodity price curves, may result in the following:

- asset impairment charges resulting from reductions in the carrying values of our crude oil and/or natural gas properties at the date of assessment, such as occurred in 2008, 2009 and 2010; or
- a reduction in the carrying value of goodwill.

Failure to effectively execute our major development projects could result in significant delays and/or cost over-runs, damage to our reputation, limitations on our growth and negative effects on our operating results.

We currently have an extensive inventory of major development projects, some of which will take several years before first production, including Aseng, Alen, Galapagos, Tamar, Gunflint, and others. Some of these projects, such as oil and gas projects offshore West Africa and Israel, have a great deal of complexity, including extensive subsea tiebacks to an FPSO or production platform, pressure maintenance systems, gas re-injection systems, onshore receiving terminals, or other specialized infrastructure. This level of development will require significant effort from our management and technical personnel as well as place additional burden on our financial resources and internal financial controls. We may not be able to attract and retain personnel with the skills necessary to bring complicated projects to successful conclusions.

In addition, we have increased dependency on third-party technology and service providers and other suppliers for these complex projects. Significant delays in delivery of essential items or performance of services, cost overruns, supplier insolvency, or other critical supply failure, could adversely affect development of our projects. We may not be able to compensate for, or fully mitigate, these risks.

Concentration of our operations in a few key areas may increase our risk of production loss.

Our operations are concentrated in four key areas: the Central DJ Basin and the deepwater Gulf of Mexico in the US, offshore West Africa, and the Eastern Mediterranean. These key areas provide most of our current crude oil and natural gas production, each of our major development projects, and most of our exploration potential. In the past several years, we have made several asset divestitures to high-grade and focus our portfolio. Divestitures included non-core, non-strategic assets in the Gulf of Mexico shelf, Mid-Continent and Illinois Basin areas in the US, and Argentina.

As a result of these portfolio changes, our operations and production are concentrated in fewer areas. Although none of these areas represented more than 25% of our 2010 total consolidated sales volumes, disruption of our business in one of these areas, such as from an accident, natural disaster, government intervention, or other event, would result in a greater impact on our production profile, cash flows and overall business plan than if we operated in a larger number of areas.

We do not maintain business interruption (loss of production) insurance for all of our assets. Loss of production from one of our key operating areas could have a significant negative impact on our cash flows and profitability.

We are subject to increasing governmental regulations and environmental risks that may cause us to incur substantial costs.

From time to time, in varying degrees, political developments and federal and state laws and regulations affect our operations. In particular, price controls, taxes and other laws relating to the crude oil and natural gas industry, changes in these laws and changes in administrative regulations have affected and in the future could affect crude oil and natural gas production, operations and economics. We cannot predict how agencies or courts will interpret existing laws and regulations or the effect these adoptions and interpretations may have on our business or financial condition.

Our business is subject to laws and regulations promulgated by international, federal, state and local authorities relating to the exploration for, and the development, production and marketing of, crude oil and natural gas, as well as safety matters. Legal requirements are frequently changed and subject to interpretation and we are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations. We may be required to make significant expenditures to comply with governmental laws and regulations.

Our operations are subject to complex international, federal, state and local environmental laws and regulations including, for example, in the case of federal laws, the Comprehensive Environmental Response, Compensation and Liability Act, as amended, the Resource Conservation and Recovery Act, as amended, the Oil Pollution Act of 1990, the Clean Air Act, the Clean Water Act and the Occupational Safety and Health Act. Environmental laws and regulations change frequently and the implementation of new, or the modification of existing, laws or regulations could negatively impact our operations. The discharge of natural gas, crude oil, or other pollutants into the air, soil or water may give rise to significant liabilities on our part to government agencies and third parties and may require us to incur substantial costs of remediation. In addition, we may incur costs and penalties in addressing regulatory agency procedures involving instances of possible non-compliance.

Our international operations may be adversely affected by economic and political developments.

We have significant international crude oil and natural gas operations compared to companies we consider to be our peers, with approximately 43% of our 2010 total consolidated sales volumes coming from international operations, and will be increasing our exposure through our major development projects offshore Equatorial Guinea and Israel. We are also conducting exploration activities in these and other international areas. Our operations may be adversely affected by political and economic developments, including the following:

- renegotiation, modification or nullification of existing contracts, such as may occur pursuant to the proposed changes in Israel's fiscal regime, or the hydrocarbons law enacted in 2006 by the government of Equatorial Guinea, which can result in an increase in the amount of revenues that the host government receives from production (government take) or otherwise decrease project profitability;
- loss of revenue, property and equipment as a result of actions taken by foreign crude oil and natural gas producing nations, such as expropriation or nationalization of assets or termination of contracts, such as the recent termination of our Block 3 PSC by the Ecuadorian government pursuant to Ecuador's new hydrocarbon law;
- disruptions caused by territorial or boundary disputes in certain international regions, including the Eastern Mediterranean, where Lebanon recently made claims related to our projects in Israeli waters;
- changes in drilling or safety regulations in other countries being considered as a result of the Deepwater Horizon Incident, which changes will increase costs and development cycle time;
- changes in taxation policies, such as the recent recommendations by a committee established by the Israeli Finance Minister to increase government take, the UK Finance Act of 2006, which increased the income tax rate on our UK operations effective January 1, 2006, and the China Petroleum Special Profits Tax enacted in 2006, which imposed an excise tax on crude oil produced in the country;

- laws and policies of the US and foreign jurisdictions affecting foreign investment, taxation, trade and business conduct;
- foreign exchange restrictions;
- international monetary fluctuations and changes in the relative value of the US dollar as compared with the currencies of other countries in which we conduct business, such as Israel and the UK; and
- other hazards arising out of foreign governmental sovereignty over areas in which we conduct operations.

Certain of these risks could be intensified by significant new discoveries in the Levantine Basin, where we are currently conducting exploration activities, and other developing basins in the Eastern Mediterranean where there is vast exploration potential remaining and where a large discovery could have a significant impact on the natural gas supply for the nations of Europe and the Eastern Mediterranean region.

Such political and economic developments as mentioned above could have a negative impact on our results of operations and cash flows and reduce the fair values of our properties, resulting in impairment charges. In addition, we may not have enough insurance to cover any loss of property resulting from these risks.

Our international operations may be adversely affected by war, terrorist acts, or civil disturbances that may occur in regions that encompass our operations.

We conduct exploration and development activities in the Eastern Mediterranean and offshore West Africa. These areas have historically been less politically stable than other areas in which we conduct business such as Europe or the US.

In recent weeks, civil unrest, which began in Tunisia and resulted in changes in the Tunisian government, has spread to the Middle East. There have been numerous demonstrations by Egyptian protestors demanding a regime change in their country, and some of the demonstrations have been marked by violence. Recently, the King of Jordan reconstituted his government after protestors demanded economic and political reforms.

Civil unrest could continue to spread throughout the region and involve other areas such as the Gaza Strip or nations such as Syria, Yemen, Lebanon or others. Such unrest, if it continues to spread or grow in intensity, could lead to civil wars; regime changes resulting in governments that are hostile to the US and/or Israel, such as has previously occurred in the region; violations of the 1979 Egypt-Israel Peace Treaty; or regional conflict.

At this time, we are uncertain of the outcome of these events. However, prolonged and/or widespread regional conflict in the Middle East could have the following results, among others:

- volatility in global crude oil prices which could negatively impact the global economy, resulting in slower economic growth rates, which could reduce demand for our products;
- negative impact on the world crude oil supply if transportation avenues are disrupted, leading to further commodity price volatility;
- capital market reassessment of risk and subsequent redeployment of capital to more stable areas making it more difficult for partners to obtain financing for potential development projects;
- security concerns in Israel, making it more difficult for our personnel or supplies to enter or exit the country;
- reduced market demand in Israel for natural gas due to efforts to conserve domestic resources;
- security concerns leading to evacuation of our personnel;
- damage to or destruction of our wells, production facilities, receiving terminals or other operating assets;
- damage to or destruction of property belonging to our natural gas purchasers leading to interruption of gas deliveries, claims of force majeure, and/or termination of natural gas sales contracts, resulting in a reduction in our revenues;
- inability of our service and equipment providers to deliver items necessary for us to conduct our operations in the Eastern Mediterranean, resulting in delayed start-up of our Tamar project or shut-in of the Mari-B field; and
- lack of availability of drilling rig, oilfield equipment or services if third party providers decide to exit the region.

Loss of property and/or interruption of our business plans resulting from hostile acts could have a significant negative impact on our earnings and cash flow. In addition, we may not have enough insurance to cover any loss of property or other claims resulting from these risks.

Our operations may be adversely affected by changes in the fiscal regimes of the countries in which we operate.

Fiscal regimes impact oil and gas companies through laws and regulations governing royalties, taxes or level of government participation in oil and gas projects. We operate in the US and other countries whose fiscal regimes may change over time. Changes in fiscal regimes result in an increase or decrease in the amount of government take, and a corresponding decrease or increase in the revenues of an oil and gas company operating in that particular country.

Governments are currently experiencing fiscal problems triggered by the lingering effects of the global financial crisis, associated recession and current slower economic growth rates. Higher unemployment and slower growth rates, coupled with a reduced tax base, have resulted in reduced government revenues, while government expenditures have increased due to the need for public entitlement or economic stimulus programs. Many countries have generated budget deficits or even approached insolvency and there has been social unrest in many regions.

Due to pressures from local constituents as well as the Organization for Economic Cooperation and Development (OECD) to address these negative fiscal situations and initiate deficit reduction measures, many governments are seeking additional revenue sources, including increases in government take from oil and gas projects.

For example, The US Administration's fiscal year 2011 budget contained many revenue-raising proposals, including business tax increases, some of which impact oil and gas companies. Notwithstanding the recent extension of reduced tax rates or other favorable energy provisions contained in the Tax Relief Act of 2010, it is likely that some of these proposals will be re-proposed in the fiscal year 2012 budget. It is unclear whether, and to what extent such proposals will pass both houses of Congress and be signed into law. However, it is likely that some of these proposals, such as elimination of certain oil and gas company tax preferences, will receive consideration.

In March 2010, the President of the United States signed into law The Patient Protection and Affordable Care Act and The Health Care and Education Reconciliation Act of 2010 (collectively referred to as Health Insurance Reform Legislation) which enacted significant reforms to various aspects of the US health insurance industry including expansion of health care coverage to many uninsured individuals and expansion of coverage to those already insured. Due to its complexity and need for further implementing regulations, the full impact of the Health Insurance Reform Legislation is not yet fully known. However, any future changes in employer funding requirements or tax benefits will likely increase our employee health care costs and reduce our cash flows.

In 2010, the Finance Minister of Israel established an advisory committee to study the country's fiscal policy as it relates to the upstream oil and natural gas sector, as well as various options, including an increase in royalties or cancellation of tax incentives. In January 2011, the Finance Ministry advisory committee issued its final recommendations which included cancellation of currently-existing tax incentives, including the depletion allowance, and imposition of a special levy ranging from 20% to 50% on oil and gas profits after a return on investment has been achieved. At this time we are uncertain of the final outcome of these recommendations, which must be voted on by Israel's Parliament, and are unable to predict the complete economic impact any change in Israel's fiscal regime would have on our operations. A change in Israel's fiscal regime could reduce the profitability of our Tamar project or a future development project at Leviathan. A retroactive change could reduce the cash flows from our Mari-B project.

In 2010, China began implementing a new price-based energy resource tax on oil and gas extraction in certain of its provinces.

Changes in fiscal regimes have long-term impacts on our business strategy, and uncertainty makes it more difficult to formulate capital investment programs. The implementation of new, or the modification of existing, laws or regulations impacting the amount of government take could disrupt our business plans and negatively impact our operations in the following ways, among others:

- reduce exploration activities, which could have a long-term negative impact on the quantities of proved reserves we record and inhibit future production growth;
- have a negative impact on the ability of us and/or our partners to obtain project financing;
- cause delay in or cancellation of development plans, which could also have a long-term negative impact on the quantities of proved reserves we record and inhibit future production growth;
- reduce the profitability of our projects, resulting in decreases in net income and cash flows;
- result in current projects becoming uneconomic, to the extent fiscal changes are retroactive, thereby reducing the amount of proved reserves we record and cash flows we receive, and possibly resulting in asset impairment charges;
- require that valuation allowances be established against deferred tax assets, with offsetting increases in income tax expense, resulting in decreases in net income;
- restrict our ability to compete with imported volumes of crude oil or natural gas; and/or
- adversely affect the price of our common stock.

We have insufficient insurance to cover all of the risks we face, which could result in significant financial exposure.

Exploration for and production of crude oil and natural gas can be hazardous, involving natural disasters and other unfortuitous events such as blowouts, well cratering, fire and explosion and loss of well control which can result in damage to or destruction of wells or production facilities, injury to persons, loss of life, or damage to property and the environment. Exploration and production activities are also subject to risk from political developments such as war, terrorist acts, civil disturbances, expropriation or nationalization of assets, which can cause loss of or damage to our property.

In accordance with industry practices, we maintain insurance against many, but not all, potential perils confronting our operations and in coverage amounts and deductible levels that we believe to be economic. Consistent with that profile, our insurance program is structured to provide us financial protection from unfavorable loss severity resulting from damages to or the loss of physical assets or loss of human life, liability claims of third parties, and business interruption (loss of production) attributed to certain assets and including such occurrences as well blowouts and resulting oil spills, at a level that balances cost of insurance with our assessment of risk and our ability to achieve a reasonable rate of return on our investments. Although we believe the coverages and amounts of insurance carried are adequate and consistent with industry practice, we do not have insurance protection against all the risks we face, because we chose not to insure certain risks, insurance is not available at a level that balances the cost of insurance and our desired rates of return, or actual losses exceed coverage limits. We regularly review our risks of loss and the cost and availability of insurance and revise our insurance program accordingly.

We expect the future availability and cost of insurance to be impacted by the Deepwater Horizon Incident. Impacts could include: tighter underwriting standards, limitations on scope and amount of coverage, and higher premiums, and will depend, in part, on future changes in laws and regulations regarding exploration and production activities in the Gulf of Mexico and other areas in which we operate, including possible increases in liability caps for claims of damages from oil spills. We will continue to monitor the legislative and regulatory response to the Incident and its impact on the insurance market and our overall risk profile, and adjust our risk and insurance program to provide protection, at a level that we can afford considering the cost of insurance and our desired rates of return, against disruption to our operations and cash flows.

If an event occurs that is not covered by insurance or not fully protected by insured limits, it could have a significant adverse impact on our financial condition, results of operations and cash flows. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – *Risk and Insurance Program.*

Our operations in the deepwater Gulf of Mexico, as well as onshore US and international locations, could be adversely affected by future changes in laws and regulations which may occur as a result of the Deepwater Horizon Incident.

The legislative and regulatory response to the Deepwater Horizon Incident is ongoing and may not be limited to the US. In 2010, the US Department of the Interior issued new rules designed to improve drilling and workplace safety, and various Congressional committees began pursuing legislation to regulate drilling activities and increase liability. In January 2011, the President's National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling released its report, recommending that the federal government require additional regulation and an increase in liability caps. The European Commission has recommended that new legislation be enacted to enhance the safety of offshore oil and gas activities.

Additional regulatory review, slower permitting processes and increased oversight will likely result in longer development cycle time for our deepwater Gulf of Mexico projects. Cycle time is the length of time it takes for a project to progress from first discovery to first production, and longer development cycle times could result in lower rates of return on our investments.

Increased regulation could also have a negative impact on our planned deepwater Gulf of Mexico exploration program. A significant delay or cancellation of planned exploratory activities will reduce our longer term ability to replace reserves, resulting in a negative impact on production over time. To the extent current exploration activities are significantly delayed, a gap could occur in our long-term production profile with a negative impact on our operating results and cash flows.

Additional legislation or regulation is being discussed which could require each company doing business in the Gulf of Mexico to establish and maintain a higher level of financial responsibility under its Certificate of Financial Responsibility (COFR), a certificate required by the Oil Pollution Act of 1990 which evidences a company's financial ability to pay for cleanup and damages caused by oil spills. There have also been discussions regarding the establishment of a new industry mutual fund in which companies would be required to participate and which would be available to pay for consequential damages arising from an oil spill. These and/or other legislative or regulatory changes could require us to maintain a certain level of financial strength and may reduce our financial flexibility.

We are monitoring legislative and regulatory developments; however, the full legislative and regulatory response to the Incident is not yet known. An expansion of safety and performance regulations or an increase in liability for drilling activities may have one or more of the following impacts on our business:

- increase the costs of drilling exploratory and development wells;
- cause delays in, or preclude, the development of our projects in the deepwater Gulf of Mexico or other locations;
- result in higher operating costs;
- divert our cash flows from capital investments in order to maintain minimum financial levels or participate in a mandatory industry mutual clean-up fund;
- increase or remove liability caps for claims of damages from oil spills; and
- limit our ability to obtain additional insurance coverage, at a level that balances the cost of insurance and our desired rates of return, to protect against any increase in liability.

Any of the above operating or financial factors may result in a reduction of our cash flows, profitability, and the fair value of our properties or reduce our financial flexibility. Because we strive to achieve certain levels of return on our projects, an increase in our financial responsibility could result in certain of our planned projects becoming uneconomic.

Derivatives regulation included in current financial reform legislation could impede our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices and interest rates.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), which was passed by Congress and signed into law in July 2010, contains significant derivatives regulation, including a requirement that certain transactions be cleared on exchanges and a requirement to post cash collateral (commonly referred to as “margin”) for such transactions. The Act provides for a potential exception from these clearing and cash collateral requirements for commercial end-users and it includes a number of defined terms that will be used in determining how this exception applies to particular derivative transactions and the parties to those transactions. The Act requires the Commodities Futures and Trading Commission (CFTC) to promulgate rules to define these terms. The CFTC is in the process of proposing definitions to determine which entities will face additional requirements for clearing, trading and posting of margin. However, the process is incomplete and we are unsure how these definitions will apply to us.

We use crude oil and natural gas derivative instruments with respect to a portion of our expected production in order to reduce commodity price uncertainty and enhance the predictability of cash flows relating to the marketing of our production and in support of our capital investment program. We use interest rate derivative instruments to minimize the impact of interest rate fluctuations associated with anticipated debt issuances. As commodity prices increase or interest rates decrease, our derivative liability positions increase; however, none of our current derivative contracts require the posting of margin or similar cash collateral when there are changes in the underlying commodity prices or interest rates that are referred to in these contracts.

Depending on the rules and definitions adopted by the CFTC, we could be required to post significant amounts of cash collateral with our dealer counterparties for our derivative transactions. A sudden, unexpected margin call triggered by rising commodity prices or falling interest rates would have an immediate negative impact on our business plan, forcing us to divert capital from exploration, development and production activities. Requirements to post cash collateral could not only cause significant liquidity issues by reducing our flexibility in using our cash and other sources of funds such as our credit facility, but could also cause us to incur additional debt. In addition, a requirement for our counterparties to post cash collateral would likely result in additional costs being passed on to us, thereby decreasing the effectiveness of our hedges and our profitability.

We face various risks associated with the trend toward increased activism against oil and gas exploration and development activities.

Opposition toward oil and gas drilling and development activity has been growing globally and is particularly pronounced in OECD countries which include the US, the UK and Israel. Companies in the oil and gas industry, such as us, are often the target of activist efforts from both individuals and non-governmental organizations regarding safety, human rights, environmental compliance and business practices. Anti-development activists are working to, among other things, reduce access to federal and state government lands and delay or cancel certain projects such as offshore drilling or the development of oil shale. For example, environmental activists have recently challenged decisions to grant air-quality permits for offshore drilling and have advocated for increased regulations on shale drilling in the US.

Future activist efforts could result in the following:

- delay or denial of drilling permits;
- shortening of lease terms or reduction in lease size;
- restrictions on installation or operation of gathering or processing facilities;
- restrictions on the use of certain operating practices, such as hydraulic fracturing;
- legal challenges or lawsuits;
- damaging publicity about us;
- increased costs of doing business;
- reduction in demand for our products; and
- other adverse affects on our ability to develop our properties and expand production.

Our need to incur costs associated with responding to these initiatives or complying with any resulting new legal or regulatory requirements resulting from these activities that are substantial and not adequately provided for, could have a material adverse effect on our business, financial condition and results of operations.

Slower economic growth rates in the US and other countries in which we operate may materially adversely impact our operating results.

The US and other economies are recovering from a global financial crisis and recession which began in 2008. Growth has resumed, but has been modest and at an unsteady rate. There are likely to be significant long-term effects resulting from the financial crisis and recession, including a future global economic growth rate that is slower than what was experienced in the years leading up to the crisis, and more volatility may occur before a sustainable, yet lower, growth rate is achieved.

In addition, the OECD has encouraged countries with large federal budget deficits, such as the US, to initiate deficit reduction measures. Such measures, if they are undertaken too rapidly, could further undermine economic recovery and slow growth by reducing demand.

Global economic growth drives demand for energy from all sources, including fossil fuels. A lower future economic growth rate is likely to result in decreased demand growth for our crude oil and natural gas production. A decrease in demand, excluding changes in other factors, could potentially result in lower commodity prices, which would reduce our cash flows from operations and our profitability.

Failure to fund continued capital expenditures could adversely affect our properties.

Our exploration, development, and acquisition activities require substantial capital expenditures especially in the case of our major development projects, such as the Central DJ Basin, Galapagos in the deepwater Gulf of Mexico, Aseng and Alen, offshore Equatorial Guinea, and Tamar, offshore Israel. Significant capital investments on these major development projects are estimated to total approximately $1.1 billion in 2011. However, first production from the major offshore projects is not expected to occur until Galapagos begins to produce in late 2011 or early 2012.

Historically, we have funded our capital expenditures through a combination of cash flows from operations, our revolving bank credit facility and debt issuances. Future cash flows are subject to a number of variables, such as the level of production from existing wells, prices of crude oil and natural gas, and our success in finding, developing and producing new reserves. If revenues were to decrease as a result of lower crude oil and natural gas prices or decreased production, and our access to debt or capital were limited, we would have a reduced ability to replace our reserves, resulting in lower production over time. If our cash flows from operations are not sufficient to meet our obligations and fund our capital investment program, we may not be able to access capital markets on an economic basis to meet these requirements. If we are not able to fund our capital expenditures, our ownership interests in some properties might be reduced or forfeited as a result.

Commodity and interest rate hedging transactions may limit our potential gains.

In order to reduce commodity price uncertainty and increase cash flow predictability relating to the marketing of our crude oil and natural gas, we enter into crude oil and natural gas price hedging arrangements with respect to a portion of our expected production. Our hedges, consisting of a series of contracts, are limited in duration, usually for periods of one to three years. While intended to reduce the effects of volatile crude oil and natural gas prices, such transactions may limit our potential gains if crude oil and natural gas prices rise over the price established by the arrangements.

Global commodity prices fluctuated significantly in 2010. Such volatility challenges our ability to forecast and, as a result, it may become more difficult to manage our hedging program. In trying to manage our exposure to commodity price risk, we may end up hedging too much or too little, depending upon how our crude oil or natural gas volumes and our production mix fluctuate in the future. In addition, hedging transactions may expose us to the risk of financial loss in certain circumstances, including instances in which our production is less than expected; there is a widening of price basis differentials between delivery points for our production and the delivery point assumed in the hedge arrangement; the counterparties to our futures contracts fail to perform under the contracts; or a sudden unexpected event materially impacts crude oil or natural gas prices.

We use interest rate derivative instruments to minimize the impact of interest rate fluctuations associated with anticipated debt issuances. Interest rates are also variable and we may also end up hedging too much or too little when we attempt to effectively fix cash flows related to interest payments on an anticipated debt issuance.

We cannot assure that our hedging transactions will reduce the risk or minimize the effect of volatility in crude oil or natural gas prices or interest rates. See Item 8. Financial Statements and Supplementary Data – Note 10. Derivative Instruments and Hedging Activities.

We are exposed to counterparty credit risk as a result of our receivables, hedging transactions and cash investments.

We are exposed to risk of financial loss from trade, joint venture, and other receivables. We sell our crude oil, natural gas and NGLs to a variety of purchasers. In addition, we are the operator on a majority of our large joint venture development projects. As operator of the joint ventures, we pay joint venture expenses and make cash calls on our nonoperating partners for their respective shares of joint venture costs. These projects are capital cost intensive and, in some cases, a nonoperating partner may experience a delay in obtaining financing for its share of the joint venture costs.

In addition, some of our purchasers and joint venture partners are not as creditworthy as we are and may experience credit downgrades or liquidity problems. For example, the international credit rating of IEC, our largest natural gas purchaser in Israel, was recently downgraded. Counterparty liquidity problems could result in a delay in our receiving proceeds from commodity sales or reimbursement of joint venture costs. Credit enhancements have been obtained from some parties in the way of parental guarantees or letters of credit, including our largest crude oil purchaser; however, not all of our trade credit is protected through guarantees or credit support. Nonperformance by a trade creditor or joint venture partner could result in significant financial losses.

Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a contract. During periods of falling commodity prices, our hedge receivable positions increase, which increases our counterparty exposure. We conduct our hedging activities with a diverse group of highly-rated major banks and market participants and control our level of financial exposure. We use master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be "net settled" at the time of election. "Net settlement" refers to a process by which all transactions between counterparties are resolved into a single amount owed by one party to the other.

We had $1.1 billion in cash and cash equivalents, a majority of which was invested in money market funds and short-term deposits with major financial institutions at December 31, 2010. We monitor the creditworthiness of the banks and financial institutions with which we invest and review the securities underlying our investment accounts. However, we are unable to predict sudden changes in solvency of our financial institutions.

We monitor the creditworthiness of our trade creditors, joint venture partners, hedging counterparties and financial institutions on an ongoing basis. However, if one of them were to experience a sudden change in liquidity, it could impair their ability to perform under the terms of our contracts. We are unable to predict sudden changes in creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our ability to negate the risk may be limited and we could incur significant financial losses.

Offshore development involves significant financial risks.

We have ongoing major development projects as well as current or planned exploration activities in the deepwater Gulf of Mexico, offshore West Africa and offshore Eastern Mediterranean. In these areas, there may be limited availability of suitable drilling rigs, drilling equipment, support vessels, and qualified operating personnel. Deepwater drilling rigs are typically subject to long-term contracts. In addition, frontier areas lack the physical and oilfield service infrastructure necessary for production and transportation. As a result, development of an offshore discovery, such as Tamar, Aseng, Alen, or Gunflint, may be a lengthy process and require substantial capital investment.

Difficulty and delays in consistently obtaining drilling rigs and other equipment and services at acceptable rates may lead to project delay, increased costs, and/or inability to forecast production, which could prevent the realization of our targeted return on capital or lead to unexpected future losses.

Due to the current lack of drilling activity in the deepwater Gulf of Mexico caused by the regulatory response to the Deepwater Horizon Incident, drilling, equipment and oilfield services companies may decide to exit the Gulf of Mexico making such services even less available and/or more expensive once drilling activities are allowed to resume.

We may be unable to make attractive acquisitions, successfully integrate acquired businesses and/or assets, or adjust to the effects of divestitures, causing a disruption to our business.

One aspect of our business strategy calls for acquisitions of businesses and assets that complement or expand our current business, such as our Central DJ Basin asset acquisition in 2010. This may present greater risks for us than those faced by peer companies that do not consider acquisitions as a part of their business strategy. We cannot provide assurance that we will be able to identify attractive acquisition opportunities. Even if we do identify attractive opportunities, we cannot provide assurance that we will be able to complete the acquisition due to capital market constraints, even if such capital is available on commercially acceptable terms. If we acquire an additional business, we could have difficulty integrating its operations, systems, management and other personnel and technology with our own, or could assume unidentified or unforeseeable liabilities, resulting in a loss of value.

We maintain an ongoing portfolio management program which includes sales of non-core, non-strategic assets, such as the sales of non-core onshore US assets in 2010 and our interest in Argentina in 2008. These transactions can also result in changes in operations, systems, or management and other personnel.

Organizational modifications due to acquisitions, divestitures or other portfolio management actions, or other strategic changes can alter the risk and control environments, disrupt ongoing business, distract management and employees, increase expenses and adversely affect results of operations. Even if these challenges can be dealt with successfully, we cannot provide assurance that the anticipated benefits of any acquisition, divestiture or other strategic change would be realized.

Estimates of crude oil and natural gas reserves are not precise.

There are numerous uncertainties inherent in estimating crude oil and natural gas reserves and their value, including factors that are beyond our control. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact manner. In accordance with the SEC's revisions to rules for oil and gas reserves reporting, which we implemented effective December 31, 2009, our reserves estimates are based on 12-month average prices; therefore, reserves quantities will change when actual prices increase or decrease. The reserves estimates depend on a number of factors and assumptions that may vary considerably from actual results, including:

- historical production from the area compared with production from other areas;
- the assumed effects of regulations by governmental agencies, including the impact of the SEC's revisions to oil and gas company reserves reporting requirements;
- assumptions concerning future crude oil and natural gas prices;
- anticipated development cycle time;
- future development costs;
- future operating costs;

- severance and excise taxes; and
- workover and remedial costs.

For these reasons, estimates of the economically recoverable quantities of crude oil and natural gas attributable to any particular group of properties, classifications of those reserves based on risk of recovery and estimates of the future net cash flows expected from them prepared by different petroleum engineers or by the same petroleum engineers but at different times may vary substantially. Accordingly, reserves estimates may be subject to positive or negative revisions, and actual production, revenue and expenditures with respect to our reserves likely will vary, possibly materially, from estimates.

Additionally, because some of our reserves estimates are calculated using volumetric analysis, those estimates are less reliable than the estimates based on a lengthy production history. Volumetric analysis involves estimating the volume of a reservoir based on the net feet of pay of the structure and an estimation of the area covered by the structure. In addition, realization or recognition of proved undeveloped reserves will depend on our development schedule and plans. A change in future development plans for proved undeveloped reserves could cause the discontinuation of the classification of these reserves as proved.

Exploration, development and production risks and natural disasters could result in liability exposure or the loss of production and revenues.

Our operations are subject to hazards and risks inherent in the drilling, production and transportation of crude oil and natural gas, including:

- injuries and/or deaths of employees, supplier personnel, or other individuals;
- pipeline ruptures and spills;
- fires;
- explosions, blowouts and well cratering;
- equipment malfunctions;
- formations with abnormal pressures;
- release of pollutants;
- hurricanes, such as Gustav and Ike in 2008, which could affect our operations in areas such as the Gulf Coast and deepwater Gulf of Mexico, and cyclones, which could affect our operations offshore China; and
- other natural disasters.

Any of these can result in loss of hydrocarbons, environmental pollution and other damage to our properties or the properties of others.

Exploratory drilling may not result in the discovery of commercially productive reservoirs.

We depend on exploration success to provide growth in production and reserves and are planning an active exploratory drilling program in 2011. Exploratory drilling requires significant capital investment and is not always successful. For example, we incurred dry hole expense in 2010 because the Double Mountain exploratory well in the deepwater Gulf of Mexico found noncommercial quantities of hydrocarbons.

Exploratory dry holes can occur because seismic data and other technologies we use to determine potential exploratory drilling locations do not allow us to know conclusively prior to drilling a well that crude oil or natural gas is present or may be produced economically.

Exploratory drilling activities may be curtailed, delayed or canceled, resulting in significant exploration expense, as a result of a variety of factors, including:

- title problems;
- compliance with environmental and other governmental requirements;
- increases in the cost of, or shortages or delays in the availability of, drilling rigs, equipment and qualified personnel;
- unexpected drilling conditions;
- pressure or other irregularities in formations;
- equipment failures or accidents; and
- adverse weather conditions.

In addition, companies seeking new reserves often face more difficult environments, such as oil sands, deepwater, or ultra-deepwater, and often need to develop or invest in new technologies. This increases cost as well as drilling risk.

For certain capital-intensive deepwater Gulf of Mexico or international projects, it may take several years to evaluate the future potential of an exploration well and make a determination of its economic viability, resulting in delays in cash flows from production start-up and a lower return on our investment.

Due to our level of planned exploration activity, future dry hole cost could be significant and have a negative impact on our results of operations and cash flows.

Development drilling may not result in commercially productive quantities of oil and gas reserves.

Our exploration success has provided us with a number of major development projects on which we are moving forward. We depend on these projects to provide long life, sustained cash flows after investment and attractive financial returns. However, development drilling is not always successful and the profitability of development projects may change over time.

For example, in new development areas such as Gunflint or Tamar, available data may not allow us to completely know the extent of the reservoir or choose the best locations for drilling development wells. Therefore, a development well we drill may be a dry hole or result in noncommercial quantities of hydrocarbons. Projects in frontier areas may require the development of special technology for development drilling or well completion and we may not have the knowledge or expertise in applying new technology. Our efforts may result in a dry hole or a well that finds noncommercial quantities of hydrocarbons. Development drilling has the same legal and physical risks as exploratory drilling, described above, which can result in the drilling of a development dry hole or the incurrence of substantial development costs without a corresponding increase in proved reserves.

All costs of development drilling and other development activities are capitalized, even if the activities do not result in commercially productive quantities of oil and gas. This puts a property at higher risk for future impairment if commodity prices decrease or operating or development costs increase.

Even if development drilling is successful and we find commercial quantities of reserves, we may encounter difficulties or delays in completing development wells. For example, in areas of high activity and demand in which we concentrate, such as the Rocky Mountains, we may experience delays in obtaining well completion rigs and services. Frontier areas may not have adequate infrastructure for gathering, processing or transportation, and production may be delayed until they are constructed. This results in a decrease in current cash flows and reduces the return on our investment.

Costs of drilling, completing and operating wells are often uncertain, and cost factors can adversely affect the economics of a project. Even a development project with significant reserves that is currently economic can become uneconomic in the future if commodity prices decrease or operating or development costs increase, resulting in impairment charges and a negative impact on our results of operations.

The magnitude of the Leviathan discovery will present financial and technical challenges for us due to the large-scale development requirements.

In December 2010, we announced a significant natural gas discovery at the Leviathan prospect, offshore Israel. The Leviathan field is currently the largest discovery in our history and we believe it is the largest deepwater natural gas discovery in the last decade. As a result of the combined discoveries of Tamar and Leviathan, Israel now faces a potential surplus of natural gas.

Development options for Leviathan include export of surplus natural gas to Europe or Asia through development of LNG terminals or underwater pipelines. Each of these development options would require a multi-billion dollar investment and take a number of years to complete. We have a nearly 40% working interest in Leviathan. As a result, we will likely seek partners to provide technical and financial support as well as midstream and downstream expertise.

In addition, we must resolve with the Israeli government Leviathan's treatment as a result of the proposed changes in Israel's fiscal regime, discussed above, that could potentially reduce the anticipated profitability of the project.

Failure to execute a successful development scenario for Leviathan could result in damage to our reputation, limitations on our growth and negative effects on our operating results.

The unavailability or high cost of drilling rigs, equipment, supplies, other oil field services and personnel could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies and oilfield services. There may also be a shortage of trained and experienced personnel. During these periods, the costs of such items are substantially greater and their availability may be limited, particularly in areas of high activity and demand in which we concentrate, such as the Rocky Mountains, deepwater Gulf of Mexico, prior to the Deepwater Moratorium, and in some international locations that typically have limited availability of equipment and personnel, such as West Africa and the Eastern Mediterranean.

During periods of increasing levels of industry exploration and production, such as we currently are experiencing in the Rocky Mountains Niobrara formation, the demand for, and cost of, drilling rigs and oilfield services increases. In addition, regulatory changes in response to the Deepwater Horizon Incident may also result in higher costs for these rigs and services. As a result, drilling rigs and oilfield services may not be available at rates that provide a satisfactory return on our investment. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – *Contractual Obligations* for additional information on drilling rig contracts.

We face significant competition and many of our competitors have resources in excess of our available resources.

We operate in the highly competitive areas of crude oil and natural gas exploration, exploitation, acquisition and production. We face intense competition from:

- large multi-national, integrated oil companies;
- state-controlled national oil companies;
- US independent oil and gas companies;
- service companies engaging in exploration and production activities; and
- private oil and gas equity funds.

We face competition in a number of areas such as:

- seeking to acquire desirable producing properties or new leases for future exploration;
- marketing our crude oil and natural gas production;
- seeking to acquire the equipment and expertise necessary to operate and develop properties; and
- attracting and retaining employees with certain skills.

Many of our competitors have financial and other resources substantially in excess of those available to us. Such companies may be able to pay more for seismic and lease rights on crude oil and natural gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. This highly competitive environment could have an adverse impact on our business.

Indebtedness may limit our liquidity and financial flexibility.

As of December 31, 2010, we had long-term indebtedness of $2.3 billion (including an FPSO lease obligation of $295 million), with $350 million drawn under our bank credit facility. Our indebtedness represented 25% of our total book capitalization at December 31, 2010.

Our indebtedness affects our operations in several ways, including the following:

- a portion of our cash flows from operating activities must be used to service our indebtedness and is not available for other purposes;
- we may be at a competitive disadvantage as compared to similar companies that have less debt;
- a covenant contained in our revolving credit facility provides that our total debt to capitalization ratio (as defined) will not exceed 60% at any time, which may limit our ability to borrow additional funds, thereby affecting our flexibility in planning for, and reacting to, changes in the economy and in our industry;
- a covenant contained in our revolving credit facility restricts the payment of dividends on our common stock if, after giving effect thereto, an Event of Default shall have occurred and be continuing or been caused thereby;
- additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes may have higher costs and more restrictive covenants;
- changes in the credit ratings of our debt may negatively affect the cost, terms, conditions and/or availability of future financing, and lower ratings will increase the interest rate and fees we pay on our revolving credit facility; and
- we may be more vulnerable to general adverse economic and industry conditions.

We may incur additional debt in order to fund our exploration, development and acquisition activities. A higher level of indebtedness increases the risk that our liquidity may deteriorate and we default on our debt obligations. Our ability to meet our debt obligations and service our debt depends on future performance. General economic conditions, crude oil and natural gas prices and financial, business and other factors will affect our operations and our future performance. Many of these factors are beyond our control and we may not be able to generate sufficient cash flow to pay the interest on our debt, and future working capital, borrowings and equity financing may not be available to pay or refinance such debt. See Item 8. Financial Statements and Supplementary Data – Note 12. Long-Term Debt.

The marketability of our Rocky Mountain and deepwater Gulf of Mexico production is dependent upon transportation and processing facilities over which we may have no control.

The marketability of our production from the Rocky Mountain area and the deepwater Gulf of Mexico depends in part upon the availability, proximity and capacity of pipelines, natural gas gathering systems and processing facilities. We deliver crude oil and natural gas produced from these areas through gathering systems and pipelines that we do not own. The lack of availability of capacity on these systems and facilities could reduce the price offered for our production or result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Although we have some contractual control over the transportation of our production through firm transportation arrangements, third-party systems and facilities may be temporarily unavailable due to market conditions or mechanical or other reasons, including adverse weather conditions, such as occurred when our deepwater Gulf of Mexico Ticonderoga development became shut in as a result of hurricane damage to third party processing and pipeline facilities in 2008.

Third-party systems and facilities may not be available to us in the future at a price that is acceptable to us. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities, could delay production, thereby harming our business and, in turn, our financial condition, results of operations and cash flows.

Our operations and investment in the Machala power plant in Ecuador have been adversely affected by the Ecuadorian government's termination of our PSC for Block 3.

A newly enacted hydrocarbon law in Ecuador aims to change current production-sharing arrangements into service contracts and provided for renegotiation of certain contracts by November 23, 2010. It also allows the Ecuadorian government to nationalize oil and gas fields if a private operator does not comply with local laws.

A service contract on Block 3 (100% working interest) was not negotiated, and the government of Ecuador terminated the Block 3 PSC with our subsidiary, EDC Ecuador Ltd. on November 25, 2010. We are continuing to work with the government of Ecuador to resolve this matter. However, we are uncertain as to the potential outcome of this matter, resolution of which could ultimately lead to a reduction in the value of the receivable or our investments in Ecuador which, as of December 31, 2010, had a net book value of approximately $66 million.

Our operations require us to comply with a number of US and international laws and regulations, violations of which could result in substantial fines or sanctions and/or impair our ability to do business.

Our operations require us to comply with a number of US and international laws and regulations, including those involving anti-corruption. For example, the US Foreign Corrupt Practices Act (FCPA) and similar laws and regulations enacted or promulgated by countries pursuant to the 1997 Organization for Economic Co-operation and Development Anti-Bribery Convention generally prohibit improper payments to foreign officials for the purpose of obtaining or keeping business. The scope and enforcement of anti-corruption laws and regulations may vary. The recently-enacted UK Bribery Act of 2010, which was originally scheduled to become effective in April 2011, is broader in scope than the FCPA and applies to public and private sector corruption and contains no facilitating payments exception. Violations of such laws or regulations could result in substantial civil or criminal fines or sanctions. Actual or alleged violations could damage our reputation, be expensive to defend, and impair our ability to do business.

We have merged with or acquired other companies in the past. Mergers of businesses often require the approval of certain government or regulatory agencies and such approval could contain terms, conditions, or restrictions that would be detrimental to our business after a merger. US anti-trust laws require waiting periods and even after completion of a merger, governmental authorities could seek to block or challenge a merger as they deem necessary or desirable in the public interest. Prevention of a merger by anti-trust laws could impair our ability to do business.

