NOBLE ENERGY INC
Form 10-Q
July 29, 2010

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

FORM 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2010

OR

o 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 or other jurisdiction of incorporation or organization)	(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)

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 x No o

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 x No o

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 the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer x Accelerated filer o Non-accelerated filer o Smaller reporting company o
(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 Exchange Act).
Yes o No x

As of July 15, 2010, there were 174,800,348 shares of the registrant's common stock,
par value $3.33 1/3 per share, outstanding.

TABLE OF CONTENTS

Table of Contents

Part I. Financial Information

Item 1. Financial Statements

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

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Revenues				
Oil, Gas and NGL Sales	$710	$460	$1,398	$866
Income from Equity Method Investees	24	16	50	27
Other Revenues	17	15	36	39
Total	751	491	1,484	932
Costs and Expenses				
Production Expense	150	129	289	260
Exploration Expense	52	33	132	75
Depreciation, Depletion and Amortization	215	196	431	396
General and Administrative	63	60	129	119
Asset Impairments	-	-	-	437
Other Operating (Income) Expense, Net	41	(3)	55	(11)
Total	521	415	1,036	1,276
Operating Income (Loss)	230	76	448	(344)
Other (Income) Expense				
(Gain) Loss on Commodity Derivative Instruments	(96)	139	(242)	66
Interest, Net of Amount Capitalized	19	23	39	41
Other Non-Operating (Income) Expense, Net	(13)	4	(13)	12
Total	(90)	166	(216)	119
Income (Loss) Before Income Taxes	320	(90)	664	(463)
Income Tax Provision (Benefit)	116	(33)	223	(218)
Net Income (Loss)	$204	$(57)	$441	$(245)
Earnings (Loss) Per Share, Basic	$1.17	$(0.33)	$2.53	$(1.42)
Earnings (Loss) Per Share, Diluted	1.10	(0.33)	2.44	(1.42)
Weighted Average Number of Shares Outstanding, Basic	175	173	175	173
Weighted Average Number of Shares Outstanding, Diluted	178	173	178	173

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

Table of Contents

Noble Energy, Inc.
Consolidated Balance Sheets
(millions)

	(unaudited) June 30, 2010	December 31, 2009
ASSETS		
Current Assets		
Cash and Cash Equivalents	$1,017	$ 1,014
Accounts Receivable, Net	538	465
Assets Held for Sale	375	-
Other Current Assets	257	199
Total Assets, Current	2,187	1,678
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method of Accounting)	13,381	12,584
Property, Plant and Equipment, Other	252	240
Total Property, Plant and Equipment, Gross	13,633	12,824
Accumulated Depreciation, Depletion and Amortization	(4,067)	(3,908)
Total Property, Plant and Equipment, Net	9,566	8,916
Goodwill	757	758
Other Noncurrent Assets	503	455
Total Assets	$13,013	$ 11,807
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable - Trade	$751	$ 548
Other Current Liabilities	464	442
Total Liabilities, Current	1,215	990
Long-Term Debt	2,584	2,037
Deferred Income Taxes, Noncurrent	2,162	2,076
Other Noncurrent Liabilities	511	547
Total Liabilities	6,472	5,650
Commitments and Contingencies		
Shareholders' Equity		
Preferred Stock - Par Value $1.00 per share; 4 Million Shares Authorized, None Issued	-	-
Common Stock - Par Value $3.33 1/3 per share; 250 Million Shares Authorized; 195 Million and 194 Million Shares Issued, Respectively	649	645
Additional Paid in Capital	2,327	2,260
Accumulated Other Comprehensive Loss	(128)	(75)
Treasury Stock, at Cost; 19 Million Shares	(627)	(615)
Retained Earnings	4,320	3,942
Total Shareholders' Equity	6,541	6,157
Total Liabilities and Shareholders' Equity	$13,013	$ 11,807

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

4

Table of Contents

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

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Cash Flows From Operating Activities		
Net Income (Loss)	$441	$(245)
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities		
Depreciation, Depletion and Amortization	431	396
Dry Hole Cost	54	9
Asset Impairments	-	437
Deferred Income Taxes	85	(359)
Income from Equity Method Investees	(50)	(27)
Dividends from Equity Method Investees	48	5
Unrealized (Gain) Loss on Commodity Derivative Instruments	(210)	358
Gain on Asset Sale	-	(24)
Other Adjustments for Noncash Items Included in Income	24	(1)
Changes in Operating Assets and Liabilities		
(Increase) Decrease in Accounts Receivable	(73)	7
Decrease in Other Current Assets	28	17
Increase in Accounts Payable	102	10
Decrease in Other Current Liabilities	(3)	(47)
Other Operating Assets and Liabilities, Net	(33)	(38)
Net Cash Provided by Operating Activities	844	498
Cash Flows From Investing Activities		
Additions to Property, Plant and Equipment	(782)	(777)
DJ Basin Asset Acquisition	(466)	-
Net Cash Used in Investing Activities	(1,248)	(777)
Cash Flows From Financing Activities		
Exercise of Stock Options	28	13
Excess Tax Benefits from Stock-Based Awards	16	3
Dividends Paid, Common Stock	(63)	(63)
Purchase of Treasury Stock	(12)	(1)
Proceeds from Credit Facilities	1,165	340
Repayment of Credit Facilities	(727)	(1,161)
Proceeds from Issuance of Senior Long-Term Debt	-	989
Repayment of Installment Note	-	(25)
Net Cash Provided by Financing Activities	407	95
Increase (Decrease) in Cash and Cash Equivalents	3	(184)
Cash and Cash Equivalents at Beginning of Period	1,014	1,140
Cash and Cash Equivalents at End of Period	$1,017	$956

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

5

Table of Contents

Noble Energy, Inc.
Consolidated Statements of Shareholders' Equity
(millions)
(unaudited)