Increased regulation of business practices could result in higher operating costs.

The current trend is toward increased regulation of business practices and additional reporting requirements. For example the EPA issued the Final Mandatory Reporting of Greenhouse Gases Rule. We are subject to these new reporting requirements Under Subpart W, Petroleum and Natural Gas Systems. Compliance with these and other new rules results in additional effort on the part of our personnel. In addition, other legislation may be enacted in order to restrict GHG emissions in the US or regulate hydraulic fracturing under the Safe Drinking Water Act.

The Dodd-Frank Act requires both the CFTC and the SEC to enact numerous rules and regulations, some of which could impact our business practices and negatively affect our financial flexibility or place additional reporting burdens on us.

Although it is not possible at this time to predict the final outcome of these rule-making and standard-setting efforts, it is likely that the magnitude of these changes will require an unprecedented compliance effort on our part, could divert management's attention, and may require significant expenditures, as well as place additional burden on our internal financial controls.

We operate in a litigious environment.

We operate in the US and other countries which have proven to be unusually litigious environments. Most oil and gas companies, such as us, are involved in various legal proceedings, such as title, royalty, or contractual disputes, in the ordinary course of business. We defend ourselves vigorously in all such matters.

Because we maintain a diversified portfolio of assets that is balanced between US and international projects, the complexity and types of legal procedures with which we may become involved may vary, and we could incur significant legal and support expenses in different jurisdictions. If we are not able to successfully defend ourselves, there could be a delay or even halt in our exploration, development or production activities or other business plans, resulting in a reduction in reserves, loss of production and reduced cash flows. Legal proceedings could result in a substantial liability. In addition, legal proceedings distract management and other personnel from their primary responsibilities.

A change in US energy policy can have a significant impact on our operations and profitability.

US energy policy and laws and regulations could change quickly. Currently, substantial uncertainty exists about the nature of potential rules and regulations that could impact the sources and uses of energy in the US. We design our exploration and development strategy and related capital investment programs years in advance. As a result, we are hindered in our ability to plan, invest and respond to potential changes in our business. This can result in a reduction of our cash flows and profitability to the extent we are unable to respond to sudden or significant changes in our operating environment due to changes in US energy policy.

The adoption of GHG emission or other environmental legislation could result in increased operating costs, create delays in our obtaining air pollution permits for new or modified facilities, and reduce demand for the crude oil and natural gas we produce.

In recent years, each house of Congress has considered legislation to address GHG emissions, such as the American Clean Energy and Security Act of 2009, also known as the Waxman-Markey Bill, passed by the House of Representatives, and The Clean Energy Jobs and American Power Act, or the Boxer-Kerry Bill, introduced to the Senate. Future legislation could include mandatory carbon dioxide emissions goals, measures to encourage use of renewable energy over fossil-based fuels, higher penalties and fines for violations of various environmental laws, or other regulations designed to curb GHG emissions.

One measure considered frequently has been the establishment of a "cap and trade" system for restricting GHG emissions in the US. Under such system, certain sources of GHG emissions would be required to obtain GHG emission "allowances" corresponding to their annual emissions of GHGs. The number of emission allowances issued each year would decline as necessary to meet overall emission reduction goals. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly.

The EPA has issued GHG monitoring and reporting regulations that went into effect January 1, 2010, and require reporting by regulated facilities by March 2011 and annually thereafter. Beyond measuring and reporting, the EPA issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding GHG pollution threatens the public health and welfare of current and future generations. The EPA has issued final regulations requiring petroleum and natural gas operators meeting a certain emissions threshold to report their GHG emissions to the EPA (Subpart W). The EPA has indicated that it will use data collected through the reporting rules to decide whether to promulgate future GHG limits.

Since approximately 61% of our total 2010 crude oil and NGL production and 51% of our total 2010 natural gas production derive from the US, any laws or regulations that may be adopted to restrict or reduce emissions of US GHGs could require us to incur higher operating costs, increase our development cycle time, and have an adverse effect on demand for the crude oil and natural gas we produce. In addition, we could be required to make significant capital expenditures to comply with new environmental legislation, which would cause us to divert capital from exploration, development and production activities.

Federal or state hydraulic fracturing legislation could increase our costs and restrict our access to oil and gas reserves.

Hydraulic fracturing involves the injection of a mixture, comprised primarily of water and sand, and a small amount of chemicals, under pressure into rock formations to stimulate production. We find that the use of hydraulic fracturing is necessary to produce commercial quantities of crude oil and natural gas from many reservoirs, including Wattenberg, which represented 25% of our 2010 consolidated sales volumes.

Hydraulic fracturing using fluids other than diesel is currently exempt from regulation under the federal Safe Drinking Water Act, but opponents of hydraulic fracturing have called for further study of the technique's environmental effects and, in some cases, a moratorium on the use of the technique. Several proposals have been submitted to Congress that, if implemented, would subject all hydraulic fracturing to regulation under the Safe Drinking Water Act. Further, the EPA's Office of Research and Development (ORD) is conducting a scientific study to investigate the possible relationships between hydraulic fracturing and drinking water. The ORD expects to initiate the study in 2011 and have the initial study results available by late 2012.

In addition, some states have taken actions concerning hydraulic fracturing. In October 2010, the Governor of Pennsylvania issued a moratorium on new natural gas development on state forest lands. The New York Legislature passed a bill imposing a moratorium on issuance of new permits for the drilling of wells that use hydraulic fracturing for the purpose of stimulating natural gas or oil in the Marcellus Shale formation, but the Governor of New York subsequently vetoed the bill. On December 13, 2010, however, the Governor of New York issued Executive Order No. 41, which prohibits issuance of state permits for high-volume hydraulic fracturing combined with horizontal drilling until the New York Department of Environmental Conservation completes its Final Supplemental Generic Environmental Impact Statement (SGEIS). Under the order, the New York Department of Environmental Conservation must publish a revised draft SGEIS on or about June 1, 2011 and allow a public comment period of at least 30 days. Accordingly, this moratorium is expected to last until at least July 1, 2011. Other states could take similar action.

Several states have considered, or are considering, legislation or regulations that would require disclosure of chemicals used for hydraulic fracturing. In June 2010, the Wyoming Oil and Gas Conservation Commission passed a rule requiring disclosure of hydraulic fracturing fluid content. In November 2010, the Pennsylvania Environmental Quality Board proposed regulations that would require reporting of the chemicals used in fracturing fluids.

Although it is not possible at this time to predict the final outcome of the ORD's study or the requirements of any additional federal or state legislation or regulation regarding hydraulic fracturing, any new federal or state restrictions on hydraulic fracturing that may be imposed in areas in which we conduct business could significantly increase our operating, capital and compliance costs as well as delay our ability to develop oil and gas reserves.

Provisions in our Certificate of Incorporation and Delaware law may inhibit a takeover of us.

Under our Certificate of Incorporation, our Board of Directors is authorized to issue shares of our common or preferred stock without approval of our shareholders. Issuance of these shares could make it more difficult to acquire us without the approval of our Board of Directors as more shares would have to be acquired to gain control. In addition, Delaware law imposes restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock. These provisions may deter hostile takeover attempts that could result in an acquisition of us that would have been financially beneficial to our shareholders.

Disclosure Regarding Forward-Looking Statements

This annual report on Form 10-K and the documents incorporated by reference in this report contain forward-looking statements within the meaning of the federal securities laws. Forward-looking statements give our current expectations or forecasts of future events. These forward-looking statements include, among others, the following:

- our growth strategies;
- our ability to successfully and economically explore for and develop crude oil and natural gas resources;
- anticipated trends in our business;
- our future results of operations;
- our liquidity and ability to finance our exploration, development, and acquisition activities;
- market conditions in the oil and gas industry;
- our ability to make and integrate acquisitions; and
- the impact of governmental regulation.

Forward-looking statements are typically identified by use of terms such as "may," "will," "expect," "anticipate," "target," "estimate" and similar words, although some forward-looking statements may be expressed differently. These forward-looking statements are made based upon management's current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve a number of risks and uncertainties. We caution that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements. You should consider carefully the statements under Item 1A. Risk Factors and other sections of this report, which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

We are involved in various legal proceedings in the ordinary course of business. These proceedings are subject to the uncertainties inherent in any litigation. We are defending ourselves vigorously in all such matters and we do not believe that the ultimate disposition of such proceedings will have a material adverse effect on our financial position, results of operations or cash flows.

Item 4. [Removed and Reserved]

Executive Officers

The following table sets forth certain information, as of February 10, 2011, with respect to our executive officers.

Name	Age	Position
Charles D. Davidson (1)	60	Chairman of the Board, Chief Executive Officer and Director
David L. Stover (2)	53	President, Chief Operating Officer
Kenneth M. Fisher (3)	49	Senior Vice President, Chief Financial Officer
Ted D. Brown (4)	55	Senior Vice President, Northern Region
Rodney D. Cook (5)	53	Senior Vice President, International
Susan M. Cunningham (6)	55	Senior Vice President, Exploration
Arnold J. Johnson (7)	55	Senior Vice President, General Counsel and Secretary
Andrea Lee Robison (8)	52	Vice President, Human Resources

(1) Charles D. Davidson was elected Chief Executive Officer of Noble Energy in October 2000 and Chairman of the Board in April 2001, also serving as President until April 2009 (at which time Mr. Stover assumed that position). Prior to October 2000, he served as President and Chief Executive Officer of Vastar Resources, Inc. from March 1997 to September 2000 (Chairman from April 2000) and was a Vastar Director from March 1994 to September 2000. From September 1993 to March 1997, he served as a Senior Vice President of Vastar. From 1972 to October 1993, he held various positions with ARCO.

(2) David L. Stover was elected President and Chief Operating Officer of Noble Energy in April 2009. Prior thereto, he served as Executive Vice President and Chief Operating Officer of Noble Energy from August 2006 to April 2009. He served as Senior Vice President of North America and Business Development from July 2004 through July 2006, and he served as Noble Energy's Vice President of Business Development from December 2002 through June 2004. Previous to his employment with Noble Energy, he was employed by BP America, Inc. as Vice President, Gulf of Mexico Shelf from September 2000 to August 2002. Prior to joining BP, Mr. Stover was employed by Vastar, as Area Manager for Gulf of Mexico Shelf from April 1999 to September 2000, and prior thereto, as Area Manager for Oklahoma/Arklatex from January 1994 to April 1999. From 1979 to 1994, he held various positions with ARCO.

(3) Kenneth M. Fisher was elected a Senior Vice President and Chief Financial Officer of Noble Energy in November 2009. Prior to joining Noble Energy, Mr. Fisher served as Executive Vice President of Finance for Upstream Americas for Shell from July 2009 to November 2009. Prior to his most recent position with Shell, Mr. Fisher served as Director of Strategy & Business Development for Royal Dutch Shell plc in The Hague from August 2007 to July 2009. He served as Executive Vice President of Strategy & Portfolio for Shell's downstream business in London from January 2005 to August 2007. Mr. Fisher joined Shell in August 2002 and served as Chief Financial Officer for Shell Oil Products U.S. until December 2004. As Chief Financial Officer for Shell Oil Products U.S., he was responsible for U.S. oil products finance, information technology and contracting and procurement activities. Prior to joining Shell, he held positions of increasing responsibility with General Electric (GE) from 1984 to 2002, including Vice President and Chief Financial Officer of the Aircraft Engines Services division and Director of Finance & Business Development of GE's Asia Pacific plastics business.

(4) Ted D. Brown was elected a Senior Vice President of Noble Energy in April 2008 and is currently responsible for the Northern Region of our North America division. He served as Vice President, responsible for the same region, from August 2006 to April 2008 and as a vice president of that division since joining us upon our acquisition of Patina Oil & Gas Corporation (Patina) in May 2005. He served as Senior Vice President of Patina from July 2004 to May 2005. Prior thereto he served as Director, Piceance Basin Asset along with Engineering Manager for Williams and Barrett Resources since 1993 and, before that, in various positions with Union Pacific Resources and Amoco Production Company.

(5) Rodney D. Cook was elected a Senior Vice President of Noble Energy in April 2008 and is currently responsible for the International division. He served as Vice President of Noble Energy, responsible for the Southern Region of our North America division, from August 2006 to April 2008 and as a vice president of that division from May 2005 to August 2006. He served as Manager of our West Africa and Middle East Business Unit from 2002 to 2005. Prior thereto he served as Operations Manager of the International division since 1996. From 1980 to 1996 he held various positions with Noble Energy. Prior to joining Noble Energy in 1980, Mr. Cook held various positions with Texas Pacific Oil.

(6) Susan M. Cunningham was elected a Senior Vice President of Noble Energy in April 2001 and is currently responsible for our world-wide exploration. Prior to joining Noble Energy, Ms. Cunningham was Texaco's Vice President of worldwide exploration from April 2000 to March 2001. From 1997 through 1999, she was employed by Statoil, beginning in 1997 as Exploration Manager for deepwater Gulf of Mexico, appointed a Vice President in 1998 and responsible, in 1999, for Statoil's West Africa exploration efforts. She joined Amoco Canada in 1980 as a geologist and held various exploration and development positions with Amoco Production Company until 1997.

(7) Arnold J. Johnson was elected Senior Vice President, General Counsel and Secretary of Noble Energy in July 2008. Prior thereto, he served as Vice President, General Counsel and Secretary of Noble Energy since February 2004. He served as Associate General Counsel and Assistant Secretary of Noble Energy from January 2001 through January 2004. Previous to his employment with Noble Energy, he served as Senior Counsel for BP America, Inc. from October 2000 to January 2001. Mr. Johnson held several positions as an attorney for Vastar and ARCO from March 1989 through September 2000, most recently as Assistant General Counsel and Assistant Secretary of Vastar from 1997 through 2000. From 1980 to March 1989, he held various positions with ARCO.

(8) Andrea Lee Robison was elected to the position of Vice President of Noble Energy in November 2007 and is responsible for Human Resources. Prior thereto, she served as Director of Human Resources from May 2002 through October 2007. Prior to joining us, Ms. Robison was Manager of Human Resources for the Gulf of Mexico Shelf for BP America, Inc. from September 2000 through April 2002. Prior to her employment at BP, she served as HR Director at Vastar from 1997 through September 2000, and Compensation Consultant from January 1994 through 1996. From 1980 through 1993 she held various positions with ARCO.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Common Stock Our common stock, $3.33 1/3 par value, is listed and traded on the NYSE under the symbol "NBL." The declaration and payment of dividends are at the discretion of our Board of Directors and the amount thereof will depend on our results of operations, financial condition, contractual restrictions, cash requirements, future prospects and other factors deemed relevant by the Board of Directors.

Stock Prices and Dividends by Quarters The high and low sales price per share of our common stock on the NYSE and quarterly dividends paid per share were as follows:

	High	Low	Dividends Per Share
2009			
First Quarter	$ 58.24	$ 40.33	$ 0.18
Second Quarter	69.07	50.86	0.18
Third Quarter	70.35	51.49	0.18
Fourth Quarter	74.09	62.25	0.18
2010			
First Quarter	$ 79.19	$ 68.38	$ 0.18
Second Quarter	81.50	56.23	0.18
Third Quarter	77.63	59.22	0.18
Fourth Quarter	89.00	75.07	0.18

On January 25, 2011, the Board of Directors declared a quarterly cash dividend of $0.18 per common share, which will be paid February 22, 2011 to shareholders of record on February 7, 2011.

Transfer Agent and Registrar The transfer agent and registrar for our common stock is Wells Fargo Bank, N.A., 161 North Concord Exchange, South St. Paul, MN, 55075.

Stockholders' Profile Pursuant to the records of the transfer agent, as of January 27, 2011, the number of holders of record of our common stock was 723.

Stock Repurchases The following table summarizes repurchases of our common stock occurring fourth quarter 2010.

Period	Total Number of Shares Purchased [1]	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
				(in thousands)
10/01/10 - 10/31/10	477	$ 77.69	-	$ -
11/01/10 - 11/30/10	1,935	80.82	-	-
12/01/10 - 12/31/10	936	84.61	-	-
Total	3,348	$ 80.82	-	-

[1] Stock repurchases during the period related to stock received by us from employees for the payment of withholding taxes due on shares issued under stock-based compensation plans.

Equity Compensation Plan Information The following table summarizes information regarding the number of shares of our common stock that are available for issuance under all of our existing equity compensation plans as of December 31, 2010.

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
	(a)	(b)	(c)
Equity Compensation Plans Approved by Security Holders	6,266,960	$ 52.87	3,975,729
Equity Compensation Plans Not Approved by Security Holders	-	-	-
Total	6,266,960	$ 52.87	3,975,729

Stock Performance Graph This graph shows our cumulative total shareholder return over the five-year period from December 31, 2005, to December 31, 2010. The graph also shows the cumulative total returns for the same five-year period of the S&P 500 Index, an old peer group of companies and a new peer group of companies. The cumulative total return of the common stock of our old and new peer groups of companies includes the cumulative total return of our common stock.

The companies in the old peer group, which has been adjusted for the effects of industry consolidation, consisted of the following:

Anadarko Petroleum Corp.
Apache Corp.
Cabot Oil & Gas Corp.
Chesapeake Energy Corp.
Devon Energy Corp.
EOG Resources, Inc.
Forest Oil Corp.
Murphy Oil Corp.
Newfield Exploration Company
Noble Energy, Inc.
Pioneer Natural Resources Company
Plains Exploration and Production Company
Range Resources Corp.
Southwestern Energy Company

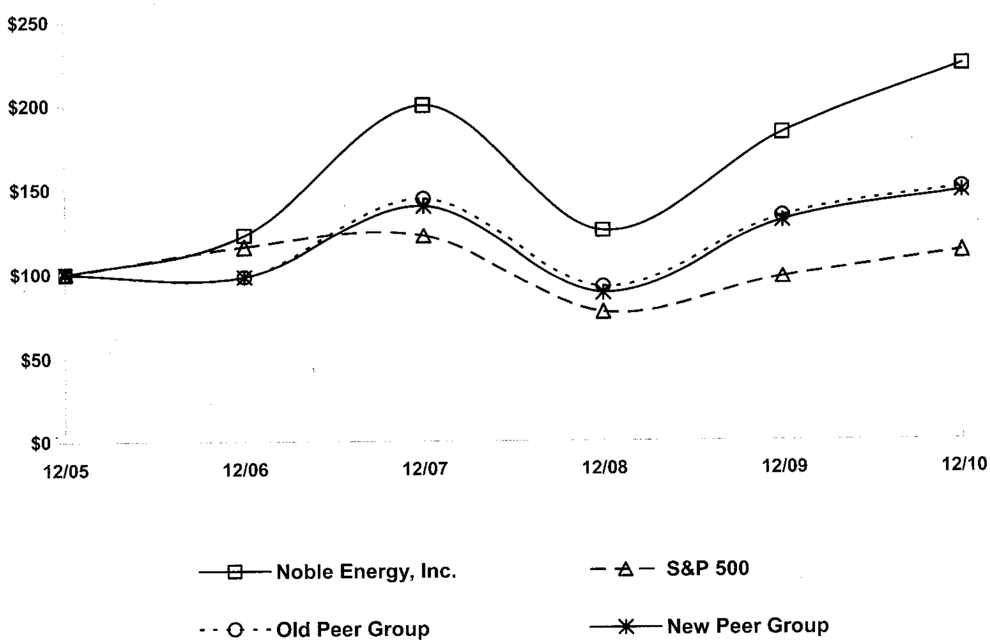
At December 31, 2010 (after certain industry consolidation during 2010 and pursuant to a resolution adopted by the Compensation, Benefits and Stock Option Committee of the Board of Directors), our peer group of companies consisted of the following:

Anadarko Petroleum Corp.
Apache Corp.
Cabot Oil & Gas Corp.
Chesapeake Energy Corp.
Devon Energy Corp.
EOG Resources, Inc.
Forest Oil Corp.
Murphy Oil Corp.
Newfield Exploration Company
Noble Energy, Inc.
Pioneer Natural Resources Company
Plains Exploration and Production Company
Range Resources Corp.
Southwestern Energy Company
Talisman Energy Inc.

The comparison assumes $100 was invested on December 31, 2005, in our common stock, in the S&P 500 Index and in our old and new peer groups and assumes that all of the dividends were reinvested.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among Noble Energy, Inc., the S&P 500 Index,
an Old Peer Group and a New Peer Group



*$100 invested on 12/31/05 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

Year Ended December 31,	2005	2006	2007	2008	2009	2010
Noble Energy, Inc.	$ 100.00	$ 122.48	$ 199.84	$ 124.92	$ 182.96	$ 223.28
S&P 500	100.00	115.80	122.16	76.96	97.33	111.99
Old Peer Group	100.00	98.18	144.19	91.74	133.36	149.88
New Peer Group	100.00	98.10	140.09	88.01	130.71	147.74

Item 6. Selected Financial Data

	Year Ended December 31,				
(millions, except as noted)	2010	2009	2008	2007	2006
Revenues and Income (Loss)					
Total Revenues	$ 3,022	$ 2,313	$ 3,901	$ 3,272	$ 2,940
Net Income (Loss)	725	(131)	1,350	944	678
Per Share Data					
Earnings (Loss) Per Share					
Basic	$ 4.15	$ (0.75)	$ 7.83	$ 5.52	$ 3.86
Diluted	4.10	(0.75)	7.58	5.45	3.79
Cash Dividends Per Share	0.720	0.720	0.660	0.435	0.275
Year-End Stock Price Per Share	86.08	71.22	49.22	80.66	49.07
Weighted Average Shares Outstanding					
Basic	175	173	173	171	176
Diluted	177	173	176	173	179
Cash Flows					
Net Cash Provided by Operating Activities	$ 1,946	$ 1,508	$ 2,285	$ 2,017	$ 1,730
Additions to Property, Plant and Equipment	1,885	1,268	1,971	1,414	1,357
Acquisitions	458	-	292	-	412
Proceeds from Sale of Property, Plant and Equipment	564	3	131	9	520
Financial Position					
Cash and Cash Equivalents	1,081	1,014	1,140	660	153
Commodity Derivative Instruments - Current	62	13	437	15	35
Property, Plant, and Equipment, Net	10,264	8,916	9,004	7,945	7,171
Goodwill	696	758	759	761	781
Total Assets	13,282	11,807	12,384	10,831	9,589
Long-term Obligations					
Long-Term Debt	2,272	2,037	2,241	1,851	1,801
Deferred Income Taxes	2,110	2,076	2,174	1,984	1,758
Commodity Derivative Instruments	51	17	2	83	329
Asset Retirement Obligations	208	181	184	131	128
Other	371	349	300	337	275
Shareholders' Equity	6,848	6,157	6,309	4,809	4,114
Operations Information					
Consolidated Crude Oil Sales (MBbl/d)	64	62	69	77	75
Average Realized Price ($/Bbl) (1)	$ 76.46	$ 55.76	$ 82.60	$ 60.61	$ 54.47
Consolidated Natural Gas Sales (MMcf/d)	787	781	767	687	623
Average Realized Price ($/Mcf) (1)	$ 3.00	$ 2.54	$ 5.04	$ 5.26	$ 5.55
Consolidated NGL Sales (MBbl/d) (2)	14	10	9	-	-
Average Realized Price ($/Bbl)	$ 41.21	$ 27.96	$ 50.15	$ -	$ -
Proved Reserves					
Crude Oil, Condensate and NGL Reserves (MMBbls)	365	336	311	329	296
Natural Gas Reserves (Bcf)	4,361	2,904	3,315	3,307	3,231
Total Reserves (MMBoe)	1,092	820	864	880	835
Number of Employees	1,772	1,630	1,571	1,398	1,243

(1) Prices include effects of oil and gas hedging activities. See Item 8. Financial Statements and Supplementary Data – Note 10. Derivative Instruments and Hedging Activities.

(2) Prior to 2008, US NGL sales volumes were included with natural gas volumes. Effective in 2008 we began reporting US NGLs separately where we have the right to take title, which lowered the comparative natural gas sales volumes for 2008.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

We are a leading independent energy company engaged in worldwide oil and gas exploration and production. The accompanying consolidated financial statements, including the notes thereto, contain detailed information that should be read in conjunction with the following discussion.

EXECUTIVE OVERVIEW

We are a worldwide producer of crude oil and natural gas. Our strategy is to achieve growth in earnings and cash flows through the continued expansion of a high quality portfolio of producing assets that is balanced and diversified among US and international projects, crude oil and natural gas, and near, medium and long-term opportunities.

Strategy We seek to achieve growth in earnings and cash flow through exploration success and the development of a high quality, diverse portfolio of assets that is balanced between US and international projects, while maintaining a strong balance sheet and ample liquidity levels. We primarily focus on organic growth from exploration and development drilling, and we augment that with a strong, opportunistic new business development (mergers and acquisition) capability and ongoing portfolio management. We concentrate on basins or plays where we have strategic competitive advantage and which we believe offer superior returns.

Key operating areas are the onshore US, deepwater Gulf of Mexico, offshore West Africa and the Eastern Mediterranean. We actively manage our portfolio with periodic divestments to "high grade" the portfolio. As a result of our continued exploration success, we are focused on the execution of a significant portfolio of major development projects that will deliver visible growth including: among others, the Central DJ Basin, onshore US; Galapagos and Gunflint in the deepwater Gulf of Mexico; Aseng and Alen, offshore West Africa; and Tamar, offshore Israel. Our major development projects typically offer long life, sustained cash flows after investment and attractive financial returns. We maintain a balanced portfolio between US and international assets and strive to maintain a balanced geographic and political risk profile. We also maintain a geographical diversity of production mix among crude oil, US natural gas, and international natural gas.

Financial and Operating Results During 2010, the US and other economies resumed growth which had been interrupted by the 2008 global financial crisis and associated recession. Although growth has resumed, it has been modest and at an unsteady rate. Commodity prices were volatile, but crude oil prices showed improvement from increased demand. Higher crude oil prices combined with higher sales volumes resulted in significant increases in our net income and cash flows for 2010. In addition, we increased our capital spending program over our 2009 level, advanced our major development projects, and completed a significant property acquisition, while maintaining a strong balance sheet and ample liquidity levels.

Our 2010 financial results included the following:

- net income of $725 million as compared with a net loss of $131 million for 2009;
- net gain on asset sales of $113 million as compared with $22 million for 2009;
- asset impairment charges of $144 million as compared with $604 million for 2009;
- gain on commodity derivative instruments of $157 million (including unrealized mark-to-market gain of $70 million) as compared with $110 million loss on commodity derivative instruments (including unrealized mark-to-market loss of $606 million) for 2009;
- diluted earnings per share of $4.10, as compared with diluted loss per share of $0.75 for 2009;
- cash flows provided by operating activities of $1.9 billion, as compared with $1.5 billion in 2009;
- capital spending of $2.3 billion (including $458 million for the Central DJ Basin asset acquisition) as compared with $1.3 billion in 2009;
- refocus of our development activities toward more liquids-rich areas, as opposed to dry gas areas, in response to depressed US natural gas prices, resulting in an increase in our liquids production as compared with 2009;
- proceeds from property sales of $564 million as compared with $3 million in 2009;
- ending cash and cash equivalents balance of $1.1 billion at December 31, 2010, as compared with $1 billion at December 31, 2009;
- net decrease of $32 million principal amount of debt, excluding $266 increase in FPSO accrual, from December 31, 2009;
- total liquidity of $2.8 billion at December 31, 2010, consisting of year-end cash balance plus funds available under credit facility, as compared with $2.7 billion at December 31, 2009; and
- year-end ratio of debt-to-book capital of 25% (including FPSO lease accrual), unchanged from December 31, 2009.

Significant operational highlights included the following:

Overall

- recorded proved reserves of nearly 1.1 billion Boe at December 31, 2010, a 33% increase from year-end 2009; and
- a 3% increase in total sales volumes as compared with 2009.

Onshore United States

- Central DJ Basin asset acquisition which enhanced our largest onshore US property in Wattenberg;
- increased Central DJ Basin position to over 830,000 net acres;
- drilled and completed 21 horizontal wells in the Central DJ Basin Niobrara formation;
- increased Wattenberg production volumes to a record 54.2 MBoe/d; and
- closed on the sale of certain Mid-Continent and Illinois Basin assets for $552 million.

Deepwater Gulf of Mexico

- successfully adjusted our Gulf of Mexico business plan in response to the Deepwater Moratorium;
- finalized well completion work at Isabela and Santa Cruz at the Galapagos project in the deepwater Gulf of Mexico; and
- awarded 11 deepwater lease blocks from the Central Gulf of Mexico lease sale 213.

International

- sanctioned the development plan for the Tamar project, offshore Israel;
- sanctioned the development plan for the Alen project, offshore Equatorial Guinea;
- major exploration discovery at Leviathan, offshore Israel;
- completed two new Mari-B wells, offshore Israel, maintaining field deliverability of 600 MMcf/d, gross; and
- concluded field drilling and initiated completions at Aseng, offshore Equatorial Guinea.

Acquisitions and Divestitures On March 1, 2010, we closed the acquisition of substantially all of the US Rockies upstream assets of Petro-Canada Resources (USA) Inc. and Suncor Energy (Natural Gas) America Inc. for cash of $458 million, plus liabilities assumed. The transaction increased our presence in Wattenberg and further expanded our opportunity in the Central DJ Basin. The acquisition added approximately 10 MBoe/d to our daily production base and approximately 46 MMBoe of proved reserves, expanding our acreage and development opportunity in the area. A majority of the reserves are within Wattenberg, where our largest onshore US asset is located.

On August 12, 2010, we closed the sale of certain non-core assets in the Mid-Continent and Illinois Basin areas for sales proceeds of $552 million and recorded a pre-tax gain of $110 million on the sale. The properties represented approximately 5.7 MBoe/d of production and 32 MMBoe of reserves.

The government of Ecuador terminated our PSC for Block 3 (100% working interest) on November 25, 2010. A recently enacted hydrocarbon law required that certain existing PSCs be renegotiated as service contracts by November 23, 2010. A service contract on Block 3 has not been negotiated. We are continuing to work with the government of Ecuador to resolve this matter. The net book value of our investment in Ecuador was approximately $66 million at December 31, 2010.

See Item 8. Financial Statements and Supplementary Data – Note 3. Acquisitions and Divestitures.

Sales Volumes On a BOE basis, total sales volumes were 3% higher in 2010 as compared with 2009. Our mix of sales volumes was 39% global liquids, 30% international natural gas with long-term pricing contracts, and 31% US natural gas. In the US, production was higher in the onshore areas due to record production in Wattenberg primarily due to the recent acquisition of producing properties and continued field development. The Deepwater Moratorium had no impact on deepwater Gulf of Mexico production for 2010. However, it is likely to have an impact on future production. See Deepwater Gulf of Mexico, below.

In Israel, there was an increase in demand for natural gas to produce electricity due to warmer weather, and a higher percentage of the demand was met by production from our properties. There was also an increase in crude oil volumes lifted in the North Sea. These increases were partially offset by a decrease in crude oil volumes lifted in Equatorial Guinea.

Commodity Price Changes and Hedging The liquids (crude oil) market strengthened during 2010, benefiting from the global economic recovery. As a result, 2010 average realized crude oil prices were significantly higher than those we experienced in 2009. However, the domestic natural gas market remains weak primarily due to an abundant supply. Natural gas prices remain volatile and prices are still low compared to prices realized in 2006 - 2008. See Item 6. Selected Financial Data.

We have hedged approximately 50% of our expected global crude oil production and 57% of our expected domestic natural gas production for 2011. We use mark-to-market accounting for our commodity derivative instruments and recognize all gains and losses on such instruments in earnings in the period in which they occur. Derivative gains and losses included in net income include both pre-tax realized gains and losses and pre-tax, unrealized, non-cash gains or losses which are due to the change in the mark-to-market value of our commodity contracts related to production in future periods. Unrealized mark-to-market gains or losses recognized in the current period will be realized in the future when they are cash settled in the month that the related production occurs. The amount of gain or loss actually realized may be more or less than the amount of unrealized mark-to-market gain or loss previously reported. The use of mark-to-market accounting adds volatility to our net income. See Item 8. Financial Statements and Supplementary Data – Note 10. Derivative Instruments and Hedging Activities.

Asset Impairment Charges During 2010, we recorded asset impairment charges of $144 million related to some of our oil and gas assets. The impairments were due to declines in natural gas prices, recent drilling results, the classification of non-core onshore US assets as held-for-sale, and a change in the intended use of certain assets. Future decreases in forward natural gas prices could result in significant additional impairment charges. See *Potential for Future Asset Impairments* below and Item 8. Financial Statements and Supplementary Data – Note 4. Asset Impairments.

OPERATING OUTLOOK

2011 Production Our expected crude oil, natural gas and NGL production for 2011 may be impacted by several factors including:

- ongoing development activity in Wattenberg and horizontal drilling in the Niobrara formation;
- overall level and timing of capital expenditures which, as discussed below, and dependent upon our drilling success, are expected to maintain our near-term production volumes;
- natural field decline in the deepwater Gulf of Mexico, Gulf Coast and Mid-Continent areas of our US operations and in the North Sea;
- impact of potential legislative and regulatory changes on deepwater Gulf of Mexico operating and safety standards for producing activities due to the Deepwater Horizon Incident;
- variations in sales volumes of natural gas from the Alba field in Equatorial Guinea related to potential downtime at the methanol, LPG and/or LNG plants;
- Israeli demand for electricity which affects demand for natural gas as fuel for power generation, market growth and competing deliveries of natural gas from Egypt;
- variations in North Sea sales volumes due to potential FPSO downtime and timing of liftings;
- potential hurricane-related volume curtailments in the deepwater Gulf of Mexico and Gulf Coast areas;
- potential winter storm-related volume curtailments in the Rocky Mountain area of our US operations;
- potential pipeline and processing facility capacity constraints in the Rocky Mountain area of our US operations;
- impact of purchases of producing properties;
- timing of significant project completion and initial production; and
- impact of divestments of non-core, non-strategic operating assets.

2011 Capital Investment Program Our total capital investment program for 2011 is estimated at $2.7 billion, with investment split relatively evenly between the US and international operations. Approximately 42% of the program is going toward major project developments, 18% for exploration and appraisal activities, and the remaining 40% for ongoing maintenance and near-term growth opportunities. Major project investments include our development activities in the deepwater Gulf of Mexico, West Africa, Eastern Mediterranean, and our horizontal program in the Central DJ Basin.

In addition to the capital investment program discussed above, we expect to accrue approximately $70 million for the Aseng FPSO capital lease obligation.

We expect that the 2011 capital investment program will be funded from cash flows from operations, cash on hand, and borrowings under our revolving credit facility and/or other financing such as an issuance of long-term debt. See Liquidity and Capital Resources – Financing Activities – *Interest Rate Locks*.

We will evaluate the level of capital spending throughout the year based on the following factors, among others:

- commodity prices;
- cash flows from operations;
- permitting activity in the deepwater Gulf of Mexico;
- potential changes in the fiscal regimes of the US and other countries in which we operate;
- impact of implementation of the Dodd-Frank Act on our business practices, including, among others, requirements regarding the posting of cash collateral in hedging transactions;
- drilling results;
- property acquisitions and divestitures; and
- potential legislative or regulatory changes regarding the use of hydraulic fracturing.

Exploration Program We have significant remaining exploration potential, primarily in the onshore US, deepwater Gulf of Mexico, offshore West Africa, Eastern Mediterranean and other international areas where we hold acreage positions. In December 2010, we announced a significant natural gas discovery at the Leviathan prospect, offshore

Israel, our largest discovery to date. We are continuing to drill at the Leviathan-1 well in order to evaluate two additional intervals for the existence of other hydrocarbons. Results from the deeper tests, which have a low chance of success, are expected over the next couple of months.

Pending permit approval, we plan to resume exploratory drilling at Deep Blue and Santiago and appraisal drilling at Gunflint in the deepwater Gulf of Mexico in 2011. In addition, we are planning further exploratory drilling offshore West Africa and in the Eastern Mediterranean.

Exploration activity, particularly offshore, requires significant capital investment. We do not always encounter commercially productive reservoirs through our drilling operations and, as a result, could incur significant dry hole cost. We are planning an active exploratory drilling program in 2011. As a result, dry hole cost could be significant.

Major Development Project Inventory Our current inventory of major development projects includes the Central DJ Basin, Galapagos, Gunflint, Tamar, Aseng, Alen, Diega/Carmen and other West Africa gas projects. These projects will require significant capital investments. For example, total development costs for the Aseng oil project, excluding costs related to a leased FPSO, are estimated at $1.3 billion ($530 million for our share). Total development costs for the Tamar natural gas project are estimated at $3.0 billion ($1.1 billion for our share).

We expect to spend approximately $1.1 billion in 2011 for major development projects. We plan to fund these projects from cash flows from operations, cash on hand, and borrowings under our revolving credit facility and/or other financing such as a public debt offering. First production from our major offshore development projects is targeted to occur when Galapagos begins to produce in late 2011 or early 2012. First production at Aseng is targeted for 2012, and first production at Tamar is targeted for late 2012 or early 2013. Once these three projects begin producing, we expect to begin generating sufficient amounts of cash flow to self-fund the remaining discovered major projects investments.

As operator on the majority of our development projects, we pay gross joint venture expenses and make cash calls on our nonoperating partners for their respective shares of joint venture costs. These projects are capital cost intensive and a nonoperating partner may experience a delay in obtaining financing for its share of the joint venture costs. In addition, some of our joint venture partners may not be as creditworthy as we are and may experience liquidity problems. This could result in a delay in our receiving reimbursement of joint venture costs and increases our counterparty credit risk. See Item 1A. Risk Factors – *Failure to effectively execute our major development projects could result in significant delays and/or cost over-runs, damage to our reputation, limitations on our growth and negative effects on our operating results* and *We are exposed to counterparty credit risk as a result of our receivables, hedging transactions, and cash investments.*

Potential for Future Asset Impairments The domestic natural gas market remains weak. A decrease in forward natural gas prices during 2011 could result in significant impairment charges. Our Piceance Basin (western Colorado) and Shattuck (western Oklahoma) properties have significant natural gas reserves and therefore are sensitive to declines in natural gas prices. These assets, which have a combined net book value of approximately $923 million at December 31, 2010, are at risk of impairment if future NYMEX Henry Hub natural gas prices experience further decline. The cash flow model that we use to assess proved properties for impairment includes numerous assumptions, such as management's estimates of future oil and gas production and commodity prices, market outlook on forward commodity prices, operating and development costs, and discount rates. All inputs to the cash flow model must be evaluated at each date of estimate. However, a decrease in forward natural gas prices alone could result in a significant impairment for our properties that are sensitive to declines in natural gas prices. See Item 8. Financial Statements and Supplementary Data – Note 4. Asset Impairments.

Deepwater Gulf of Mexico The Deepwater Horizon Incident will have a significant impact on our industry, most likely in the areas of development cycle time, which is the length of time it takes for a project to progress from first discovery to first production, and in higher expected operating and development costs. Longer development cycle times result from additional regulatory reviews and slower permitting processes and oversight. We are currently experiencing significant delay in the processing and approval of our permits and cannot predict when necessary plans and permits will be approved for our planned future drilling activity. Longer development cycle time could potentially result in lower rates of return on our investments and a negative impact on cash flows from our projects.

Continued delay and disruption in the regulatory and permitting process could potentially have a negative impact on our planned exploration program for the deepwater Gulf of Mexico. A significant delay or cancellation of planned exploratory activities reduces our longer term ability to find and develop new reserves, resulting in a negative impact on production over time. To the extent current exploration activities are significantly delayed, a gap could occur in our future production growth late in the decade with a negative impact on our operating results and cash flows.

Despite the Deepwater Moratorium, we were able to move forward on our major development project at Galapagos and are targeting late 2011 or early 2012 for the start-up. At Gunflint, we are reviewing host platform options including: subsea tieback to existing third-party host, procurement and modification of existing platform, and new construction. If we choose to connect to an existing third-party host, the project could have an accelerated completion schedule, thereby potentially absorbing time lost due to the Deepwater Moratorium and permit-related delay. We are targeting 2015 for the start-up of Gunflint. We currently believe there will be no significant impact on the total cash flows we expect to derive from these two projects.

The deepwater Gulf of Mexico is one of our key operating areas. Our net investment in the deepwater Gulf of Mexico was approximately $911 million at December 31, 2010. Notwithstanding our progress at Galapagos and Gunflint, we are adjusting our business model going forward to account for longer development cycle time and higher expected operating and development costs and expect that future projects could be less profitable. In addition, higher development and operating costs could ultimately impact the fair values of our properties in the deepwater Gulf of Mexico.

See also Items 1 and 2. Business and Properties – Deepwater Horizon Incident, Item 1A. Risk Factors – *Our operations in the deepwater Gulf of Mexico, as well as onshore US and international locations, could be adversely affected by future changes in laws and regulations which may occur as a result of the Deepwater Horizon Incident*, and Liquidity and Capital Resources – Risk and Insurance Program below.