	Common Stock	Additional Paid in Capital	Acumulated Other Comprehensive Loss	Treasury Stock at Cost	Retained Earnings	Total Shareholder's Equity
December 31, 2009	$645	$2,260	$ (75)	$(615)	$3,942	$ 6,157
Net Income	-	-	-	-	441	441
Stock-based Compensation	-	27	-	-	-	27
Exercise of Stock Options	2	26	-	-	-	28
Tax Benefits Related to Exercise of Stock Options	-	16	-	-	-	16
Restricted Stock Awards, Net	2	(2)	-	-	-	-
Dividends (36 cents per share)	-	-	-	-	(63)	(63)
Changes in Treasury Stock, Net	-	-	-	(12)	-	(12)
Oil and Gas Cash Flow Hedges Realized Amounts Reclassified Into Earnings	-	-	6	-	-	6
Interest Rate Cash Flow Hedges Unrealized Change in Fair Value	-	-	(61)	-	-	(61)
Net Change in Other	-	-	2	-	-	2
June 30, 2010	$649	$2,327	$ (128)	$(627)	$4,320	$ 6,541
December 31, 2008	$641	$2,193	$ (110)	$(614)	$4,199	$ 6,309
Net Loss	-	-	-	-	(245)	(245)
Stock-based Compensation	-	24	-	-	-	24
Exercise of Stock Options	2	11	-	-	-	13
Tax Benefits Related to Exercise of Stock Options	-	3	-	-	-	3
Restricted Stock Awards, Net	2	(2)	-	-	-	-
Dividends (36 cents per share)	-	-	-	-	(63)	(63)
Changes in Treasury Stock, Net	-	-	-	(1)	-	(1)
Oil and Gas Cash Flow Hedges Realized Amounts Reclassified Into Earnings	-	-	20	-	-	20
Net Change in Other	-	-	(1)	-	-	(1)
June 30, 2009	$645	$2,229	$ (91)	$(615)	$3,891	$ 6,059

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

6

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements
(unaudited)

Note 1. Organization and Nature of Operations
Noble Energy, Inc. (Noble Energy, we or us) is an independent energy company engaged in global crude oil, natural gas and NGL exploration and production. We operate primarily in the Rocky Mountains, Mid-Continent, and deepwater Gulf of Mexico areas in the US, with core international operations offshore Israel and West Africa.

Note 2. Basis of Presentation
Presentation Our consolidated accounts include our accounts and the accounts of our wholly-owned subsidiaries. The accompanying unaudited consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the US for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and notes required by US generally accepted accounting principles (GAAP) for complete financial statements. The accompanying consolidated financial statements at June 30, 2010 and December 31, 2009 and for the three and six months ended June 30, 2010 and 2009 contain all normally recurring adjustments considered necessary for a fair presentation of our financial position, results of operations and cash flows for such periods. Operating results for the three and six months ended June 30, 2010 are not necessarily indicative of the results that may be expected for the year ended December 31, 2010. Certain reclassifications of amounts previously reported have been made to conform to current year presentations. These consolidated financial statements should be read in conjunction with the consolidated financial statements and accompanying notes included in our annual report on Form 10-K for the year ended December 31, 2009.

Estimates The preparation of consolidated financial statements in conformity with 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. Actual results could differ significantly from those estimates.

Statements of Operations Information Other statements of operations information is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
(millions)				
Other Revenues				
Electricity Sales (1)	$16	$11	$35	$32
Other	1	4	1	7
Total	$17	$15	$36	$39
Production Expense				
Lease Operating Expense	$100	$93	$188	$193
Production and Ad Valorem Taxes	34	23	67	42
Transportation Expense	16	13	34	25
Total	$150	$129	$289	$260
Other Operating (Income) Expense, Net				
Rig Contract Termination Expense (2)	$26	$-	$26	$-
Gain on Asset Sale (3)	-	(24)	-	(24)
Electricity Generation Expense (1)	7	11	17	(19)
Other, Net	8	10	12	32

Total	$41	$(3)	$55	$(11)
Other Non-Operating (Income) Expense, Net				
Deferred Compensation (4)	$(13)	$5	$(11)	$10
Interest Income	(2)	(1)	(4)	(1)
Other (Income) Expense, Net	2	-	2	3
Total	$(13)	$4	$(13)	$12

(1) Includes amounts related to our 100%-owned Ecuador integrated power project. The project includes the Amistad natural gas field, offshore Ecuador, which supplies natural gas to fuel the Machala power plant located in Machala, Ecuador. Electricity generation expense includes all operating and non-operating expenses associated with the plant, including depreciation, depletion and amortization expense (DD&A) and changes in the allowance for doubtful accounts. Electricity generation expense for the first six months of 2009 includes a reduction in the allowance for doubtful accounts of $46 million received in accordance with the terms of a settlement with entities purchasing electricity in Ecuador.

(2) See Note 3. Impact of Federal Deepwater Moratorium.

(3) In February 2008, effective July 1, 2007, we sold our interest in Argentina. The gain on sale was deferred until second quarter 2009 when the Argentine government approved the sale.

(4) Amount represents increases (decreases) in the fair value of our common stock held in a rabbi trust.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements
(unaudited)

Balance Sheet Information   Other balance sheet information is as follows:

(millions)	June 30, 2010	December 31, 2009
Accounts Receivable, Net		
Commodity Sales	$254	$ 205
Joint Interest Billings	282	140
Refund of Deepwater Gulf of Mexico Royalties (1)	-	97
Other	30	54
Allowance for Doubtful Accounts	(28)	(31)
Total	$538	$ 465
Other Current Assets		
Inventories, Current	$99	$ 89
Commodity Derivative Assets, Current	71	13
Prepaid Expenses and Other Assets, Current	26	65
Deferred Income Taxes, Net, Current	61	32
Total	$257	$ 199
Other Noncurrent Assets		
Equity Method Investments	$305	$ 303
Mutual Fund Investments	103	108
Commodity Derivative Assets, Noncurrent	51	1
Other Assets, Noncurrent	44	43
Total	$503	$ 455
Accounts Payable - Trade		
Capital Costs	$441	$ 277
Royalties Payable	86	65
Lease Operating Expense	40	27
Rig Contract Termination Expense (2)	26	-
Other	158	179
Total	$751	$ 548
Other Current Liabilities		
Production and Ad Valorem Taxes	$102	$ 103
Commodity Derivative Liabilities, Current	4	100
Interest Rate Derivative Liability, Current	94	-
Income Taxes Payable	77	60
Asset Retirement Obligations, Current	63	51
Interest Payable	37	37
Other	87	91
Total	$464	$ 442
Other Noncurrent Liabilities		
Deferred Compensation Liabilities, Noncurrent	$200	$ 213
Asset Retirement Obligations, Noncurrent	187	181
Accrued Benefit Costs, Noncurrent	80	76
Commodity Derivative Liabilities, Noncurrent	1	17

Other	43	60
Total	$511	$ 547

(1) During 2010, we received a refund, including interest thereon, 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.

(2) See Note 3. Impact of Federal Deepwater Moratorium.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements
(unaudited)

Recently Adopted Accounting Standards   In February 2010, the Financial Accounting Standards Board (FASB) amended its guidance on subsequent events to remove the requirement for SEC filers to disclose the date through which an entity has evaluated subsequent events. The guidance was effective upon issuance. We adopted this guidance effective first quarter 2010.

The FASB also issued new guidance requiring additional disclosures about fair value measurements, adding a new requirement to disclose transfers in and out of Levels 1 and 2 measurements and gross presentation of activity within a Level 3 roll forward. The guidance also clarified existing disclosure requirements regarding the level of disaggregation of fair value measurements and disclosures regarding inputs and valuation techniques. We adopted this guidance effective first quarter 2010. Adoption had no impact on our financial position or results of operations. See Note 7. Fair Value Measurements and Disclosures.

Note 3. Impact of Federal Deepwater Moratorium

During second quarter 2010, a six-month moratorium on drilling in the deepwater Gulf of Mexico (Federal Deepwater Moratorium or Moratorium) was enacted in response to an apparent blowout and fire on a deepwater drilling rig, Deepwater Horizon, which was engaged in drilling operations for another operator (the Deepwater Horizon Incident or the Incident). The Incident resulted in the loss of life and a significant oil spill. As a result, all deepwater drilling activities in progress at the time the Moratorium was announced were suspended.

As a result of the Moratorium, we entered into an agreement to terminate our contract for the Noble Clyde Boudreaux drilling rig and recognized rig contract termination expense of $26 million during second quarter 2010, in accordance with GAAP for contract termination costs. The amount is included in other operating (income) expense, net in our consolidated statements of operations. The US reporting unit recorded a related $26 million liability at June 30, 2010.

Note 4. Acquisitions and Divestitures

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 Greater Denver-Julesberg (DJ) Basin, one of our core onshore US operating areas. We funded the acquisition using our existing credit facility.

The total purchase price and allocation of the total purchase price are as follows:

(millions)		June 30, 2010
Total Purchase Price		
Cash Paid	$	466
Net Liabilities Assumed		43
Total	$	509
Allocation of Total Purchase Price		
Proved Oil and Gas Properties	$	363
Unproved Oil and Gas Properties		146
Total	$	509

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, 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 DJ Basin properties which we operate; and
- estimated timing and amounts of future operating and development costs based on our experience with similar 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.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements
(unaudited)

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 as of June 30, 2010, or our consolidated results of operations for the three and six months ended June 30, 2010.

Sale of Onshore US Assets   We have entered into an agreement to divest certain non-core properties in the Mid-Continent and Illinois Basin areas for a sales price of approximately $550 million. We expect the sale, which will be effective as of April 1, 2010, to close in third quarter 2010. Information regarding assets and liabilities of the disposal group held for sale is as follows:

(millions)	June 30, 2010
Property, Plant and Equipment Held for Sale (Net Book Value)	$ 375
Goodwill Allocated to Properties Held for Sale	65
Asset Retirement Obligations Associated with Properties Held for Sale	(12)

Note 5. Debt
Our debt consists of the following:

	June 30, 2010		December 31, 2009	
(millions, except percentages)	Debt	Interest Rate	Debt	Interest Rate
Credit Facility (1)	$ 820	0.66 %	$ 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 (2)	137	-	29	-
Total	2,591		2,045	
Unamortized Discount	(7)		(8)	
Total Debt, Net of Discount	$ 2,584		$ 2,037	

(1) The increase in the credit facility balance from December 31, 2009 represents amounts drawn to fund the DJ Basin asset acquisition and other capital expenditures. See Note 4. Acquisitions and Divestitures.

(2) Amount reported is based on percentage of floating production, storage and offloading vessel (FPSO) construction activities completed as of June 30, 2010, and therefore does not reflect future minimum lease obligations. The increase in the FPSO lease obligation is a non-cash financing activity.

Note 6. Derivative Instruments and Hedging Activities

Objectives 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, collars and basis swaps. While these instruments mitigate the cash flow risk of future reductions in commodity prices they may also curtail benefits from future increases in commodity prices.

We may 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.

All derivative instruments are reflected as either assets or liabilities at fair value in our consolidated balance sheets. See Note 7. Fair Value Measurements and Disclosures for a discussion of methods and assumptions used to estimate the fair values of derivative instruments and gross amounts of derivative assets and liabilities.

Counterparty Credit Risk Derivative instruments expose us to counterparty credit risk. Our commodity derivative instruments are currently with a diversified group of financial institutions. We generally execute commodity derivative instruments 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 cash settled at the time of election.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements
(unaudited)

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 as well as incur a loss. We include a measure of counterparty credit risk in our estimates of the fair values of derivative instruments in an asset position.

Accounting for Commodity Derivative Instruments We recognize all gains and losses on commodity derivative instruments 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. Net derivative gains and losses that were deferred in accumulated other comprehensive loss (AOCL) as of January 1, 2008, as a result of previous cash flow hedge accounting, are reclassified to earnings in future periods as the original hedged transactions occur. See Derivative Instruments in Cash Flow Hedging Relationships table below.

Accounting for Interest Rate Derivative Instruments 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. In January 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.

Unsettled Derivative Instruments As of June 30, 2010, we had entered into the following crude oil derivative instruments:

	Variable to Fixed Price Swaps			Two Way Collars			
Period	Index	Bbls Per Day	Weighted Average Fixed Price	Index	Bbls Per Day	Weighted Average Floor Price	Weighted Average Ceiling Price
3rd Qtr - 4th Qtr 2010	NYMEX WTI	3,000	$ 83.36	NYMEX WTI	14,500	$ 61.48	$ 75.63
3rd Qtr - 4th Qtr 2010	Dated Brent	1,000	80.05	Dated Brent	7,000	64.00	73.96
2010 Average		4,000	82.53		21,500	62.30	75.09
2011	-	-	-	NYMEX WTI	13,000	80.15	94.63
2012	NYMEX WTI	5,000	91.84	-	-	-	-

			Three Way Collars (1)		
Period	Index	Bbls Per Day	Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
2011	NYMEX WTI	5,000	$ 56.00	$ 76.00	$ 101.46

(1) A three-way collar consists of a collar contract combined with a put option contract sold by us with a price below the floor price of the collar.