Recent Developments in Israel In 2010, the Finance Minister of Israel established an advisory committee to study the country's fiscal policy as it relates to the upstream crude oil and natural gas sector. In January 2011, the Finance Ministry advisory committee issued its final recommendations including cancellation of currently-existing tax incentives, including the depletion allowance, and imposition of a special levy ranging from 20% to 50% on oil and gas profits after a return on investment has been achieved. At this time we are uncertain of the final outcome of these proposals which must be legislated by Israel's Parliament.

We have significant operations offshore Israel including the Mari-B field, a major ongoing development project at Tamar, and a recent exploration success at the Leviathan prospect. Each of these represents a substantial capital investment. At year-end 2010, approximately 28% of our total proved reserves were located in Israel.

A significant change in Israel's fiscal regime could, among other things, disrupt our business plan for one of our key operating areas, have a negative impact on the ability of us and/or our partners to obtain project financing, cause delay in plans for development in the area, reduce the amount of proved reserves we record, impede our ability to compete with imports of natural gas from Egypt, reduce the profitability of our Tamar project, reduce the cash flows from our Mari-B project if the changes are retroactive, and/or adversely affect the price of our common stock. See Item 1A. Risk Factors – *Our operations may be adversely affected by changes in the fiscal regimes of the countries in which we operate.*

Climate Change Climate change has become the subject of an important public policy debate. While climate change remains a complex issue, scientific research suggests that an increase in greenhouse gas emissions (GHGs) may pose a risk to society and the environment. The oil and natural gas exploration and production industry is a source of certain GHGs, namely carbon dioxide and methane, and future restrictions on the combustion of fossil fuels or the venting of natural gas could have a significant impact on our future operations. We are actively monitoring the following climate change related issues:

Impact of Legislation and Regulation The commercial risk associated with the exploration and production of fossil fuels lies in the uncertainty of government-imposed climate change legislation, including cap and trade schemes, and regulations that may affect us, our suppliers, and our customers. The cost of meeting these requirements may have an adverse impact on our financial condition, results of operations and cash flows, and could reduce the demand for our products.

Climate change legislation and regulations have been adopted by many foreign countries and states in the US; however, legislation and regulations have not been enacted in all of the foreign countries where we operate or at the federal level in the US. The status of development of many state and federal climate change regulatory initiatives in areas where we operate makes it difficult to predict with certainty the future impact on us, including accurately estimating the related compliance costs that we may incur.

The EPA issued regulations requiring monitoring and reporting of GHG emissions from petroleum and natural gas systems. This action does not require control of GHGs. These new US, and other international, regulations may affect our operations by potentially increasing operating costs for maintaining our facilities, compliance costs for managing new GHG regulatory programs and capital costs for installing new GHG emission controls.

Impact of International Accords The Kyoto Protocol to the United Nations Framework Convention on Climate Change (Protocol) went into effect in February 2005 and requires all industrialized nations that ratified the Protocol to reduce or limit GHG emissions to a specified level by 2012. The US has not ratified the Protocol. The US, Israel, and the European Union have participated in international discussions to develop a treaty or other agreement to require reductions in GHG emissions after 2012 and have indicated that they wish to associate themselves with the Copenhagen Accord, which includes a non-binding commitment to reduce GHG emissions. In December 2010, the annual conference of parties reconvened in Cancun, Mexico to continue pursuing the global accord, committing countries to cut GHG emissions. At this time, no agreement between participating countries has been reached.

While no specific new international climate change accord has been adopted that would affect our operating locations, the current state of development of many initiatives makes it difficult to assess the timing or effect of any pending discussions of future accords or predict with certainty the future costs that we may incur in order to comply with future international treaties or regulations.

Indirect Consequences of Regulation or Business Trends We believe there are both risks and opportunities arising from the global response to potential climate change. See Items 1 and 2. Business and Properties – Regulation and the following risk factors listed in Item 1A. Risk Factors –

- *We are subject to increasing governmental regulations and environmental risks that may cause us to incur substantial costs;*
- *Increased regulation of business practices could result in increased operating costs; and*
- *The adoption of GHG emission or other environmental legislation could result in increased operating costs, create delays in our obtaining air pollution permits for new or modified facilities, and reduce demand for the crude oil and natural gas we produce.*

In terms of opportunities, the regulation of GHGs and introduction of formal technology incentives, such as enhanced oil recovery, carbon sequestration and low carbon fuel standards, could benefit us in a variety of ways.

First, approximately 61% of our 2010 total consolidated production was natural gas. GHG emissions regulation could reduce the demand for the crude oil and natural gas we produce. At the same time, the burning of natural gas produces lower levels of emissions than other readily available fossil fuels such as oil and coal. Therefore, the use of natural gas may increase should the use of other fossil fuels decrease due to GHG emissions regulation. Furthermore, should renewable resources, such as wind or solar power become more prevalent, natural gas-fired electric plants may provide an alternative backup to maintain consistent electricity supply.

Second, market-based incentives for the capture and storage of carbon dioxide in underground reservoirs, particularly in oil and natural gas reservoirs, could benefit us through the potential to obtain GHG allowances or offsets from or government incentives for the sequestration of carbon dioxide.

Finally, as the EPA's new GHG standards for light duty vehicles become effective in 2011, natural gas may prove to be a more attractive transportation fuel. This may increase the market demand for natural gas.

Physical Impacts of Climate Change on our Costs and Operations There has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornados and snow or ice storms, as well as rising sea levels. Extreme weather conditions increase our costs, and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations, particularly our offshore operations. See Item 1A. Risk Factors – *We have insufficient insurance to cover all of the risks we face, which could result in significant financial exposure.*

RESULTS OF OPERATIONS

Selected financial information is as follows:

	Year Ended December 31,		
	2010	2009	2008
(millions, except per share)			
Total Revenues	$ 3,022	$ 2,313	$ 3,901
Total Operating Expenses	2,070	2,371	2,266
Operating Income (Loss)	952	(58)	1,635
Total Other (Income) Expense	(79)	206	(426)
Income (Loss) Before Income Taxes	1,031	(264)	2,061
Net Income (Loss)	725	(131)	1,350
Earnings (Loss) Per Share			
Basic	$ 4.15	$ (0.75)	$ 7.83
Diluted	4.10	(0.75)	7.58

Factors contributing to the increase in income (loss) before income taxes in 2010 as compared with 2009 included the following:

- $709 million increase in total revenues due primarily to higher commodity prices;
- $460 million decrease in asset impairment charges;
- $91 million increase in net gain on asset sales; and
- $157 million mark-to-market gain on commodity derivative instruments as opposed to a $110 million mark-to-market loss in 2009;

offset by:

- $45 million increase in total production expense;
- $101 million increase in exploration expense; and
- $67 million increase in DD&A expense.

Factors contributing to the decrease in income (loss) before income taxes in 2009 as compared with 2008 included the following:

- $1.6 billion decrease in total revenues due primarily to lower commodity prices;
- $110 million mark-to-market loss on commodity derivative instruments as compared with a $440 million mark-to-market gain in 2008;
- $310 million increase in asset impairment charges;
- $90 million decrease in income from equity investees; and
- $25 million increase in DD&A expense;

offset by:

- $86 million refund of deepwater Gulf of Mexico royalties plus interest of $11 million;
- $69 million decrease in total production expense; and
- $73 million decrease in exploration expense.

See following discussion for explanation of year-to-year changes.

Revenues

Oil, Gas and NGL Sales An analysis of the factors contributing to the changes in revenues from sales of crude oil, natural gas and NGLs from 2008 through 2010 is as follows:

	Crude Oil & Condensate	Natural Gas	NGLs	Total
(millions)				
2008 Sales Revenues	$ 2,101	$ 1,375	$ 175	$ 3,651
Changes due to				
Increase (Decrease) in Sales Volumes	(232)	15	-	(217)
Decrease in Sales Prices Before Hedging	(915)	(655)	(77)	(1,647)
Change in Amounts Reclassified from AOCL	307	(34)	-	273
2009 Sales Revenues	1,261	701	98	2,060
Changes due to				
Increase in Sales Volumes	48	5	40	93
Increase in Sales Prices Before Hedging	447	129	65	641
Change in Amounts Reclassified from AOCL	39	(1)	-	38
2010 Sales Revenues	$ 1,795	$ 834	$ 203	$ 2,832

Average daily sales volumes and average realized sales prices were as follows:

	Sales Volumes				Average Realized Sales Prices		
	Crude Oil & Condensate (MBbl/d)	Natural Gas (MMcf/d)	NGLs (MBbl/d)	Total (MBoe/d) (1)	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)	NGLs (Per Bbl)
Year Ended December 31, 2010							
United States (2)	39	400	14	119	$ 75.03	$ 4.17	$ 41.21
Equatorial Guinea (3) (4)	11	226	-	49	78.44	0.27	-
Israel	-	130	-	22	-	4.03	-
North Sea	10	6	-	11	80.24	5.35	-
Ecuador (5)	-	25	-	4	-	-	-
China	4	-	-	4	75.15	-	-
Total Consolidated Operations	64	787	14	209	76.46	3.00	41.21
Equity Investees (6)	2	-	5	7	77.98	-	53.68
Total	66	787	19	216	$ 76.50	$ 3.00	$ 44.90
Year Ended December 31, 2009							
United States (2)	37	397	10	113	$ 55.19	$ 3.61	$ 27.96
Equatorial Guinea (3) (4)	14	239	-	54	55.94	0.27	-
Israel	-	114	-	19	-	3.47	-
North Sea	7	5	-	8	59.51	5.75	-
Ecuador	-	26	-	4	-	-	-
China	4	-	-	4	54.40	-	-
Total Consolidated Operations	62	781	10	202	55.76	2.54	27.96
Equity Investees (6)	2	-	6	8	59.51	-	36.03
Total	64	781	16	210	$ 55.87	$ 2.54	$ 31.20
Year Ended December 31, 2008							
United States (2)	40	395	9	116	$ 75.53	$ 8.12	$ 50.15
Equatorial Guinea (3) (4)	15	206	-	49	88.95	0.27	-
Israel	-	139	-	23	-	3.10	-
North Sea	10	5	-	11	100.56	10.54	-
Ecuador	-	22	-	4	-	-	-
China	4	-	-	4	82.66	-	-
Total Consolidated Operations	69	767	9	207	82.60	5.04	50.15
Equity Investees (6)	2	-	6	8	96.77	-	58.81
Total	71	767	15	215	$ 82.96	$ 5.04	$ 53.45

(1) Natural gas is converted on the basis of six Mcf of gas per one barrel of oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency. Given recent commodity price disparities, the price for a barrel of oil equivalent for natural gas is less than the price for a barrel of oil.

(2) Average realized crude oil and condensate prices reflect reductions of $1.32 per Bbl for 2010, $2.13 per Bbl for 2009, and $22.06 per Bbl for 2008 from hedging activities. Average realized natural gas prices reflect a decrease of $0.01 per Mcf for 2010 and an increase of $0.23 per Mcf for 2008 from hedging activities. The effect of hedging activities on the average realized natural gas price for 2009 was de minimis. These price increases and reductions resulted from hedge gains and losses that had been previously deferred AOCL. All hedge gains or losses relating to US production had been reclassified to revenues by December 31, 2010.

(3) Average realized crude oil and condensate prices reflect reductions of $5.57 per Bbl for 2009 and $7.59 per Bbl for 2008 from hedging activities. These price reductions resulted from hedge losses that had been previously deferred in AOCL. All hedge gains or losses relating to Equatorial Guinea production had been reclassified to revenues by December 31, 2009.

(4) Natural gas from the Alba field in Equatorial Guinea is under contract for $0.25 per MMBtu to a methanol plant, an LPG plant and an LNG plant. The methanol and LPG plants are owned by affiliated entities accounted for under the equity method of accounting.

(5) Includes production through November 24, 2010. Our Block 3 PSC was terminated by the Ecuadorian government on November 25, 2010. Intercompany natural gas sales were eliminated for accounting purposes. Electricity sales are included in other revenues. See Termination of Ecuador PSC, above.

(6) Volumes represent sales of condensate and LPG from the Alba Plant in Equatorial Guinea. See Income from Equity Method Investees below.

If the realized gains and losses on commodity derivative instruments, which are included in (gain) loss on commodity derivative instruments in our consolidated statements of operations, had been included in oil and gas revenues, the effect on average realized prices would have been as follows:

	Commodity Price Increase (Decrease)					
	2010		2009		2008	
	Crude Oil & Condensate	Natural Gas	Crude Oil & Condensate	Natural Gas	Crude Oil & Condensate	Natural Gas
	(Per Bbl)	(Per Mcf)	(Per Bbl)	(Per Mcf)	(Per Bbl)	(Per Mcf)
Year Ended December 31,						
United States	$ (0.65)	$ 0.76	$ 12.26	$ 1.73	$ (3.85)	$ (0.07)
Equatorial Guinea	(3.41)	-	15.36	-	(2.97)	-
Total Consolidated Operations	(1.00)	0.40	10.86	0.91	(2.85)	(0.04)
Total	(0.97)	0.40	10.55	0.91	(2.77)	(0.04)

Crude Oil and Condensate Sales Revenues from crude oil and condensate sales increased by a net $534 million, or 42%, in 2010 as compared with 2009 due to the following:

- a 37% increase in total consolidated average realized prices due to increased demand resulting from the global economic recovery;
- increased production due to ongoing development activity in the Central DJ Basin, including horizontal drilling in the Niobrara formation;
- additional production from the Central DJ Basin asset acquisition in March 2010;
- crude oil production from a Swordfish sidetrack oil well that commenced production first quarter 2010;
- renewed production from Ticonderoga in the deepwater Gulf of Mexico which was off-line first quarter 2009 as a result of hurricane damage to third-party processing and pipeline facilities; and
- an increase in North Sea sales volumes primarily as a result of increased deliverability at the Dumbarton complex, which included the addition of two Lochranza wells in 2010;

partially offset by

- a decrease in onshore US volumes due to the divestment of mature oil assets;
- a decrease in deepwater Gulf of Mexico volumes due to natural field decline and third party downstream facility constraints;
- a decrease in onshore US volumes due to natural field decline in the Mid-Continent and Gulf Coast areas; and
- a decrease in Equatorial Guinea sales volumes due to the planned shut-down of the Alba field for facilities maintenance and repair during 2010 and the timing of liftings.

Revenues from crude oil sales decreased by a net $840 million, or 40%, in 2009 as compared with 2008 due to the following:

- a 32% decline in consolidated average realized prices due to the decreased demand for oil resulting from the economic slowdown;
- natural field decline in the deepwater Gulf of Mexico and Gulf Coast area;
- the shut-in of Ticonderoga in the deepwater Gulf of Mexico until August 2009 after being offline due to Hurricane Ike in 2008;
- a decrease in Equatorial Guinea sales volumes due to timing of liftings; and
- a decrease in North Sea sales volumes due to natural field decline and downtime beginning in mid-August at the Dumbarton field due to FPSO repairs;

partially offset by

- increased production due to ongoing development activity in the Central DJ Basin.

Crude oil revenues include amounts reclassified from AOCL related to commodity derivative instruments which were accounted for as cash flow hedges through December 31, 2007. Amounts included decreases of $19 million in 2010, $58 million in 2009, and $365 million in 2008. At December 31, 2010, there were no further amounts related to commodity derivative instruments remaining to be reclassified from AOCL to crude oil revenues. See Item 8. Financial Statements and Supplementary Data – Note 10. Derivative Instruments and Hedging Activities.

Natural Gas Sales Revenues from natural gas sales increased by a net $133 million, or 19%, in 2010 as compared with 2009 due to the following:

- an increase in total consolidated and US average realized prices due to increased demand resulting from the economic recovery;
- an increase in Israel average realized prices under the terms of a natural gas sales contract entered into in the third quarter of 2009;
- increased production due to ongoing development activity in the Central DJ Basin, including the horizontal drilling in the Niobrara formation;
- additional production from the Central DJ Basin asset acquisition in March 2010; and

- an increase in Israel sales volumes due to an increase in demand for our natural gas driven by increased electricity production due to warmer weather and lower levels of competitor natural gas imports from Egypt;

partially offset by

- a decrease in Equatorial Guinea sales volumes due to the planned shut-down of the Alba field for facilities maintenance and repair; and
- natural field decline in the deepwater Gulf of Mexico, Gulf Coast and Mid-Continent areas.

Revenues from natural gas sales decreased by a net $674 million, or 49%, in 2009 as compared with 2008 due the following:

- a 50% decline in consolidated average realized prices due to increased supply and decreased demand for natural gas resulting from the economic slowdown;
- natural field decline in the deepwater Gulf of Mexico, Gulf Coast and Mid-Continent areas;
- a decrease in Israel sales volumes due to customer power plant downtime, warmer than normal winter weather conditions, and competing natural gas sales from Egypt; and
- lower average realized prices in the North Sea;

partially offset by

- increased production from Wattenberg, Piceance Basin and Western Oklahoma areas of our US operations;
- an increase in sales volumes to the LNG plant in West Africa; and
- an increase in average realized sales prices in Israel due to a new natural gas sales contract.

Natural gas revenues include amounts reclassified from AOCL related to commodity derivative instruments which were accounted for as cash flow hedges through December 31, 2007. Amounts included a decrease of $1 million in 2010 and an increase of $34 million in 2008. At December 31, 2010, there were no further amounts related to commodity derivative instruments remaining to be reclassified from AOCL to natural gas revenues. See Item 8. Financial Statements and Supplementary Data – Note 10. Derivative Instruments and Hedging Activities.

NGL Sales Most of our US NGL production is from Wattenberg and deepwater Gulf of Mexico.

NGL sales revenues increased $105 million during 2010 as compared with 2009 due to an increase in sales volumes from ongoing development activity in the Central DJ Basin, including horizontal drilling in the Niobrara formation, as well as an increase in consolidated average realized prices which benefited from increased demand resulting from the global economic recovery.

NGL sales revenues decreased $77 million during 2009 as compared with 2008 due to the decrease in average realized prices resulting from the economic slowdown.

Income from Equity Method Investees We have a 45% interest in AMPCO, which owns and operates a methanol plant and related facilities. We also have a 28% interest in Alba Plant, which owns and operates an LPG processing plant. The plants and related facilities are located in Equatorial Guinea. We account for investments in entities that we do not control but over which we exert significant influence using the equity method of accounting.

Our share of operations of equity method investees was as follows:

	Year Ended December 31,		
	2010	2009	2008
Net Income (in millions)			
AMPCO and Affiliates	$ 29	$ 18	$ 56
Alba Plant	89	66	118
Dividends (in millions)			
AMPCO and Affiliates	44	29	65
Alba Plant	95	63	156
Sales Volumes			
Methanol (MMgal)	129	145	119
Condensate (MBbl/d)	2	2	2
LPG (MBbl/d)	5	6	6
Average Realized Prices			
Methanol (per gallon)	$ 0.84	$ 0.60	$ 1.25
Condensate (per Bbl)	77.98	59.51	96.77
LPG (per Bbl)	53.68	36.03	58.81

AMPCO and Affiliates Net income from AMPCO and affiliates increased in 2010 as compared with 2009 due to an increase in average realized methanol prices from increased demand due to the global economic recovery. During fourth quarter 2010, the methanol plant successfully completed a major turnaround in 31 days. Production resumed on October 30, 2010.

Net income from AMPCO and affiliates decreased in 2009 as compared with 2008 due to the significant decrease in the average realized price for methanol. The price decrease was the result of an oversupply of methanol and the impact of the economic slowdown. Methanol sales volumes increased as there was minimal down time for repairs as compared with 2008.

Alba Plant Net income from Alba Plant increased in 2010 as compared with 2009 due to an increase in average realized condensate and LPG prices from increased demand due to the global economic recovery.

Net income from Alba Plant decreased in 2009 as compared with 2008 due to significant decreases in average realized prices for condensate and LPG. The price decrease was the result of decreases in liquids prices and the impact of the economic slowdown.

Other Revenues Other revenues were as follows:

	Year Ended December 31,		
	2010	2009	2008
(millions)			
Other Revenues	$ 72	$ 169	$ 76

Other revenues include electricity sales, a refund of deepwater Gulf of Mexico royalties and other revenue items. See Item 8. Financial Statements and Supplementary Data – Note 2. Additional Financial Statement Information.

Costs and Expenses

Production Expense Components of production expense were as follows:

	Total per BOE	Total	United States	Equatorial Guinea	Israel	North Sea	Other Int'l [1]
(millions, except per unit)							
Year Ended December 31, 2010							
Lease Operating Expense [2]	$ 4.93	$ 376	$ 258	$ 43	$ 9	$ 47	$ 19
Production and Ad Valorem Taxes	1.64	125	103	-	-	-	22
Transportation Expense	0.91	69	59	-	-	8	2
Total Production Expense [3]	$ 7.48	$ 570	$ 420	$ 43	$ 9	$ 55	$ 43
Total Production Expense per BOE		$ 7.48	$ 9.69	$ 2.38	$ 1.15	$ 13.37	$ 14.51
Year Ended December 31, 2009							
Lease Operating Expense [2]	$ 5.05	$ 372	$ 258	$ 45	$ 9	$ 43	$ 17
Production and Ad Valorem Taxes	1.28	94	81	-	-	-	13
Transportation Expense	0.80	59	52	-	-	4	3
Total Production Expense [3]	$ 7.13	$ 525	$ 391	$ 45	$ 9	$ 47	$ 33
Total Production Expense per BOE		$ 7.13	$ 9.51	$ 2.30	$ 1.36	$ 17.50	$ 10.27
Year Ended December 31, 2008							
Lease Operating Expense [2]	$ 4.90	$ 371	$ 257	$ 39	$ 9	$ 53	$ 13
Production and Ad Valorem Taxes	2.19	166	135	-	-	-	31
Transportation Expense	0.75	57	49	-	-	7	1
Total Production Expense [3]	$ 7.84	$ 594	$ 441	$ 39	$ 9	$ 60	$ 45
Total Production Expense per BOE		$ 7.84	$ 10.43	$ 2.17	$ 1.07	$ 14.30	$ 15.94

(1) Other international includes China and Argentina (through February 2008).

(2) Lease operating expense includes oil and gas operating costs (labor, fuel, repairs, replacements, saltwater disposal and other related lifting costs) and workover and repair expense.

(3) Consolidated unit rates exclude sales volumes and costs attributable to equity method investees.

Lease Operating Expense Lease operating expense was flat in 2010 as compared with 2009. Changes included following:

- an increase in US production volumes due to ongoing development activity in Central DJ Basin, including horizontal drilling in the Niobrara formation;
- an increase in US production volumes due to the Central DJ Basin asset acquisition; and
- an increase in North Sea lease operating expense due to higher sales volumes;

offset by

- a decrease in Equatorial Guinea lease operating expense due to the planned shut-down of the Alba field for facilities maintenance and repair; and
- the sale of non-core, non-strategic assets in the Mid-Continent and Illinois Basin areas, which had higher lease operating costs.

Lease operating expense remained flat overall in 2009 as compared with 2008. Changes included the following:

- a decrease in lease operating expense due to cost savings initiatives which included reduced workover and repair programs and a reduction of other discretionary spending in our onshore US operations;
- a decrease in lease operating expense due to lower sales volumes in the North Sea, where a higher volume of crude oil was inventoried resulting in a deferral of production cost;

offset by

- an increase in lease operating expense in Equatorial Guinea due to higher contractor costs.

Production and Ad Valorem Tax Expense Production and ad valorem tax expense for 2010 increased as compared with 2009 due to higher commodity prices in the US and China.

Production and ad valorem tax expense for 2009 decreased as compared with 2008 due to reduced proceeds from sales attributable to lower commodity prices and the cessation of production due to the sale of our Argentina assets in 2008.

Transportation Expense Transportation expense increased in 2010 as compared with 2009 due to an increase in crude oil and condensate production in Wattenberg and the use of a new interstate crude oil transportation pipeline system to market production.

Transportation expense increased in 2009 as compared with 2008 due to the start up of a new interstate crude oil transportation pipeline system used to market our Wattenberg production and offset by lower sales volumes in the North Sea.

Unit Rate Per BOE The unit rate of total production expense per BOE increased for 2010 as compared with 2009 primarily due to increases in production and ad valorem taxes and transportation expense.

The unit rate of total production expense per BOE decreased for 2009 as compared with 2008 primarily due to the decline in production and ad valorem taxes.

Oil and Gas Exploration Expense Exploration expense was as follows:

	Total	United States	West Africa (1)	Eastern Mediter-ranean (2)	North Sea	Other Int'l, Corporate (3)
(millions)						
Year Ended December 31, 2010						
Dry Hole Expense	$ 58	$ 54	$ 3	$ -	$ -	$ 1
Seismic	102	51	5	11	-	35
Staff Expense	69	10	6	2	3	48
Other	16	15	-	-	-	1
Total Exploration Expense	$ 245	$ 130	$ 14	$ 13	$ 3	$ 85
Year Ended December 31, 2009						
Dry Hole Expense	$ 11	$ 8	$ 3	$ -	$ -	$ -
Seismic	62	47	-	15	-	-
Staff Expense	65	13	10	1	2	39
Other	6	6	-	-	-	-
Total Exploration Expense	$ 144	$ 74	$ 13	$ 16	$ 2	$ 39
Year Ended December 31, 2008						
Dry Hole Expense	$ 84	$ 42	$ 1	$ -	$ 8	$ 33
Seismic	57	50	-	3	4	-
Staff Expense	62	14	7	1	5	35
Other	14	13	-	-	1	-
Total Exploration Expense	$ 217	$ 119	$ 8	$ 4	$ 18	$ 68

(1) West Africa includes Equatorial Guinea and Cameroon.

(2) Eastern Mediterranean includes Israel and Cyprus.

(3) Other international, corporate includes China and new ventures.

Oil and gas exploration expense for 2010 increased by $101 million, or 70%, as compared with 2009. US dry hole expense was associated with the Double Mountain exploration well in the deepwater Gulf of Mexico, which found noncommercial quantities of hydrocarbons. Seismic expenditures related to the Central Gulf of Mexico lease sale, and the acquisition of 3-D seismic information for offshore Israel, Cameroon, Nicaragua, and France.

Exploration expense for 2009 decreased by $73 million, or 34%, as compared with 2008. The decrease was almost entirely related to the decrease in dry hole expense as a result of our exploration successes in the deepwater Gulf of Mexico, Israel and Equatorial Guinea.

Exploration expense included stock-based compensation expense of $10 million in 2010, $9 million in 2009, and $1 million in 2008.

Depreciation, Depletion and Amortization Expense Depreciation, depletion and amortization (DD&A) expense was as follows:

	Year Ended December 31,		
	2010	2009	2008
(millions, except unit rate)			
United States	$ 719	$ 689	$ 646
Equatorial Guinea	39	38	34
Israel	22	20	24
North Sea	64	34	55
Other International, Corporate, and Other	39	35	32
Total DD&A Expense [1]	$ 883	$ 816	$ 791
Unit Rate per BOE [2]	$ 11.57	$ 11.08	$ 10.44

(1) DD&A expense includes accretion of discount on asset retirement obligations of $17 million in 2010, $14 million in 2009, and $10 million in 2008.

(2) Consolidated unit rates exclude sales volumes and costs attributable to equity method investees.

Total DD&A expense increased for 2010 as compared with 2009 due to the following:

- higher production in the Central DJ Basin, Piceance Basin and Western Oklahoma areas of our US operations, which have higher DD&A rates relative to production from Equatorial Guinea and Israel;
- ongoing development activity in Central DJ Basin, including horizontal drilling in the Niobrara formation; and
- higher sales volumes in the North Sea;

partially offset by

- lower DD&A expense in the Mid-Continent area which has a reduced net book value resulting from an impairment recorded at the end of 2009; and
- the cessation of DD&A associated with assets sold or held-for-sale during the year.

The unit rate per BOE increased for 2010 as compared with 2009 due to the change in mix of production, including decreases in lower-cost sales volumes from Equatorial Guinea, offset by a lower rate for the Mid-Continent area and the cessation of DD&A associated with assets sold or held-for-sale.

Total DD&A expense increased for 2009 as compared with 2008 due to the following:

- higher production in Wattenberg, Piceance Basin and Western Oklahoma areas of our US operations which have higher DD&A rates relative to production from Equatorial Guinea and Israel which have lower DD&A rates;
- ongoing capital spending in our US operations; and
- negative reserves revisions at December 31, 2009;

partially offset by

- lower sales volumes in the North Sea.

DD&A expense for the fourth quarter of 2009 increased approximately $16 million due to the change in the SEC's pricing rules from the use of year-end prices to 12-month average prices, which resulted in negative reserves revisions at December 31, 2009. See Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Information (Unaudited) for effects of reserves revisions due to lower commodity prices at December 31, 2009.

The unit rate per BOE increased for 2009 as compared with 2008 due to the change in the mix of production, including a decrease in lower-cost volumes from Israel; ongoing capital spending in onshore US areas; and negative reserves revisions related to lower year-end 2009 commodity prices.

General and Administrative Expense General and administrative (G&A) expense was as follows:

	Year Ended December 31,		
	2010	2009	2008
G&A Expense (in millions)	$ 277	$ 237	$ 236
Unit Rate per BOE [1]	$ 3.63	$ 3.22	$ 3.12

(1) Consolidated unit rates exclude sales volumes and costs attributable to equity method investees.

G&A expense increased for 2010 as compared with 2009 primarily due to additional expenses relating to personnel and office costs in support of our major development projects and increased performance incentive compensation. G&A expense remained flat in 2009 as compared with 2008.

G&A expense is impacted by the number of stock-based awards, the market price of our common stock and price volatility, all of which result in a higher fair value of stock-based awards as calculated using the Black-Scholes-Merton option pricing model. G&A included stock-based compensation expense of $39 million in 2010, $36 million in 2009, and $38 million in 2008. See Item 8. Financial Statements and Supplementary Data – Note 15. Stock-Based Compensation.

Net Gain on Asset Sales Net gain on asset sales was as follows:

	Year Ended December 31,		
	2010	2009	2008
(millions)			
Net Gain on Asset Sales	$ (113)	$ (22)	$ (5)

Net gain on asset sales for 2010 includes a $110 million gain on the sale of certain non-core assets in the Mid-Continent and Illinois Basin areas. Net gain on asset sales for 2009 includes a $24 million gain on the sale of our Argentina assets. We sold our Argentina assets in 2008; however, recognition of the gain on the sale was deferred until 2009 when the Argentine government approved the sale. See Item 8. Financial Statements and Supplementary Data – Note 3. Acquisitions and Divestitures.

Asset Impairments Asset impairment expense was as follows:

	Year Ended December 31,		
	2010	2009	2008
(millions)			
Asset Impairments	$ 144	$ 604	$ 294

For information regarding asset impairment charges, see Critical Accounting Policies and Estimates – Impairment of Proved Oil and Gas Properties and Other Investments and Impairment of Unproved Oil and Gas Properties, below, and Item 8. Financial Statements – Note 4. Asset Impairments.

Other Operating Expense, Net Other operating expense, net was as follows:

	Year Ended December 31,		
	2010	2009	2008
(millions)			
Other Operating Expense, Net	$ 64	$ 67	$ 139

Other operating expense, net includes electricity generation expense, rig contract termination expense related to the Deepwater Moratorium, and other items of operating income or expense. See Item 8. Financial Statements and Supplementary Data – Note 2. Additional Financial Statement Information.

(Gain) Loss on Commodity Derivative Instruments Gain (loss) on commodity derivative instruments was as follows:

	Year Ended December 31,		
	2010	2009	2008
(millions)			
(Gain) Loss on Commodity Derivative Instruments	$ (157)	$ 110	$ (440)

We recognize all gains and losses on commodity derivative instruments in earnings in the period in which they occur. See Critical Accounting Policies and Estimates – Derivative Instruments and Hedging Activities, below, and Item 8. Financial Statements and Supplementary Data – Note 10. Derivative Instruments and Hedging Activities and Note 16. Fair Value Measurements and Disclosures.

Interest Expense and Capitalized Interest Interest expense and capitalized interest were as follows:

	Year Ended December 31,		
	2010	2009	2008
(millions, except per unit)			
Interest Expense	$ 139	$ 129	$ 102
Capitalized Interest	(67)	(45)	(33)
Interest Expense, Net	$ 72	$ 84	$ 69
Unit Rate per BOE [1]	$ 0.94	$ 1.13	$ 0.91

[1] Consolidated unit rates exclude sales volumes and costs attributable to equity method investees.

Net interest expense decreased in 2010 as compared with 2009. However, gross interest expense increased due to the higher interest rate associated with our $1 billion 8¼% senior unsecured notes due March 1, 2019, which were outstanding for a full 12 months in 2010 as compared with ten months in 2009. The increase in gross interest expense was more than offset by an increase in the amount of interest capitalized due to higher work in progress amounts related to major long-term projects in the deepwater Gulf of Mexico, West Africa, and Israel.

Net interest expense increased in 2009 as compared with 2008. The increase primarily relates to our $1 billion 8¼% senior unsecured notes due March 1, 2019, which we issued on February 27, 2009. This increase was partially offset by a significant decrease in credit facility interest expense due to a decline in both the average outstanding balance and the average interest rate.

Interest is capitalized on exploration and development projects using an interest rate equivalent to the average rate paid on long-term debt. Capitalized interest is included in the cost of oil and gas assets and amortized with other costs on a unit-of-production basis. The majority of the capitalized interest is related to long lead-time projects in the deepwater Gulf of Mexico (2008 - 2010), West Africa (2008 - 2010) and Israel (2009 - 2010) and numerous projects in the Rocky Mountain area (2008). See Item 8. Financial Statements and Supplementary Data – Note 7. Capitalized Exploratory Well Costs.

Other Non-operating (Income) Expense, Net Other non-operating (income) expense, net was as follows:

	Year Ended December 31,		
	2010	2009	2008
(millions)			
Other Non-operating (Income) Expense, Net	$ 6	$ 12	$ (55)

Other non-operating (income) expense, net includes deferred compensation (income) expense, interest income and other (income) expense, net.

Deferred Compensation (Income) Expense We have assets and liabilities related to a deferred compensation plan. The assets of the deferred compensation plan are held in a rabbi trust and include shares of our common stock and mutual fund investments. At December 31, 2010, approximately 46% of the market value of the assets in the rabbi trust related to our common stock. Increases in the market value of our common stock held in the trust result in the recognition of deferred compensation expense. Decreases in the market value of our common stock held in the trust result in the recognition of deferred compensation income. We recognized deferred compensation expense of $15 million in 2010 and $23 million in 2009, and deferred compensation income of $32 million in 2008. See Item 8. Financial Statements and Supplementary Data – Note 14. Benefit Plans.

Interest Income Interest income includes $3 million and $11 million for 2010 and 2009, respectively, related to interest received on the refund of deepwater Gulf of Mexico royalties.

Income Tax Provision (Benefit) The income tax provision (benefit) was as follows:

	Year Ended December 31,		
	2010	2009	2008
(millions)			
Income Tax Provision (Benefit)	$ 306	$ (133)	$ 711
Effective Rate	30%	50%	35%

Our effective tax rate decreased for 2010 as compared with 2009. For 2010, the effective rate is lower than the federal statutory rate because our income from equity method investees and other permanent differences have the impact of decreasing the effective rate when we have pre-tax income. In addition, during 2010, we reversed a valuation allowance of $28 million that, as of December 31, 2009, had been provided against a deferred tax asset of the same amount for the future foreign tax credits associated with deferred tax liabilities recorded by foreign branch operations. The reversal of the valuation allowance resulted in a reduction in income tax expense. We now believe it is more likely than not that this deferred tax asset will be realized.

Our effective tax rate increased for 2009 as compared with 2008 and is the result of a tax benefit divided by a pre-tax loss. In the case of a loss, our favorable permanent differences, such as income from equity method investees, have the effect of increasing the tax benefit which, in turn, increases the effective rate. During 2009, we repatriated $180 million of accumulated earnings of foreign subsidiaries and used the proceeds for debt repayment and general corporate purposes. The repatriation increased US tax expense by $13 million, of which $9 million was recorded in 2008. Repatriation of additional earnings in the future could result in a decrease in our net income and cash flows.

See Item 8. Financial Statements and Supplementary Data – Note 13. Income Taxes.

PROVED RESERVES

We have historically added reserves through our exploration program, development activities, and acquisition of producing properties. (See Items 1. and 2. Business and Properties). Changes in proved reserves were as follows:

	Year Ended December 31,		
	2010	2009	2008
(MMBOE)			
Proved Reserves Beginning of Year	820	864	880
Revisions of Previous Estimates	5	(64)	(44)
Extensions, Discoveries and Other Additions	360	95	98
Purchase of Minerals in Place	47	2	15
Sale of Minerals in Place	(61)	-	(7)
Production	(79)	(77)	(78)
Proved Reserves End of Year	1,092	820	864

Revisions Revisions of previous estimates represent changes in previous reserves estimates, either upward (positive) or downward (negative), resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors, such as commodity prices, operating costs, or development costs. Revisions included the following:

- Changes for the year ended December 31, 2010 included a positive revision of 43 MMBoe due to higher year-end commodity prices, a negative revision of 30 MMBoe due to reclassifications of proved undeveloped reserves to probable reserves as a result of the SEC's five year development rule, a negative revision of 7 MMBoe due to a change in the likelihood that the Noa field, offshore Israel, will be pursued for development, and a negative revision of 2 MMBoe due to well performance;
- Changes for the year ended December 31, 2009 included negative revisions due to reclassifications of proved undeveloped reserves to probable reserves as a result of the SEC's new five year development rule and lower natural gas prices, partially offset by positive revisions due to higher crude oil prices; and
- Changes for the year ended December 31, 2008 included negative revisions due to lower year-end commodity prices.

Extensions, Discoveries and Other Additions These are additions to proved reserves that result from (1) extension of the proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to discovery and (2) discovery of new fields with proved reserves or of new reservoirs of proved reserves in old fields. Extensions, discoveries and other additions included the following:

- Changes for the year ended December 31, 2010 included an increase of 48 MMBoe, which were primarily driven by the execution of low-risk development projects onshore in Wattenberg and the Rocky Mountain area, an increase of 286 MMBoe related to the initial recording of reserves for the Tamar field offshore Israel, and an increase of approximately 27 MMBoe related to the initial recording of reserves for the Alen field, offshore Equatorial Guinea;
- Changes for the year ended December 31, 2009 included US additions, which were primarily driven by the execution of low-risk development projects onshore in Wattenberg and the Piceance Basin, as well as from the sanctioning of the development plan for Galapagos in the deepwater Gulf of Mexico, and international additions, related primarily to the initial recording of reserves at the Aseng oil project, offshore Equatorial Guinea; and
- Changes for the year ended December 31, 2008 included US additions, which were due to US onshore infill drilling activities and other US development programs, and international additions, which were due to drilling in China.

We expect that a significant portion of future reserve additions will come from our major development projects at the Central DJ Basin, Gunflint, Aseng, Alen, and Tamar and from new discoveries resulting from our active exploration programs in the deepwater Gulf of Mexico and international locations, such as Leviathan, offshore Israel. We may also purchase proved properties in strategic acquisitions. See Operating Outlook – Major Development Project Inventory, above and Acquisition, Capital and Other Exploration Expenditures, below.

Purchase of Minerals in Place We occasionally enhance our asset portfolio with strategic acquisitions of producing properties. Purchases included the following:

- the Central DJ Basin asset acquisition in 2010; and
- the Mid-Continent acquisition in 2008.

Sale of Minerals in Place We maintain an ongoing portfolio management program. Sales included the following:

- the sale of non-core assets in the Mid-Continent and Illinois Basin areas in 2010; and

- the sale of our Argentina assets in 2008.

Sales of Minerals in Place also included a reduction in natural gas reserves due to the Ecuadorian government's termination of our Block 3 PSC. See Items 1. and 2. Business and Properties and Item 8. Financial Statements and Supplementary Data – Note 3. Acquisitions and Divestitures.

Production See Oil, Gas and NGL Sales above.

See also Critical Accounting Policies and Estimates – Reserves, below, and Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Information (Unaudited).

LIQUIDITY AND CAPITAL RESOURCES

Capital Structure/Financing Strategy

In seeking to effectively fund and monetize our major development projects, we employ a capital structure and financing strategy designed to provide ample liquidity throughout the commodity price cycle. Specifically, we strive to retain the ability to fund long cycle, multi-year, capital intensive development projects while also maintaining the capability to execute a robust exploration program and financially attractive periodic mergers and acquisitions activity. We endeavor to maintain an investment grade debt rating in service of these objectives. We also utilize a commodity price hedging program to reduce commodity price uncertainty and enhance the predictability of cash flows along with a risk and insurance program to protect against disruption to our cash flows and operations.

Traditional sources of our liquidity are cash on hand, cash flows from operations and available borrowing capacity under our credit facility. Occasional sales of non-strategic crude oil and natural gas properties as well as our periodic access to capital markets may also generate cash.

Our financial capacity, coupled with our balanced and diversified portfolio, provides us with flexibility in our investment decisions including execution of our major development projects and increased exploration activity.