Between July 1 and July 15, 2010, we entered into additional Dated Brent swaps covering 5,000 Bbls per day for calendar year 2012 with a weighted average fixed price of $83.09.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements
(unaudited)

As of June 30, 2010, we had entered into the following natural gas derivative instruments:

	Variable to Fixed Price Swaps			Two Way Collars			
Period	Index	MMBtu Per Day	Weighted Average Fixed Price	Index	MMBtu Per Day	Weighted Average Floor Price	Weighted Average Ceiling Price
3rd Qtr - 4th Qtr 2010	NYMEX HH	40,000	$6.10	NYMEX HH (1)	210,000	$5.90	$6.73
3rd Qtr - 4th Qtr 2010	-	-	-	IFERC CIG (2)	15,000	6.25	8.10
2010 Average		40,000	6.10		225,000	5.93	6.82
2011	NYMEX HH	25,000	6.41	NYMEX HH	140,000	5.95	6.82

Three Way Collars

Period	Index	MMBtu Per Day	Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
2011	NYMEX HH	50,000	$ 4.00	$ 5.00	$ 6.70
2012	NYMEX HH	50,000	$ 4.75	$ 5.50	$ 7.92

(1) Henry Hub
(2) Colorado Interstate Gas - Northern System

As of June 30, 2010, we had entered into the following natural gas basis swaps:

Basis Swaps

Period	Index	Index Less Differential	MMBtu Per Day	Weighted Average Differential
3rd Qtr - 4th Qtr 2010	IFERC CIG	NYMEX HH	110,000	$ (1.49)
2011	IFERC CIG	NYMEX HH	120,000	(0.73)
2012	IFERC CIG	NYMEX HH	40,000	(0.52)

Between July 1 and July 15, 2010, we entered into an additional basis swap covering 10,000 MMBtus per day for calendar year 2012 with a NYMEX HH to IFERC CIG differential of $(0.54).

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			
	June 30, 2010		December 31, 2009		June 30, 2010		December 31, 2009	
(millions)	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity Derivative Instruments (Not Designated as Hedging Instruments)	Current Assets	$ 71	Current Assets	$ 13	Current Liabilities	$ 4	Current Liabilities	$ 100
	Noncurrent Assets	51	Noncurrent Assets	1	Noncurrent Liabilities	1	Noncurrent Liabilities	17
Interest Rate Derivative Instruments (Designated as Hedging Instruments)	Current Assets	-	Current Assets	-	Current Liabilities	94	Current Liabilities	-
Total		$ 122		$ 14		$ 99		$ 117

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements
(unaudited)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
(millions)				
Realized Mark-to-Market (Gain) Loss	$(33)	$(138)	$(32)	$(292)
Unrealized Mark-to-Market (Gain) Loss	(63)	277	(210)	358
Total (Gain) Loss on Commodity Derivative Instruments	$(96)	$139	$(242)	$66

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	2010	2009
(millions)				
Three Months Ended June 30,				
Commodity Derivative Instruments in Previously Designated Cash Flow Hedging Relationship (1)				
Crude Oil Derivative Instruments	$-	$-	$4	$15
Interest Rate Derivative Instruments in Cash Flow Hedging Relationships	83	-	-	-
Total	$83	-	$4	$15
Six Months Ended June 30,				
Commodity Derivative Instruments in Previously Designated Cash Flow Hedging Relationships (1)				
Crude Oil Derivative Instruments	$-	$-	$9	$32
Natural Gas Derivative Instruments	-	-	1	-
Interest Rate Derivative Instruments in Cash Flow Hedging Relationships	94	-	-	-
Total	$94	-	$10	$32

(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, are reclassified to earnings in future periods as the original hedged transactions occur.

AOCL   As of June 30, 2010, the balance in AOCL included deferred losses of $6 million related to the fair value of commodity derivative instruments previously accounted for as cash flow hedges. The deferred losses are net of deferred income tax benefits of $4 million. All remaining deferred losses will be reclassified to earnings during the period July 1 through December 31, 2010, as the forecasted transactions occur, and will be recorded as a reduction in oil and gas sales of approximately $10 million before tax.

AOCL also included deferred losses of $63 million, net of tax, related to interest rate derivative instruments. Of this amount, $2 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. Approximately $61 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.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements
(unaudited)

Note 7. 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, collars and basis swaps. We estimate the fair values of these instruments based on published forward commodity price curves for the underlying commodities 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 credit 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 value of the contract floors and ceilings using an option pricing model which takes into account market volatility, market prices and contract terms. See Note 6. 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 credit 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.

Deferred Compensation Liability A portion of our deferred compensation liability is measured at fair value, which 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) (2)	Significant Unobservable Inputs (Level 3) (3)	Adjustment (4)	Fair Value Measurement
(millions)					
June 30, 2010					
Financial Assets					

Mutual Fund Investments	$103	$-	$ -	$-	$ 103
Commodity Derivative Instruments	-	172	-	(50)	122
Financial Liabilities					
Commodity Derivative Instruments	-	(55)	-	50	(5)
Interest Rate Derivative Instrument	-	(94)	-	-	(94)
Portion of Deferred Compensation					
Liability Measured at Fair Value	(151)	-	-	-	(151)
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) Level 1 measurements are fair value measurements which use quoted market prices (unadjusted) in active markets for identical assets or liabilities. We use Level 1 inputs when available as Level 1 inputs generally provide the most reliable evidence of fair value.

(2) 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.

(3) Level 3 measurements are fair value measurements which use unobservable inputs.

(4) Amount represents the impact of master netting agreements that allow us to net cash settle asset and liability positions with the same counterparty.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements
(unaudited)

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. The following methods and assumptions were used to estimate the fair values:

DJ Basin Asset Acquisition See Note 4. Acquisitions and Divestitures.

Asset Impairments (2009) We determined that the carrying amount of Granite Wash, an onshore US area where we have significantly reduced investments beginning in 2007, was not recoverable from future cash flows and, therefore, was impaired. We also impaired our Gulf of Mexico Main Pass asset which had been reclassified from held-for-sale to held-and-used. The assets were reduced to their estimated fair values. Information about the impaired assets is as follows:

			Fair Value Measurements Using			
Description	Net Book Value	Fair Value Measurement	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Pre-tax (Non-cash) Impairment Loss
(millions)						
June 30, 2009						
Impaired US Oil and Gas Properties	$753	$ 316	$-	$-	$ 316	$437

The fair values of the properties were determined as of the date of the assessment using a discounted cash flow method, as comparable market data was not available. The discounted cash flows were based on management's expectations for the future. Inputs included 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.

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 amounts 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 5. Debt.