Information regarding cash and debt balances was as follows:

	December 31,		
	2010	2009	2008
(millions, except percentages)			
Cash and Cash Equivalents	$ 1,081	$ 1,014	$ 1,140
Amount Available to be Borrowed Under Credit Facility [1]	1,750	1,718	494
Total Liquidity	$ 2,831	$ 2,732	$ 1,634
Total Debt [2]	$ 2,279	$ 2,045	$ 2,270
Total Shareholders' Equity	6,848	6,157	6,309
Debt-to-Capital Ratio [3]	25%	25%	26%

(1) Our credit facility is committed in the amount of $2.1 billion until December 9, 2011 at which time the commitment reduces to $1.8 billion.

(2) Total debt includes FPSO obligation and excludes unamortized debt discount.

(3) We define our ratio of debt-to-book capital as total debt (which includes both long-term debt, excluding unamortized discount, and short-term borrowings) divided by the sum of total debt plus shareholders' equity.

Cash and Cash Equivalents We had $1.1 billion in cash and cash equivalents at December 31, 2010, compared with $1 billion at December 31, 2009. At December 31, 2010, our cash was primarily denominated in US dollars and was invested in money market funds and short-term deposits with major financial institutions. Substantially all of this cash is attributable to our foreign subsidiaries and most would be subject to US income taxes if repatriated. We currently expect to use a significant amount of this cash during 2011 to fund international projects, including the development of our properties in West Africa and Israel.

Commodity Derivative Instruments We use various derivative contracts in connection with anticipated crude oil and natural gas sales to minimize the impact of product price fluctuations and ensure cash flow for future capital needs. Such instruments include variable to fixed commodity price swaps, two-way and three-way collars and basis swaps.

As of December 31, 2010, we had commodity derivative assets totaling $62 million and commodity derivative liabilities totaling $75 million (after consideration of netting agreements). Our hedging arrangements are currently with a diversified group of highly-rated major banks and market participants. See Item 1A. Risk Factors – *Commodity and interest rate hedging transactions may limit our potential gains* and *We are exposed to counterparty credit risk as a result of our receivables, hedging transactions, and cash investments.*

Current period settlements on commodity derivative instruments impact our liquidity, since we are either paying cash to, or receiving cash from, our counterparties. If actual commodity prices are higher than the fixed or ceiling prices in our derivative instruments, our cash flows will be lower than if we had no derivative instruments. Conversely, if actual commodity prices are lower than the fixed or floor prices in our derivative instruments, our cash flows will be higher than if we had no derivative instruments. None of our counterparty agreements currently contain margin requirements. However, see Item 1A. Risk Factors – *Derivatives regulation included in current financial reform legislation could impede our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices and interest rates.*

See Critical Accounting Policies and Estimates – Derivative Instruments and Hedging Activities, Item 7A. Quantitative and Qualitative Disclosures About Market Risk, and Item 8. Financial Statements and Supplementary Data – Note 10. Derivative Instruments and Hedging Activities.

Accounts Receivable We have accounts receivable from sales of our crude oil, natural gas and NGLs, as well as electricity. We also have accounts receivable from joint venture partners for their share of expenses on joint venture projects for which we are the operator. Some of these parties are not as creditworthy as we are and may experience liquidity problems. We have obtained credit enhancements from some parties in the way of parental guarantees or letters of credit, including our largest crude oil purchaser; however, not all of our trade credit is protected through guarantees or credit support. Nonperformance by a trade creditor or joint venture partner could result in losses. Other than reductions in the carrying value of a receivable from SemCrude, L.P., a crude oil purchaser that declared bankruptcy in 2008, and certain entities purchasing electricity in Ecuador, we have experienced no significant collection issues with purchasers or joint venture partners. See Item 1A. Risk Factors – *We are exposed to counterparty credit risk as a result of our receivables, hedging transactions, and cash investments* and Item 8. Financial Statements and Supplementary Data – Note 5. Allowance for Doubtful Accounts.

Cash Flows

Summary cash flow information is as follows:

	Year Ended December 31,		
	2010	2009	2008
(millions)			
Total Cash Provided By (Used in)			
Operating Activities	$ 1,946	$ 1,508	$ 2,285
Investing Activities	(1,779)	(1,265)	(2,132)
Financing Activities	(100)	(369)	327
Increase (Decrease) in Cash and Cash Equivalents	$ 67	$ (126)	$ 480

Operating Activities Net cash provided by operating activities in 2010 increased $438 million, or 29%, as compared with 2009. Sales revenues were higher due to increases in commodity prices and sales volumes. In addition, we received a refund of deepwater Gulf of Mexico royalties and higher dividends from equity method investees.

Net cash provided by operating activities in 2009 decreased $777 million, or 34%, as compared with 2008 due primarily to decreases in sales revenues resulting from significant declines in commodity prices.

Investing Activities The primary use of cash in investing activities is for capital spending, which may be offset by proceeds from property sales.

Capital spending, on a cash basis, totaled $2.3 billion in 2010, including $458 million spent on the Central DJ Basin asset acquisition, representing an increase of $1.1 billion as compared with 2009. A significant portion of the spending was related to our major development projects. We received $564 million total proceeds from asset sales.

Capital spending totaled $1.3 billion in 2009, as compared with $2.3 billion in 2008. In 2009, due to the uncertain economic and commodity price environment, we reduced spending and designed a flexible capital spending program that was responsive to conditions that developed during 2009. We received net proceeds from property sales of $3 million.

In 2008, our capital spending including acquisitions, totaled $2.3 billion. We received net proceeds from property sales of $131 million.

Financing Activities In 2010, net cash of $100 million was used in financing activities. Funds were provided by cash proceeds from, and tax benefits related to, the exercise of stock options ($72 million). Funds were used for net repayments under our revolving credit facility ($32 million). We paid cash dividends on our common stock ($127 million), and repurchased shares of our common stock ($13 million).

In 2009, net cash of $369 million was used in financing activities. We received $989 million net proceeds from the issuance of our 8¼% senior notes. Funds were also provided by cash proceeds from, and tax benefits related to, the exercise of stock options ($22 million). We made net repayments of amounts outstanding under our revolving credit facility ($1.2 billion), repaid an installment note ($25 million), and repurchased a portion of our 7¼% Senior Debentures due August 1, 2097 ($4 million). We also paid cash dividends on our common stock ($126 million) and repurchased shares of our common stock ($1 million).

In 2008, net cash of $327 million was provided by financing activities. We borrowed a net $426 million under our credit facility in support of an expanded capital investment program, which included significant domestic exploration, development and acquisition activities and new international ventures. Funds were also provided by the cash proceeds from, and tax benefits related to, the exercise of stock options ($51 million). Other financing activities included the payment of cash dividends on our common stock ($115 million), the repayment of installment and other notes ($32 million) and the repurchase of stock ($3 million).

Acquisition, Capital and Other Exploration Expenditures

Acquisition, Capital and Other Exploration Expenditures Information for investing activities (on an accrual basis) is as follows:

	Year Ended December 31,		
	2010	2009	2008
(millions)			
Acquisition, Capital and Exploration Expenditures			
Unproved Property Acquisition [1]	$ 305	$ 92	$ 302
Proved Property Acquisition [2]	352	-	256
Exploration	343	242	448
Development	1,520	881	1,193
Corporate and Other	121	102	65
Total	$ 2,641	$ 1,317	$ 2,264
Increase in FPSO Lease Obligation [3]	$ 266	$ 29	$ -

(1) Unproved property acquisition cost for 2010 includes $146 million related to the Central DJ Basin asset acquisition, $38 million for deepwater Gulf of Mexico lease blocks, and the remainder for other US onshore lease acquisitions primarily in Wattenberg. Unproved property acquisition cost for 2009 includes $56 million for deepwater Gulf of Mexico lease blocks and the remainder primarily for other onshore US lease acquisition. Unproved property acquisition cost for 2008 includes $179 million for deepwater Gulf of Mexico lease blocks, $38 million related to the Mid-Continent acquisition, $39 million related to lease acquisitions in East Texas, and the remainder primarily for other onshore US lease acquisitions.

(2) Proved property acquisition cost for 2010 includes $352 million related to Central DJ Basin asset acquisition. Proved property acquisition cost for 2008 includes $254 million related to the Mid-Continent acquisition.

(3) Relates to estimated construction progress to date on an FSPO to be used in the development of the Aseng field, offshore Equatorial Guinea.

Total expenditures in 2010 doubled as compared with 2009 due to major development project expenditures and the Central DJ Basin asset acquisition. In addition, seismic and dry hole expense increased.

Total expenditures in 2009 decreased by $947 million, or 42%, as compared with 2008, as we reduced our capital spending program in response to economic conditions.

Asset Sales In August 2010, we sold certain non-core assets in the Mid-Continent and Illinois Basin areas for cash proceeds of $552 million. In 2008, we sold our Argentina assets for a sales price of $117.5 million.

Risk and Insurance Program

Our business is subject to all of the operating risks normally associated with the exploration, production, gathering, processing and transportation of crude oil and natural gas, including hurricanes, blowouts, well cratering and fire, any of which could result in damage to, or destruction of, oil and natural gas wells or formations or production facilities and other property and injury to persons. As protection against financial loss resulting from many, but not all of these operating hazards, we maintain insurance coverage, including certain physical damage, business interruption (loss of production), employer's liability, comprehensive general liability and worker's compensation insurance. We maintain insurance at levels that we believe are appropriate and consistent with industry practice and we regularly review our potential risks of loss and the cost and availability of insurance and revise our insurance program accordingly.

For example, in certain international locations (including Israel and Equatorial Guinea) we carry business interruption insurance for loss of revenue arising from physical damage to our facilities caused by fire and natural disasters. The coverage is subject to customary deductibles, waiting periods and recovery limits.

In the Gulf of Mexico, we have begun self-insuring for windstorm exposure. We made this decision because recent abandonment activities on the Gulf of Mexico shelf significantly reduced our windstorm exposure, as our remaining Gulf of Mexico assets are primarily subsea operations. In addition, the cost of windstorm insurance has recently increased while the amounts of coverage have been reduced. Therefore, we believe it is more cost-effective for us to self-insure these assets. However, we are now responsible for substantially all windstorm-related damages to our Gulf of Mexico assets.

In accordance with industry practice, oil and gas well owners generally indemnify drilling rig contractors against certain risks, such as those arising from property and environmental losses, pollution from sources such as oil spills, or contamination resulting from well blowout or fire or other uncontrolled flow of hydrocarbons. Most of our domestic and international drilling contracts contain such indemnification clauses. In addition, oil and gas well owners typically assume all costs of well control in the event of an uncontrolled well. We currently carry insurance protection for our net share of any potential financial losses occurring as a result of events such as the Deepwater Horizon Incident. This protection consists of $250 million of well control, pollution cleanup and consequential damages coverage and $251 million of additional pollution cleanup and consequential damages coverage, which also covers third party personal injury and death. Consequently if we were to experience an accident similar to the Deepwater Horizon

Incident, our total coverage for cleanup and consequential damages would be $501 million for our net share, subject to reduction for claims related to well control and third party damages.

We expect the future availability and cost of insurance to be impacted by the Deepwater Horizon Incident. Impacts could include: tighter underwriting standards, limitations on scope and amount of coverage, and higher premiums, and will depend, in part, on future changes in laws and regulations regarding exploration and production activities in the Gulf of Mexico, including possible increases in liability caps for claims of damages from oil spills.

During 2010, various Congressional committees began pursuing legislation to increase or remove liability caps for deepwater drilling. The current $75 million liability limit under the Oil Pollution Act may be materially increased or lifted in its entirety. Such a requirement would ultimately require a company to maintain either a much higher level of insurance coverage than was standard for the industry in the past, or a financial position large enough that a company could settle its own damage claims. We anticipate that, at a minimum, less insurance coverage will be available and at a higher cost. We continue to monitor the legislative and regulatory response to the Deepwater Horizon Incident and its impact on the insurance market and our overall risk profile. Accordingly, we may adjust our risk and insurance program to provide protection at insured levels that reflect our perception of the cost of risk relative to frequency and severity of the exposure.

Deepwater drilling entails inherent risks. We have a risk assessment program that analyzes safety and environmental hazards and establishes procedures, work practices, training programs and equipment requirements, including monitoring and maintenance rules, for continuous improvement. We have a strong safety performance record and continue to manage our risks and operations such that the likelihood of a significant accident or spill is remote. However, if an event occurs that is not covered by insurance or not fully protected by insured limits, it could have a material adverse impact on our financial condition, results of operations and cash flows. See Item 1A. Risk Factors – *We have insufficient insurance to cover all of the risks we face, which could result in significant financial exposure.*

We are a member in Oil Insurance Limited (OIL). OIL is a mutual insurance company which insures property, pollution liability, control of well and other catastrophic risks. See *Contractual Obligations* below for a discussion of our theoretical withdrawal premium liability.

Financing Activities

Long-Term Debt Our long-term debt totaled $2.3 billion (including an FPSO lease obligation) at December 31, 2010, with maturities ranging from 2012 to 2097. Our principal source of liquidity is an unsecured revolving credit facility that matures December 9, 2012. The commitment is $2.1 billion until December 9, 2011 at which time the commitment reduces to $1.8 billion. We do not believe the reduction in the commitment will have a material impact on our liquidity.

The credit facility (i) provides for credit facility fee rates that range from 5 basis points to 15 basis points per year depending upon our credit rating, (ii) makes available short-term loans up to an aggregate amount of $300 million within the current $2.1 billion commitment, and (iii) provides for interest rates that are based upon the Eurodollar rate plus a margin that ranges from 20 basis points to 70 basis points depending upon our credit rating and utilization of the credit facility.

At December 31, 2010, $350 million in borrowings were outstanding under the credit facility, leaving almost $1.75 billion available for use. The weighted average interest rate applicable to borrowings under the credit facility at December 31, 2010 was 0.57%. We expect to use the credit facility to fund our capital investment program, and we periodically borrow amounts under provision (ii) above for working capital purposes.

The credit facility contains customary representations and warranties and affirmative and negative covenants. The credit facility requires that our total debt to capitalization ratio (as defined in the credit agreement), expressed as a percentage, not exceed 60% at any time. A violation of this covenant could result in a default under the credit facility, which would permit the participating banks to restrict our ability to access the credit facility and require the immediate repayment of any outstanding advances under the credit facility. As of December 31, 2010, we were in compliance with our debt covenants.

The credit facility is with certain commercial lending institutions and its funds are available for general corporate purposes. Our bank group is comprised of 22 commercial lending institutions, each holding between 1.0% and 11.4% of the total facility. Due to consolidation in the banking sector resulting from heightened stress in the credit markets, the number of lenders and their effective commitment levels within our credit facility may be reallocated over time.

In 2009, we entered into an agreement with an unrelated offshore technology provider for the construction and lease of an FPSO to be used for development of the Aseng field, offshore Equatorial Guinea. We expect to account for the lease agreement as a capital lease. Throughout the construction phase, we will include both the FPSO asset and associated long-term obligation in our balance sheet, based upon the percentage of construction completed at the end of each reporting period. The obligation increased $266 million during 2010.

In 2009, we closed an offering of $1 billion senior unsecured notes receiving net proceeds of $989 million, after deducting the discount and underwriting fees. We used substantially all of the net proceeds to repay outstanding indebtedness under our credit facility. The notes are due March 1, 2019, and pay interest semi-annually at 8¼%.

We had a total of $1.6 billion of fixed-rate debt outstanding at December 31, 2010 with a weighted average interest rate of 7.73%. Maturities range from 2014 to 2097.

See Item 8. Financial Statements and Supplementary Data – Note 12. Long-Term Debt.

Interest Rate Locks We occasionally enter into forward contracts or swap agreements to hedge exposure to interest rate risk. In 2010, in anticipation of a long-term debt issuance which we project to occur during 2011, we entered into an interest rate forward starting swap to effectively fix the cash flows related to interest payments on the anticipated debt issuance. The swap is in the notional amount of $500 million and is based on a 30-year LIBOR swap rate. See Critical Accounting Policies and Estimates – Derivative Instruments and Hedging Activities, Item 7A. Quantitative and Qualitative Disclosures About Market Risk, and Item 8. Financial Statements and Supplementary Data – Note 10. Derivative Instruments and Hedging Activities.

We also entered into interest rate derivative instruments related to the issuance of 5¼% Senior Notes due April 2014 and are amortizing remaining amounts from AOCL to interest expense over the term of the notes.

Short-Term Borrowings Our committed credit facility has been supplemented by short-term borrowings under various uncommitted credit lines used for working capital purposes. Uncommitted credit lines may be offered by certain banks from time to time at rates negotiated at the time of borrowing. No amounts were outstanding under uncommitted credit lines at December 31, 2010 or 2009, nor did we borrow any funds under uncommitted credit lines during 2010 or 2009. Depending upon future credit market conditions, these sources may or may not be available. However, we are not dependent on them to fund our day-to-day operations.

Ratio of Debt-to-Book Capital Our ratio of debt-to-book capital was 25% at both December 31, 2010 and December 31, 2009. Significant changes in our financial position included the following:

- $234 million increase in total principal amount of debt from the balance at December 31, 2009; and
- $127 million decrease in shareholders' equity from dividends paid;

offset by:

- $725 million increase in shareholders' equity from current year net income.

Cash Interest Payments We made cash interest payments of $133 million in 2010, $97 million in 2009, and $109 million in 2008.

Exercise of Stock Options Proceeds from the exercise of stock options totaled $47 million in 2010, $17 million in 2009, and $27 million in 2008. Proceeds received from the exercise of stock options fluctuate primarily based on the number of options exercised which is influenced by the price at which our common stock trades on the NYSE in relation to the exercise price of the options issued.

Dividends We paid cash dividends totaling 72 cents per common share in 2010, 72 cents per common share in 2009, and 66 cents per common share in 2008. On January 25, 2011, the Board of Directors declared a quarterly cash dividend of 18 cents per common share, which will be paid February 22, 2011 to shareholders of record on February 7, 2011. The amount of future dividends will be determined on a quarterly basis at the discretion of our Board of Directors and will depend on earnings, financial condition, capital requirements and other factors.

Common Stock Repurchases We receive shares of our common stock from employees for the payment of withholding taxes due on the vesting of restricted shares issued under stock-based compensation plans. We received approximately 168,000 shares with a total value of $13 million in 2010, 21,000 shares with a total value of $1 million in 2009 and 33,000 shares with a total value of $3 million in 2008.

Off-Balance Sheet Arrangements We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2010, the material off-balance sheet arrangements and transactions that we have entered into included drilling rig contracts, operating lease agreements, and undrawn letters of credit, all of which are customary in the oil and gas industry. Other than the off-balance sheet arrangements listed above, we have no transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect our liquidity or availability of or requirements for capital resources. See *Contractual Obligations* below for more information regarding off-balance sheet arrangements.

Contractual Obligations

The following table summarizes certain contractual obligations that are reflected in the consolidated balance sheets and/or disclosed in the accompanying notes. Unless otherwise noted, all amounts are net to our interest.

Obligation	Total	2011	2012 and 2013	2014 and 2015	2016 and beyond
(millions)					
Long-Term Debt (Excluding Interest) (1)	$ 1,984	$ -	$ 350	$ 200	$ 1,434
FPSO Lease Payments (2)	485	-	110	150	225
Drilling and Equipment Obligations (3)					
United States	104	74	30	-	-
International	223	211	12	-	-
Purchase Obligations (4)	652	496	156	-	-
Throughput Agreement (5)	65	19	38	8	-
Transportation and Gathering (6)	35	9	13	5	8
Operating Lease Obligations (7)	230	68	59	49	54
Other Liabilities (8)					
Asset Retirement Obligations (9)	253	45	26	19	163
Interest Rate Derivative Instrument (10)	63	63	-	-	-
Commodity Derivative Instruments (11)	75	24	51	-	-
Total Contractual Obligations	$ 4,169	$ 1,009	$ 845	$ 431	$ 1,884

(1) Long-term debt excludes our FPSO lease obligation. Based on the total debt balance, scheduled maturities and interest rates in effect at December 31, 2010, our cash payments for interest would be $128 million in 2011, $128 million in 2012, $126 million in 2013, $121 million in 2014, $116 million in 2015 and $1.1 billion for the remaining years for a total of $1.7 billion. See Item 8. Financial Statements and Supplementary Data – Note 12. Long-Term Debt.

(2) The FPSO is currently under construction. Annual lease payments, net to our interest, exclude regular maintenance and operational costs, and will begin when the FPSO initiates producing operations. These payments are also subject to change based on change orders implemented during the construction period, final accounting treatment, and other factors. See Item 8. Financial Statements and Supplementary Data – Note 12. Long-Term Debt.

(3) Drilling and equipment obligations represent contractual agreements with third-party service providers to procure drilling rigs and other related equipment for exploratory and development drilling activities. See Item 8. Financial Statements and Supplementary Data – Note 21. Commitments and Contingencies.

(4) Purchase obligations represent agreements to purchase goods or services that are enforceable, are legally binding and specify all significant terms, including fixed and minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transaction. See Item 8. Financial Statements and Supplementary Data – Note 21. Commitments and Contingencies.

(5) We have a five-year throughput agreement on an interstate crude oil transportation pipeline system running from Weld County, Colorado to Cushing, Oklahoma. See Item 8. Financial Statements and Supplementary Data – Note 21. Commitments and Contingencies.

(6) Transportation and gathering obligations represent minimum charges for our firm transportation and gathering agreements. See Item 8. Financial Statements and Supplementary Data – Note 21. Commitments and Contingencies.

(7) Operating lease obligations represent non-cancelable leases for office buildings and facilities and oil and gas operations equipment used in our daily operations. See Item 8. Financial Statements and Supplementary Data – Note 21. Commitments and Contingencies.

(8) The table excludes deferred compensation liabilities of $229 million and accrued benefit costs of $76 million as specific payment dates are unknown. See Item 8. Financial Statements and Supplementary Data – Note 14. Benefit Plans.

(9) Asset retirement obligations are discounted. See Item 8. Financial Statements and Supplementary Data – Note 11. Asset Retirement Obligations.

(10) Amount represents open treasury rate lock in a net payable position with the counterparty at December 31, 2010. See Item 8. Financial Statements and Supplementary Data – Note 10. Derivative Instruments and Hedging Activities.

(11) Amount represents open commodity derivative instruments that were in a net payable position with the counterparty at December 31, 2010. Our remaining commodity derivative instruments were in a net receivable position at December 31, 2010. See Item 8. Financial Statements and Supplementary Data – Note 10. Derivative Instruments and Hedging Activities.

As of December 31, 2010, we accrued approximately $23 million for an insurance contingency due to our membership in OIL. OIL is a mutual insurance company which insures specific property, pollution liability and other catastrophic risks. As part of our membership, we are contractually committed to pay termination fees should we elect to withdraw from OIL. We do not anticipate withdrawing from OIL; however, the potential termination fee is calculated annually based on OIL's past losses and the liability reflecting this potential charge has been accrued.

In addition, in the ordinary course of business, we maintain letters of credit in support of certain performance obligations of our subsidiaries. Outstanding letters of credit totaled approximately $22 million at December 31, 2010.

Other

Contributions to Pension and Other Postretirement Benefit Plans We made contributions to the pension and other postretirement benefit plans totaling $24 million in 2010, $21 million in 2009, and $38 million in 2008. The actual return on plan assets was a gain of $23 million in 2010, a gain of $33 million in 2009, and a loss of $43 million in 2008. The investment return has tended to follow market performance. Certain provisions of the Pension Protection Act of 2006 (the Act) changed the calculation related to the maximum contribution amount deductible for income tax purposes and required that defined benefit pension plans become fully funded over a seven-year period beginning in 2008. As a result of previous contributions made to the pension plan, the plan is adequately funded at the balance sheet date, and we expect the plan would not be subject to any of the benefit limitations that would be imposed by the Act if the plan were not adequately funded. We expect to make cash contributions of approximately $13 million to the pension plan during 2011. We expect to make contributions to the restoration and medical and life plans of approximately $4 million during 2011, an amount which is estimated to be equal to the benefits expected to be paid by those plans.

Income Taxes We made cash payments for income taxes, net of refunds, of $173 million in 2010, $227 million in 2009, and $263 million in 2008.

Contingencies Payments to settle legal proceedings totaled approximately $7 million in 2010, $19 million in 2009, and $2 million in 2008. We regularly analyze current information and accrue for probable liabilities on the disposition of certain matters, as necessary. Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of the consolidated financial statements requires our management to make a number of estimates and assumptions relating to the reported amounts of assets and liabilities and the disclosures of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. When alternatives exist among various accounting methods, the choice of accounting method can have a significant impact on reported amounts. The following is a discussion of the accounting policies, estimates and judgments which management believes are most significant in the application of US generally accepted accounting principles used in the preparation of the consolidated financial statements.

Reserves All of the reserves data in this Form 10-K are estimates. Estimates of our crude oil and natural gas reserves are prepared by our qualified petroleum engineers in accordance with guidelines established by the SEC, including rule revisions designed to modernize the oil and gas company reserves reporting requirements, which we implemented effective December 31, 2009. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas. There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. Uncertainties include the projection of future production rates and the expected timing of development expenditures. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserves estimates may be different from the quantities of crude oil and natural gas that are ultimately recovered. In addition, economic producibility of reserves is dependant on the oil and gas prices used in the reserves estimate. We based our December 31, 2010 and 2009 reserves estimates on 12-month average commodity prices, unless contractual arrangements designate the price to be used, in accordance with SEC rules. However, oil and gas prices are volatile and, as a result, our reserves estimates will change in the future.

Estimates of proved crude oil and natural gas reserves significantly affect our DD&A expense. For example, if estimates of proved reserves decline, the DD&A rate will increase, resulting in a decrease in net income. A decline in estimates of proved reserves could also cause us to perform an impairment analysis to determine if the carrying amount of crude oil and natural gas properties exceeds fair value and could result in an impairment charge, which would reduce earnings. In addition, a decline in estimates of proved reserves could prompt a goodwill impairment analysis. See Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Information (Unaudited).

Oil and Gas Properties We account for crude oil and natural gas properties under the successful efforts method of accounting. Under the successful efforts method, costs to acquire mineral interests in crude oil and natural gas properties, drill and equip exploratory wells that find commercial quantities of proved reserves, and drill and equip development wells are capitalized. Proved property acquisition costs are amortized to expense by the unit-of-production method on a field-by-field basis based on total proved crude oil and natural gas reserves as estimated by our qualified petroleum engineers. Costs to drill and equip exploratory wells that find proved reserves and drill and equip development wells are also amortized to expense by the unit-of-production method on a field-by-field basis. These costs, along with support equipment and facilities, are amortized based on proved developed crude oil and natural gas reserves. Costs of certain gathering facilities or processing plants serving a number of properties or used for third-party processing are depreciated using the straight-line method over the useful lives of the assets. Application of the successful efforts method results in the expensing of certain costs including geological and geophysical costs, exploratory dry holes and delay rentals, during the periods the costs are incurred.

The alternative method of accounting for crude oil and natural gas properties is the full cost method. Under the full cost method, geological and geophysical costs, exploratory dry holes and delay rentals are capitalized as assets and charged to earnings in future periods as a component of DD&A expense. In addition, under the full cost method, capitalized costs are accumulated in pools on a country-by-country basis. DD&A is computed on a country-by-country basis, and capitalized costs are limited on the same basis through the application of a ceiling test. We believe the successful efforts method is the most appropriate method to use in accounting for our crude oil and natural gas properties because it provides a better representation of our results of operations, especially during periods of active exploration. If we had used the full cost method, our financial position and results of operations could have been significantly different.

Exploratory Well Costs In accordance with the successful efforts method of accounting, the costs associated with drilling an exploratory well may be capitalized temporarily, or "suspended," pending a determination of whether commercial quantities of crude oil or natural gas have been discovered. We carry the costs of an exploratory well as an asset if the well has found a sufficient quantity of reserves to justify its completion as a producing well and as long as we are making sufficient progress assessing the reserves and the economic and operating viability of the project. For certain capital-intensive deepwater Gulf of Mexico or international projects, it may take several years to evaluate the future potential of the exploration well and make a determination of its economic viability. Our ability to move forward on a project may be dependent on gaining access to transportation or processing facilities or obtaining permits and government or partner approval, the timing of which is beyond our control. In such cases, exploratory well costs remain suspended as long as we are actively pursuing access to necessary facilities and submitting requests for permits and approvals and believe they will be obtained.

Management assesses the status of suspended exploratory well costs on a quarterly basis. These costs may be charged to exploration expense in future periods if we decide not to pursue additional exploratory or development activities. At December 31, 2010, the balance of property, plant and equipment included $426 million of suspended exploratory well costs, $278 million of which had been capitalized for a period greater than one year. The wells relating to these suspended costs continue to be evaluated by various means including additional seismic work, drilling additional appraisal wells to confirm the size of the hydrocarbon deposit, or evaluating the potential commerciality of the exploration wells. See Item 8. Financial Statements and Supplementary Data – Note 7. Capitalized Exploratory Well Costs.

Impairment of Proved Oil and Gas Properties and Other Investments We assess proved crude oil and natural gas properties and other investments for possible impairment when events or circumstances indicate that the recorded carrying value of the assets may not be recoverable. We recognize an impairment loss as a result of an event that causes us to consider the possibility that impairment may have occurred and when the estimated undiscounted future cash flows from a property or other investment are less than the carrying value. If impairment is indicated, the carrying values are written down to fair value, which, in the absence of comparable market data, is estimated using a discounted cash flow method. In our cash flow method, cash flows are discounted using a risk-adjusted rate and compared to the carrying value for determining the amount of the impairment loss to record. Estimated future cash flows are based on management's expectations for the future and include estimates of crude oil and natural gas reserves and future commodity prices, revenues and operating and development costs. Negative revisions in estimates of reserves quantities or expectations of falling commodity prices or rising operating or development costs could result in a reduction in undiscounted future cash flows and could indicate property impairment.

During 2010, we assessed proved properties for possible impairment due to lower commodity prices, performance issues, and/or changes in our intended use. Certain assets were determined to be impaired and were written down to their estimated fair values under a discounted cash flow model. The discounted cash flow model included management's estimates of future oil and gas production; commodity prices based on forward commodity price curves at the date of the estimate; operating and development costs, and discount rates. Assets held for sale during 2010 were reduced to expected sales proceeds less costs to sell.

We recorded total pre-tax (non-cash) asset impairment charges of $144 million in 2010, $604 million in 2009 and $219 million in 2008 for proved oil and gas properties and other investments. See Item 8. Financial Statements and Supplementary Data – Note 4. Asset Impairments.

Impairment of Unproved Oil and Gas Properties We also perform assessments of individually significant unproved crude oil and natural gas properties for impairment on a quarterly basis and recognize a loss at the time of impairment by providing an impairment allowance. In determining whether a significant unproved property is impaired we consider numerous factors including, but not limited to, current exploration plans, favorable or unfavorable exploration activity on the property being evaluated and/or adjacent properties, our geologists' evaluation of the property, and the remaining months in the lease term for the property.

When we have allocated fair values to a significant unproved property (probable and/or possible reserves) as the result of a business combination or other purchase of proved and unproved properties, we use a future cash flow analysis to assess the property for impairment. Cash flows used in the impairment analysis are determined based upon management's estimates of crude oil and natural gas reserves, from probable and possible reserves, future commodity prices and future costs to extract the reserves. *Probable reserves* are defined in SEC Regulation S-X, Rule 4-10(a)(18) as those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. *Possible reserves* are defined in SEC Regulation S-X, Rule 4-10(a)(17) as those additional reserves that are less certain to be recovered than probable reserves.

Negative revisions in estimated reserves quantities, reductions in commodity prices, or increases in estimated costs could cause a reduction in the value of an unproved property and, therefore, could also cause a reduction in the carrying amount of the property. If undiscounted future net cash flows are less than the carrying value of the property, indicating impairment, the cash flows are discounted using a risk-adjusted rate and compared to the carrying value for determining the amount of the impairment loss to record. The estimated prices used in the cash flow analysis are determined by management based on forward commodity price curves as of the date of the estimate, adjusted for average historical location and quality differentials. Estimates of cash flows related to probable and possible reserves are reduced by additional risk-weighting factors.

Due to the volatility of crude oil and natural gas prices, these cash flow estimates are inherently imprecise. Management's assessment of the results of exploration activities, availability of funds for future activities and the current and projected political climate in areas in which we operate also impact the amounts and timing of impairment provisions.

We assessed the recoverability of our significant unproved oil and gas properties periodically during the years ended December 31, 2010 and 2009 and determined there were no impairments. We recorded impairments of $75 million in 2008 for unproved properties. See Item 8. Financial Statements and Supplementary Data – Note 4. Asset Impairments.

Purchase Price Allocations We occasionally acquire assets and assume liabilities in transactions accounted for as business combinations, such as our Central DJ Basin asset acquisition in 2010. In connection with a purchase business combination, the acquiring company must allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. Deferred taxes must be recorded for any differences between the assigned values and tax bases of assets and liabilities. Any excess of the purchase price over amounts assigned to assets and liabilities is recorded as goodwill. Any excess of amounts assigned to assets and liabilities over the purchase price is recorded as a gain on bargain purchase. The amount of goodwill or gain on bargain purchase recorded in any particular business combination can vary significantly depending upon the value attributed to assets acquired and liabilities assumed.

In estimating the fair values of assets acquired and liabilities assumed in a business combination, we make various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved and unproved crude oil and natural gas properties. If sufficient market data is not available regarding the fair values of proved and unproved properties, we must prepare estimates. To estimate the fair values of these properties, we prepare estimates of crude oil and natural gas reserves. We estimate future prices to apply to the estimated reserves quantities acquired, and estimate future operating and development costs, to arrive at estimates of future net cash flows. For estimated proved reserves, the future net cash flows are discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the acquisition. The market-based weighted average cost of capital rate is subjected to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved reserves, the discounted future net cash flows of probable and possible reserves are reduced by additional risk-weighting factors.

Estimated deferred taxes are based on available information concerning the tax bases of assets acquired and liabilities assumed and loss carryforwards at the merger date, although such estimates may change in the future as additional information becomes known.

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. A higher fair value assigned to a property results in higher DD&A expense, which results in lower net earnings. Fair values are based on estimates of future commodity prices, reserves quantities, operating expenses and development costs. This increases the likelihood of impairment if future commodity prices or reserves quantities are lower than those originally used to determine fair value, or if future operating expenses or development costs are higher than those originally used to determine fair value. Impairment would have no effect on cash flows but would result in a decrease in net income for the period in which the impairment is recorded. See Item 8. Financial Statements and Supplementary Data – Note 3. Acquisitions and Divestitures.

Goodwill As of December 31, 2010, the consolidated balance sheet included $696 million of goodwill, all of which has been assigned to the US reporting unit. Goodwill is not amortized to earnings but is tested, at least annually, for impairment at the reporting unit level. We conduct the goodwill impairment test as of December 31 of each year. Other events and changes in circumstances may require goodwill to be tested for impairment between annual measurement dates. If the carrying value of goodwill is determined to be impaired, the amount of goodwill is reduced and a corresponding charge is made to earnings in the period in which the goodwill is determined to be impaired.

A two-step impairment test is used to identify potential goodwill impairment and measure the amount of a goodwill impairment loss to be recognized. The first step of the goodwill impairment test, used to identify potential impairment, compares the fair value of a reporting unit with its carrying amount, including goodwill. If the fair value of the reporting unit exceeds its carrying amount, goodwill is not considered to be impaired, and the second step of the test is not required. If necessary, the second step of the impairment test, used to measure the amount of impairment loss, compares the implied fair value of reporting unit goodwill with the carrying amount of that goodwill. If the carrying amount of reporting unit goodwill exceeds the implied fair value of that goodwill, an impairment loss is recognized in an amount equal to the excess.

The first step of the impairment test requires management to make estimates regarding the fair value of the reporting unit to which goodwill has been assigned. In determining the fair value of the US reporting unit, we use a combination of the income approach and the market approach.

Under the income approach, the fair value of the US reporting unit is estimated based on the present value of expected future cash flows. The income approach is dependent on a number of factors including estimates of forecasted revenue and operating costs, proved reserves, as well as the success of future exploration for and development of unproved reserves, discount rates and other variables. Negative revisions of estimated reserves quantities, increases in future cost estimates, divestiture of a significant component of the reporting unit, or sustained decreases in crude oil or natural gas prices could lead to a reduction in expected future cash flows and possibly an impairment of all or a portion of goodwill in future periods.

Key assumptions used in the discounted cash flow model described above include estimated quantities of crude oil and natural gas reserves, including both proved reserves and risk-adjusted unproved reserves; estimates of market prices considering forward commodity price curves in place as of December 31, 2010; and estimates of operating, administrative and capital costs adjusted for inflation. We discounted the resulting future cash flows using a peer company based weighted average cost of capital of 9%.

Under the market approach, we estimated the value of the US reporting unit by comparison to similar businesses whose securities are actively traded in the public market. This requires management to make certain judgments about the selection of comparable companies and/or comparable recent company and asset transactions and transaction premiums. At December 31, 2010, we used a peer company multiple method for the market approach. Market multiples represent market estimates of fair value based on selected financial metrics. We use earnings before interest, taxes, DD&A and exploration expense (also known as EBITDAX) as our financial metric as it more accurately compares companies using successful efforts and full cost accounting methods, both of which are in our peer group.

Using the range of US reporting unit fair values provided by the income and market approaches as of December 31, 2010, we determined that the fair value of our US reporting unit substantially exceeded its carrying amount. Therefore, the second step of the goodwill impairment test was unnecessary, and no goodwill impairment was recognized.

Although we based the fair value estimate of the US reporting unit on assumptions we believe to be reasonable, those assumptions are inherently unpredictable and uncertain and actual results could differ from the estimate. In the event of a prolonged global recession, commodity prices may stay depressed or decline further, thereby causing the fair value of the US reporting unit to decline, which could result in an impairment of goodwill.

When we dispose of a reporting unit or a portion of a reporting unit that constitutes a business, we include goodwill associated with that business in the carrying amount of the business in order to determine the gain or loss on disposal. The amount of goodwill to be included in that carrying amount is based on the relative fair value of the business to be disposed of and the portion of the reporting unit that will be retained. In 2010, we allocated $61 million of goodwill to the sale of non-core onshore US assets. The amount of goodwill allocated to the carrying amount of a business can significantly impact the amount of gain or loss recognized on the sale of that business. See Item 8. Financial Statements and Supplementary Data – Note 9. Goodwill.

Derivative Instruments and Hedging Activities In order to reduce commodity price uncertainty and increase cash flow predictability relating to the marketing of our crude oil and natural gas, we enter into crude oil and natural gas price hedging arrangements with respect to a portion of our expected production. In addition, we have used derivative instruments in connection with acquisitions and certain price-sensitive projects. Management exercises significant judgment in determining the types of instruments to be used, production volumes to be hedged, prices at which to hedge and the counterparties' creditworthiness. All derivative instruments are reflected at fair value in our consolidated balance sheets.

Our open commodity derivative instruments were in a net payable position with a fair value of $13 million at December 31, 2010. In order to determine the fair value at the end of each reporting period, we compute discounted cash flows for the duration of each commodity derivative instrument using the terms of the related contract. Inputs consist of published forward commodity price curves as of the date of the estimate. We compare these prices to the price parameters contained in our hedge contracts to determine estimated future cash inflows or outflows. We then discount the cash inflows or outflows using a combination of published LIBOR rates, Eurodollar futures rates and interest swap rates. The fair values of our commodity derivative assets and liabilities include a measure of credit risk based on current published credit default swap rates. In addition, for collars, we estimate the option value of the contract floors and ceilings using an option pricing model which takes into account market volatility, market prices and contract parameters.

Changes in the fair values of our commodity derivative instruments have a significant impact on our net income because we follow mark-to-market accounting and recognize all gains and losses on such instruments in earnings in the period in which they occur. For the year ended December 31, 2010, we reported a $157 million mark-to-market gain on commodity derivative instruments.

We also use derivative instruments to manage interest rate risk by entering into forward contracts or swap agreements to minimize the impact of interest rate fluctuations associated with fixed or floating rate borrowings. We designate these as cash flow hedges and all changes in fair value are reported in AOCL, to the extent the hedge is effective, until the forecasted transaction occurs, at which time they are recorded as adjustments to interest expense over the term of the related debt issuance.

Our interest rate derivative instrument was in a payable position with a fair value of $63 million at December 31, 2010. In order to determine the fair value at the end of each reporting period, we compute discounted cash flows for the duration of the instrument using the terms of the related contract. Inputs consist of published interest rate yield curves as of the date of the estimate and a measure of our own nonperformance risk, based on the current published credit default swap rates.

We compare our estimates of the fair values of our commodity and interest rate derivative instruments with those provided by our counterparties. There have been no significant differences. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk – Commodity Price Risk and Interest Rate Risk and Item 8. Financial Statements and Supplementary Data – Note 10. Derivative Instruments and Hedging Activities and Note 16. Fair Value Measurements and Disclosures.

Asset Retirement Obligations Our asset retirement obligations (ARO) consist of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. We recognize the fair value of a liability for an ARO in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying cost of the oil and gas asset. The recognition of an ARO requires that management make numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO; estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. In periods subsequent to initial measurement of the ARO, we recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Revisions also result in increases or decreases in the carrying cost of the oil and gas asset. Increases in the ARO liability due to passage of time impact net income as accretion expense. The related capitalized cost, including revisions thereto, is charged to expense through DD&A. Asset retirement obligations totaled $253 million at December 31, 2010. See Item 8. Financial Statements and Supplementary Data – Note 11. Asset Retirement Obligations.

Income Tax Expense and Deferred Tax Assets We are subject to income and other taxes in numerous taxing jurisdictions worldwide. For financial reporting purposes, we provide taxes at rates applicable for the appropriate tax jurisdictions. Estimates of amounts of income tax to be recorded involve interpretation of complex tax laws, assessment of the effects of foreign taxes on domestic taxes, and estimates regarding the timing and amounts of future repatriation of earnings from controlled foreign corporations.

The consolidated balance sheets include deferred tax assets. Deferred tax assets arise when expenses are recognized in the financial statements before they are recognized in the tax returns or when income items are recognized in the tax return before they are recognized in the financial statements. Deferred tax assets also arise when operating losses or tax credits are available to offset tax payments due in future years. Ultimately, realization of a deferred tax asset depends on the existence of sufficient taxable income within the future periods to absorb future deductible temporary differences, loss carryforwards or credits.

In assessing the realizability of deferred tax assets, management must consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. Management considers all available evidence (both positive and negative) in determining whether a valuation allowance is required. Such evidence includes the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment, and judgment is required in considering the relative weight of negative and positive evidence. We continue to monitor facts and circumstances in the reassessment of the likelihood that operating loss carryforwards, credits and other deferred tax assets will be utilized prior to their expiration. As a result, we may determine, and we have determined in the past, that a deferred tax asset valuation allowance should be established. Any increases or decreases in a deferred tax asset valuation allowance would impact net income through offsetting changes in income tax expense. In third quarter 2010, we reversed a $28 million valuation allowance that had been provided against a deferred tax asset of the same amount for the future foreign tax credits associated with deferred tax liabilities recorded by foreign branch operations and recorded a corresponding reduction in income tax expense. We now believe it is more likely than not that this deferred tax asset will be realized.

As of December 31, 2010, the accumulated undistributed earnings of our foreign subsidiaries on which no US taxes have been recorded totaled approximately $1.5 billion. Management must consider numerous factors in determining timing and amounts of possible future distribution of these earnings to the parent company and whether a US deferred tax liability should be recorded for these earnings. These factors include the future operating and capital requirements of both the parent company and the subsidiaries, remittance restrictions imposed by foreign governments or financial agreements and tax consequences of the remittance, including possible application of US foreign tax credits and limitations on foreign tax credits that may be imposed by the Internal Revenue Service (IRS) or IRS regulations.

In 2009, we repatriated $180 million of accumulated earnings of foreign subsidiaries and used the proceeds for debt repayment and general corporate purposes. The repatriation increased US tax expense a total of $13 million. Repatriation of additional earnings in the future could result in a decrease in our net income and cash flows due to the payment of additional taxes. We currently intend to use a majority of our international cash to fund international projects, including the development of our properties in West Africa and Israel. However, we estimate that a repatriation of $1 billion as of December 31, 2010, if we had elected not to use the cash to fund international development, would have had a net cash tax impact of approximately $187 million. This amount is net of estimated foreign tax credits. See Item 8. Financial Statements and Supplementary Data – Note 13. Income Taxes.

Allowance for Doubtful Accounts We assess the recoverability of all material trade and other receivables to determine their collectibility on a quarterly basis. We accrue a reserve on a receivable when, based on management's judgment, it is probable that a receivable will not be collected and the amount of such reserve may be reasonably estimated. In determining the amount of the reserve, management must analyze the aging of accounts receivable at the date of the consolidated financial statements and assess collectibility based on historic results, current collection trends and an evaluation of economic conditions. If estimates are inaccurate, we may incur gains or losses that could have a material effect on our results of operations.

We have recorded an allowance for doubtful accounts related to our Ecuador power operations to cover potentially uncollectible balances, as certain entities purchasing electricity in Ecuador have been slow to pay amounts due us. The amount totaled $19 million at December 31, 2010.

We also reduced the carrying value of a receivable from SemCrude, L.P., a crude oil purchaser who filed a voluntary petition for reorganization under Chapter 11 of the Bankruptcy Code, by $38 million in 2008 and an additional $12 million in 2009.

During 2010, there were no significant changes in our allowance for doubtful accounts, which, including the Ecuador allowance, totaled $27 million at December 31, 2010. See Item 8. Financial Statements and Supplementary Data – Note 5. Allowance for Doubtful Accounts.

Benefit Plans We sponsor a qualified defined benefit pension plan, a non-qualified defined benefit pension plan (restoration plan), and other postretirement benefit plans. The actuarial determination of the projected benefit obligations and related benefit expense requires that certain assumptions be made regarding such variables as expected return on plan assets, discount rates, rates of future compensation increases, estimated future employee turnover rates and retirement dates, distribution election rates, mortality rates, retiree utilization rates for health care services and health care cost trend rates. The selection of assumptions requires considerable judgment concerning future events and has a significant impact on the amount of the obligations recorded in the consolidated balance sheets and on the amount of expense included in the consolidated statements of operations.

We base our determination of the asset return component of pension expense on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of January 1, 2011, cumulative asset losses of approximately $2 million remained to be recognized in the calculation of the market-related value of assets.

In selecting the assumption for expected long-term rate of return on assets, we consider the average rate of earnings expected on the funds invested or to be invested to provide for plan benefits included in the projected benefit obligations. This includes considering the returns being earned by the plan assets and the rates of return expected to be available for reinvestment. We assume that the long-term asset mix will be consistent with the target asset allocation of 70% equity and 30% fixed income, with a range of plus or minus 10% acceptable degree of variation in asset allocation. The plan assets had a fair value of $206 million at December 31, 2010, and the expected return assumption used in the calculation of 2010 net periodic benefit cost was 7.50%. A 1% decrease in the expected return on plan assets assumption would have increased 2010 net periodic benefit cost by approximately $2 million. The expected return assumption will be reduced to 7.25% for the calculation of 2011 net periodic benefit cost.

In selecting a discount rate, employers may look to rates of return on high quality fixed-income investments available as of the year-end measurement date and expected to be available during the period to maturity of the pension benefits. In order to determine an appropriate December 31, 2010 discount rate, we performed an analysis of the Citigroup Pension Discount Curve (the CPDC) for each of our plans. The CPDC uses spot rates that represent the equivalent yield on high quality, zero coupon bonds for specific maturities. We used these rates to develop an equivalent single discount rate based on our plans' expected future benefit payment streams and duration of plan liabilities.

A 1% increase in the discount rate assumption would have decreased 2010 net periodic benefit cost by $3 million and decreased the benefit obligation for the combined plans by $24 million at December 31, 2010. A 1% decrease in the discount rate assumption would have increased 2010 net periodic benefit cost by $3 million and increased the benefit obligation for the combined plans by $26 million at December 31, 2010. The assumed discount rate used to determine net periodic benefit cost for 2010 was 6.0% for the defined benefit pension and restoration plans and 5.5%

for the medical and life plans. The assumed discount rates used to determine the benefit obligations at December 31, 2010 were 5.50% for the defined benefit pension plan, 5.25% for the restoration plan and 5.00% for the medical and life plans. The total projected benefit obligation for the defined benefit pension, restoration and medical and life plans was $286 million at December 31, 2010. See Item 8. Financial Statements and Supplementary Data – Note 14. Benefit Plans.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

Derivative Instruments Held for Non-Trading Purposes We are exposed to market risk in the normal course of business operations, and the uncertainty of crude oil and natural gas prices continues to impact the oil and gas industry. Due to the volatility of crude oil and natural gas prices, we continue to use derivative instruments as a means of managing our exposure to price changes.

At December 31, 2010, we had entered into variable to fixed price commodity swaps, two-way and three-way collars and basis swaps related to future crude oil and natural gas sales. Our open commodity derivative instruments were in a net payable position with a fair value of $13 million. Based on the December 31, 2010 published forward commodity price curves, a price increase of $1.00 per Bbl for crude oil would increase the fair value of our net commodity derivative payable by approximately $14 million. A price increase of $0.10 per MMBtu for natural gas would increase the fair value of our net commodity derivative payable by approximately $8 million. Our derivative instruments are executed under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net settled at the time of election. See Item 8. Financial Statements and Supplementary Data – Note 10. Derivative Instruments and Hedging Activities.

Interest Rate Risk

Changes in interest rates affect the amount of interest we pay on borrowings under our revolving credit facility and the amount of interest we earn on our short-term investments.

At December 31, 2010, we had $2 billion (excluding our FPSO lease obligation and unamortized discount) of long-term debt outstanding. Of this amount, $1.6 billion was fixed-rate debt with a weighted average interest rate of 7.73%. Although near-term changes in interest rates may affect the fair value of our fixed-rate debt, they do not expose us to the risk of earnings or cash flow loss.

The remainder of our long-term debt, $350 million at December 31, 2010, was variable-rate debt. Variable-rate debt exposes us to the risk of earnings or cash flow loss due to increases in market interest rates. We estimate that a hypothetical 25 basis point change in the floating interest rates applicable to the December 31, 2010 balance of our variable-rate debt would result in a change in annual interest expense of approximately $1 million.

We also enter into forward contracts or swap agreements to hedge exposure to interest rate risk. Changes in fair value of interest rate swaps or interest rate "locks" used as cash flow hedges are reported in AOCL, to the extent the hedge is effective, until the forecasted transaction occurs, at which time they are recorded as adjustments to interest expense. At December 31, 2010, AOCL included $42 million, net of tax, related to interest rate derivative instruments. Of this amount, $1 million, net of tax, is currently being reclassified into earnings as adjustments to interest expense over the term of our 5¼% Senior Notes due April 2014. The remainder ($41 million, net of tax) is related to the change in fair value of an interest rate forward starting swap. Based on the notional amount subject to the interest rate forward starting swap at December 31, 2010, a hypothetical 10% increase in the implied 30-year forward starting swap rate would decrease the fair value of the interest rate derivative liability by approximately $35 million. See Item 8. Financial Statements and Supplementary Data – Note 10. Derivative Instruments and Hedging Activities.

We are also exposed to interest rate risk related to our interest-bearing cash and cash equivalents balances. As of December 31, 2010, our cash and cash equivalents totaled $1.1 billion, approximately 65% of which was invested in money market funds and short-term deposits with major financial institutions. A hypothetical 25 basis point change in the floating interest rates applicable to the amount invested as of December 31, 2010 would result in a change in annual interest income of approximately $2 million.

Foreign Currency Risk

The US dollar is considered the functional currency for each of our international operations. Substantially all of our international crude oil, natural gas and NGL production is sold pursuant to US dollar denominated contracts. Transactions, such as operating costs and administrative expenses that are paid in a foreign currency, are remeasured into US dollars and recorded in the financial statements at prevailing currency exchange rates. Certain monetary assets and liabilities, such as foreign deferred tax liabilities in certain foreign tax jurisdictions, are denominated in a foreign currency. An increase in exchange rates between the US dollar and the currency of the foreign tax jurisdiction in which these liabilities are located could result in the use of additional cash to settle these liabilities. Transaction gains or losses were not material in any of the periods presented and are included in other non-operating (income) expense, net in the consolidated statements of operations.

Item 8. Financial Statements and Supplementary Data

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Consolidated Financial Statements of Noble Energy, Inc.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed under the supervision of our Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America.

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

As of December 31, 2010, our management assessed the effectiveness of our internal control over financial reporting based on the criteria for effective internal control over financial reporting established in *Internal Control – Integrated Framework*, issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, management determined that we maintained effective internal control over financial reporting as of December 31, 2010, based on those criteria. Management included in its assessment of internal control over financial reporting all consolidated entities.

KPMG LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of internal control over financial reporting as of December 31, 2010 which is included herein.

Noble Energy, Inc.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Noble Energy, Inc.:

We have audited the accompanying consolidated balance sheets of Noble Energy, Inc. and subsidiaries as of December 31, 2010 and 2009, and the related consolidated statements of operations, stockholders' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2010. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We did not audit the financial statements of the Alba Plant LLC (Alba) as of December 31, 2009 and for each of the years in the two-year period ended December 31, 2009, the investment in which, as discussed in Note 8 of the consolidated financial statements, is accounted for by the equity method of accounting. The Company's investment in Alba at December 31, 2009 was $111 million, and its equity in earnings of Alba was $66 million, and $118 million, for the years ended December 31, 2009, and 2008, respectively. The financial statements of Alba were audited by other auditors whose reports have been furnished to us, and our opinion, insofar as it relates to the amounts included for Alba, is based solely on the reports of the other auditors.

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

In our opinion, based on our audits and the reports of the other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Noble Energy, Inc. and subsidiaries as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Noble Energy, Inc.'s internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 10, 2011 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 10, 2011

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Noble Energy, Inc.:

We have audited Noble Energy, Inc.'s internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Noble Energy, Inc.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Noble Energy, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Noble Energy, Inc. and subsidiaries as of December 31, 2010 and 2009, and the related consolidated statements of operations, stockholders' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2010, and our report dated February 10, 2011 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas
February 10, 2011

Noble Energy, Inc. and Subsidiaries
Consolidated Statements of Operations
(in millions, except per share amounts)

	Year Ended December 31,		
	2010	2009	2008
Revenues			
Oil, Gas and NGL Sales	$ 2,832	$ 2,060	$ 3,651
Income from Equity Method Investees	118	84	174
Other Revenues	72	169	76
Total Revenues	3,022	2,313	3,901
Costs and Expenses			
Production Expense	570	525	594
Exploration Expense	245	144	217
Depreciation, Depletion and Amortization	883	816	791
General and Administrative	277	237	236
Net Gain on Asset Sales	(113)	(22)	(5)
Asset Impairments	144	604	294
Other Operating Expense, Net	64	67	139
Total Operating Expenses	2,070	2,371	2,266
Operating Income (Loss)	952	(58)	1,635
Other (Income) Expense			
(Gain) Loss on Commodity Derivative Instruments	(157)	110	(440)
Interest, Net of Amount Capitalized	72	84	69
Other Non-Operating (Income) Expense, Net	6	12	(55)
Total Other (Income) Expense	(79)	206	(426)
Income (Loss) Before Income Taxes	1,031	(264)	2,061
Income Tax Provision (Benefit)	306	(133)	711
Net Income (Loss)	$ 725	$ (131)	$ 1,350
Earnings (Loss) Per Share, Basic	$ 4.15	$ (0.75)	$ 7.83
Earnings (Loss) Per Share, Diluted	4.10	(0.75)	7.58
Weighted Average Number of Shares Outstanding, Basic	175	173	173
Weighted Average Number of Shares Outstanding, Diluted	177	173	176

The accompanying notes are an integral part of these financial statements.

Noble Energy, Inc.
Consolidated Balance Sheets
(in millions)

	December 31, 2010	December 31, 2009
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 1,081	$ 1,014
Accounts Receivable, Net	556	465
Other Current Assets	201	199
Total Assets, Current	1,838	1,678
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method of Accounting)	14,393	12,584
Property, Plant and Equipment, Other	263	240
Total Property, Plant and Equipment, Gross	14,656	12,824
Accumulated Depreciation, Depletion and Amortization	(4,392)	(3,908)
Total Property, Plant and Equipment, Net	10,264	8,916
Goodwill	696	758
Other Noncurrent Assets	484	455
Total Assets	$ 13,282	$ 11,807
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable - Trade	$ 927	$ 548
Other Current Liabilities	495	442
Total Liabilities, Current	1,422	990
Long-Term Debt	2,272	2,037
Deferred Income Taxes, Noncurrent	2,110	2,076
Other Noncurrent Liabilities	630	547
Total Liabilities	6,434	5,650
Commitments and Contingencies		
Shareholders' Equity		
Preferred Stock - Par Value $1.00; 4 Million Shares Authorized, None Issued	-	-
Common Stock - Par Value $3.33 1/3; 250 Million Shares Authorized; 195 Million and 194 Million Shares Issued, Respectively	651	645
Additional Paid in Capital	2,385	2,260
Accumulated Other Comprehensive Loss	(104)	(75)
Treasury Stock, at Cost; 19 Million Shares	(624)	(615)
Retained Earnings	4,540	3,942
Total Shareholders' Equity	6,848	6,157
Total Liabilities and Shareholders' Equity	$ 13,282	$ 11,807

The accompanying notes are an integral part of these financial statements.

Noble Energy, Inc.
Consolidated Statements of Cash Flows
(in millions)

	Year Ended December 31,		
	2010	2009	2008
Cash Flows From Operating Activities			
Net Income (Loss)	$ 725	$ (131)	$ 1,350
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities			
Depreciation, Depletion and Amortization	883	816	791
Dry Hole Expense	58	11	84
Net Gain on Asset Sales	(113)	(22)	(5)
Asset Impairments	144	604	294
Deferred Income Taxes	71	(296)	359
Dividends (Income) from Equity Method Investees, Net	21	8	47
Unrealized (Gain) Loss on Commodity Derivative Instruments	(70)	606	(522)
Settlement of Previously Recognized Hedge Losses	-	-	(194)
Other Adjustments for Noncash Items Included in Income	69	59	84
Changes in Operating Assets and Liabilities			
(Increase) Decrease in Accounts Receivable	(86)	(28)	121
(Increase) Decrease in Other Current Assets	18	(4)	(17)
Increase (Decrease) in Accounts Payable	234	(19)	(142)
Increase (Decrease) in Other Current Liabilities	34	(38)	67
Other Operating Assets and Liabilities, Net	(42)	(58)	(32)
Net Cash Provided by Operating Activities	1,946	1,508	2,285
Cash Flows From Investing Activities			
Additions to Property, Plant and Equipment	(1,885)	(1,268)	(1,971)
Acquisitions, Net of Cash Acquired	(458)	-	(292)
Proceeds from Sale of Property, Plant and Equipment	564	3	131
Net Cash Used in Investing Activities	(1,779)	(1,265)	(2,132)
Cash Flows From Financing Activities			
Exercise of Stock Options	47	17	27
Excess Tax Benefits from Stock-Based Awards	25	5	24
Dividends Paid, Common Stock	(127)	(126)	(115)
Purchase of Treasury Stock	(13)	(1)	(3)
Proceeds from Credit Facilities	760	340	951
Repayment of Credit Facilities	(792)	(1,564)	(525)
Proceeds from Issuance of Senior Long-Term Debt	-	989	-
Other	-	(29)	(32)
Net Cash Provided by (Used in) Financing Activities	(100)	(369)	327
Increase (Decrease) in Cash and Cash Equivalents	67	(126)	480
Cash and Cash Equivalents at Beginning of Period	1,014	1,140	660
Cash and Cash Equivalents at End of Period	$ 1,081	$ 1,014	$ 1,140

The accompanying notes are an integral part of these financial statements.

Noble Energy, Inc. and Subsidiaries
Consolidated Statements of Shareholders' Equity
(in millions)

	Common Stock	Additional Paid in Capital	Accumulated Other Comprehensive Loss	Treasury Stock at Cost	Retained Earnings	Total Shareholders' Equity
December 31, 2007	$ 636	$ 2,106	$ (284)	$ (613)	$ 2,964	$ 4,809
Net Income	-	-	-	-	1,350	1,350
Stock-based Compensation Expense	-	39				39
Exercise of Stock Options	4	23	-	-	-	27
Tax Benefits Related to Exercise of Stock Options	-	24	-	-	-	24
Restricted Stock Awards, Net	1	(1)	-	-	-	-
Cash Dividends (66 cents per share)	-	-	-	-	(115)	(115)
Purchase of Treasury Stock	-	-	-	(3)	-	(3)
Rabbi Trust Shares Sold	-	2	-	2	-	4
Oil and Gas Cash Flow Hedges						
Realized Amounts Reclassified Into Earnings	-	-	207	-	-	207
Net Change in Other	-	-	(33)	-	-	(33)
December 31, 2008	641	2,193	(110)	(614)	4,199	6,309
Net Loss	-	-	-	-	(131)	(131)
Stock-based Compensation Expense	-	49	-	-	-	49
Exercise of Stock Options	2	15	-	-	-	17
Tax Benefits Related to Exercise of Stock Options	-	5	-	-	-	5
Restricted Stock Awards, Net	2	(2)	-	-	-	-
Cash Dividends (72 cents per share)	-	-	-	-	(126)	(126)
Purchase of Treasury Stock	-	-	-	(1)	-	(1)
Oil and Gas Cash Flow Hedges						
Realized Amounts Reclassified Into Earnings	-	-	36	-	-	36
Net Change in Other	-	-	(1)	-	-	(1)
December 31, 2009	645	2,260	(75)	(615)	3,942	6,157
Net Income	-	-	-	-	725	725
Stock-based Compensation Expense	-	54	-	-	-	54
Exercise of Stock Options	5	42	-	-	-	47
Tax Benefits Related to Exercise of Stock Options	-	25	-	-	-	25
Restricted Stock Awards, Net	1	(1)	-	-	-	-
Cash Dividends (72 cents per share)	-	-	-	-	(127)	(127)
Purchase of Treasury Stock	-	-	-	(13)	-	(13)
Rabbi Trust Shares Sold	-	5	-	4	-	9
Oil and Gas Cash Flow Hedges						
Realized Amounts Reclassified Into Earnings	-	-	12	-	-	12
Interest Rate Cash Flow Hedges						
Unrealized Change in Fair Value	-	-	(41)	-	-	(41)
Net Change in Other	-	-	-	-	-	-
December 31, 2010	$ 651	$ 2,385	$ (104)	$ (624)	$ 4,540	$ 6,848

The accompanying notes are an integral part of these financial statements

Noble Energy, Inc.
Consolidated Statements of Comprehensive Income
(in millions)

	Year Ended December 31,		
	2010	2009	2008
Net Income (Loss)	$ 725	$ (131)	$1,350
Other Items of Comprehensive Income (Loss)			
Oil and Gas Cash Flow Hedges			
Realized Losses Reclassified Into Earnings	20	58	331
Less Tax Benefit	(8)	(22)	(124)
Interest Rate Cash Flow Hedges			
Unrealized Change in Fair Value	(63)	-	-
Less Tax Benefit	22	-	-
Net Change in Other	-	(2)	(52)
Less Tax Provision (Benefit)	-	1	19
Other Comprehensive Income (Loss)	(29)	35	174
Comprehensive Income (Loss)	$ 696	$ (96)	$1,524

The accompanying notes are an integral part of these financial statements.

Note 1. Summary of Significant Accounting Policies

General Noble Energy, Inc. (Noble Energy, we or us) is a leading independent energy company engaged in worldwide oil and gas exploration and production. Our key operating areas are the Central DJ Basin, deepwater Gulf of Mexico, offshore Eastern Mediterranean, and offshore West Africa.

Basis of Presentation and Consolidation Accounting policies used by us and our subsidiaries conform to accounting principles generally accepted in the US (US GAAP). Significant policies are discussed below. Our consolidated accounts include our accounts and the accounts of our wholly-owned subsidiaries. We use the equity method of accounting for investments in entities that we do not control but over which we exert significant influence. We carry equity method investments at our share of net assets of the equity investees plus our loans and advances. Differences in the basis of the investment and the separate net asset value of the investee, if any, are amortized into income over the remaining useful life of the underlying assets. See Note 8. Equity Method Investments. All significant intercompany balances and transactions have been eliminated upon consolidation.

Use of Estimates The preparation of consolidated financial statements in conformity with US GAAP requires us to make a number of estimates and assumptions relating to the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period.

Estimated quantities of crude oil and natural gas reserves are the most significant of our estimates. All the reserves data included in this Form 10-K are estimates. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas. There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserves estimates may be different from the quantities of crude oil and natural gas that are ultimately recovered. Qualified petroleum engineers in our Houston and Denver offices prepare all reserves estimates for our different geographical regions. These reserves estimates are reviewed and approved by senior engineering staff and division management with final approval by the Vice President - Strategic Planning, Environmental Analysis & Reserves and certain members of senior management. See Supplemental Oil and Gas Information (Unaudited).

Other items subject to estimates and assumptions include the carrying amounts of property, plant and equipment and goodwill, asset retirement obligations, valuation allowances for receivables and deferred income tax assets, valuation of derivative instruments, and obligations related to employee benefits, among others. Management evaluates estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic and commodity price environment. Volatile commodity prices result in increased uncertainty inherent in such estimates and assumptions. As future commodity prices cannot be determined accurately, actual results could differ significantly from our estimates.

Reclassification Certain reclassifications have been made to the 2009 and 2008 consolidated financial statements to conform to the 2010 presentation. These reclassifications were not material to the financial statements.

Fair Value Measurements Fair value measurements are based on a hierarchy which prioritizes the inputs to valuation techniques used to measure fair value into three levels. The fair value hierarchy is as follows:

- Level 1 measurements are fair value measurements which use quoted market prices (unadjusted) in active markets for identical assets or liabilities.
- Level 2 measurements are fair value measurements which use inputs, other than quoted prices included within Level 1, which are observable for the asset or liability, either directly or indirectly.
- Level 3 measurements are fair value measurements which use unobservable inputs.

The fair value hierarchy gives the highest priority to Level 1 measurements and the lowest priority to Level 3 measurements. We use Level 1 inputs when available as Level 1 inputs generally provide the most reliable evidence of fair value. See Note 16. Fair Value Measurements and Disclosures.

Cash and Cash Equivalents For purposes of reporting cash flows, cash and cash equivalents include unrestricted cash on hand and investments with original maturities of three months or less at the time of purchase.

Allowance for Doubtful Accounts We routinely assess the recoverability of all material trade and other receivables to determine their collectibility. We accrue a reserve on a receivable when, based on management's judgment, it is probable that a receivable will not be collected and the amount of such reserve may be reasonably estimated. See Note 5. Allowance for Doubtful Accounts.

Inventories Inventories consist primarily of tubular goods and production equipment used in our oil and gas operations, and crude oil produced but not yet sold. Materials and supplies inventories are stated at the lower of average cost or market. The cost of crude oil inventory includes production costs and DD&A expense. See Note 6. Inventories.

Property, Plant and Equipment Significant accounting policies for our property, plant and equipment are as follows:

Successful Efforts Method We account for crude oil and natural gas properties under the successful efforts method of accounting. Under this method, costs to acquire mineral interests in crude oil and natural gas properties, drill and equip exploratory wells that find proved reserves, and drill and equip development wells are capitalized. Capitalized costs of producing crude oil and natural gas properties, along with support equipment and facilities, are amortized to expense by the unit-of-production method based on proved crude oil and natural gas reserves on a field-by-field basis as estimated by our qualified petroleum engineers. Our policy is to use quarter-end reserves and add back current period production to compute quarterly DD&A expense. Costs of certain gathering facilities or processing plants serving a number of properties or used for third-party processing are depreciated using the straight-line method over the useful lives of the assets ranging from five to 14 years. Upon sale or retirement of depreciable or depletable property, the cost and related accumulated DD&A are eliminated from the accounts and the resulting gain or loss is recognized. Repairs and maintenance are expensed as incurred.

Proved Property Impairment We review proved oil and gas properties and other long-lived assets for impairment when events and circumstances indicate a decline in the recoverability of the carrying values of such properties, such as a negative revision of reserves estimates or sustained decrease in commodity prices. We estimate future cash flows expected in connection with the properties and compare such future cash flows to the carrying amount of the properties to determine if the carrying amount is recoverable. When the carrying amount of a property exceeds its estimated undiscounted future cash flows, the carrying amount is reduced to estimated fair value. Fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two. In the discounted cash flow method, estimated future cash flows are based on management's expectations for the future and include estimates of future oil and gas production, commodity prices based on published forward commodity price curves as of the date of the estimate, operating and development costs, and a risk-adjusted discount rate.

We recorded proved property impairment charges in 2010, 2009, and 2008. It is reasonably possible that other proved oil and gas properties could become impaired in the future if commodity prices decline. See Note 4. Asset Impairments.

Unproved Property Impairment We assess individually significant unproved properties for impairment of value on a quarterly basis and recognize a loss at the time of impairment by providing an impairment allowance. In determining whether a significant unproved property is impaired we consider numerous factors including, but not limited to, current exploration plans, favorable or unfavorable exploration activity on the property being evaluated and/or adjacent properties, our geologists' evaluation of the property, and the remaining months in the lease term for the property.

When we have allocated significant fair value to an unproved property as the result of a transaction accounted for as a business combination, we use a future cash flow analysis to assess the unproved property for impairment. Cash flows used in the impairment analysis are determined based on management's estimates of crude oil and natural gas reserves, future commodity prices and future costs to extract the reserves. Cash flow estimates related to probable and possible reserves are reduced by additional risk-weighting factors. Other individually insignificant unproved properties are amortized on a composite method based on our experience of successful drilling and average holding period.

We recorded unproved property impairment charges in 2008. It is reasonably possible that other unproved oil and gas properties could become impaired in the future if commodity prices decline. See Note 4. Asset Impairments.

Properties Acquired in Business Combinations If sufficient market data is not available, we determine the fair values of proved and unproved properties acquired in transactions accounted for as business combinations by preparing our own estimates of crude oil and natural gas reserves. We estimate future prices to apply to the estimated reserves quantities acquired, and estimate future operating and development costs, to arrive at estimates of future net cash flows. For the fair value assigned to proved reserves, future net cash flows are discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the business combination. To compensate for the inherent risk of estimating and valuing unproved reserves, discounted future net cash flows of probable and possible reserves are reduced by additional risk-weighting factors. See Note 3. Acquisitions and Divestitures.

Exploration Costs Geological and geophysical costs, delay rentals, amortization of unproved leasehold costs, and costs to drill exploratory wells that do not find proved reserves are expensed as oil and gas exploration. We carry the costs of an exploratory well as an asset if the well finds a sufficient quantity of reserves to justify its capitalization as a producing well and as long as we are making sufficient progress assessing the reserves and the economic and operating viability of the project. For certain capital-intensive deepwater Gulf of Mexico or international projects, it may take us more than one year to evaluate the future potential of the exploration well and make a determination of its economic viability. Our ability to move forward on a project may be dependent on gaining access to transportation or processing facilities or obtaining permits and government or partner approval, the timing of which is beyond our control. In such cases, exploratory well costs remain suspended as long as we are actively pursuing access to necessary facilities and access to such permits and approvals and believe they will be obtained. We assess the status of suspended exploratory well costs on a quarterly basis. See Note 7. Capitalized Exploratory Well Costs.

Other Property Other property includes automobiles, trucks, airplanes, office furniture, computer equipment and other fixed assets such as building and leasehold improvements. These items are recorded at cost and are depreciated on the straight-line method based on expected lives of the individual assets or group of assets, which range from three to ten years.

Capitalization of Interest We capitalize interest costs associated with the development and construction of significant properties or projects to bring them to a condition and location necessary for their intended use, which for crude oil and natural gas assets is at first production from the field. Interest is capitalized using an interest rate equivalent to the average rate we pay on long-term debt, including the credit facility and bonds. Capitalized interest is included in the cost of oil and gas assets and amortized with other costs on a unit-of-production basis. Capitalized interest totaled $67 million in 2010, $45 million in 2009, and $33 million in 2008.

Asset Retirement Obligations Asset retirement obligations consist of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. An asset retirement obligation and the related asset retirement cost are recorded when an asset is first constructed or purchased. The asset retirement cost is determined and discounted to present value using a credit-adjusted risk-free rate. After initial recording the liability is increased for the passage of time, with the increase being reflected as accretion expense in the statement of operations. Subsequent adjustments in the cost estimate are reflected in the liability and the amounts continue to be amortized over the useful life of the related long-lived asset. See Note 11. Asset Retirement Obligations.

Goodwill Goodwill represents the excess of the cost of an acquired entity over the net amounts assigned to assets acquired and liabilities assumed. Goodwill is not amortized to earnings but is tested annually in the fourth quarter or whenever events or changes in circumstances indicate that the carrying value may not be recoverable. No goodwill impairment was indicated at December 31, 2010. However, it is reasonably possible that goodwill could become impaired in the future if commodity prices or other economic factors become less favorable. See Note 9. Goodwill.

Derivative Instruments and Hedging Activities All derivative instruments (including certain derivative instruments embedded in other contracts) are recorded in our consolidated balance sheets as either an asset or liability and measured at fair value. Changes in the derivative instrument's fair value are recognized currently in earnings, unless the derivative instrument has been designated as a cash flow hedge and specific cash flow hedge accounting criteria are met. Under cash flow hedge accounting, unrealized gains and losses are reflected in shareholders' equity as accumulative other comprehensive loss (AOCL) until the forecasted transaction occurs. The derivative's gains or losses are then offset against related results on the hedged transaction in the statements of operations.

A company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting. Only derivative instruments that are expected to be highly effective in offsetting anticipated gains or losses on the hedged cash flows and that are subsequently documented to have been highly effective can qualify for hedge accounting. Effectiveness must be assessed both at inception of the hedge and on an ongoing basis. Any ineffectiveness in hedging instruments whereby gains or losses do not exactly offset anticipated gains or losses of hedged cash flows is measured and recognized in earnings in the period in which it occurs. When using hedge accounting, we assess hedge effectiveness quarterly based on total changes in the derivative instrument's fair value by performing regression analysis. A hedge is considered effective if certain statistical tests are met. We record hedge ineffectiveness in (gain) loss on commodity derivative instruments.

Accounting for Commodity Derivative Instruments We account for our commodity derivative instruments using mark-to-market accounting and recognize all gains and losses in earnings during the period in which they occur. Prior to January 1, 2008, we elected to designate certain of our commodity derivative instruments as cash flow hedges. Effective January 1, 2008, we voluntarily discontinued cash flow hedge accounting for our commodity derivative instruments. Net derivative gains and losses that were deferred in AOCL as of January 1, 2008, as a result of previous cash flow hedge accounting, were reclassified to earnings during the years ended December 31, 2008 through December 31, 2010 as the original transactions occurred.

We offset the fair value amounts recognized for derivative instruments and the fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral. The cash collateral (commonly referred to as a "margin") must arise from derivative instruments recognized at fair value that are executed with the same counterparty under a master netting arrangement.

Accounting for Interest Rate Derivative Instruments We designate interest rate derivative instruments as cash flow hedges. Changes in fair value of interest rate swaps or interest rate "locks" used as cash flow hedges are reported in AOCL, to the extent the hedge is effective, until the forecasted transaction occurs, at which time they are recorded as adjustments to interest expense over the term of the related notes.

See Note 10. Derivative Instruments and Hedging Activities.

Pension and Other Postretirement Benefit Plans We recognize the funded status (the difference between the fair value of plan assets and the projected benefit obligation) of our defined benefit pension, restoration and other postretirement benefit plans in the consolidated balance sheets, with a corresponding adjustment to AOCL, net of tax. The amount remaining in AOCL at December 31, 2010 represents unrecognized net actuarial loss, unrecognized prior service cost, and unrecognized net transition obligation remaining from the initial adoption of US GAAP for employers' accounting for pensions and other postretirement benefits. These amounts are currently being recognized as net periodic benefit cost pursuant to our historical accounting policy for amortizing such amounts. Any actuarial gains and losses that arise during the plan year, but which are not required to be recognized as net periodic benefit cost in the same period, are recognized as a component of AOCL. See Note 14. Benefit Plans.

Stock-Based Compensation We recognize the grant-date fair value of stock options and other stock-based compensation issued to employees in the statement of operations. Expense is recognized on a straight-line basis over the employee's requisite service period (generally the vesting period of the award). See Note 15. Stock-Based Compensation.

Income Taxes Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized when items of income and expense are recognized in the financial statements in different periods than when recognized in the applicable tax return. Deferred tax assets arise when expenses are recognized in the financial statements before the tax returns or when income items are recognized in the tax return prior to the financial statements. Deferred tax assets also arise when operating losses or tax credits are available to offset tax payments due in future years. Deferred tax liabilities arise when income items are recognized in the financial statements before the tax returns or when expenses are recognized in the tax return prior to the financial statements. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the date when the change in the tax rate was enacted. See Note 13. Income Taxes.

Treasury Stock We record treasury stock purchases at cost, which includes incremental direct transaction costs. Amounts are recorded as reductions in shareholders' equity in the consolidated balance sheets.

Revenue Recognition and Imbalances We record revenues from the sales of crude oil, natural gas and natural gas liquids (NGLs) when the product is delivered at a fixed or determinable price, title has transferred and collectibility is reasonably assured.

When we have an interest with other producers in properties from which natural gas is produced, we use the entitlements method to account for any imbalances. Imbalances occur when we sell more or less product than we are entitled to under our ownership percentage. Revenue is recognized only on the entitlement percentage of volumes sold. Any amount that we sell in excess of our entitlement is treated as a liability and is not recognized as revenue. Any amount of entitlement in excess of the amount we sell is recognized as revenue and a receivable is accrued.

Revenues derived from electricity generation are recognized when power is transmitted or delivered, the price is fixed and determinable and collectibility is reasonably assured.

Basic and Diluted Earnings Per Share Basic earnings per share (EPS) of our common stock have been computed on the basis of the weighted average number of shares outstanding during each period. The diluted EPS of our common stock includes the effect of outstanding common stock equivalents such as stock options, shares of restricted stock, and/or shares of our stock held in a rabbi trust, except in periods in which there is a net loss. See Note 17. Earnings Per Share.

Contingencies We are subject to legal proceedings, claims and liabilities that arise in the ordinary course of business. We accrue for losses associated with legal claims when such losses are considered probable and the amounts can be reasonably estimated. See Note 21. Commitments and Contingencies.

We self-insure the medical and dental coverage provided to certain employees, certain workers' compensation and the first $1 million of general liability coverage. Liabilities are accrued for self-insured claims, or when estimated losses exceed coverage limits, and when sufficient information is available to reasonably estimate the amount of the loss.

Foreign Currency The US dollar is considered the functional currency for each of our international operations. Transactions that are completed in foreign currencies are remeasured into US dollars and recorded in the financial statements at prevailing foreign exchange rates. Transaction gains or losses were not material in any of the periods presented and are included in other non-operating (income) expense, net in the consolidated statements of operations.

Segment Information Accounting policies for geographical segments are the same as those described above. Transfers between segments are accounted for at market value. We do not consider interest income and expense or income tax benefit or expense in our evaluation of the performance of geographical segments. See Note 18. Segment Information.

Note 2. Additional Financial Statement Information

Additional statements of operations information is as follows:

	Year Ended December 31,		
	2010	2009	2008
(millions)			
Other Revenues			
Electricity Sales [1]	$ 73	$ 72	$ 56
Refund of Deepwater Gulf of Mexico Royalties [2]	-	86	-
Other	(1)	11	20
Total	$ 72	$ 169	$ 76
Production Expense			
Lease Operating Expense	$ 376	$ 372	$ 371
Production and Ad Valorem Taxes	125	94	166
Transportation Expense	69	59	57
Total	$ 570	$ 525	$ 594
Other Operating Expense, Net			
Rig Contract Termination Expense [3]	$ 27	$ -	$ -
Electricity Generation Expense [1]	39	18	57
Write-down of SemCrude L.P. Receivable [4]	-	12	38
Miscellaneous Income	13	-	-
Other, Net	(15)	37	44
Total	$ 64	$ 67	$ 139
Other Non-Operating (Income) Expense, Net			
Deferred Compensation (Income) Expense [5]	$ 15	$ 23	$ (32)
Interest Income [6]	(7)	(13)	(20)
Other (Income) Expense, Net	(2)	2	(3)
Total	$ 6	$ 12	$ (55)

(1) Amount represents electricity sales from the Machala power plant located in Machala, Ecuador. Electricity generation expense includes all operating and non-operating expenses associated with the plant, including DD&A and changes in the allowance for doubtful accounts. See Note 3. Acquisitions and Divestitures, Note 4. Asset Impairments, and Note 5. Allowance for Doubtful Accounts.

(2) The refund was attributable to royalties that we previously paid on crude oil and natural gas produced in the deepwater Gulf of Mexico from January 1, 2003 through July 31, 2009.

(3) Amount relates primarily to an agreement to terminate our contract for the *Noble Clyde Boudreaux* drilling rig as a result of the Deepwater Moratorium.

(4) See Note 5. Allowance for Doubtful Accounts.

(5) Amount represents increases (decreases) in the fair value of shares of our common stock held in a rabbi trust. See Note 14. Benefit Plans.

(6) Interest income for 2010 and 2009 includes $3 million and $11 million, respectively, related to the refund of deepwater Gulf of Mexico royalties.