Fair value information regarding our debt is as follows:

	June 30, 2010		December 31, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
(millions)				
Long-Term Debt, Net of Unamortized Discount (1)	$ 2,447	$ 2,715	$ 2,008	$ 2,279

(1) Excludes obligation under FPSO lease.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements
(unaudited)

Note 8. Capitalized Exploratory Well Costs

Changes in capitalized exploratory well costs are as follows and exclude amounts that were capitalized and subsequently expensed in the same period:

(millions)	Six Months Ended June 30, 2010
Capitalized Exploratory Well Costs, Beginning of Period	$432
Additions to Capitalized Exploratory Well Costs Pending Determination of Proved Reserves	65
Reclassified to Proved Oil and Gas Properties Based on Determination of Proved Reserves	(11)
Capitalized Exploratory Well Costs Charged to Expense	(3)
Capitalized Exploratory Well Costs, End of Period	$483

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:

(millions)	June 30, 2010	December 31, 2009
Exploratory Well Costs Capitalized for a Period of One Year or Less	$100	$ 158
Exploratory Well Costs Capitalized for a Period Greater Than One Year After Completion of Drilling	383	274
Balance at End of Period	$483	$ 432
Number of Projects with Exploratory Well Costs That Have Been Capitalized for a Period Greater Than One Year After Completion of Drilling	9	5

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 June 30, 2010:

		Suspended Since		
(millions)	Total	2009	2008	2007 & Prior
Project				
Blocks O and I (West Africa)	$190	$9	$71	$110
Tamar and Dalit (Israel)	89	63	26	-
Gunflint (Deepwater Gulf of Mexico)	49	-	49	-
Redrock (Deepwater Gulf of Mexico)	17	-	-	17
Flyndre (North Sea)	13	-	-	13
Selkirk (North Sea)	20	-	-	20
Other	5	1	4	-
Total Exploratory Well Costs Capitalized for a Period Greater Than One Year After Completion of Drilling	$383	$73	$150	$160

West Africa   The West Africa project includes Blocks O and I offshore Equatorial Guinea and the YoYo concession and Tilapia production sharing contract offshore Cameroon. We have evaluated the potential for additional liquids and gas projects, and determined that the next development after Aseng will be at the Alen (formerly known as Belinda) field, offshore Equatorial Guinea. We are also evaluating future oil projects at Diega and Carmen, offshore Equatorial Guinea. In Cameroon, we recently completed a 3-D seismic acquisition, and results are being processed for future drilling potential.

Israel   The Israel project includes the Tamar and Dalit prospects, both significant 2009 natural gas discoveries located offshore Israel. We are moving forward with Tamar development plans, and are targeting project sanction in 2010, with first production projected for 2012. We have also signed letters of intent to sell natural gas from the Tamar field.

Gunflint (Deepwater Gulf of Mexico)   Gunflint (Mississippi Canyon Block 948) is our largest deepwater Gulf of Mexico discovery to date. We had planned to drill one or two appraisal wells in 2010. These plans have been delayed until at least November 2010 by the Federal Deepwater Moratorium. We are currently reviewing host platform options. If we are able to connect to an existing third-party host, the project could have an accelerated completion schedule, thereby absorbing time lost to the drilling delay.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements
(unaudited)

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). The anticipated development plan consists of tying Raton South back to a host platform at Viosca Knoll Block 900 for processing and then connecting Redrock into this gathering system. Tie-back of Redrock is anticipated to occur following the development of Raton South.

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.

Other   Other projects consist of three onshore US wells which continue to be evaluated by various means including additional seismic work, drilling additional wells and evaluating the potential of the exploration well.

Note 9. Asset Retirement Obligations

Asset retirement obligations consist primarily of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. Changes in asset retirement obligations were as follows:

	Six Months Ended June 30,	
	2010	2009
(millions)		
Asset Retirement Obligations, Beginning of Period	$232	$211
Liabilities Incurred in Current Period	14	4
Liabilities Settled in Current Period	(9)	(8)
Revisions	4	17
Accretion Expense	9	7
Asset Retirement Obligations, End of Period	$250	$231

Liabilities incurred in 2010 were due to the DJ Basin asset acquisition. Accretion expense is included in DD&A expense in the consolidated statements of operations.

Note 10.   Employee Benefit Plans

We have a noncontributory, tax-qualified defined benefit pension plan covering employees who were hired prior to May 1, 2006. 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. Net periodic benefit cost related to the retirement and restoration plans was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
(millions)				

Service Cost	$4	$3	$7	$6
Interest Cost	3	3	7	6
Expected Return on Plan Assets	(3)	(3)	(7)	(7)
Other	1	-	3	1
Net Periodic Benefit Cost	$5	$3	$10	$6

During the six months ended June 30, 2010, we made cash contributions of $4 million to the pension plan.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements
(unaudited)

Note 11. Stock-Based Compensation

We recognized stock-based compensation expense as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
(millions)				
Stock-Based Compensation Expense	$13	$12	$27	$24
Tax Benefit Recognized	(5)	(4)	(9)	(8)

During the six months ended June 30, 2010, we granted stock options and awarded shares of restricted stock, subject to service conditions, as follows:

	Number Granted/Awarded	Weighted Average Fair Value
Stock Options	1,023,858	$25.07
Shares of Restricted Stock	419,496	75.11

Note 12. Basic and Diluted Earnings (Loss) Per Share

Basic earnings (loss) per share of common stock is computed using the weighted average number of shares of common stock outstanding during each period. The diluted earnings (loss) per share of common stock may include the effect of our shares held in a rabbi trust, outstanding stock options or shares of restricted stock, except in periods in which there is a net loss. The following table summarizes the calculation of basic and diluted earnings (loss) per share:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
(millions, except per share amounts)				
Net Income (Loss)	$204	$(57)	$441	$(245)
Earnings Adjustment from Assumed Conversion of Dilutive Shares of Common Stock in Rabbi Trust (1)	(9)	-	(7)	-
Net Income (Loss) Used for Diluted Earnings Per Share Calculation	$195	$(57)	$434	$(245)
Weighted Average Number of Shares Outstanding, Basic	175	173	175	173
Incremental Shares from Assumed Conversion of Dilutive Options, Restricted Stock and Shares of Common Stock in Rabbi Trust	3	-	3	-
Weighted Average Number of Shares Outstanding, Diluted	178	173	178	173
Earnings (Loss) Per Share, Basic	$1.17	$(0.33)	$2.53	$(1.42)
Earnings (Loss) Per Share, Diluted	1.10	(0.33)	2.44	(1.42)

(1) The diluted earnings per share calculation for the three and six months ended June 30, 2010 includes decreases to net income of $9 million and $7 million (net of tax), respectively, related to a deferred compensation gain from Noble Energy shares held in a rabbi trust. When dilutive, the deferred compensation gain or loss (net of tax) is

excluded from net income while the Noble Energy shares held in the rabbi trust are included in the diluted share count.