Additional balance sheet information is as follows:

	December 31, 2010	December 31, 2009
(millions)		
Accounts Receivable, Net		
Commodity Sales	$ 291	$ 205
Joint Interest Billings	259	140
Other	33	151
Allowance for Doubtful Accounts	(27)	(31)
Total	$ 556	$ 465
Other Current Assets		
Inventories, Current	$ 112	$ 89
Commodity Derivative Assets, Current	62	13
Deferred Income Taxes, Net, Current	8	32
Prepaid Expenses and Other Assets, Current	19	65
Total	$ 201	$ 199
Other Noncurrent Assets		
Equity Method Investments	$ 285	$ 303
Mutual Fund Investments	112	108
Other Assets, Noncurrent	87	44
Total	$ 484	$ 455
Accounts Payable - Trade		
Capital Costs	$ 642	$ 277
Royalties Payable	94	65
Lease Operating Expense	29	27
Other	162	179
Total	$ 927	$ 548
Other Current Liabilities		
Production and Ad Valorem Taxes	$ 110	$ 103
Commodity Derivative Liabilities, Current	24	100
Interest Rate Derivative Liability, Current	63	-
Income Taxes Payable	90	60
Asset Retirement Obligations, Current	45	51
Interest Payable	36	37
Other	127	91
Total	$ 495	$ 442
Other Noncurrent Liabilities		
Deferred Compensation Liabilities, Noncurrent	$ 229	$ 213
Asset Retirement Obligations, Noncurrent	208	181
Accrued Benefit Costs, Noncurrent	76	76
Commodity Derivative Liabilities, Noncurrent	51	17
Other	66	60
Total	$ 630	$ 547

Supplemental statements of cash flow information is as follows:

	Year Ended December 31,		
	2010	2009	2008
(millions)			
Cash Paid During the Year For			
Interest, Net of Amount Capitalized	$ 66	$ 52	$ 76
Income Taxes Paid, Net	173	227	263
Non-Cash Financing and Investing Activities			
Increase in FPSO Lease Obligation [1]	266	29	-

[1] See Note 12. Long-Term Debt.

Note 3. Acquisitions and Divestitures

Central DJ Basin Asset Acquisition On March 1, 2010, we acquired substantially all of the US Rocky Mountain assets of Petro-Canada Resources (USA) Inc. and Suncor Energy (Natural Gas) America Inc. The acquisition included properties located in the Central DJ Basin, one of our key operating areas.

The total purchase price and allocation of the total purchase price are as follows:

	December 31,
	2010
(millions)	
Total Purchase Price	
Cash Paid	$ 458
Net Liabilities Assumed	40
Total	$ 498
Allocation of Total Purchase Price	
Proved Oil and Gas Properties	$ 352
Unproved Oil and Gas Properties	146
Total	$ 498

The difference between the total purchase price and the fair values of the assets acquired was de minimis.

To estimate the fair values of the properties as of the acquisition date, we used an income approach as comparable market data was not available. We utilized a discounted cash flow model which took into account the following inputs to arrive at estimates of future net cash flows:

- estimated quantities of crude oil and natural gas prepared by our qualified petroleum engineers;
- estimated future commodity prices based on NYMEX crude oil and natural gas futures prices as of the acquisition date and adjusted for estimated location and quality differentials;
- estimated future production rates based on our experience with similar Central DJ Basin properties which we operate; and
- estimated timing and amounts of future operating and development costs based on our experience with similar Central DJ Basin properties which we operate.

To estimate the fair value of proved properties, we discounted the future net cash flows using a market-based weighted average cost of capital rate determined appropriate at the acquisition date. To compensate for the inherent risk of estimating and valuing unproved properties, we reduced the discounted future net cash flows of probable and possible reserves by additional risk-weighting factors. The fair values of the proved and unproved oil and gas properties are considered Level 3 fair value measurements.

Certain data necessary to complete the final purchase price allocation is not yet available, and includes, but is not limited to, final appraisals of assets acquired and liabilities assumed. We expect to complete the final purchase price allocation during the 12-month period following the acquisition date, during which time the preliminary allocation may be revised.

Related transaction costs were expensed. We have not presented pro forma information for the acquired business as the impact of the acquisition was not material to our consolidated balance sheet or results of operations. See also Note 16. Fair Value Measurements and Disclosures.

Sale of Onshore US Assets In August 2010, we closed the sale of non-core assets in the Mid-Continent and Illinois Basin areas. Information regarding the assets sold is as follows:

	Year Ended December 31, 2010
(millions)	
Cash Proceeds	$ 552
Less	
Net Book Value of Assets Sold	(394)
Goodwill Allocated to Assets Sold	(61)
Asset Retirement Obligations Associated with Assets Sold	10
Other Closing Adjustments	3
Gain on Asset Sale	$ 110

Mid-Continent Acquisition In 2008, we acquired producing properties in western Oklahoma for $292 million. The total purchase price was allocated to the proved and unproved properties acquired based on fair values at the acquisition date. Approximately $254 million was allocated to proved properties and $38 million to unproved properties.

Sale of Argentina Assets In 2008, we sold our interest in Argentina for a sales price of $117.5 million. The sale was subject to Argentine government approval. The $24 million gain on sale was deferred in other current liabilities until 2009 when the Argentine government approved the sale.

Termination of Ecuador PSC The government of Ecuador terminated the Block 3 PSC (100% working interest) with our subsidiary, EDC Ecuador Ltd. as we had not negotiated a service contract on Block 3 in accordance with the terms of a newly enacted hydrocarbon law. The hydrocarbon law aims to change current production-sharing arrangements into service contracts and provided for renegotiation of certain contracts by November 23, 2010. It also allows the Ecuadorian government to nationalize oil and gas fields if a private operator does not comply with local laws.

We are continuing to work with the government of Ecuador to resolve this matter. However, we are uncertain as to the potential outcome of this matter, resolution of which could ultimately lead to a reduction in the value of our investment in Ecuador which, as of December 31, 2010, had a net book value of approximately $66 million.

Note 4. Asset Impairments

Pre-tax (non-cash) asset impairment charges were as follows:

	Year Ended December 31,		
	2010	2009	2008
(millions)			
Iron Horse Development (Onshore US)	$ 89	$ -	$ -
New Albany Shale (Onshore US)	19	44	-
Granite Wash (Onshore US)	-	389	-
Main Pass (Gulf of Mexico Shelf)	5	48	38
Raton (Deepwater Gulf of Mexico)	6	23	-
Noa/Noa South (Israel)	25	-	-
Ecuador	-	100	70
Other Onshore US Proved Properties	-	-	111
Other Onshore US Unproved Properties	-	-	75
Total	$ 144	$ 604	$ 294

2010 Asset Impairments Due to declines in natural gas prices and recent drilling results, we determined that the carrying amount of our onshore US development at Iron Horse was not recoverable from future cash flows and, therefore, was impaired. We also recorded impairments of our non-core, New Albany Shale assets which had been reclassified to held-for-sale; our deepwater Gulf of Mexico development at Raton, primarily due to declines in natural gas prices; a Gulf of Mexico shelf asset; and our investment in the Noa/Noa South development, offshore Israel. We believe that it is less likely that Noa will be pursued for development due to near-term capability at the Mari-B field and the longer-term outlook from our discoveries at Tamar and Leviathan.

The Iron Horse, Raton and Gulf of Mexico Shelf assets were written down to their estimated fair values, which were determined using discounted cash flow models. The discounted cash flow models included management's estimates of future oil and gas production, commodity prices based on forward commodity price curves as of the date of the estimate, operating and development costs, and discount rates. The New Albany Shale assets were written down to anticipated sales proceeds less costs to sell.

2009 Asset Impairments Declines in natural gas prices resulted in impairments of Granite Wash, an onshore US area where we significantly reduced our investment beginning in 2007, and our New Albany Shale development. We also impaired our deepwater Gulf of Mexico development at Raton, primarily due to well performance issues and our

Gulf of Mexico shelf asset at Main Pass, which had been reclassified from held-for-sale to held-and-used. The assets were written down to their estimated fair values, which were determined using discounted cash flow models.

We also reviewed our investment in Ecuador for impairment, as a result of the increasingly unsettled economic and political environment in Ecuador, and determined that the carrying value of our investment exceeded its fair value. We estimated the fair value of our investment using a probability-weighted discounted cash flow model that considered the likelihood of possible outcomes of (1) the event of continued operation of the assets in contemplation of resolving the dispute and in accordance with the existing contract, (2) the event of a sale of our investment to a third party, and (3) the event of arbitration with varying degrees of award and collection. The use of alternative judgments and/or assumptions could have resulted in the recognition of an impairment charge that was significantly different.

2008 Asset Impairments As a result of the depressed economic environment, coupled with a severe decrease in commodity prices during the fourth quarter of 2008, we assessed the recoverability of our proved oil and gas properties, individually significant unproved oil and gas properties, and investment in Ecuador as of December 31, 2008. As a result, we determined that certain of our assets were impaired. The assets were written down to their estimated fair values, which were determined using discounted cash flow models. Onshore US unproved properties impaired in 2008 had been acquired in previous business combinations and their fair values were attributable to probable and possible reserves. We also recorded an impairment charge related to our Main Pass asset based on anticipated sales proceeds less costs to sell.

See also Note 16. Fair Value Measurements and Disclosures.

Note 5. Allowance for Doubtful Accounts

Changes in the allowance for doubtful accounts were as follows:

	Year Ended December 31,		
	2010	2009	2008
(millions)			
Balance, Beginning of Period	$ 31	$ 97	$ 50
Changes			
Allowance for Ecuador Receivable	1	14	11
Recovery of Ecuador Receivable [1]	(7)	(46)	-
Allowance for SemCrude L.P. Receivable	-	12	38
Other Changes	2	2	-
Net Changes Before Write-offs	(4)	(18)	49
Write-off of SemCrude Receivable [2]	-	(49)	-
Other Write-offs	-	1	(2)
Balance, End of Period	$ 27	$ 31	$ 97

(1) Amount in 2009 was received in accordance with the terms of a settlement agreement and included as a reduction in electricity generation expense.

(2) SemCrude, L.P. was a crude oil purchaser who filed a voluntary petition for reorganization under Chapter 11 of the Bankruptcy Code in 2008.

Note 6. Inventories

Inventories consisted of the following:

	December 31,	
	2010	2009
(millions)		
Materials and Supplies	$ 95	$ 71
Crude Oil	17	18
Total	$ 112	$ 89

Note 7. Capitalized Exploratory Well Costs

We capitalize exploratory well costs until a determination is made that the well has found proved reserves or is deemed noncommercial. If a well is deemed to be noncommercial, the well costs are immediately charged to exploration expense.

Changes in capitalized exploratory well costs are as follows and exclude amounts that were capitalized and subsequently expensed in the same period:

	Year Ended December 31,		
	2010	2009	2008
(millions)			
Capitalized Exploratory Well Costs, Beginning of Period	$ 432	$ 501	$ 249
Additions to Capitalized Exploratory Well Costs Pending Determination of Proved Reserves	143	136	253
Reclassified to Proved Oil and Gas Properties Based on Determination of Proved Reserves	(146)	(198)	-
Capitalized Exploratory Well Costs Charged to Expense	(3)	(7)	(1)
Capitalized Exploratory Well Costs, End of Period	$ 426	$ 432	$ 501

The following table provides an aging of capitalized exploratory well costs (suspended well costs) based on the date the drilling was completed and the number of projects for which exploratory well costs have been capitalized for a period greater than one year since the completion of drilling:

	December 31,		
	2010	2009	2008
(millions)			
Exploratory Well Costs Capitalized for a Period of One Year or Less	$ 148	$ 158	$ 256
Exploratory Well Costs Capitalized for a Period Greater Than One Year After Completion of Drilling	278	274	245
Balance at End of Period	$ 426	$ 432	$ 501
Number of Projects w ith Exploratory Well Costs That Have Been Capitalized for a Period Greater Than One Year After Completion of Drilling	8	5	6

The following table provides a further aging of those exploratory well costs that have been capitalized for a period greater than one year since the completion of drilling as of December 31, 2010:

		Suspended Since		
	Total	2009	2008	2007 & Prior
(millions)				
Project				
Blocks O and I (West Africa)	$ 133	$ 14	$ 9	$ 110
Dalit (Israel)	20	20	-	-
Gunflint (Deepw ater Gulf of Mexico)	52	3	49	-
Redrock (Deepw ater Gulf of Mexico)	17	-	-	17
Deep Blue (Deepw ater Gulf of Mexico)	19	19	-	-
Flyndre (North Sea)	13	-	-	13
Selkirk (North Sea)	20	-	-	20
Other	4	1	3	-
Total Exploratory Well Costs Capitalized for a Period Greater Than One Year After Completion of Drilling	$ 278	$ 57	$ 61	$ 160

Blocks O and I (West Africa) The West Africa project includes Blocks O and I offshore Equatorial Guinea and the YoYo mining concession and Tilapia PSC offshore Cameroon. In December 2010, we and our partners sanctioned the development plan for Alen, which was subsequently approved by the government of Equatorial Guinea in January 2011. Approximately $61 million of capitalized costs were reclassified to proved oil and gas properties. In 2009, we sanctioned the Aseng development project and reclassified $76 million of capitalized costs to proved oil and gas properties. We are evaluating future oil projects and planning to drill an appraisal well at Diega/Carmen, offshore Equatorial Guinea. In Cameroon, we recently completed a 3-D seismic acquisition, and results are being processed for future drilling potential.

Dalit (Israel) Dalit is a 2009 natural gas discovery located offshore Israel. We are currently working with our partners on a cost-effective development plan. In 2010, we sanctioned the Tamar development project and reclassified $77 million of capitalized costs to proved oil and gas properties.

Gunflint (Deepwater Gulf of Mexico) Gunflint (Mississippi Canyon Block 948) is a 2008 crude oil discovery. Our plans to drill one or two appraisal wells in 2010 were delayed by the Deepwater Moratorium. Once a drilling permit is approved, we plan to drill one or two appraisal wells. We are also reviewing host platform options including: subsea tieback to an existing third-party host, procurement and modification of an existing platform, and new construction. If we are able to connect to an existing third-party host, the project could have an accelerated completion schedule, thereby potentially absorbing time lost due to the drilling delay caused by the Deepwater Moratorium.

Redrock (Deepwater Gulf of Mexico) Redrock (Mississippi Canyon Block 204) was a 2006 natural gas/condensate discovery and is currently considered a co-development candidate with Raton South (Mississippi Canyon Block 292). We are in the process of tying back Raton South to a host platform at Viosca Knoll Block 900. We plan to tie back Redrock after Raton South commences production, which is currently expected to occur by the end of 2011.

Deep Blue (Deepwater Gulf of Mexico) Deep Blue (Green Canyon Block 723) was a significant test well, which began drilling during 2009. When the Deepwater Moratorium was announced in May 2010, we were required to suspend sidetrack drilling activities at the Deep Blue prospect. Once a drilling permit is approved, we plan to resume exploration activities at Deep Blue.

Flyndre (North Sea) The Flyndre project is located in the UK sector of the North Sea and we successfully completed an exploratory appraisal well in 2007. We are currently working with the project operator and other partners to finalize the field development plan and relevant operating agreements.

Selkirk (North Sea) The Selkirk project is also located in the UK sector of the North Sea. Capitalized costs to date primarily consist of the cost of drilling an exploratory well. We are currently working with our partners on a cost-effective development plan, including selection of a host facility.

Note 8. Equity Method Investments

Investments accounted for under the equity method consist primarily of the following:

- 45% interest in Atlantic Methanol Production Company, LLC (AMPCO), which owns and operates a methanol plant and related facilities in Equatorial Guinea; and
- 28% interest in Alba Plant LLC (Alba Plant), which owns and operates a liquefied petroleum gas processing plant in Equatorial Guinea.

Equity method investments are included in other noncurrent assets in the consolidated balance sheets, and our share of earnings is reported as income from equity method investees in the consolidated statements of operations. Our share of income taxes incurred directly by the equity method investees is reported in income from equity method investments and is not included in our income tax provision in our consolidated statements of operations. At December 31, 2010, our retained earnings included $122 million related to the undistributed earnings of equity method investees.

The carrying value of our AMPCO investment was $21 million higher than the underlying net assets of the investee at December 31, 2010. The difference includes $12 million relating to capitalized interest which is being amortized into earnings over the remaining useful life of the plant. The remaining $9 million relates to a note receivable from our funding a portion of the local government's share of the plant's development. The note receivable is being recovered through distributions from AMPCO.

Equity method investments are as follows:

	December 31,	
	2010	2009
(millions)		
Equity Method Investments		
AMPCO	$ 166	$ 180
Alba Plant	107	111
Other	12	12
Total Equity Method Investments	$ 285	$ 303

Summarized, 100% combined financial information for equity method investees is as follows:

	December 31,	
	2010	2009
(millions)		
Balance Sheet Information		
Current Assets	$ 307	$ 269
Noncurrent Assets	735	751
Current Liabilities	265	187
Noncurrent Liabilities	16	59

	Year Ended December 31,		
	2010	2009	2008
(millions)			
Statements of Operations Information			
Operating Revenues	$ 809	$ 632	$ 1,022
Operating Expenses	296	264	301
Operating Income	513	368	721
Other Income, Net	(12)	(13)	(14)
Income Before Income Taxes	525	381	735
Income Tax Provision	133	95	183
Net Income	$ 392	$ 286	$ 552

Note 9. Goodwill

Changes in the carrying amount of goodwill were as follows:

	Year Ended December 31,	
	2010	2009
(millions)		
Goodwill, Beginning Balance	$ 758	$ 759
Amount Allocated to Sale of Business Unit	(61)	-
Other	(1)	(1)
Goodwill, Ending Balance	$ 696	$ 758

Note 10. Derivative Instruments and Hedging Activities

Objective and Strategies for Using Derivative Instruments In order to reduce commodity price uncertainty and enhance the predictability of cash flows relating to the marketing of our crude oil and natural gas, we enter into crude oil and natural gas price hedging arrangements with respect to a portion of our expected production. The derivative instruments we use include variable to fixed price commodity swaps, two-way and three-way collars and basis swaps.

The fixed price swap, two-way collar, and basis swap contracts entitle us (floating price payor) to receive settlement from the counterparty (fixed price payor) for each calculation period in amounts, if any, by which the settlement price for the scheduled trading days applicable for each calculation period is less than the fixed strike price or floor price. We would pay the counterparty if the settlement price for the scheduled trading days applicable for each calculation period is more than the fixed strike price or ceiling price. The amount payable by us, if the floating price is above the fixed or ceiling price, is the product of the notional quantity per calculation period and the excess, if any, of the floating price over the fixed or ceiling price in respect of each calculation period. The amount payable by the counterparty, if the floating price is below the fixed or floor price, is the product of the notional quantity per calculation period and the excess, if any, of the fixed or floor price over the floating price in respect of each calculation period.

A three-way collar consists of a two-way collar contract combined with a put option contract sold by us with a strike price below the floor price of the two-way collar. We receive price protection at the purchased put option floor price of the two-way collar if commodity prices are above the sold put option strike price. If commodity prices fall below the sold put option strike price, we receive the cash market price plus the delta between the two put option strike prices. This type of instrument allows us to capture more value in a rising commodity price environment, but limits our benefits in a downward commodity price environment.

We also enter into forward contracts or swap agreements to hedge exposure to interest rate risk.

While these instruments mitigate the cash flow risk of future reductions in commodity prices or increases in interest rates, they may also curtail benefits from future increases in commodity prices or decreases in interest rates.

See Note 16. Fair Value Measurements and Disclosures for a discussion of methods and assumptions used to estimate the fair values of our derivative instruments.

Counterparty Credit Risk Derivative instruments expose us to counterparty credit risk. Our commodity derivative instruments are currently with a diversified group of highly rated major banks or market participants, and we control our level of financial exposure. Our commodity derivative contracts are executed under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net settled at the time of election.

We monitor the creditworthiness of our counterparties. However, we are not able to predict sudden changes in counterparties' creditworthiness. In addition, even if such changes are not sudden, we may be limited in our ability to mitigate an increase in counterparty credit risk. Possible actions would be to transfer our position to another counterparty or request a voluntary termination of the derivative contracts resulting in a cash settlement. Should one of these financial counterparties not perform, we may not realize the benefit of some of our derivative instruments under lower commodity prices or higher interest rates, and could incur a loss.

Unsettled Derivative Instruments We have entered into the following crude oil derivative instruments:

				Swaps	Collars		
Period	Type of Contract	Index	Bbls Per Day	Weighted Average Fixed Price	Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
Instruments entered into prior to December 31, 2010							
2011	Swaps	NYMEX WTI [1]	5,000	$ 85.52	$ -	$ -	$ -
2011	Two-Way Collars	NYMEX WTI	13,000	-	-	80.15	94.63
2011	Three-Way Collars	NYMEX WTI	12,000	-	58.33	78.33	100.71
2012	Swaps	NYMEX WTI	5,000	91.84	-	-	-
2012	Swaps	Dated Brent	5,000	83.09	-	-	-
2012	Three-Way Collars	NYMEX WTI	23,000	-	61.09	83.04	101.66
Instruments entered into during January 1-31, 2011							
2012	Swaps	Dated Brent	3,000	99.00	-	-	-
2012	Three-Way Collars	Dated Brent	3,000	-	70.00	95.83	105.00
2013	Swaps	Dated Brent	3,000	98.03	-	-	-
2013	Three-Way Collars	NYMEX WTI	5,000	-	65.00	85.00	113.63
2013	Three-Way Collars	Dated Brent	5,000	-	70.00	94.01	110.00

(1) West Texas Intermediate

We have entered into the following natural gas derivative instruments:

				Swaps	Collars		
Period	Type of Contract	Index	MMBtu Per Day	Weighted Average Fixed Price	Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
Instruments entered into prior to December 31, 2010							
2011	Swaps	NYMEX HH [1]	25,000	$ 6.41	$ -	$ -	$ -
2011	Two-Way Collars	NYMEX HH	140,000	-	-	5.95	6.82
2011	Three-Way Collars	NYMEX HH	50,000	-	4.00	5.00	6.70
2012	Three-Way Collars	NYMEX HH	80,000	-	4.60	5.35	7.11
Instruments entered into during January 1-31, 2011							
2012	Swaps	NYMEX HH	30,000	5.10	-	-	-
2012	Three-Way Collars	NYMEX HH	30,000	-	4.00	5.00	5.48
2013	Swaps	NYMEX HH	30,000	5.25	-	-	-
2013	Three-Way Collars	NYMEX HH	50,000	-	4.00	5.25	5.59

(1) Henry Hub

As of December 31, 2010, we had entered into the following natural gas basis swaps:

Period	Index	Index Less Differential	MMBtu Per Day	Weighted Average Differential
2011	IFERC CIG [1]	NYMEX HH	140,000	$ (0.70)
2012	IFERC CIG	NYMEX HH	150,000	(0.52)

(1) Colorado Interstate Gas – Northern System

Fair Value Amounts and Gains and Losses on Derivative Instruments The fair values of derivative instruments in our consolidated balance sheets were as follows:

Fair Value of Derivative Instruments

	Asset Derivative Instruments				Liability Derivative Instruments			
	December 31,				December 31,			
	2010		2009		2010		2009	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
(millions)								
Commodity Derivative Instruments (Not Designated as Hedging Instruments)	Current Assets	$ 62	Current Assets	$ 13	Current Liabilities	$ 24	Current Liabilities	$ 100
	Noncurrent Assets	-	Noncurrent Assets	1	Noncurrent Liabilities	51	Noncurrent Liabilities	17
Interest Rate Derivative Instrument (Designated as Hedging Instrument) [1]	Current Assets	-	Current Assets	-	Current Liabilities	63	Current Liabilities	-
	Total	$ 62	Total	$ 14	Total	$138	Total	$ 117

[1] In 2010, in anticipation of a long-term debt issuance, we entered into an interest rate forward starting swap to effectively fix the cash flows related to interest payments on the anticipated debt issuance. We are accounting for the instrument as a cash flow hedge against the variability of interest payments attributable to changes in interest rates on the forecasted issuance of fixed-rate debt. The swap is in the notional amount of $500 million and is based on a 30-year LIBOR swap rate.

The effect of derivative instruments on our consolidated statements of operations was as follows:

Commodity Derivative Instruments Not Designated as Hedging Instruments

Amount of (Gain) Loss on Derivative Instruments Recognized in Income

	Year Ended December 31,		
	2010	2009	2008
(millions)			
Realized Mark-to-Market (Gain) Loss	$ (87)	$ (496)	$ 82
Unrealized Mark-to-Market (Gain) Loss	(70)	606	(522)
Total (Gain) Loss on Commodity Derivative Instruments	$ (157)	$ 110	$ (440)

Derivative Instruments in Cash Flow Hedging Relationships

	Amount of (Gain) Loss on Derivative Instruments Recognized in Other Comprehensive (Income) Loss			Amount of (Gain) Loss on Derivative Instruments Reclassified from Accumulated Other Comprehensive Loss		
	2010	2009	2008	2010	2009	2008
(millions)						
Commodity Derivative Instruments in Previously Designated Cash Flow Hedging Relationships [1]						
Crude Oil	$ -	$ -	$ -	$ 19	$ 58	$ 365
Natural Gas	-	-	-	1	-	(34)
Interest Rate Derivative Instruments in Cash Flow Hedging Relationships	(63)	-	(1)	1	1	1
Total	$ (63)	$ -	$ (1)	$ 21	$ 59	$ 332

[1] Includes effect of commodity derivative instruments previously accounted for as cash flow hedges. Net derivative gains and losses that were deferred in AOCL as of January 1, 2008, as a result of previous cash flow hedge accounting, were reclassified to oil, gas and NGL sales in our consolidated statements of operations in 2008, 2009 and 2010 as the original hedged transactions occurred.

AOCL – Commodity Derivative Instruments At December 31, 2010, AOCL included no further amounts related to commodity derivative instruments. At December 31, 2009, the balance in AOCL included net deferred losses of $12 million (net of deferred income tax benefits of $8 million) related to the fair value of crude oil and natural gas derivative instruments previously designated as cash flow hedges. The net deferred losses were reclassified to earnings during 2010 as the forecasted transactions occurred and recorded as a reduction in oil, gas and NGL sales of approximately $20 million before tax.

AOCL – Interest Rate Derivative Instruments At December 31, 2010, AOCL included deferred losses of $42 million, net of tax, related to interest rate derivative instruments. Of this amount, $1 million, net of tax, is currently being reclassified into earnings as adjustments to interest expense over the term of our Senior Notes due April 2014. Approximately $41 million will remain in AOCL until fixed-rate debt is issued, at which time we will begin amortizing it to interest expense over the life of the related debt issuance.

Note 11. Asset Retirement Obligations

Changes in asset retirement obligations were as follows:

	Year Ended December 31,	
	2010	2009
(millions)		
Asset Retirement Obligations, Beginning Balance	$ 232	$ 211
Liabilities Incurred	17	22
Liabilities Settled	(56)	(36)
Revision of Estimate	43	21
Accretion Expense	17	14
Asset Retirement Obligations, Ending Balance	$ 253	$ 232

For the year ended December 31, 2010, liabilities incurred were primarily due to the Central DJ Basin asset acquisition. Liabilities settled related to non-core onshore US properties sold, abandoned Gulf of Mexico shelf assets, and Block 3 offshore Ecuador. Revisions resulted from changes in estimated timing of actual abandonment due to shortened field lives for certain UK assets and overall cost increases for assets located primarily in the deepwater Gulf of Mexico.

For the year ended December 31, 2009, liabilities incurred related primarily to properties in the deepwater Gulf of Mexico, the Aseng field, offshore Equatorial Guinea, and North Sea projects. Liabilities settled related primarily to properties in the Main Pass and Viosca Knoll areas of the Gulf of Mexico. Revisions related to the Main Pass asset and a deepwater Gulf of Mexico property.

Accretion expense is included in depreciation, depletion and amortization expense in the consolidated statements of operations.

Note 12. Long-Term Debt

Our debt consists of the following:

	December 31,			
	2010		2009	
	Debt	Interest Rate	Debt	Interest Rate
(millions, except percentages)				
Credit Facility, due December 9, 2012	$ 350	0.57%	$ 382	0.54%
5¼% Senior Notes, due April 15, 2014	200	5.25%	200	5.25%
8¼% Senior Notes, due March 1, 2019	1,000	8.25%	1,000	8.25%
7¼% Notes, due October 15, 2023	100	7.25%	100	7.25%
8% Senior Notes, due April 1, 2027	250	8.00%	250	8.00%
7¼% Senior Debentures, due August 1, 2097	84	7.25%	84	7.25%
FPSO Lease Obligation [1]	295	-	29	-
Total Debt	2,279		2,045	
Unamortized Discount	(7)		(8)	
Total Debt, Net of Discount	$ 2,272		$ 2,037	

[1] Amount reported is based on percentage of FPSO construction activities completed as of December 31, 2010 and therefore does not reflect future minimum lease payments. See *FPSO Lease Obligation* below.

All of our long-term debt is senior unsecured debt and is, therefore, *pari passu* with respect to the payment of both principal and interest. The indenture documents of each of our notes provide that we may prepay the instruments by creating a defeasance trust. The defeasance provisions require that the trust be funded with securities sufficient, in the opinion of a nationally recognized accounting firm, to pay all scheduled principal and interest due under the respective agreements. Interest on each of these issues is payable semi-annually. Debt issuance costs of approximately $11 million remain and are being amortized to expense over the life of the related debt issues.

Credit Facility Our bank revolving credit facility (the credit facility) is committed in the amount of $2.1 billion until December 9, 2011 at which time the commitment reduces to $1.8 billion. The credit facility (i) provides for credit facility fee rates that range from 5 basis points to 15 basis points per year depending upon our credit rating, (ii) makes available short-term loans up to an aggregate amount of $300 million within the current $2.1 billion commitment and (iii) provides for interest rates that are based upon the Eurodollar rate plus a margin that ranges from 20 basis points to 70 basis points depending upon our credit rating and utilization of the credit facility. The credit facility requires that our total debt to capitalization ratio (as defined in the credit agreement), expressed as a percentage, not exceed 60% at any time. A violation of this covenant could result in a default under the credit facility, which would permit the participating banks to restrict our ability to access the credit facility and require the immediate repayment of any outstanding advances under the credit facility. As of December 31, 2010, we were in compliance with our debt covenants. The credit facility is with certain commercial lending institutions and is available for general corporate purposes.

Certain lenders that are a party to the credit facility have in the past performed investment banking, financial advisory, lending or commercial banking services for us, for which they have received customary compensation and reimbursement of expenses.

The credit facility does not restrict the payment of dividends on our common stock, except, if after giving effect thereto, an Event of Default shall have occurred and be continuing or been caused thereby.

FPSO Lease Obligation In 2009, we entered into an agreement with an unrelated offshore technology provider for the construction and lease of an FPSO to be used for development of the Aseng field, offshore Equatorial Guinea. We serve as technical operator of the development project with a 40% working interest.

Construction of the FPSO is scheduled to be completed in 2012, at which time the FPSO will be delivered to Block I, offshore Equatorial Guinea, for the start-up of the Aseng field. The initial term of the lease is for a period of 15 years. We expect to account for the lease agreement as a capital lease. As a result, the FPSO will be included in oil and gas properties and the associated long-term obligation will be included in our balance sheet. We expect that the lease obligation will total approximately $358 million, net to our 40% interest. This amount represents our share of the expected present value of the future minimum lease payments, excluding executory costs, and is subject to change based on change orders implemented during the construction period, final accounting treatment and other factors.

Throughout the construction phase, we will include both the FPSO asset and associated long-term obligation in our balance sheet, based upon the percentage of construction completed at the end of each reporting period.

Monthly lease payments will exclude regular maintenance and operational costs, and will begin when the FPSO initiates producing operations. See Note 21. Commitments and Contingencies for estimated annual lease payments.

2009 Debt Offering In 2009, we closed an offering of $1 billion senior unsecured notes receiving net proceeds of $989 million, after deducting the discount and underwriting fees. The notes are due March 1, 2019, and pay interest semi-annually at 8¼%. Debt issuance costs of approximately $2 million were incurred and are being amortized to expense over the life of the debt issue. Substantially all of the net proceeds from the offering were used to repay outstanding indebtedness under our revolving credit facility maturing 2012. The notes are senior unsecured debt and rank *pari passu* with any of our other senior unsecured indebtedness with respect to the payment of both principal and interest.

2009 Debt Repurchase In 2009, we repurchased $5 million of our Senior Debentures due August 1, 2097, recognizing a debt extinguishment gain of $1 million.

Annual Maturities Annual maturities of outstanding debt, excluding FPSO lease payments, are as follows:

	As of December 31, 2010	
(millions)		
2011	$	-
2012		350
2013		-
2014		200
2015		-
Thereafter		1,434
Total	$	1,984

Short-Term Borrowings Our credit agreement is supplemented by short-term borrowings under various uncommitted credit lines used for working capital purposes. Uncommitted credit lines may be offered by certain banks from time to time at rates negotiated at the time of borrowing. No short-term borrowings were outstanding at December 31, 2010 or 2009.

Note 13. Income Taxes

Components of income (loss) before income taxes are as follows:

	Year Ended December 31,		
	2010	2009	2008
(millions)			
Domestic	$ 235	$ (808)	$ 1,032
Foreign	796	544	1,029
Total	$ 1,031	$ (264)	$ 2,061

The income tax provision (benefit) consists of the following:

	Year Ended December 31,		
	2010	2009	2008
(millions)			
Current Taxes			
Federal	$ 25	$ 45	$ 45
State	2	1	1
Foreign	208	117	306
Total Current	235	163	352
Deferred Taxes			
Federal	86	(320)	363
State	1	(5)	4
Foreign	(16)	29	(8)
Total Deferred	71	(296)	359
Total Income Tax Provision (Benefit)	$ 306	$ (133)	$ 711
Effective Tax Rate	30%	50%	35%

A reconciliation of the federal statutory tax rate to the effective tax rate is as follows:

	Year Ended December 31,		
	2010	2009	2008
(percentages)			
Federal Statutory Rate	35.0	35.0	35.0
Effect of			
Earnings of Equity Method Investees	(4.0)	11.3	(2.9)
State Taxes, Net of Federal Benefit	0.3	1.5	0.2
Difference Between US and Foreign Rates	1.7	(1.4)	1.8
Percentage Depletion in Excess of Basis	(1.6)	4.5	(0.6)
Change in Valuation Allowance	(2.2)	1.5	1.7
Other, Net	0.5	(2.0)	(0.7)
Effective Rate	29.7	50.4	34.5

Deferred tax assets and liabilities resulted from the following:

	December 31, 2010	December 31, 2009
(millions)		
Deferred Tax Assets		
Loss Carryforwards	$ 72	$ 49
Ecuador Investment	12	20
Accrued Expenses	10	17
Allowance for Doubtful Accounts	5	6
Net Pension Obligation	35	34
Postretirement Benefits	35	34
Deferred Compensation	94	73
Foreign Tax Credits	25	28
Commodity Derivative Assets	38	54
Other	32	35
Total Deferred Tax Assets	358	350
Valuation Allowance - Foreign Loss Carryforwards	(58)	(45)
Valuation Allowance - Foreign Tax Credits	-	(28)
Valuation Allowance - Ecuador Investment	(12)	(20)
Net Deferred Tax Assets	288	257
Deferred Tax Liabilities		
Depreciation, Amortization, Lease Impairment and Abandonments	(2,389)	(2,302)
Total Deferred Tax Liability	(2,389)	(2,302)
Net Deferred Tax Liability	$ (2,101)	$ (2,045)

Net deferred tax liabilities were classified in the consolidated balance sheets as follows:

	December 31, 2010	December 31, 2009
(millions)		
Deferred Income Tax Asset	$ 9	$ 32
Deferred Income Tax Liability - Current	-	(1)
Deferred Income Tax Liability - Noncurrent	(2,110)	(2,076)
Net Deferred Tax Liability	$ (2,101)	$ (2,045)

Deferred Tax Assets In assessing the realizability of deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income in the appropriate tax jurisdictions during the periods in which those temporary differences become deductible. We consider the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. Based upon the level of historical taxable income and projections for future taxable income over the periods in which the deferred tax assets are deductible, we believe it is more likely than not that we will realize the benefits of these deductible differences at December 31, 2010. The amount of the deferred tax assets considered realizable could be reduced in the future if estimates of future taxable income during the carryforward period are reduced.

We have recognized deferred tax assets associated with foreign loss carryforwards. The tax effects of these carryforwards totaled $35 million in 2008, increased to $47 million in 2009 and increased to $70 million in 2010. Losses continue to be incurred on our projects in Equatorial Guinea and new venture activities which are not yet commercial.

During 2010, we reversed a $28 million valuation allowance that had been provided against a deferred tax asset of the same amount for the future foreign tax credits associated with deferred tax liabilities recorded by foreign branch operations and recorded a reduction in income tax expense. We now believe it is more likely than not that this deferred tax asset will be realized.

Effective Tax Rate Our effective tax rate decreased in 2010 as compared with 2009. For 2010, the effective rate was lower than the federal statutory rate because our income from equity method investees and other permanent differences have the impact of decreasing the effective rate when we have pre-tax income. We also recorded a reduction in income tax expense due to the reversal of a deferred tax asset valuation allowance.

Our effective tax rate increased in 2009 as compared with 2008 and is the result of a tax benefit divided by a pre-tax loss. In the case of a loss, our favorable permanent differences, such as income from equity method investees, have the effect of increasing the tax benefit which, in turn, increases the effective rate.

Repatriation During 2009, we repatriated $180 million of accumulated earnings of foreign subsidiaries and used the proceeds for debt repayment and general corporate purposes. The repatriation increased US tax expense by $13 million, of which $9 million was recorded in 2008. Repatriation of additional earnings in the future could result in a decrease in our net income and cash flows.

Accumulated Undistributed Earnings of Foreign Subsidiaries As of December 31, 2010, the accumulated undistributed earnings of the foreign subsidiaries on which no US taxes have been recorded were approximately $1.5 billion. Upon distribution of additional earnings in the form of dividends or otherwise, we would likely be subject to US income taxes and foreign withholding taxes. It is not practicable, however, to determine precisely the amount of taxes that may be payable on the eventual remittance of these earnings because of the possible application of US foreign tax credits. Although we are currently claiming foreign tax credits, we may not be in a credit position when any future remittance of foreign earnings takes place, or the limitations imposed by the Internal Revenue Code and IRS Regulations may not allow the credits to be utilized during the applicable carryback and carryforward periods. However, if full use of tax credits is assumed, we estimate that the future US taxes on eventual remittance would be approximately $260 million.

Unrecognized Tax Benefits We did not have significant unrecognized tax benefits resulting from differences between positions taken in tax returns and amounts recognized in the financial statements as of December 31, 2010 or 2009. Our policy is to recognize any interest and penalties related to unrecognized tax benefits in income tax expense. However, we did not accrue interest or penalties at December 31, 2010 or 2009, because the jurisdiction in which we have unrecognized tax benefits does not currently impose interest on underpayments of tax and we believe that we are below the minimum statutory threshold for imposition of penalties. We do not expect that the total amount of unrecognized tax benefits will significantly increase or decrease during the next 12 months.

Years Open to Examination In our major tax jurisdictions, the earliest years remaining open to examination are as follows: US – 2006, Equatorial Guinea – 2007, Israel – 2008, UK – 2007, the Netherlands – 2009, and China – 2006.

Note 14. Benefit Plans

Pension and Other Postretirement Benefit Plans We have a noncontributory, tax-qualified defined benefit pension plan covering employees who were hired prior to May 1, 2006. The benefits are based on an employee's years of service and average earnings for the 60 consecutive calendar months of highest compensation. Our funding policy has been to make annual contributions equal to at least the minimum required contribution, but no greater than the maximum deductible for federal income tax purposes. We also have an unfunded, nonqualified restoration plan that provides the pension plan formula benefits that cannot be provided by the qualified pension plan because of pay deferrals and the compensation and benefit limitations imposed on the pension plan by the Internal Revenue Code of 1986, as amended. We sponsor other plans for the benefit of our employees and retirees, which include medical and life insurance benefits. We use a December 31 measurement date for the plans.

Changes in the benefit obligation and plan assets of the pension, restoration and other postretirement benefit plans were as follows at December 31:

	Retirement and Restoration Plans		Medical and Life Plans	
	2010	2009	2010	2009
(millions)				
Change in Benefit Obligation				
Benefit Obligation, Beginning Balance	$ 228	$ 194	$ 23	$ 22
Service Cost	14	12	2	2
Interest Cost	13	11	1	1
Employee Contributions	-	-	1	-
Benefits Paid	(12)	(13)	(1)	(1)
Plan Amendments [1]	-	-	-	(2)
Actuarial Net (Gains) Losses	19	24	(2)	1
Benefit Obligation, Ending Balance	262	228	24	23
Change in Plan Assets				
Fair Value of Plan Assets, Beginning Balance	172	132	-	-
Actual Return on Plan Assets	23	33	-	-
Employer Contributions	23	20	1	1
Benefits Paid	(12)	(13)	(1)	(1)
Fair Value of Plan Assets, Ending Balance	206	172	-	-
Funded Status of Plan				
Funded Status at End of Year	(56)	(56)	(24)	(23)
Net Amount Recognized in Consolidated Balance Sheets	(56)	(56)	(24)	(23)
Amounts Recognized in Consolidated Balance Sheets Consist of				
Current Liabilities	(3)	(2)	(1)	(1)
Noncurrent Liabilities	(53)	(54)	(23)	(22)
Net Amount Recognized in Consolidated Balance Sheets	(56)	(56)	(24)	(23)
Amounts Not Yet Reflected in Net Periodic Benefit Cost and Included in AOCL				
Net Prior Service (Cost) Credit, Before Tax	(3)	(3)	6	7
Net Gains (Losses), Before Tax	(93)	(88)	(9)	(11)
AOCL	(96)	(91)	(3)	(4)
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	40	35	(21)	(19)
Net Amount Recognized in Consolidated Balance Sheets	$ (56)	$ (56)	$ (24)	$ (23)

[1] Plan amendments relate to an increase in the monthly retiree contributions for the medical and life plan.

Net periodic benefit cost recognized for the pension, restoration and other postretirement benefit plans was as follows:

	Retirement and Restoration Plans			Medical and Life Plans		
	Year Ended December 31,			Year Ended December 31,		
	2010	2009	2008	2010	2009	2008
(millions)						
Components of Net Periodic Benefit Cost						
Service Cost	$ 14	$ 12	$ 12	$ 2	$ 2	$ 2
Interest Cost	13	11	12	1	1	1
Expected Return on Plan Assets	(14)	(14)	(12)	-	-	-
Amortization of Prior Service (Credit) Cost	-	-	-	(1)	(1)	(1)
Amortization of Net Loss and Other	5	3	2	1	1	1
Net Periodic Benefit Cost	$ 18	$ 12	$ 14	$ 3	$ 3	$ 3
Other Changes Recognized in AOCL						
Prior Service Cost Arising During Period	$ -	$ -	$ -	$ -	$ (2)	$ -
Net Loss (Gain) Arising During Period	10	5	53	(2)	1	(3)
Amortization of Prior Service Credit	-	-	-	1	1	1
Amortization of Net Loss	(5)	(3)	(2)	(1)	(1)	(1)
Total Recognized in AOCL	$ 5	$ 2	$ 51	$ (2)	$ (1)	$ (3)
Expected Amortizations for Next Fiscal Year						
Amortization of Net Prior Service Cost (Credit)	$ -	$ -	$ -	$ (1)	$ (1)	$ (1)
Amortization of Net Losses	6	5	2	-	1	1
Weighted-Average Assumptions Used to Determine Benefit Obligations						
Discount Rate [1]	5.50% / 5.25%	6.00%	6.00% / 6.25%	5.00%	5.50%	6.25%
Rate of Compensation Increase	5.00%	5.00%	5.00%	-	-	-
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Costs						
Discount Rate [1]	6.00%	6.00% / 6.25%	6.50%	5.50%	6.25%	6.25%
Expected Long-Term Return on Assets	7.50%	8.00%	8.25%	-	-	-
Rate of Compensation Increase	5.00%	5.00%	5.00%	-	-	-

[1] The discount rates used to determine benefit obligations at December 31, 2010 were 5.50% for the retirement plan and 5.25% for the restoration plan. The discount rates used to determine benefit obligations at December 31, 2008 and net periodic benefit costs for the year ended December 31, 2009 were 6.00% for the retirement plan and 6.25% for the restoration plan.

Additional disclosures for the retirement and restoration plans are as follows:

	December 31,	
	2010	2009
(millions)		
Accumulated Benefit Obligation	$ 230	$ 197
Information for Pension Plans With Projected Benefit Obligations in Excess of Plan Assets		
Projected Benefit Obligation	262	228
Fair Value of Plan Assets	206	172
Information for Pension Plans With Accumulated Benefit Obligations in Excess of Plan Assets		
Accumulated Benefit Obligation	37	31
Fair Value of Plan Assets	-	-

In selecting the assumption for expected long-term rate of return on assets, we consider the average rate of earnings expected on the funds to be invested to provide for plan benefits. This includes considering the plan's asset allocation, historical returns on these types of assets, the current economic environment and the expected returns likely to be earned over the life of the plan. We assume the long-term asset mix will be consistent with a target asset allocation of 70% equity and 30% fixed income, with a range in the acceptable degree of variation in the plan's asset allocation of plus or minus 10%. Based on these factors we assumed an average of 7.50% per annum over the life of the plan for the calculation of 2010 net periodic benefit cost. The assumption will be reduced to 7.25% for the calculation of 2011 net periodic benefit cost. No plan assets are expected to be returned to us in 2011.

In order to determine an appropriate discount rate at December 31, 2010, we performed an analysis of the Citigroup Pension Discount Curve (the CPDC) as of that date for each of our plans. The CPDC uses spot rates that represent the equivalent yield on high quality, zero coupon bonds for specific maturities. We used these rates to develop an equivalent single discount rate based on our plans' expected future benefit payment streams and duration of plan liabilities. A 1% increase in the discount rate would have resulted in a decrease in net periodic benefit cost of approximately $3 million in 2010. A 1% decrease in the discount rate would have resulted in an increase in net periodic benefit cost of approximately $3 million in 2010.

Assumed health care cost trend rates were as follows:

	December 31,	
	2010	2009
Health Care Cost Trend Rate Assumed for Next Year	7.83%	8.00%
Ultimate Health Care Cost Trend Rate	4.50%	4.50%
Year Rate Reaches Ultimate Trend Rate	2030	2030

Assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
(millions)		
Effect on Total Service and Interest Cost Components for 2010	$ -	$ -
Effect on Year-End 2010 Postretirement Benefit Obligation	3	(3)

Weighted-average asset allocations for the tax-qualified defined benefit pension plan are as follows:

	Target Allocation	Plan Assets	
	2011	2010	2009
Asset Category			
Equity Securities	70%	73%	73%
Fixed Income	30%	27%	27%
Total	100%	100%	100%

The investment policy for the tax-qualified defined benefit pension plan is determined by an employee benefits committee (the committee) with input from a third-party investment consultant. Based on a review of historical rates of return achieved by equity and fixed income investments in various combinations over multi-year holding periods and an evaluation of the probabilities of achieving acceptable real rates of return, the committee has determined the target asset allocation deemed most appropriate to meet immediate and future benefit payment requirements for the plan and to provide a diversification strategy which reduces market and interest rate risk. The fixed income allocation is expected to directionally track a portion of the plan's liabilities, thus reducing overall plan interest rate risk. A 1% increase (decrease) in the expected return on plan assets would have resulted in a (decrease) increase, respectively, in net periodic benefit cost of approximately $2 million in 2010.

We base our determination of the asset return component of pension expense on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of January 1, 2011, we had cumulative asset losses of approximately $2 million, which remain to be recognized in the calculation of the market-related value of assets.

Additional fair value disclosures about plan assets are as follows:

	Fair Value Measurements Using			
Asset Category	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
(millions)				
December 31, 2010				
Federal Money Market Funds	$ 2	$ -	$ -	$ 2
Mutual Funds				
Equity Securities (Common Stocks)	85	-	-	85
Fixed Income Securities	55	-	-	55
Common Collective Trust Funds	-	64	-	64
Total	$ 142	$ 64	$ -	$ 206
December 31, 2009				
Federal Money Market Funds	$ 2	$ -	$ -	$ 2
Mutual Funds				
Equity Securities (Common Stocks)	76	-	-	76
Fixed Income Securities	47	-	-	47
Common Collective Trust Funds	-	47	-	47
Total	$ 125	$ 47	$ -	$ 172

Additional information about plan assets, including methods and assumptions used to estimate the fair values of plan assets, is as follows:

Federal Money Market Funds Investments in federal money market funds consist of portfolios of high quality fixed income securities (such as US Treasury securities) which, generally, have maturities of less than one year. The fair value of these investments is based on quoted market prices for identical assets as of the measurement date.

Mutual Funds Investments in mutual funds consist of diversified portfolios of common stocks and fixed income instruments. The common stock mutual funds are diversified by market capitalization and investment style as well as economic sector and industry. The fixed income mutual funds are diversified primarily in government bonds, mortgage backed securities, and corporate bonds, most of which are rated investment grade. The fair values of these investments are based on quoted market prices for identical assets as of the measurement date.

Common Collective Trust Funds Investments in common collective trust funds consist of common stock investments in both US and non-US equity markets. Portfolios are diversified by market capitalization and investment style as well as economic sector and industry. The investments in the non-US equity markets are used to further enhance the plan's overall equity diversification which is expected to moderate the plan's overall risk volatility. In addition to the normal risk associated with stock market investing, investments in foreign equity markets may carry additional political, regulatory, and currency risk which is taken into account by the committee in its deliberations. The fair value of these investments is based on quoted prices for similar assets in active markets. All of the investments in common collective trust funds represent exchange-traded securities with readily observable prices.

Contributions We expect to make cash contributions of approximately $13 million to the pension plan during 2011. We expect to make cash contributions of $3 million to the unfunded restoration plan and $1 million to the medical and life plans in 2011, which amounts equal expected benefit payments from those plans. (Unaudited).

Estimated Future Benefit Payments As of December 31, 2010, the following future benefit payments are expected to be paid:

	Retirement and Restoration Plans	Medical and Life Plans
(millions)		
2011	$ 18	$1
2012	22	1
2013	20	2
2014	22	2
2015	26	2
Years 2016 to 2020	131	14

The estimate of expected future benefit payments is based on the same assumptions used to measure the benefit obligation at December 31, 2010 and includes estimated future employee service.

401(k) Plan We sponsor a 401(k) savings plan. All regular employees are eligible to participate. We make contributions to match employee contributions up to the first 6% of compensation deferred into the plan, and certain profit sharing contributions for employees hired on or after May 1, 2006, based upon their ages and salaries. We made cash contributions of $11 million in 2010, $9 million in 2009, and $7 million in 2008.

Deferred Compensation Plans We have a non-qualified deferred compensation plan for which participant-directed investments are held in a rabbi trust and are available to satisfy the claims of our creditors in the event of bankruptcy or insolvency. Participants may elect to receive distributions in either cash or shares of our common stock. Components of the rabbi trust are as follows:

	December 31,	
	2010	2009
(millions, except share amounts)		
Rabbi Trust Assets		
Mutual Fund Investments	$ 96	$ 93
Noble Energy Common Stock (at Fair Value) (1)	82	75
Total Rabbi Trust Assets	178	168
Liability Under Related Deferred Compensation Plan	$ 178	$ 168
Number of Shares of Noble Energy Common Stock Held by Rabbi Trust	949,040	1,049,140

(1) Shares of our common stock are accounted for as treasury stock and recorded at cost in the consolidated balance sheets.

Assets of the rabbi trust, other than our common stock, are invested in certain mutual funds that cover an investment spectrum ranging from equities to money market instruments. These mutual funds have published market prices and are reported at fair value. See Note 16. Fair Value Measurements and Disclosures. The mutual funds are included in the mutual fund investments account in other noncurrent assets in the consolidated balance sheets.

Shares of our common stock held by the rabbi trust are accounted for as treasury stock (recorded at cost) in the shareholders' equity section of the consolidated balance sheets. The amounts payable to the plan participants are included in other noncurrent liabilities in the consolidated balance sheets and include the market value of the shares of our common stock. Approximately 900,000 shares, or 95%, of our common stock held in the plan at December 31, 2010 were attributable to a member of our Board of Directors. Plan participants received distributions of 100,000 shares of our common stock in 2010, and sold 100 shares of our common stock in 2010, 1,892 shares in 2009, and 50,000 shares in 2008. Proceeds were invested in mutual funds and/or distributed to plan participants. Distributions to plan participants totaled $17 million in 2010, were de minimis in 2009, and totaled $1 million in 2008.

All fluctuations in market value of the deferred compensation liability have been reflected in other non-operating (income) expense, net in the consolidated statements of operations. We recognized deferred compensation expense of $15 million in 2010 and $23 million in 2009 and deferred compensation income of $32 million in 2008.

We also maintain an unfunded deferred compensation plan for the benefit of certain of our employees. Deferred compensation liabilities of $51 million and $45 million were outstanding at December 31, 2010 and 2009, respectively, under the unfunded plan.

Note 15. Stock-Based Compensation

We recognized total stock-based compensation expense as follows:

	Year Ended December 31,		
	2010	2009	2008
(millions)			
Stock-Based Compensation Expense Included in			
General and Administrative Expense	$ 39	$ 36	$ 38
Exploration Expense and Other	15	13	1
Total Stock-Based Compensation Expense	$ 54	$ 49	$ 39
Tax Benefit Recognized	$ (19)	$ (17)	$ (15)

Stock Option and Restricted Stock Plans and Incentive Plan Our stock option and restricted stock plans and incentive plan are described below.

1992 Stock Option and Restricted Stock Plan Under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan, as amended (the 1992 Plan), the Compensation, Benefits and Stock Option Committee of the Board of Directors (the Committee) may grant stock options and award restricted stock to our officers or other employees and those of our subsidiaries. In 2009, our stockholders approved an amendment to the 1992 Plan that increased the maximum number of shares of our common stock that may be issued from 22 million to 24 million shares. At December 31, 2010, 10,684,230 shares of our common stock were reserved for issuance, including 3,438,888 shares available for future grants and awards, under the 1992 Plan.

Stock options are issued with an exercise price equal to the market price of our common stock on the date of grant, and are subject to such other terms and conditions as may be determined by the Committee. Unless granted by the Committee for a shorter term, the options expire ten years from the grant date. Option grants generally vest ratably over a three-year period.

Restricted stock awards made under the 1992 Plan are subject to such restrictions, terms and conditions, including forfeitures, if any, as may be determined by the Committee. Restricted stock awards generally vest over three years. Shares of restricted stock awarded in 2010 and 2009 time-vest 20% after year one, an additional 30% after year two and the remaining 50% after year three.

2004 Long-Term Incentive Plan Under the Noble Energy, Inc. 2004 Long-Term Incentive Plan (the 2004 LTIP), the Committee may make incentive awards to our key employees and those of our subsidiaries. Incentive compensation is based upon the attainment of specific market and performance goals established by the Committee. Awards may be in the form of stock options or restricted stock or in the form of performance units or other incentive measurements providing for the payment of bonuses in cash, or in any combination thereof, as determined by the Committee in its discretion. Stock options granted and restricted stock awarded under the 2004 LTIP are granted and awarded pursuant to the terms of the 1992 Plan.

2005 Stock Plan for Non-Employee Directors The 2005 Stock Plan for Non-Employee Directors of Noble Energy, Inc. (the 2005 Plan) provides for grants of stock options and awards of restricted stock to our non-employee directors. The 2005 Plan superseded and replaced the 1988 Nonqualified Stock Option Plan for Non-Employee Directors. The total number of shares of our common stock that may be issued under the 2005 Plan is 800,000. At December 31, 2010, 715,378 shares of our common stock were reserved for issuance, including 536,841 shares available for future grants and awards under the 2005 Plan.

The 2005 Plan provides for the granting to a non-employee director of up to a maximum of 11,200 stock options on the date of election to the Board of Directors, annual grants of 2,800 options per non-employee director on February 1 of each year, and discretionary grants by the Board of Directors (with the February 1 annual and the discretionary grants made to a non-employee director during any calendar year being limited to a combined maximum of 11,200 options). Options are issued with an exercise price equal to the market price of our common stock on the date of grant and may be exercised one year after the date of grant. The options expire ten years from the date of grant.

The 2005 Plan also provides for the awarding to a non-employee director of up to a maximum of 4,800 shares of restricted stock on the date of election to the Board of Directors, annual awards of 1,200 shares of restricted stock per non-employee director on February 1 of each year, and discretionary awards by the Board of Directors (with the February 1 annual and the discretionary awards made to a non-employee director during any calendar year being limited to a combined maximum of 4,800 shares of restricted stock). Restricted stock is restricted for a period of at least one year from the date of award.

1988 Nonqualified Stock Option Plan for Non-Employee Directors The 1988 Nonqualified Stock Option Plan for Non-Employee Directors of Noble Energy, Inc., as amended, (the 1988 Plan) provided for the issuance of stock options to our non-employee directors. Options issued under the 1988 Plan may be exercised one year after grant and expire ten years from the grant date. The 1988 Plan provided for the granting of a fixed number of stock options to each non-employee director annually (10,000 stock options for the first calendar year of service and 5,000 stock options for each year thereafter) on February 1 of each year. The 1988 Plan was terminated in 2005, and no additional options can be granted thereunder.

Stock Option Grants The fair value of each stock option granted was estimated on the date of grant using a Black-Scholes-Merton option valuation model that used the assumptions described below:

- *Expected term* The expected term represents the period of time that options granted are expected to be outstanding, which is the grant date to the date of expected exercise or other expected settlement for options granted. The hypothetical midpoint scenario we use considers our actual exercise and post-vesting cancellation history and expectations for future periods, which assumes that all vested, outstanding options are settled halfway between their vesting date and their expiration date.

- *Expected volatility* The expected volatility represents the extent to which our stock price is expected to fluctuate between the grant date and the expected term of the award. We use the historical volatility of our common stock for a period equal to the expected term of the option prior to the date of grant. We believe that historical volatility produces an estimate that is representative of our expectations about the future volatility of our common stock over the expected term.
- *Risk-free rate* The risk-free rate is the implied yield available on US Treasury securities with a remaining term equal to the expected term of the option. We base our risk-free rate on a weighting of five and seven year US Treasury securities as of the date of grant.
- *Dividend yield* The dividend yield represents the value of our stock's annualized dividend as compared to our stock's average price for the three-year period ended prior to the date of grant. It is calculated by dividing one full year of our expected dividends by our average stock price over the three-year period ended prior to the date of grant.

The assumptions used in valuing stock options granted were as follows:

	Year Ended December 31,		
	2010	2009	2008
(weighted averages)			
Expected Term (in Years)	5.6	5.5	5.5
Expected Volatility	35.4%	43.0%	27.7%
Risk-Free Rate	2.6%	2.0%	2.9%
Expected Dividend Yield	1.1%	1.2%	1.0%
Weighted Average Grant-Date Fair Value	$ 25.05	$ 19.14	$ 20.40

Stock option activity was as follows:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
		(per share)	*(in years)*	*(in millions)*
Outstanding at December 31, 2009	6,820,291	$ 45.01		
Granted	1,029,224	75.08		
Exercised	(1,502,454)	31.55		
Forfeited	(80,101)	62.47		
Outstanding at December 31, 2010	6,266,960	$ 52.87	6.4	$ 209
Exercisable at December 31, 2010	4,017,172	$ 46.14	5.3	$ 161

The total intrinsic value of options exercised was $68 million in 2010, $19 million in 2009, and $67 million in 2008.

As of December 31, 2010, $29 million of compensation cost related to unvested stock options granted under the Plans remained to be recognized. The cost is expected to be recognized over a weighted-average period of 1.3 years. We issue new shares of our common stock to settle option exercises. Dividends are not paid on unexercised options.

Restricted Stock Awards Restricted stock activity was as follows:

	Shares Subject to Service Conditions	Weighted Average Award Date Fair Value
		(per share)
Outstanding at December 31, 2009	1,421,200	$ 58.31
Awarded	421,683	75.07
Vested	(575,536)	75.20
Forfeited	(34,480)	71.22
Outstanding at December 31, 2010	1,232,867	$ 66.11

The total fair value of restricted stock that vested was $43 million in 2010, $4 million in 2009, and $10 million in 2008.

Awards of time-vested restricted stock (shares subject to service conditions) were valued at the price of our common stock at the date of award.

As of December 31, 2010, $34 million of compensation cost related to all of our unvested restricted stock awarded under the Plans remained to be recognized. The cost is expected to be recognized over a weighted-average period of 1.3 years. Common stock dividends accrue on restricted stock awards and are paid upon vesting. We issue new shares of our common stock when awarding restricted stock.

Note 16. Fair Value Measurements and Disclosures

Assets and Liabilities Measured at Fair Value on a Recurring Basis Certain assets and liabilities are measured at fair value on a recurring basis in our consolidated balance sheets. The following methods and assumptions were used to estimate the fair values:

Cash, Cash Equivalents, Accounts Receivable and Accounts Payable The carrying amounts approximate fair value due to the short-term nature or maturity of the instruments.

Mutual Fund Investments Our mutual fund investments, which primarily include assets held in a rabbi trust, consist of various publicly-traded mutual funds that include investments ranging from equities to money market instruments. The fair values are based on quoted market prices for identical assets.

Commodity Derivative Instruments Our commodity derivative instruments consist of variable to fixed price commodity swaps, two-way and three-way collars and basis swaps. We estimate the fair values of these instruments based on published forward commodity price curves as of the date of the estimate. The discount rate used in the discounted cash flow projections is based on published LIBOR rates, Eurodollar futures rates and interest swap rates. The fair values of commodity derivative instruments in an asset position include a measure of counterparty nonperformance risk, and the fair values of commodity derivative instruments in a liability position include a measure of our own nonperformance risk, each based on the current published credit default swap rates. In addition, for collars, we estimate the option values of the put options sold (for three-way collars) and the contract floors and ceilings (for two-way and three-way collars) using an option pricing model which takes into account market volatility, market prices and contract terms. See Note 10. Derivative Instruments and Hedging Activities.

Interest Rate Derivative Instrument We estimate the fair value of our forward starting swap based on published interest rate yield curves as of the date of the estimate. The fair values of interest rate derivative instruments in an asset position include a measure of counterparty nonperformance risk, and the fair values of interest rate derivative instruments in a liability position include a measure of our own nonperformance risk, each based on the current published credit default swap rates. See Note 10. Derivative Instruments and Hedging Activities.

Deferred Compensation Liability The value is dependant upon the fair values of mutual fund investments and shares of our common stock held in a rabbi trust. *See Mutual Fund Investments* above.

Measurement information for assets and liabilities that are measured at fair value on a recurring basis was as follows:

	Fair Value Measurements Using				
	Quoted Prices in Active Markets (Level 1) [1]	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3) [1]	Adjustment [2]	Fair Value Measurement
(millions)					
December 31, 2010					
Financial Assets					
Mutual Fund Investments	$ 112	$ -	$ -	$ -	$ 112
Commodity Derivative Instruments	-	106	-	(44)	62
Financial Liabilities					
Commodity Derivative Instruments	-	(119)	-	44	(75)
Interest Rate Derivative Instrument	-	(63)	-	-	(63)
Portion of Deferred Compensation Liability Measured at Fair Value	(178)	-	-	-	(178)
December 31, 2009					
Financial Assets					
Mutual Fund Investments	$ 108	$ -	$ -	$ -	$ 108
Commodity Derivative Instruments	-	42	-	(28)	14
Financial Liabilities					
Commodity Derivative Instruments	-	(145)	-	28	(117)
Portion of Deferred Compensation Liability Measured at Fair Value	(168)	-	-	-	(168)

(1) See Note 1. Summary of Significant Accounting Policies - Fair Value Measurements for a description of the fair value hierarchy.
(2) Amount represents the impact of master netting agreements that allow us to settle asset and liability positions with the same counterparty.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis Certain assets and liabilities are measured at fair value on a nonrecurring basis in our consolidated balance sheets.

Central DJ Basin Asset Acquisition Information about the acquired assets as of the measurement date is as follows:

Fair Values of Acquired Assets as of the Measurement Date		
(millions)		
Proved Oil and Gas Properties	$	352
Unproved Oil and Gas Properties		146
Total	$	498

See Note 3. Acquisitions and Divestitures for a discussion of the methods and assumptions used to estimate the fair values of the acquired assets.

Asset Impairments Information about impaired assets as of the date of the assessment is as follows:

	Fair Value Measurements Using				
Description	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Book Value [1]	Total Pre-tax (Non-cash) Impairment Loss
(millions)					
Year Ended December 31, 2010					
Impaired Oil and Gas Properties	$ -	$ -	$ 30	$ 174	$ 144
Year Ended December 31, 2009					
Impaired US Oil and Gas Properties	-	-	363	867	504
Impaired Investment in Ecuador	-	-	72	172	100

(1) Amount represents net book value at date of assessment.

See Note 4. Asset Impairments for a discussion of the methods and assumptions used to estimate the fair values of the impaired assets.

Additional Fair Value Disclosures

Debt The fair value of fixed-rate debt is estimated based on the published market prices for the same or similar issues. The carrying amount of floating-rate debt approximates fair value because the interest rates paid on such debt are set for periods of three months or less. See Note 12. Long-Term Debt.

Fair value information regarding our debt is as follows:

	December 31,			
	2010		2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
(millions)				
Long-Term Debt, Net of Unamortized Discount [1]	$ 1,977	$ 2,302	$ 2,008	$ 2,279

(1) Excludes FPSO lease obligation.

Note 17. Earnings Per Share

The following table summarizes the calculation of basic and diluted earnings per share:

	Year Ended December 31,		
	2010	2009	2008
(millions, except per share amounts)			
Income (Loss)	$ 725	$ (131)	$ 1,350
Earnings Adjustment from Assumed Conversion of Dilutive Shares of Common Stock in Rabbi Trust (1)	-	-	(20)
Income (Loss) Used for Diluted Earnings Per Share Calculation	725	(131)	1,330
Weighted Average Number of Shares Outstanding, Basic	175	173	173
Incremental Shares from Assumed Conversion of Dilutive Options, Restricted Stock and Shares of Common Stock in Rabbi Trust	2	-	3
Weighted Average Number of Shares Outstanding, Diluted	177	173	176
Earnings (Loss) Per Share, Basic	**$ 4.15**	**$ (0.75)**	**$ 7.83**
Earnings (Loss) Per Share, Diluted	**4.10**	**(0.75)**	**7.58**
Additional Information			
Antidilutive stock options, shares of restricted stock and common shares held in a rabbi trust excluded from calculation above	2	4	1
Weighted average exercise price per share	$ 74.01	$ 60.40	$ 67.64
Incremental stock options and shares of restricted stock excluded from calculation of diluted earnings in loss period	-	2	-

(1) The diluted earnings per share calculation for 2008 includes a decrease to net income related to a deferred compensation gain from shares of our common stock held in a rabbi trust. When dilutive, the deferred compensation gain or loss (net of tax) is excluded from net income while the shares of our common stock held in the rabbi trust are included in the outstanding diluted share count.

Note 18. Segment Information

We have operations throughout the world and manage our operations by country. The following information is grouped into five components that are all primarily in the business of crude oil and natural gas exploration, development, and acquisition: the United States; West Africa (Equatorial Guinea and Cameroon); Eastern Mediterranean (Israel and Cyprus); the North Sea (UK and the Netherlands); and Other International and Corporate. Other International includes China, Ecuador (at December 31, 2010), Argentina (through February 2008) and new ventures.

(millions)	Consolidated	United States	West Africa	Eastern Mediterranean	North Sea	Other Int'l, Corporate
Year Ended December 31, 2010						
Revenues from Third Parties	$ 2,924	$ 1,893	$ 349	$ 191	$ 309	$ 182
Reclassification from AOCL (1)	(20)	(20)	-	-	-	-
Income from Equity Method Investees	118	-	118	-	-	-
Total Revenues (2)	3,022	1,873	467	191	309	182
DD&A	883	719	39	22	64	39
Net Gain on Asset Sales	(113)	(113)	-	-	-	-
Asset Impairments	144	119	-	25	-	-
(Gain) Loss on Commodity Derivative Instruments	(157)	(168)	11	-	-	-
Income (Loss) Before Income Taxes	1,031	713	355	119	183	(339)
Equity Method Investments	285	-	285	-	-	-
Additions to Long-Lived Assets	2,789	1,796	612	270	64	47
Goodwill at End of Year	696	696	-	-	-	-
Total Assets at End of Year (3)	13,282	9,091	2,270	919	770	232
Year Ended December 31, 2009						
Revenues from Third Parties	2,287	1,484	340	144	153	166
Reclassification from AOCL (1)	(58)	(29)	(29)	-	-	-
Income from Equity Method Investees	84	-	84	-	-	-
Total Revenues (2)	2,313	1,455	395	144	153	166
DD&A	816	689	38	20	34	35
Asset Impairments	604	504	-	-	-	100
Loss on Commodity Derivative Instruments	110	73	37	-	-	-
Income (Loss) Before Income Taxes	(264)	(287)	257	98	62	(394)
Equity Method Investments	303	-	303	-	-	-
Additions to Long-Lived Assets	1,282	911	124	103	103	41
Goodwill at End of Year	758	758	-	-	-	-
Total Assets at End of Year (3)	11,807	8,669	1,731	486	635	286
Year Ended December 31, 2008						
Revenues from Third Parties	4,058	2,749	541	157	410	201
Reclassification from AOCL (1)	(331)	(290)	(41)	-	-	-
Income from Equity Method Investees	174	-	174	-	-	-
Total Revenues (2)	3,901	2,459	674	157	410	201
DD&A	791	646	34	24	55	32
Asset Impairments	294	224	-	-	-	70
Gain on Commodity Derivative Instruments	(440)	(363)	(77)	-	-	-
Income (Loss) Before Income Taxes	2,061	1,333	689	122	284	(367)
Equity Method Investments	311	-	311	-	-	-
Additions to Long-Lived Assets	2,179	1,842	143	39	94	61
Goodwill at End of Year	759	759	-	-	-	-
Total Assets at End of Year (3)	12,384	9,212	1,614	366	775	417

(1) Revenues include decreases resulting from hedging activities. The decreases resulted from hedge gains and losses that were deferred in AOCL, as a result of previous cash flow hedge accounting, and subsequently reclassified to revenues.

(2) Revenues from third parties for all foreign countries, in total, were $1 billion in 2010, $791 million in 2009, and $1.3 billion in 2008.

(3) Long-lived assets located in all foreign countries, in total, were $2.4 billion, $1.6 billion, and $1.5 billion at December 31, 2010, 2009, and 2008, respectively.

Note 19. Concentration of Risk

Concentration of Market Risk The largest single non-affiliated purchasers of our production were as follows:

	Percentage of Crude Oil Sales	Percentage of Total Oil, Gas & NGL Sales
Year Ended December 31, 2010		
Glencore Energy UK Ltd	17%	11%
Year Ended December 31, 2009		
Glencore Energy UK Ltd	25%	16%
Year Ended December 31, 2008		
Suncor Energy Marketing	22%	13%

We believe the loss of any one purchaser would not have a material effect on our financial position or results of operations since there are numerous potential purchasers of our production.

Concentration of Credit Risk Certain of our financial instruments, including cash equivalents, trade and joint interest receivables and derivative instruments, may expose us to credit risk. Substantially all of our cash is located in our foreign subsidiaries. The cash is denominated in US dollars and invested in highly liquid money market funds and short term deposits with original maturities of three months or less at the time of purchase. Although our cash and cash equivalents are deposited with major international banks and financial institutions, concentrations of cash in certain foreign locations may increase credit risk. We monitor the creditworthiness of the banks and financial institutions with which we invest and review the securities underlying our investment accounts. We believe that losses from nonperformance are unlikely to occur; however, we are not able to predict sudden changes in creditworthiness.

Our accounts receivable result from sales of crude oil, natural gas and NGL production and electricity, and joint interest billings to our partners for their share of expenses on joint venture projects for which we are the operator. Joint venture projects, such as Aseng, offshore Equatorial Guinea, and Tamar, offshore Israel can be very capital cost intensive. Thus the receivables from our joint venture partners can become significant.

Our accounts receivable reflect a broad national and international customer base, which limits our exposure to concentrations of credit risk. The majority of these receivables have payment terms of 30 days or less. We continually monitor the creditworthiness of the counterparties, some of which are not as creditworthy as we are and may experience liquidity problems. We have obtained credit enhancements from some parties in the way of parental guarantees or letters of credit, including our largest crude oil purchaser. However, we do not have all of our trade credit protected through guarantees or credit support. Nonperformance by a trade creditor could result in losses. See Note 5. Allowance for Doubtful Accounts.

Note 20. Additional Shareholders' Equity Information

Activity in shares of our common stock and treasury stock was as follows:

	Year Ended December 31,	
	2010	2009
Common Stock Shares Issued		
Shares, Beginning of Period	193,550,391	192,296,764
Exercise of Common Stock Options	1,502,454	704,209
Restricted Stock Awards, Net of Forfeitures	387,203	549,418
Shares, End of Period	195,440,048	193,550,391
Treasury Stock		
Shares, Beginning of Period	18,582,301	18,563,409
Shares Received From Employees in Payment of Withholding Taxes Due on Vesting of Shares of Restricted Stock	167,863	20,784
Rabbi Trust Shares Distributed and/or Sold	(100,100)	(1,892)
Shares, End of Period	18,650,064	18,582,301

Accumulated other comprehensive loss in the shareholders' equity section of the balance sheet included:

	Accumulated Other Comprehensive Loss			
	Oil and Gas Cash Flow Hedges	Interest Rate Cash Flow Hedges	Pension-Related and Other	Total
(millions)				
December 31, 2007	$ (255)	$ (3)	$ (26)	$ (284)
Cash Flow Hedges				
Realized Amounts Reclassified Into Earnings	207	-	3	210
Unrealized Change in Fair Value	-	-	(4)	(4)
Net Change in Other	-	-	(32)	(32)
December 31, 2008	(48)	(3)	(59)	(110)
Cash Flow Hedges				
Realized Amounts Reclassified Into Earnings	36	1	2	39
Net Change in Other	-		(4)	(4)
December 31, 2009	(12)	(2)	(61)	(75)
Cash Flow Hedges				
Realized Amounts Reclassified Into Earnings	12	1	3	16
Unrealized Change in Fair Value	-	(41)	(4)	(45)
December 31, 2010	$ -	$ (42)	$ (62)	$ (104)

All amounts in the table above are reported net of tax. The effective income tax rate applied to AOCL was 37.6% at December 31, 2007 and 2008, and 35.0% at December 31, 2009 and 2010.

Note 21. Commitments and Contingencies

Legal Proceedings We are involved in various legal proceedings in the ordinary course of business. These proceedings are subject to the uncertainties inherent in any litigation. We are defending ourselves vigorously in all such matters and we believe that the ultimate disposition of such proceedings will not have a material adverse effect on our financial position, results of operations or cash flows.

Non-Cancelable Leases and Other Commitments We hold leases and other commitments for drilling rigs, buildings, equipment and other property. Rental expense for office buildings and oil and gas operations equipment was $27 million in 2010, $22 million in 2009, and $20 million in 2008.

Minimum commitments as of December 31, 2010 consist of the following:

	Drilling, Equipment, and Purchase Obligations	Throughput Agreement	Transportation and Gathering	Operating Lease Obligations	FPSO Lease Payments[1]	Total
(millions)						
2011	$ 781	$ 19	$ 9	$ 68	$ -	$ 877
2012	196	19	7	34	38	294
2013	2	19	6	25	72	124
2014	-	8	3	25	72	108
2015	-	-	2	24	78	104
2016 and Thereafter	-	-	8	54	225	287
Total	$ 979	$ 65	$ 35	$ 230	$ 485	$ 1,794

[1] Estimated annual lease payments, net to our interest, exclude regular maintenance and operational costs, and will begin when the FPSO initiates producing operations. These payments are also subject to change based on change orders implemented during the construction period, final accounting treatment and other factors. See Note 12. Long-Term Debt.

Noble Energy, Inc.
Supplemental Oil and Gas Information
(Unaudited)

In accordance with US GAAP for disclosures about oil and gas producing activities, and SEC rules for oil and gas reporting disclosures, we are making the following disclosures about our crude oil and natural gas reserves and exploration and production activities.

Reserves

There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. Crude oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserves estimates are often different from the quantities of crude oil and natural gas that are ultimately recovered.

SEC and FASB Rule-Making Activity Effective December 31, 2009, we implemented the SEC's final rules on the Modernization of Oil and Gas Reporting. The new rules included revisions designed to modernize the oil and gas company reserves reporting requirements. The most significant amendments to the requirements included the following:

- Commodity Prices – Economic producibility of reserves and discounted cash flows is now based on a 12-month average commodity price unless contractual arrangements designate the price to be used.
- Disclosure of Unproved Reserves – Probable and possible reserves may be disclosed separately on a voluntary basis. We have elected not to disclose probable and possible reserves in this report.
- Proved Undeveloped Reserves Guidelines – Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered and they are scheduled to be drilled within the next five years.
- Reserves Estimation Using New Technologies – Reserves may be estimated through the use of reliable technology in addition to flow tests and production history.
- Reserves Personnel and Estimation Process – Additional disclosure is required regarding the qualifications of the chief technical person who oversees the reserves estimation process. We are also required to provide a general discussion of our internal controls used to assure the objectivity of the reserves estimate.
- Disclosure by Geographic Area – Reserves in foreign countries or continents must be presented separately if they represent more than 15% of our total oil and gas proved reserves.
- Non-Traditional Resources – The definition of oil and gas producing activities has expanded and focuses on the marketable product rather than the method of extraction.

The rule changes, including those related to pricing and technology, are included in our reserves estimates as of December 31, 2010 and 2009.

In addition, in 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (Update) 2010-03, "Oil and Gas Reserve Estimation and Disclosures", to provide consistency with the new SEC rules. The Update amended existing standards to align the reserves calculation and disclosure requirements under US GAAP with the requirements in the SEC rules. We adopted the new standards effective December 31, 2009. The new standards were applied prospectively as a change in estimate.

Impact of Implementation Implementation of the SEC's updated rules resulted in the use of lower prices at December 31, 2009 for both oil and gas than would have resulted under the previous rules. Use of 12-month average pricing at December 31, 2009 as required by the updated rules resulted in a decrease in proved reserves of approximately 27 MMBoe. Use of year-end prices as required by the old rules would have resulted in an increase in proved reserves of approximately 34 MMBoe at December 31, 2009. Therefore, the total impact of the new price methodology was negative reserves revisions of 61 MMBoe. In addition, the new proved undeveloped reserves rules resulted in a reduction of proved reserves of approximately 18 MMBoe due to limiting proved undeveloped reserves locations to those scheduled to be drilled within the next five years. The majority of the reserves reclassified out of proved reserves were associated with Wattenberg, where we maintain an extensive multi-year development program.

Because we use quarter-end reserves and add back current period production to calculate quarterly DD&A, adoption of the updated FASB standards had an impact on fourth quarter 2009 DD&A expense. We estimated the impact of using 12-month average commodity prices, as required by the updated standards, instead of year-end commodity prices, to be an increase in fourth quarter 2009 DD&A expense of approximately $16 million (or $0.06 per share).

Reserves Estimates Qualified petroleum engineers in our Houston and Denver offices prepare all reserves estimates for our different geographical regions. These reserves estimates are reviewed and approved by regional management and senior engineering staff with final approval by the Vice President - Strategic Planning, Environmental Analysis & Reserves and certain members of senior management. For additional information regarding our reserves estimation process and internal controls see Items 1. and 2. Business and Properties – Proved Reserves Disclosures – Internal Controls Over Reserves Estimates and Technologies Used in Reserves Estimation.

Third-Party Reserves Audit We retained Netherland, Sewell & Associates, Inc. (NSAI), independent, third-party petroleum engineers, to perform a reserves audit of proved reserves as of December 31, 2010. The reserves audit included a detailed review of 13 of our major onshore US, deepwater Gulf of Mexico and international fields, which covered approximately 77% of US proved reserves and 97% of international proved reserves (88% of total proved reserves). For additional information regarding reserves audits for the years 2010, 2009, and 2008, see Items 1. and 2. Business and Properties – Proved Reserves Disclosures.

Geographic Areas Our supplemental disclosures are grouped by geographic area and include the United States, Equatorial Guinea, Israel and Other International. Other International includes Ecuador (through November 24, 2010), North Sea, China, and Argentina (through February 2008). Operations in Equatorial Guinea and China are conducted in accordance with the terms of PSCs. Operations in Cameroon are conducted in accordance with the terms of a PSC and a mining concession. Operations in other foreign locations are conducted in accordance with concession agreements, permits or licenses.

Definitions The following definitions apply to the terms used in the paragraphs above:

Reserves Estimate The determination of an estimate of a quantity of oil or gas reserves that are thought to exist at a certain date, considering existing prices and reservoir conditions.

Reserves Audit The process of reviewing certain of the pertinent facts interpreted and assumptions underlying a reserves estimate prepared by another party and the rendering of an opinion about the appropriateness of the methodologies employed, the adequacy and quality of the data relied upon, the depth and thoroughness of the reserves estimation process, the classification of reserves appropriate to the relevant definitions used, and the reasonableness of the estimated reserves quantities.

The following definitions apply to our categories of proved reserves:

Proved Oil and Gas Reserves Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

Developed Oil and Gas Reserves Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well.

Undeveloped Oil and Gas Reserves Proved undeveloped oil and gas reserves (PUDs) are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

For complete definitions of proved natural gas, natural gas liquids and crude oil reserves, refer to SEC Regulation S-X, Rule 4-10(a)(6), (22) and (31).

Noble Energy, Inc.
Supplemental Oil and Gas Information
(Unaudited)

Proved Oil Reserves (Unaudited) The following reserves schedule was developed by our qualified petroleum engineers and sets forth the changes in estimated quantities of proved crude oil reserves:

	Crude Oil, Condensate and NGLs (MMBbls)			
	United States	Equatorial Guinea	Other Int'l [1]	Total
Proved Reserves as of:				
December 31, 2007	207	82	40	329
Revisions of Previous Estimates [2]	(10)	1	-	(9)
Extensions, Discoveries and Other Additions [3]	16	-	11	27
Purchase of Minerals in Place [4]	3	-	-	3
Sale of Minerals in Place [5]	-	-	(7)	(7)
Production [6]	(18)	(8)	(6)	(32)
December 31, 2008	198	75	38	311
Revisions of Previous Estimates [2]	(5)	(1)	-	(6)
Extensions, Discoveries and Other Additions [3]	32	26	1	59
Purchase of Minerals in Place [4]	1	-	-	1
Sale of Minerals in Place [5]	-	-	-	-
Production [6]	(17)	(8)	(4)	(29)
December 31, 2009	209	92	35	336
Revisions of Previous Estimates [2]	15	1	(5)	11
Extensions, Discoveries and Other Additions [3]	25	26	3	54
Purchase of Minerals in Place [4]	23	-	-	23
Sale of Minerals in Place [5]	(28)	-	-	(28)
Production [6]	(19)	(7)	(5)	(31)
December 31, 2010	225	112	28	365
Proved Developed Reserves as of:				
December 31, 2007	129	71	29	229
December 31, 2008	121	57	21	199
December 31, 2009	122	49	23	194
December 31, 2010	119	43	21	183
Proved Undeveloped Reserves as of:				
December 31, 2007	78	11	11	100
December 31, 2008	77	18	17	112
December 31, 2009	87	43	12	142
December 31, 2010	106	69	7	182

(1) Other International includes Israel, the North Sea, China and Argentina. We sold our Argentina assets in 2008.