Additional information is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Antidilutive stock options, shares of restricted stock and common shares held in a rabbi trust excluded from calculation above	2	4	2	4
Incremental stock options and shares of restricted stock excluded from calculation of diluted earnings in loss period	-	2	-	2

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements
(unaudited)

Note 13. Income Taxes
The income tax provision (benefit) consists of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
(millions)				
Current	$59	$25	$138	$141
Deferred	57	(58)	85	(359)
Total Income Tax Provision (Benefit)	$116	$(33)	$223	$(218)
Effective Tax Rate	36%	37%	34%	47%

Our effective tax rate decreased for the first six months of 2010 as compared with the first six months of 2009. For 2010, the effective rate is lower than the federal statutory rate because our income from equity method investees results in a favorable permanent difference in the effective rate, which has the impact of decreasing the statutory rate when we have pre-tax income.

The 2009 rate was 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. The deferred tax benefit for the six months ended June 30, 2009 was due primarily to the realization in 2009 of a significant amount of unrealized mark-to-market gain originally recorded in 2008, resulting in the reversal of most of the associated deferred tax liability recorded in 2008. In addition, we recorded a deferred tax asset with respect to impairment losses on our US oil and gas properties.

During first quarter 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.

Unrecognized Tax Positions We do not have significant unrecognized tax benefits as of June 30, 2010. Our policy is to recognize any interest and penalties related to unrecognized tax benefits in income tax expense. We did not accrue interest or penalties at June 30, 2010, 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.

In our major tax jurisdictions, the earliest years remaining open to examination are as follows: US – 2006, Equatorial Guinea – 2007, China – 2006, Israel – 2008, UK – 2007 and the Netherlands – 2005.

Note 14. Comprehensive Income (Loss)
Comprehensive income (loss) includes net income (loss) and certain items recorded directly to shareholders' equity and classified as AOCL. Comprehensive income (loss) was calculated as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009

(millions)				
Net Income (Loss)	$204	$(57)	$441	$(245)
Other Items of Comprehensive Income (Loss)				
Oil and Gas Cash Flow Hedges				
Realized Losses Reclassified Into Earnings	4	15	10	32
Less Tax Provision	(1)	(6)	(4)	(12)
Interest Rate Cash Flow Hedges				
Unrealized Change in Fair Value	(83)	-	(94)	-
Less Tax Provision	29	-	33	-
Net Change in Other	1	-	2	(1)
Other Comprehensive Income (Loss)	(50)	9	(53)	19
Comprehensive Income (Loss)	$154	$(48)	$388	$(226)

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements
(unaudited)

Note 15. 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 and production: the United States; West Africa (Equatorial Guinea and Cameroon); Eastern Mediterranean (Israel and Cyprus); the North Sea (UK and the Netherlands); and Other International (China and Ecuador) and Corporate. The following data was prepared on the same basis as our consolidated financial statements and excludes the effects of income taxes.

(millions)	Consolidated	United States	West Africa	Eastern Mediterranean	North Sea	Other Int'l and Corporate
Three Months Ended June 30, 2010						
Revenues from Third Parties	$ 731	$ 459	$ 118	$ 48	$ 62	$ 44
Reclassification from AOCL (1)	(4)	(4)	-	-	-	-
Income from Equity Method Investees	24	-	24	-	-	-
Total Revenues	751	455	142	48	62	44
DD&A	215	177	11	7	11	9
Gain on Commodity Derivative Instruments	(96)	(81)	(15)	-	-	-
Income (Loss) Before Income Taxes	320	181	127	33	36	(57)
Three Months Ended June 30, 2009						
Revenues from Third Parties	$ 490	$ 311	$ 85	$ 24	$ 35	$ 35
Reclassification from AOCL (1)	(15)	(8)	(7)	-	-	-
Income from Equity Method Investees	16	-	16	-	-	-
Total Revenues	491	303	94	24	35	35
DD&A	196	164	9	5	9	9
Loss on Commodity Derivative Instruments	139	109	30	-	-	-
Income (Loss) Before Income Taxes	(90)	(72)	40	14	13	(85)
Six Months Ended June 30, 2010						
Revenues from Third Parties	$ 1,444	$ 968	$ 179	$ 81	$ 128	$ 88
	(10)	(10)	-	-	-	-

Reclassification from AOCL (1)						
Income from Equity Method Investees	50	-	50	-	-	-
Total Revenues	1,484	958	229	81	128	88
DD&A	431	358	19	11	26	17
Gain on Commodity Derivative Instruments	(242)	(227)	(15)	-	-	-
Income (Loss) Before Income Taxes	664	470	194	59	73	(132)
Six Months Ended June 30, 2009						
Revenues from Third Parties	$ 937	$ 599	$ 144	$ 52	$ 69	$ 73
Reclassification from AOCL (1)	(32)	(16)	(16)	-	-	-
Income from Equity Method Investees	27	-	27	-	-	-
Total Revenues	932	583	155	52	69	73
DD&A	396	333	18	10	18	17
Asset Impairments	437	437	-	-	-	-
Loss on Commodity Derivative Instruments	66	42	24	-	-	-
Income (Loss) Before Income Taxes	(463)	(481)	82	35	24	(123)
June 30, 2010						
Goodwill	$ 757	$ 757	$ -	$ -	$ -	$ -
Total Assets	13,013	9,390	2,004	651	689	279
December 31, 2009						
Goodwill	758	758	-	-	-	-
Total Assets	11,807	8,669	1,731	486	635	286

(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.

Table of Contents

Noble Energy, Inc.
Notes to Consolidated Financial Statements
(unaudited)

Note 16. 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.

Table of Contents

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

EXECUTIVE OVERVIEW

We are an independent energy company engaged in global crude oil, natural gas and NGL exploration and production. 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 diversified among US and international projects, crude oil and natural gas, and near, medium and long-term opportunities.

Our accompanying consolidated financial statements, including the notes thereto, contain detailed information that should be referred to in conjunction with the following discussion.