(2) The 2008 negative revisions within the US are primarily due to lower year-end prices (28 MMBbl), partially offset by the recording of NGLs which had previously been recorded in proved natural gas reserves. The 2009 negative revisions within the US are primarily due to performance revisions, the majority of which related to Main Pass (10 MMBbl) and reclassifications of PUDs to probable reserves as a result of the SEC's new five year development rule (5 MMBbl), partially offset by higher year-end prices (10 MMBbl). The 2010 US revisions include the impacts of higher prices and additional NGLs booked in Wattenberg, partially offset by the reclassification of 16 MMBbls of PUD reserves to probable reserves, primarily in Wattenberg, as a result of the SEC's five year development rule. The 2010 revisions to other international reserves are related to performance revisions in China and the North Sea.

(3) The 2008 increase in proved reserves includes 13 MMBbl in Wattenberg, primarily due to infill drilling activities, and 9 MMBbl in China. The 2009 increase in proved reserves includes 20 MMBbl related to the ongoing development of Wattenberg, 11 MMBbl in the deepwater Gulf of Mexico for the Santa Cruz, Isabela and Swordfish fields, and 26 MMBbl in Equatorial Guinea for the Aseng field. The 2010 increase in US proved reserves relates to continuing development of onshore assets, primarily in the Central DJ Basin. The 2010 increase in Equatorial Guinea reserves includes 26 MMBbl for the Alen field.

(4) The 2010 increase relates to the Central DJ Basin asset acquisition. See Note 3. Acquisitions and Divestitures.

(5) We sold non-core, mature onshore US assets in the Mid-Continent and Illinois Basin in 2010 and our Argentina assets in 2008. See Note 3. Acquisitions and Divestitures.

(6) Equatorial Guinea production includes sales from the Alba field to the Alba LPG plant of 3 MBbl in each of 2010, 2009, and 2008.

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Supplemental Oil and Gas Information
(Unaudited)

Proved Gas Reserves (Unaudited) The following reserves schedule was developed by our qualified petroleum engineers and sets forth the changes in estimated quantities of proved natural gas reserves:

	Natural Gas and Casinghead Gas (Bcf)				
	United States	Equatorial Guinea	Israel	Other Int'l [1]	Total
Proved Reserves as of:					
December 31, 2007	1,840	941	319	207	3,307
Revisions of Previous Estimates [2]	(253)	34	1	8	(210)
Extensions, Discoveries and Other Additions [3]	345	78	4	-	427
Purchase of Minerals in Place [4]	72	-	-	-	72
Sale of Minerals in Place [5]	-	-	-	-	-
Production	(145)	(75)	(51)	(10)	(281)
December 31, 2008	1,859	978	273	205	3,315
Revisions of Previous Estimates [2]	(397)	49	(2)	-	(350)
Extensions, Discoveries and Other Additions [3]	211	-	5	2	218
Purchase of Minerals in Place [4]	6	-	-	-	6
Sale of Minerals in Place [5]	-	-	-	-	-
Production	(145)	(87)	(42)	(11)	(285)
December 31, 2009	1,534	940	234	196	2,904
Revisions of Previous Estimates [2]	(6)	12	(41)	(3)	(38)
Extensions, Discoveries and Other Additions [3]	140	-	1,698	-	1,838
Purchase of Minerals in Place [4]	139	-	-	-	139
Sale of Minerals in Place [5]	(35)	-	-	(160)	(195)
Production	(146)	(83)	(47)	(11)	(287)
December 31, 2010	1,626	869	1,844	22	4,361
Proved Developed Reserves as of:					
December 31, 2007	1,259	830	263	204	2,556
December 31, 2008	1,268	700	216	201	2,385
December 31, 2009	1,114	638	191	192	2,135
December 31, 2010	1,156	597	145	19	1,917
Proved Undeveloped Reserves as of:					
December 31, 2007	581	111	56	3	751
December 31, 2008	591	278	57	4	930
December 31, 2009	420	302	43	4	769
December 31, 2010	470	272	1,699	3	2,444

(1) Other International includes the North Sea, Ecuador (at December 31, 2009 and 2008), and China. See Note 3. Acquisitions and Divestitures and Note 4. Asset Impairments.

(2) The 2008 negative revisions in the US are primarily due to lower year-end prices (109 Bcf), as well as additional natural gas volumes being reflected in the proved oil reserves table as NGLs. The 2009 negative revisions in the US are primarily due to lower year-end prices (224 Bcf), reclassifications of PUDs to probable reserves as a result of the SEC's new five year development rule (75 Bcf), and increased lease operating expense and various well performance issues (98 Bcf). The 2010 US revisions are a combination of increases from higher natural gas prices, which were more than offset by gas shrinkage from additional NGLs booked in Wattenberg and the reclassification of 85 Bcf of PUDs to probable reserves, primarily in Wattenberg, as a result of the SEC's five year development rule. Equatorial Guinea's positive revisions in 2008, 2009 and 2010 are primarily due to additional production allowances related to LNG sales. Israel revisions in 2010 reflect a change in the likelihood that the Noa Field will be developed.

(3) The 2008 increase in US proved reserves includes 106 Bcf in Wattenberg and 173 Bcf in the Rocky Mountain area, primarily in the Piceance Basin and Niobrara formation, primarily due to infill drilling activities. The remaining increase is due to other development programs. The 2009 increase in US proved reserves is primarily due to ongoing low-risk development programs onshore in Wattenberg, the Rocky Mountain area, and East Texas. The 2010 increase in US proved reserves is due to continuing development of onshore assets, primarily in the Central DJ Basin, Piceance Basin, and East Texas. The 2010 increase in Israel is due to the recording of initial reserves at the Tamar development.

(4) The increase relates to our Mid-Continent acquisition in 2008 and our Central DJ Basin asset acquisition in 2010. See Note 3. Acquisitions and Divestitures.

(5) We sold non-core, mature onshore US assets in the Mid-Continent and Illinois Basin in 2010. Other International sales in 2010 include 160 Bcf due to the termination of the Block 3 PSC by the Ecuadorian government.

Noble Energy, Inc.
Supplemental Oil and Gas Information
(Unaudited)

Results of Operations for Oil and Gas Producing Activities (Unaudited) Aggregate results of operations for crude oil and natural gas producing activities are as follows:

	United States	Equatorial Guinea	Israel	Other Int'l [1]	Total
(millions)					
Year Ended December 31, 2010					
Revenues					
Sales [2]	$ 1,874	$ 349	$ 191	$ 418	$ 2,832
Sales to Affiliated Power Plant	-	-	-	35	35
Total Revenues	1,874	349	191	453	2,867
Production Costs [3]	449	50	15	94	608
Exploration Expense	130	7	11	48	196
DD&A	719	39	22	82	862
Asset Impairments	119	-	25	-	144
Income before Income Taxes	457	253	118	229	1,057
Income Tax Expense	160	63	21	62	306
Results of Operations [4]	$ 297	$ 190	$ 97	$ 167	$ 751
Year Ended December 31, 2009					
Revenues					
Sales [2]	$ 1,341	$ 340	$ 144	$ 235	$ 2,060
Sales to Affiliated Power Plant	-	-	-	35	35
Total Revenues	1,341	340	144	270	2,095
Production Costs [3]	417	50	13	79	559
Exploration Expense	75	1	10	24	110
DD&A	689	38	21	50	798
Asset Impairments	504	-	-	100	604
Income before Income Taxes	(344)	251	100	17	24
Income Tax Expense	(108)	59	20	6	(23)
Results of Operations [4]	$ (236)	$ 192	$ 80	$ 11	$ 47
Year Ended December 31, 2008					
Revenues					
Sales [2]	$ 2,459	$ 500	$ 157	$ 535	$ 3,651
Sales to Affiliated Power Plant	-	-	-	30	30
Total Revenues	2,459	500	157	565	3,681
Production Costs [3]	470	42	12	123	647
Exploration Expense	111	7	4	60	182
DD&A	653	34	23	75	785
Asset Impairments	224	-	-	-	224
Income before Income Taxes	1,001	417	118	307	1,843
Income Tax Expense	339	99	22	151	611
Results of Operations [4]	$ 662	$ 318	$ 96	$ 156	$ 1,232

(1) Other International includes the North Sea, Ecuador (through November 24, 2010) China, Cameroon, Cyprus, Argentina (through February 2008), and new ventures. See Note 3. Acquisitions and Divestitures.

(2) Includes impact resulting from applying cash flow hedge accounting for related commodity derivative instruments. See Note 10. Derivative Instruments and Hedging Activities.

(3) Production costs consist of lease operating expense, production and ad valorem taxes, transportation expense, and general and administrative expense supporting oil and gas operations.

(4) Results of operations exclude the mark-to-market gain or loss on certain commodity derivative instruments designated as cash flow hedges prior to January 1, 2008, corporate overhead and interest costs. See Note 10. Derivative Instruments and Hedging Activities.

Noble Energy, Inc.
Supplemental Oil and Gas Information
(Unaudited)

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities (Unaudited) [(1)]

Costs incurred in connection with crude oil and natural gas acquisition, exploration and development are as follows:

	United States	Equatorial Guinea	Israel	Other Int'l [(2)]	Total
(millions)					
Year Ended December 31, 2010					
Property Acquisition Costs					
Proved [(3)]	$ 352	$ -	$ -	$ -	$ 352
Unproved [(4)]	304	1	-	-	305
Total Acquisition Costs	656	1	-	-	657
Exploration Costs [(5)]	306	6	52	54	418
Development Costs [(6)]	964	596	236	75	1,871
Total Consolidated Operations	$ 1,926	$ 603	$ 288	$ 129	$ 2,946
Year Ended December 31, 2009					
Property Acquisition Costs					
Proved [(3)]	$ (5)	$ -	$ -	$ -	$ (5)
Unproved [(4)]	89	1	-	2	92
Total Acquisition Costs	84	1	-	2	87
Exploration Costs [(5)]	189	30	81	13	313
Development Costs [(6)]	711	100	33	129	973
Total Consolidated Operations	$ 984	$ 131	$ 114	$ 144	$ 1,373
Year Ended December 31, 2008					
Property Acquisition Costs					
Proved [(3)]	$ 256	$ -	$ -	$ -	$ 256
Unproved [(4)]	296	-	-	6	302
Total Acquisition Costs	552	-	-	6	558
Exploration Costs [(5)]	322	105	28	62	517
Development Costs [(6)]	1,106	38	13	108	1,265
Total Consolidated Operations	$ 1,980	$ 143	$ 41	$ 176	$ 2,340

(1) Costs incurred include capitalized and expensed items.

(2) Other International includes the North Sea, Ecuador (through November 24, 2010), China, Argentina (through February 2008), Nicaragua and other new ventures. See Note 3. Acquisitions and Divestitures.

(3) Proved property acquisition costs include $352 million related to the Central DJ Basin asset acquisition in 2010, a $6 million downward purchase price adjustment related to the Mid-Continent acquisition in 2009, and $254 million related to the Mid-Continent acquisition in 2008.

(4) Unproved property acquisition costs include $146 million related to the Central DJ Basin asset acquisition, $38 million for deepwater Gulf of Mexico lease blocks and the remainder for other onshore US lease acquisitions primarily in Wattenberg in 2010; $56 million for deepwater Gulf of Mexico lease blocks and the remainder primarily for other onshore US lease acquisitions in 2009; and $179 million for deepwater Gulf of Mexico lease blocks, $38 million related to the Mid-Continent acquisition, $39 million related to lease acquisitions in East Texas, and the remainder primarily for other onshore US lease acquisitions in 2008.

(5) 2010 exploration costs include drilling and completion costs of $62 million in deepwater Gulf of Mexico and $41 million in Israel. 2009 exploration costs include drilling and completion costs of $57 million in deepwater Gulf of Mexico, $19 million in Equatorial Guinea and $71 million in Israel. 2008 exploration costs include drilling and completion costs of $72 million in deepwater Gulf of Mexico, $98 million in Equatorial Guinea and $25 million in Israel.

(6) Worldwide development costs include amounts spent to develop PUDs of approximately $1.1 billion in 2010, $440 million in 2009, and $528 million in 2008. Equatorial Guinea development costs include non-cash accruals related to estimated construction progress to date on an FSPO to be used in the development of the Aseng field of $266 million in 2010 and $29 million in 2009. These capitalized costs are included in development costs as the FPSO is constructed. US development costs include increases in asset retirement obligations of $15 million in 2010, $11 million in 2009, and $34 million in 2008. Other international development costs include increases in asset retirement obligations of $2 million in 2010, $5 million in 2009, and $18 million in 2008.

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Capitalized Costs Relating to Oil and Gas Producing Activities (Unaudited) Aggregate capitalized costs relating to crude oil and natural gas producing activities are as follows:

	December 31, 2010	December 31, 2009
(millions)		
Unproved Oil and Gas Properties [1]	$ 1,081	$ 874
Proved Oil and Gas Properties [2]	13,312	11,710
Total Oil and Gas Properties	14,393	12,584
Accumulated DD&A	(4,270)	(3,809)
Net Capitalized Costs	$ 10,123	$ 8,775

(1) Unproved oil and gas properties includes $304 million and $327 million at December 31, 2010 and 2009, respectively, remaining from the allocation of costs to unproved properties acquired in previous acquisitions.

(2) Proved oil and gas properties include asset retirement costs of $208 million and $176 million at December 31, 2010 and 2009, respectively.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Unaudited) The following information is based on our best estimate of the required data for the Standardized Measure of Discounted Future Net Cash Flows in accordance with US GAAP for extractive activities. The standards require the use of a 10% discount rate. This information is not the fair value nor does it represent the expected present value of future cash flows of our proved oil and gas reserves.

	United States	Equatorial Guinea	Israel	Other Int'l [1]	Total
(millions)					
December 31, 2010					
Future Cash Inflows [2]	$ 22,078	$ 8,373	$ 7,983	$ 2,083	$ 40,517
Future Production Costs [3]	6,140	1,598	460	664	8,862
Future Development Costs	4,099	1,154	924	240	6,417
Future Income Tax Expense	3,863	1,299	1,366	517	7,045
Future Net Cash Flows	7,976	4,322	5,233	662	18,193
10% Annual Discount for Estimated Timing of Cash Flows	3,941	1,589	3,530	127	9,187
Standardized Measure of Discounted Future Net Cash Flows	$ 4,035	$ 2,733	$ 1,703	$ 535	$ 9,006
December 31, 2009					
Future Cash Inflows [2]	$ 16,196	$ 5,151	$ 769	$ 2,832	$ 24,948
Future Production Costs [3]	5,390	1,185	96	983	7,654
Future Development Costs	3,056	1,059	126	315	4,556
Future Income Tax Expense	2,227	956	135	630	3,948
Future Net Cash Flows	5,523	1,951	412	904	8,790
10% Annual Discount for Estimated Timing of Cash Flows	2,672	814	93	279	3,858
Standardized Measure of Discounted Future Net Cash Flows	$ 2,851	$ 1,137	$ 319	$ 625	$ 4,932
December 31, 2008					
Future Cash Inflows [2]	$ 16,551	$ 3,277	$ 938	$ 2,299	$ 23,065
Future Production Costs [3]	4,646	784	120	876	6,426
Future Development Costs	3,082	62	160	349	3,653
Future Income Tax Expense	2,594	774	173	473	4,014
Future Net Cash Flows	6,229	1,657	485	601	8,972
10% Annual Discount for Estimated Timing of Cash Flows	3,180	608	106	214	4,108
Standardized Measure of Discounted Future Net Cash Flows	$ 3,049	$ 1,049	$ 379	$ 387	$ 4,864

(1) Other International includes the North Sea, Ecuador (at December 31, 2009 and 2008), and China. See Note 3. Acquisitions and Divestitures.

(2) The standardized measure of discounted future net cash flows does not include cash flows relating to anticipated future methanol sales.

(3) Production costs include oil and gas lease operating expense, production and ad valorem taxes, transportation expense and general and administrative expense supporting oil and gas operations.

Prices and Other Assumptions in Discounted Future Net Cash Flows (Unaudited) Future cash inflows are computed by applying a 12-month average commodity price, adjusted for location and quality differentials on a field-by-field basis, to year-end quantities of proved reserves, except in those instances where fixed and determinable price changes are provided by contractual arrangements at year-end. The discounted future cash flow estimates do not include the effects of derivative instruments. Average prices per region are as follows:

	United States	Equatorial Guinea	Israel	Other Int'l (1)	Total
December 31, 2010 (2)					
Average Crude Oil, Condensate and NGL Price per Bbl	$ 65.63	$ 72.93	$ 79.35	$ 77.41	$ 68.79
Average Natural Gas Price per Mcf	4.49	0.25	4.22	3.76	3.53
December 31, 2009 (2)					
Average Crude Oil, Condensate and NGL Price per Bbl	$ 50.80	$ 53.46	$ -	$ 59.55	$ 52.45
Average Natural Gas Price per Mcf	3.64	0.25	3.28	3.69	2.52
December 31, 2008 (3)					
Average Crude Oil, Condensate and NGL Price per Bbl	$ 36.62	$ 40.51	$ -	$ 40.05	$ 37.97
Average Natural Gas Price per Mcf	4.99	0.25	3.43	3.82	3.39

(1) Other International includes the North Sea, Ecuador (at December 31, 2009 and 2008), and China. See Note 3. Acquisitions and Divestitures.

(2) Average crude oil and natural gas prices are based on 12-month average prices.

(3) Average crude oil and natural gas prices are based on year-end prices.

We estimate that a $1.00 per Bbl change in the average price of crude oil from the 12-month average price for 2010 would change the discounted future net cash flows before income taxes by approximately $205 million. We estimate that a $0.10 per Mcf change in the average price of natural gas from the 12-month average price for 2010 would also change the discounted future net cash flows before income taxes by approximately $205 million.

Future production and development costs, which include dismantlement and restoration expense, are computed by estimating the expenditures to be incurred in developing and producing the proved crude oil and natural gas reserves at the end of the year, based on year-end costs, and assuming continuation of existing economic conditions.

Future development costs include amounts that we expect to spend to develop PUDs of $1.6 billion in 2011, $1.3 billion in 2012 and $900 million in 2013.

Future income tax expense is computed by applying the appropriate year-end statutory tax rates to the estimated future pretax net cash flows relating to proved crude oil and natural gas reserves, less the tax bases of the properties involved. Future income tax expense gives effect to tax credits and allowances, but does not reflect the impact of general and administrative costs and exploration expenses of ongoing operations.

Imbalance receivables and liabilities are as follows:

	Year Ended December 31,		
	2010	2009	2008
(millions)			
Imbalance receivables	$ 25	$ 21	$ 7
Imbalance liabilities	18	12	8

Imbalance receivables and imbalance liabilities have been excluded from the standardized measure of discounted future net cash flows.

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Sources of Changes in Discounted Future Net Cash Flows (Unaudited) Principal changes in the aggregate standardized measure of discounted future net cash flows attributable to proved crude oil and natural gas reserves are as follows:

	Year Ended December 31,		
	2010	2009	2008
(millions)			
Standardized Measure of Discounted Future Net Cash Flows, Beginning of Year	$ 4,932	$ 4,864	$11,651
Changes in Standardized Measure of Discounted Future Net Cash Flows			
Sales of Oil and Gas Produced, Net of Production Costs	(2,251)	(1,528)	(3,030)
Net Changes in Prices and Production Costs	3,115	(878)	(8,017)
Extensions, Discoveries and Improved Recovery, Less Related Costs	2,820	815	400
Changes in Estimated Future Development Costs	(915)	(132)	(883)
Development Costs Incurred During the Period	1,869	971	1,291
Revisions of Previous Quantity Estimates	33	436	(617)
Purchases of Minerals in Place	646	5	182
Sales of Minerals in Place	(652)	-	(66)
Accretion of Discount	722	707	1,663
Net Change in Income Taxes	(1,487)	(75)	2,853
Change in Timing of Estimated Future Production and Other	174	(253)	(563)
Aggregate Change in Standardized Measure of Discounted Future Net Cash Flows	4,074	68	(6,787)
Standardized Measure of Discounted Future Net Cash Flows, End of Year	$ 9,006	$ 4,932	$ 4,864

Supplemental Quarterly Financial Information (Unaudited)

Supplemental quarterly financial information is as follows:

	Quarter Ended				
	March 31,	June 30,	Sep 30,	Dec 31,	Total
(millions except per share amounts)					
2010 (1)					
Revenues	$ 733	$ 751	$ 755	$ 783	$ 3,022
Income Before Income Taxes	343	320	298	69	1,031
Net Income	237	204	232	52	725
Earnings Per Share					
Basic (3)	1.36	1.17	1.33	0.29	4.15
Diluted (3) (4)	1.34	1.10	1.31	0.29	4.10
2009 (2)					
Revenues	$ 441	$ 491	$ 621	$ 760	$ 2,313
Income (Loss) Before Income Taxes	(374)	(90)	115	85	(264)
Net Income (Loss)	(188)	(57)	107	8	(131)
Earnings (Loss) Per Share					
Basic (3)	$ (1.09)	$ (0.33)	$ 0.62	$ 0.05	$ (0.75)
Diluted (3)	(1.09)	(0.33)	0.61	0.05	(0.75)

(1) First quarter 2010 included the following:

- $145 million gain on commodity derivative instruments, including unrealized mark-to-market gain of $147 million (See Note 10. Derivative Instruments and Hedging Activities).

Second quarter 2010 included the following:

- $96 million gain on commodity derivative instruments, including unrealized mark-to-market gain of $63 million (See Note 10. Derivative Instruments and Hedging Activities); and
- $26 million rig contract termination expense due to the Deepwater Moratorium.

Third quarter 2010 included the following:

- $38 million gain on commodity derivative instruments, including unrealized mark-to-market gain of $5 million (See Note 10. Derivative Instruments and Hedging Activities);
- $114 gain on sale of non-core onshore US assets (See Note 3. Acquisitions and Divestitures); and
- $100 million asset impairment charges (See Note 4. Asset Impairments).

Fourth quarter 2010 included the following:

- $122 million loss on commodity derivative instruments, including unrealized mark-to-market loss of $145 million (See Note 10. Derivative Instruments and Hedging Activities); and
- $44 million asset impairment charges (See Note 4. Asset Impairments).

(2) First quarter 2009 included the following:

- $73 million gain on commodity derivative instruments, including unrealized mark-to-market loss of $80 million. (See Note 10. Derivative Instruments and Hedging Activities);
- $437 million asset impairment charges (See Note 4. Asset Impairments); and
- $46 million reversal of Ecuador allowance for doubtful accounts (See Note 5. Allowance for Doubtful Accounts).

Second quarter 2009 included the following:

- $139 million loss on commodity derivative instruments, including unrealized mark-to-market loss of $277 million. (See Note 10. Derivative Instruments and Hedging Activities); and
- $24 million gain on sale of our Argentina assets, which had been deferred until government approval of the sale.

Third quarter 2009 included the following:

- $28 million loss on commodity derivative instruments, including unrealized mark-to-market loss of $149 million (See Note 10. Derivative Instruments and Hedging Activities); and
- $12 million write-down of SemCrude, L.P. receivable.

Fourth quarter 2009 included the following:

- $16 million loss on commodity derivative instruments, including unrealized mark-to-market loss of $99 million (See Note 10. Derivative Instruments and Hedging Activities);
- $167 million asset impairment charges (See Note 4. Asset Impairments); and
- $97 million refund of deepwater Gulf of Mexico royalties, including interest (See Note 2. Additional Financial Statement Information).

(3) The sum of the individual quarterly earnings (loss) per share amounts may not agree with year-to-date earnings per share as each quarterly computation is based on the income or loss for that quarter and the weighted average number of shares outstanding during that quarter.

(4) The diluted earnings per share calculation for the quarter ended June 30, 2010 includes a decrease to net income of $9 million, net of tax for a deferred compensation gain related to shares of our common stock held in a rabbi trust.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports we file or furnish to the SEC under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms, and that information is accumulated and communicated to management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

Our principal executive officer and principal financial officer have evaluated the effectiveness of our "disclosure controls and procedures," as such term is defined in Rule 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended, as of the end of the period covered by this Annual Report on Form 10-K. Based upon their evaluation, they have concluded that our disclosure controls and procedures are designed and effective to ensure that information required to be disclosed in the reports that we file or furnish under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms and that information is accumulated and communicated to management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable, and not absolute, assurance that the objectives of the control system will be met. In addition, the design of any control system is based in part upon certain assumptions about the likelihood of future events and the application of judgment in evaluating the cost-benefit relationship of possible controls and procedures. Because of these and other inherent limitations of control systems, there is only reasonable assurance that our controls will succeed in achieving their goals under all potential future conditions.

Management's Annual Report on Internal Control over Financial Reporting

The management report called for by Item 308(a) of Regulation S-K is incorporated herein by reference to Management's Report on Internal Control over Financial Reporting, included in Item 8. Financial Statements and Supplementary Data.

The independent auditor's attestation report called for by Item 308(b) of Regulation S-K is incorporated herein by reference to Report of Independent Registered Public Accounting Firm (Internal Control Over Financial Reporting), included in Item 8. Financial Statements and Supplementary Data.

Changes in Internal Control over Financial Reporting

Our management is also responsible for establishing and maintaining adequate internal controls over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Our internal controls were designed to provide reasonable assurance as to the reliability of our financial reporting and the preparation and presentation of the consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States.

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

Our management has assessed the effectiveness of our internal controls over financial reporting as of December 31, 2010. Based on our assessment, our internal controls over financial reporting were effective. There were no changes in internal controls over financial reporting that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated herein by reference to the 2011 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2010.

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the 2011 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2010.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required by this item is incorporated herein by reference to the 2011 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2010.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this item is incorporated herein by reference to the 2011 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2010.

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated herein by reference to the 2011 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2010.

PART IV

Item 15. Exhibits, Financial Statements Schedules

a) The following documents are filed as a part of this report:

(3) Exhibits: The exhibits required to be filed by this Item 15 are set forth in the Index to Exhibits accompanying this report.

SIGNATURES

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

NOBLE ENERGY, INC.
(Registrant)

Date: February 10, 2011	By: /s/ Charles D. Davidson Charles D. Davidson, Chairman of the Board, Chief Executive Officer and Director
Date: February 10, 2011	By: /s/ Kenneth M. Fisher Kenneth M. Fisher, Senior Vice President, Chief Financial Officer
Date: February 10, 2011	By: /s/ Frederick B. Bruning Frederick B. Bruning, Vice President, Chief Accounting Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Capacity in which signed	Date
/s/ Charles D. Davidson Charles D. Davidson	Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)	February 10, 2011
/s/ Kenneth M. Fisher Kenneth M. Fisher	Senior Vice President, Chief Financial Officer (Principal Financial Officer)	February 10, 2011
/s/ Frederick B. Bruning Frederick B. Bruning	Vice President, Chief Accounting Officer (Principal Accounting Officer)	February 10, 2011
/s/ Jeffrey L. Berenson Jeffrey L. Berenson	Director	February 10, 2011
/s/ Michael A. Cawley Michael A. Cawley	Director	February 10, 2011
/s/ Edward F. Cox Edward F. Cox	Director	February 10, 2011
/s/ Thomas J. Edelman Thomas J. Edelman	Director	February 10, 2011
/s/ Eric P. Grubman Eric P. Grubman	Director	February 10, 2011
/s/ Kirby L. Hedrick Kirby L. Hedrick	Director	February 10, 2011
/s/ Scott D. Urban Scott D. Urban	Director	February 10, 2011
/s/ William T. Van Kleef William T. Van Kleef	Director	February 10, 2011

INDEX TO EXHIBITS

Exhibit Number		Exhibit **
3.1	—	Certificate of Incorporation, as amended through May 16, 2005, of the Registrant (filed as Exhibit 3.1 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference).
3.2	—	By-Laws of Noble Energy, Inc. as amended through June 1, 2009 (filed as Exhibit 3.1 to the Registrant's Current Report on Form 8-K (Date of Event: February 17, 2009) filed February 19, 2009 and incorporated herein by reference).
4.1	—	Certificate of Designations of Series A Junior Participating Preferred Stock of the Registrant dated August 27, 1997 (filed as Exhibit A of Exhibit 4.1 to the Registrant's Registration Statement on Form 8-A filed on August 28, 1997 and incorporated herein by reference).
4.2	—	Certificate of Designations of Series B Mandatorily Convertible Preferred Stock of the Registrant dated November 9, 1999 (filed as Exhibit 3.4 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999 and incorporated herein by reference).
4.3	—	Indenture dated as of February 27, 2009 between Noble Energy, Inc. and Wells Fargo Bank, National Association, as Trustee, relating to the Registrant's 8¼% Notes Due March 1, 2019 (filed as Exhibit 4.1 to the Registrant's Current Report on Form 8-K (Date of Event: February 24, 2009) filed February 27, 2009 and incorporated herein by reference.)
4.4	—	First Supplemental Indenture dated as of February 27, 2009, to Indenture dated as of February 27, 2009 between Noble Energy, Inc. and Wells Fargo Bank, National Association, as Trustee, relating to the Registrant's 8¼% Notes Due March 1, 2019 (including the form of 2019 Notes) (filed as Exhibit 4.2 to the Registrant's Current Report on Form 8-K (Date of Event: February 24, 2009) filed February 27, 2009 and incorporated herein by reference).
4.5	—	Indenture dated as of October 14, 1993 between the Registrant and U.S. Trust Company of Texas, N.A., as Trustee, relating to the Registrant's 7¼% Notes Due 2023, including form of the Registrant's 7¼% Notes Due 2023 (filed as Exhibit 4.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 1993 and incorporated herein by reference).
4.6	—	Indenture relating to Senior Debt Securities dated as of April 1, 1997 between the Registrant and U.S. Trust Company of Texas, N.A., as Trustee (filed as Exhibit 4.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 1997 and incorporated herein by reference).
4.7	—	First Indenture Supplement relating to $250 million of the Registrant's 8% Senior Notes Due 2027 dated as of April 1, 1997 between the Registrant and U.S. Trust Company of Texas, N.A., as Trustee (filed as Exhibit 4.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 1997 and incorporated herein by reference).
4.8	—	Second Indenture Supplement, between the Company and U.S. Trust Company of Texas, N.A. as trustee, relating to $100 million of the Registrant's 7¼% Senior Debentures Due 2097 dated as of August 1, 1997 (filed as Exhibit 4.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 1997 and incorporated herein by reference).
4.9	—	Third Indenture Supplement relating to $200 million of the Registrant's 5¼% Notes due 2014 dated April 19, 2004 between the Company and the Bank of New York Trust Company, N.A., as successor trustee to U.S. Trust Company of Texas, N.A. (filed as Exhibit 4.1 to the Company's Registration Statement on Form S-4 (Registration No. 333-116092) and incorporated herein by reference).
10.1*	—	Noble Energy, Inc. Retirement Restoration Plan dated effective as of January 1, 2009, (filed as Exhibit 10.1 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2008 and incorporated herein by reference).
10.2*	—	Noble Energy, Inc. Restoration Trust effective August 1, 2002 (filed as Exhibit 10.3 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2002 and incorporated herein by reference).
10.3*	—	Form of Nonqualified Stock Option Agreement under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: February 1, 2005) filed February 7, 2005 and incorporated herein by reference).
10.4*	—	1988 Nonqualified Stock Option Plan for Non-Employee Directors of the Registrant, as amended and restated, effective as of April 27, 2004 (filed as Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004 and incorporated herein by reference).

Exhibit Number		Exhibit **
10.5*	—	Form of Indemnity Agreement entered into between the Registrant and each of the Registrant's directors and bylaw officers (filed as Exhibit 10.18 to the Registrant's Annual Report of Form 10-K for the year ended December 31, 1995 and incorporated herein by reference).
10.6*	—	Amendment to the Noble Energy, Inc. Change of Control Severance Plan for Executives dated effective February 1, 2011 (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: February 1, 2011), filed February 4, 2011 and incorporated herein by reference).
10.7	—	$2.1 billion Five-Year Credit Agreement, dated November 30, 2006, among Noble Energy, Inc., JPMorgan Chase Bank, N.A., as administrative agent, Wachovia Bank, National Association and The Royal Bank of Scotland PLC, as co-syndication agents, Deutsche Bank Securities Inc., Citibank, N.A. and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as co-documentation agents, and certain other commercial lending institutions named therein (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: November 30, 2006), filed December 6, 2006 and incorporated herein by reference).
10.8*	—	Noble Energy, Inc. 2005 Non-Employee Director Fee Deferral Plan, dated December 11, 2008, and effective as of January 1, 2009, (filed as Exhibit 10.20 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2008 and incorporated herein by reference).
10.9*	—	2005 Stock Plan for Non-Employee Directors of Noble Energy, Inc. (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: April 26, 2005) filed April 29, 2005 and incorporated herein by reference).
10.10*	—	Form of Stock Option Agreement under the Noble Energy, Inc. 2005 Non-Employee Director Stock Plan (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005 and incorporated herein by reference).
10.11*	—	Amendment to the 2005 Stock Plan for Non-Employee Directors of Noble Energy, Inc. (effective September 1, 2008) (filed as Exhibit to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2008 and incorporated herein by reference).
10.12*	—	Form of Restricted Stock Agreement under the Noble Energy, Inc. 2005 Non-Employee Director Stock Plan (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: January 27, 2009) filed on February 2, 2009 and incorporated herein by reference).
10.13*	—	Form of Restricted Stock Agreement under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan, (filed as Exhibit 10.14 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2009 and incorporated herein by reference).
10.14*	—	Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (as amended through April 28, 2009), (filed as exhibit 10.1 to Registrant's Current Report on Form 8-K (Date of Event: April 28, 2009) filed April 29, 2009 and incorporated herein by reference).
10.15*	—	Noble Energy, Inc. Change of Control Severance Plan for Executives (as amended effective January 1, 2008), (filed as Exhibit 10.40 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2007 and incorporated herein by reference).
10.16*	—	Form of Noble Energy, Inc. Change of Control Agreement (as amended effective January 1, 2008), (filed as Exhibit 10.41 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2007 and incorporated herein by reference).
10.17*	—	Amendment to the Noble Energy, Inc. Change of Control Agreement dated effective February 1, 2011 (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K (Date of Event: February 1, 2011), filed February 4, 2011 and incorporated herein by reference).
10.18*	—	Noble Energy, Inc. 2004 Long-Term Incentive Plan (as amended effective January 1, 2008), (filed as Exhibit 10.42 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2007 and incorporated herein by reference).
10.19*	—	Noble Energy, Inc. 2005 Deferred Compensation Plan (as amended effective January 1, 2009), (filed as Exhibit 10.31 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2008 and incorporated herein by reference).
12.1	—	Calculation of ratio of earnings to fixed charges, filed herewith.
21	—	Subsidiaries, filed herewith.
23.1	—	Consent of Independent Registered Public Accounting Firm—KPMG LLP, filed herewith.
23.2	—	Consent of Independent Registered Public Accounting Firm—PricewaterhouseCoopers LLP, filed herewith.
23.3	—	Consent of Independent Petroleum Engineers and Geologists—Netherland, Sewell & Associates, Inc., filed herewith.

Exhibit Number		Exhibit **
31.1	—	Certification of the Company's Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241), filed herewith.
31.2	—	Certification of the Company's Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241), filed herewith.
32.1	—	Certification of the Company's Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350), filed herewith.
32.2	—	Certification of the Company's Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350), filed herewith.
99.1	—	Report of Netherland, Sewell & Associates, Inc., filed herewith.
99.2	—	Report of Independent Public Accounting Firm — PricewaterhouseCoopers LLP, filed herewith.
101.INS	—	XBRL Instance Document
101.SCH	—	XBRL Schema Document
101.CAL	—	XBRL Calculation Linkbase Document
101.LAB	—	XBRL Label Linkbase Document
101.PRE	—	XBRL Presentation Linkbase Document
101.DEF	—	XBRL Definition Linkbase Document

* Management contract or compensatory plan or arrangement required to be filed as an exhibit hereto.

** Copies of exhibits will be furnished upon prepayment of 25 cents per page. Requests should be addressed to the Senior Vice President and Chief Financial Officer, Noble Energy, Inc., 100 Glenborough Drive, Suite 100, Houston, Texas 77067.

DIRECTORS

Charles D. Davidson (4)	*Chairman of the Board and Chief Executive Officer, Noble Energy, Inc.*
Jeffery L. Berenson (2) (3)	*President and Chief Executive Officer, Berenson & Company*
Michael A. Cawley (1) (3)	*Trustee, President and Chief Executive Officer, The Samuel Roberts Noble Foundation, Inc.*
Edward F. Cox (2) (3) (4)	*Retired Partner, law firm of Patterson Belknap Webb & Tyler LLP*
Thomas J. Edelman (2) (3) (4)	*Former Chairman of the Board and Chief Executive Officer, Patina Oil & Gas Corporation*
Eric P. Grubman (1) (3)	*Executive Vice President, National Football League*
Kirby L. Hedrick (2) (3) (4)	*Former Executive Vice President, Phillips Petroleum Company*
Scott D. Urban (1) (3) (4)	*Former Group Vice President, BP*
William T. Van Kleef (1) (3)	*Former Executive Vice President and Chief Operating Officer, Tesoro Corporation*

COMMITTEE MEMBERSHIP

(1) Audit Committee
(2) Compensation, Benefits and Stock Option Committee
(3) Corporate Governance and Nominating Committee
(4) Environment, Health and Safety Committee

EXECUTIVE OFFICERS

Charles D. Davidson	*Chairman of the Board, Chief Executive Officer and Director*
David L. Stover	*President and Chief Operating Officer*
Ted D. Brown	*Senior Vice President, North America - Northern Region*
Rodney D. Cook	*Senior Vice President, International*
Susan M. Cunningham	*Senior Vice President, Exploration*
Kenneth M. Fisher	*Senior Vice President and Chief Financial Officer*
Arnold J. Johnson	*Senior Vice President, General Counsel and Secretary*
Andrea Lee Robison	*Vice President, Human Resources*

CORPORATE INFORMATION

Annual Meeting

The Annual Meeting of Stockholders of Noble Energy, Inc. will be held on Tuesday, April 26, 2011, at 9:30 a.m. Central Time, at The Woodlands Waterway Marriott Hotel & Convention Center located at 1601 Lake Robbins Drive, The Woodlands, Texas 77380. All stockholders are cordially invited to attend.

Form 10-K

The Company's Annual Report on Form 10-K for the year ended December 31, 2010, as filed with the Securities and Exchange Commission, is included in this report. Additional copies are available without charge upon request by writing to Investor Relations, Noble Energy, Inc., 100 Glenborough Drive, Suite 100, Houston, Texas 77067-3610; via the Company's website: www.nobleenergyinc.com; or via the Securities and Exchange Commission's website: www.sec.gov.

Forward-Looking Statement

This 2010 Annual Report to stockholders contains forward-looking statements based on expectations, estimates and projections as of the date of this report. These statements by their nature are subject to risks, uncertainties and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. For more information, see "Item 1A. Risk Factors. Disclosure Regarding Forward-Looking Statements" in Noble Energy's Form 10-K included in this report.

The Securities and Exchange Commission permits oil and gas companies, in their filings with the SEC, to disclose proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. Beginning with year-end reserves for 2009, the SEC permits the optional disclosure of probable and possible reserves. We have elected not to disclose the Company's probable and possible reserves in our filings with the SEC. We use certain terms in this publication, such as "net exploration resources" and "gross gas resources," that the SEC's guidelines strictly prohibit us from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved, probable and possible reserves and accordingly are subject to substantially greater risk of being actually realized. Investors are urged to consider closely the disclosures and risk factors in our Form 10-K that is included in this report.

Noble Energy, Inc.

Corporate Headquarters 100 Glenborough Drive Suite 100 Houston, Texas 77067-3610 (281) 872.3100

Investor Relations

David Larson Vice President, Investor Relations (281) 872.3100 investor_relations@nobleenergyinc.com www.nobleenergyinc.com

Independent Public Accountants

KPMG LLP

Transfer Agent and Registrar

Wells Fargo Bank N.A. Shareowner Services 161 North Concord Exchange South St. Paul, MN 55075-1139
(800) 468.9716 stocktransfer@wellsfargo.com

Common Stock Listed New York Stock Exchange

Symbol - NBL

Paper used in this annual report is certified to contain 30% post consumer fiber, produced carbon neutral by a chlorine-free process. It is also green-e and green seal certified, and saves 31,032 lbs of wood, 45,316 gallons of water, 31min BTUs of energy, 9,409 lbs of emissions and 2,751 lbs of solid waste.

PCF

noble energy

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