Our financial results for second quarter 2010 included:

- net income of $204 million, as compared with a net loss of $57 million for second quarter 2009;
- rig contract termination expense of $26 million due to the Federal Deepwater Moratorium;
- gain on commodity derivative instruments of $96 million (including unrealized mark-to-market gain of $63 million) as compared with a loss on commodity derivative instruments of $139 million (including unrealized mark-to-market loss of $277 million) for second quarter 2009;
- diluted earnings per share of $1.10, as compared with diluted loss per share of $0.33 for second quarter 2009;
- cash flow provided by operating activities of $256 million, as compared with $313 million for second quarter 2009;
- capital spending (excluding impact of the FPSO accrual) of $519 million as compared with $323 million in 2009;
- net increase of $546 million principal amount of debt, including FPSO lease accrual, from December 31, 2009;
- ending cash and cash equivalents balance of $1 billion at both June 30, 2010 and December 31, 2009;
- total liquidity of $2.3 billion at June 30, 2010, consisting of ending cash balance plus funds available under credit facility, as compared with $2.7 billion at December 31, 2009; and
- ratio of debt-to-book capital of 28% (including FPSO lease accrual) at June 30, 2010 as compared with 25% at December 31, 2009.

Significant operational highlights for second quarter 2010 included:

- total sales volumes of 219 MBoepd, a 6% increase over second quarter of 2009;
- Israel natural gas sales volumes up 27% from second quarter 2009;
- agreement to sell certain non-core US onshore assets for a sales price of approximately $550 million;
- addition of a second rig to horizontal Niobrara drilling program in Central DJ Basin; and
- completion of maintenance project at the Alba field, offshore Equatorial Guinea, bringing the field back to full production.

Impact of Deepwater Horizon Incident and Federal Deepwater Moratorium

In April 2010, the deepwater Gulf of Mexico drilling rig Deepwater Horizon, engaged in drilling operations for another operator, sank after an apparent blowout and fire. The resulting leak from the damaged well caused the largest oil spill in US history. On May 27, 2010, in response to the Incident, the President of the United States announced a six-month moratorium on drilling in the deepwater Gulf of Mexico (Federal Deepwater Moratorium or the Moratorium), which followed a one-month suspension in activity announced in May, immediately following the spill. Under the Federal Deepwater Moratorium, no new drilling, including sidetracks and bypasses of wells, is allowed in water depths greater than 500 feet for six months, or until November 27, 2010. As a result, all deepwater drilling activities in progress at the time the Moratorium was announced were suspended.

At the time the Federal Deepwater Moratorium was announced, we were engaged in two deepwater Gulf of Mexico drilling operations at prospects for which we are the operator, including an exploration well at the Santiago prospect (Galapagos project) and a sidetrack to the exploration well at the Deep Blue prospect. We suspended operations and temporarily abandoned each location.

On June 22, 2010, a US district judge in New Orleans, Louisiana, granted a preliminary injunction against the enforcement of the Moratorium. On June 23, 2010, the US administration asked the judge to delay the ruling and allow the drilling ban to stay in place during the appeals process. The motion was denied. On July 8, 2010, the US Court of Appeals for the Fifth Circuit also denied the US government's request to reinstate the Moratorium during the process of appealing the lower court's order that originally rejected the drilling ban.

On July 12, 2010, the Secretary of the Interior (the Secretary) announced a revised moratorium that will last through November 30, 2010 and focuses on drilling configurations and technologies rather than on water depth. The revised moratorium applies to most deepwater drilling operations, including those that use subsea blowout preventers, and some companies may be able to resume drilling sooner under certain conditions. To qualify, operators must certify that they have adequate plans in place to quickly shut down an out-of-control well, that the blowout preventers atop the wells it drills have passed rigorous new tests, and that sufficient cleanup resources are on hand in case of a spill. The Secretary directed federal regulators to come up with interim rules by the end of August 2010 that would clarify the steps that drilling rig operators would need to take to resume operations under the revised moratorium.

Table of Contents

Resumption of deepwater Gulf of Mexico drilling and other activities suspended by the Federal Deepwater Moratorium is unlikely until the legal status of a return to business is evident, or the Moratorium is further refined, rescinded, or ends as scheduled in November 2010. In addition, a presidential commission has been appointed to study the causes of the oil spill and to recommend improvements for offshore drilling.

Despite the Federal Deepwater Moratorium, our deepwater Gulf of Mexico production was robust for second quarter 2010, and we expect no material impact on our production for the remainder of the year. We also expect an increase in our liquidity due to the postponement of some of our Gulf of Mexico capital spending. See 2010 Budget below.

However, in the long run, we believe that the Deepwater Horizon Incident is likely to have a significant and lasting effect on the US offshore energy industry, and will likely result in a number of fundamental changes, including heightened regulatory scrutiny, more stringent operating and safety standards, changes in equipment requirements and the availability and cost of insurance, as well as increased politicization of the industry. There may be other impacts of which we are not aware at this time. See Item 1A. Our operations in the deepwater Gulf of Mexico could be adversely affected by changes in laws and regulations which are expected to occur as a result of the Deepwater Horizon Incident below.

Business Impact

The deepwater Gulf of Mexico is one of our core operating areas. Although the full impact of the Deepwater Horizon Incident and the Federal Deepwater Moratorium remains unknown, we currently expect the following effects on our operations:

Near-term Impact – The deepwater Gulf of Mexico represented approximately 8% of our total consolidated sales volumes for second quarter 2010 and 4% of our global proved reserves at December 31, 2009. The Federal Deepwater Moratorium had no impact on our currently producing properties or on our production for second quarter 2010. It is our understanding that workover operations, operations necessary to sustain reservoir pressure, waterflood, gas injections, disposal wells, and plugging and abandonment operations are still allowed, to the extent they comply with applicable regulations and permits. Therefore, we do not expect production for the remainder of 2010 to be impacted. Further, delays in capital spending resulting from the Moratorium will have a positive impact on our near-term cash flows.

Mid-term Impact – A six-month moratorium would impact our deepwater Gulf of Mexico development program as follows:

- Galapagos Project – At the time the Federal Deepwater Moratorium was announced, we were engaged in drilling the Santiago exploratory well, for which we are the operator. We suspended drilling operations, plugged and temporarily abandoned the well until we are allowed to return and complete drilling. The Galapagos project also includes the previously-drilled Santa Cruz and Isabela wells. These wells are waiting on completion, including connection to nearby infrastructure via subsea tiebacks. We currently believe we will be able to perform the completion work for these two wells in 2010 and obtained a permit in July 2010 to perform completion work on the Santa Cruz well. In the meantime, we are carrying out topside work at the host platform for the Galapagos project and working on pipeline installation. Even with a six-month suspension of drilling, we are working to keep the Galapagos Project moving forward to meet our projected 2011 start-up date.

- Gunflint Project – We are the operator of the Gunflint development and had planned to drill one or two appraisal wells in 2010. We are currently reviewing host platform options. If we are able to connect to an existing third-party host, the project could have an accelerated completion schedule as compared with our existing plans, thereby absorbing time lost to a drilling moratorium-related delay of up to a year and meeting the projected schedule for first production in 2015.

We are partners with BP Exploration & Production Inc. (BP) on these two projects. At Galapagos, the Santa Cruz and Isabela wells will be tied back to the Nakika production platform, which is partially owned and operated by BP. We are currently working with BP to effectively resource and deliver these projects. See Item 1A. Risk Factors. Our major projects at Galapagos and Gunflint in the deepwater Gulf of Mexico may be adversely affected by our partnership with BP Exploration & Production Inc., a wholly-owned subsidiary of BP America Inc.

We believe an increase in development costs or a six-month delay in drilling activities would not have a significant impact on the total cash flows we expect to derive from these deepwater Gulf of Mexico projects. However, a moratorium lasting six months or longer could have an impact on some of our oilfield service and equipment providers, which could result in delays of delivery of essential items or the performance of services after the moratorium is lifted.

Long-term Impact – The longer the delay and disruption continue, the greater the impact will be on our business in the deepwater Gulf of Mexico. Further delay in drilling and completion activities due to an extension of the Federal Deepwater Moratorium beyond six months, difficulty or delay in implementing legislative or regulatory changes, or unavailability of drilling rigs, support vessels and equipment, or other oilfield services when activities are resumed at the end of the Moratorium, could result in postponing the startup of our Galapagos and Gunflint projects, which we had expected to contribute to production growth and cash flows during 2011 and 2015, respectively.

Table of Contents

Continued delay and disruption will also have a negative impact on our planned exploration program in the deepwater Gulf of Mexico. 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 future production late in the decade with a negative impact on our operating results and cash flows. Although exploration activities may be delayed, our large Gulf of Mexico exploration acreage position is not currently at risk of impairment. A large portion of the acreage was acquired in 2008 - 2010 and the leases have significant minimum remaining terms. However, higher development and operating costs could ultimately impact the fair values of our properties in the deepwater Gulf of Mexico.

Another long-term impact which we currently expect on our business is longer development cycle time, which is the length of time it takes for a project to progress from first discovery to first production. Longer cycle times result from additional regulatory reviews, slower permitting processes and oversight and could result in lower rates of return on our investments.

It is also possible that other countries, including those in which we currently operate, will respond to the Incident with legislative or regulatory changes affecting offshore drilling activities under their control.

Finally, the potential for removal of the liability cap for claims of damages from oil spills, and/or the enactment of onerous rules and regulations regarding activities in the deepwater Gulf of Mexico could significantly alter our industry. Such rules could effectively limit which companies can operate in the deepwater Gulf of Mexico. Small and medium-sized oil and gas companies might not be able to obtain insurance coverage at economically appropriate levels or meet financial responsibility requirements and would have to exit the deepwater Gulf of Mexico. Potentially less attractive economics for exploration and development programs going forward will require companies remaining in the Gulf of Mexico to review their business models. We have drilled, and believe we can continue to drill, safely in the deepwater Gulf of Mexico. However, exploration and production companies will be able to continue doing business in the area only to the extent it remains economically viable. See Risk and Insurance Program Update below.

Mitigating Activities

We are currently engaged in the following activities designed to mitigate the impacts of the Deepwater Horizon Incident and Federal Deepwater Moratorium:

- planning for resumption of our drilling operations when activity in the deepwater Gulf of Mexico recommences;
- engaging in discussions with our rig contractors and service providers about the best way to mitigate the impact of the Moratorium, including options for moving equipment or capabilities elsewhere and to ensure there is adequate capacity when activity resumes;
- considering a reallocation of near-term Gulf of Mexico drilling capital to other opportunities if disruption continues in order to ensure a delay in drilling will not create a gap in production growth going forward;
- monitoring legislative and regulatory developments;
- implementing new, more stringent operating and safety requirements to comply with new and anticipated regulations so that we are ready to move forward as soon as possible when activity resumes;
- continuing to manage our risks and operations such that the likelihood of a significant accident or spill is remote;
- working with BP to effectively resource and deliver projects on which they are a partner;

- monitoring the impact on the insurance industry and re-evaluating our risk and insurance program; and
- monitoring our credit exposure to companies involved in the Deepwater Horizon Incident and the impact of the Incident on their liquidity, credit ratings, availability of credit, and perhaps, depending on developments, solvency.

Delays and volatility are inherent in our business. We have maintained a capital structure approach which provides a strong liquidity position allowing us to manage during periods of uncertainty. We feel we are well-positioned to respond to, and/or adjust our activities as events unfold in the deepwater Gulf of Mexico.

In addition, we have a deep and diverse international portfolio, and the Deepwater Gulf of Mexico represents only one of our four core operating areas. Our other core areas include the US onshore, West Africa and Eastern Mediterranean, and these areas have provided, and continue to provide, numerous opportunities for us to allocate capital in an optimal way going forward. The longer the delay and disruption in the deepwater Gulf of Mexico continue, and pending the outcome of legislative and regulatory activities, the more likely it would be that we would find it necessary to redeploy capital in onshore US or international areas in order to maintain our exploration momentum and production growth. See Liquidity and Capital Resources – Capital Structure/Financing Strategy below.

Table of Contents

Expenses Related to Federal Deepwater Moratorium

At the time the Federal Deepwater Moratorium was announced, we were under contract for two deepwater Gulf of Mexico drilling rigs. We have taken a proactive and cooperative approach with our drilling contractors in order to avoid force majeure and to determine our options for managing the suspension, and eventual resumption, of drilling activities. The ENSCO 8501 rig remains under contract and will be used to perform activities currently allowed in the deepwater Gulf of Mexico, including completion activities at the Santa Cruz well for which we received a permit in July 2010. We entered into an agreement to terminate the drilling contract for the Noble Clyde Boudreax rig for a fee of $26 million. This rig was in the process of drilling a sidetrack to the exploration well at the Deep Blue prospect. This rig contract termination expense is included in other operating (income) expense, net in our consolidated statements of operations. See Item 1. Financial Statements – Note 3. Impact of Federal Deepwater Moratorium.

US Onshore, West Africa and Eastern Mediterranean Update

DJ Basin Asset Acquisition 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. The transaction increases our presence in the Wattenberg field and further expands our opportunity in the DJ Basin. The acquisition added approximately 10 MBoepd to our daily production base and approximately 46 MMBoe of proved reserves. A majority of the reserves are within the Wattenberg field, where our largest onshore US asset is located.

Potential Sale of Onshore US Assets We have entered into an agreement to divest certain non-core properties in the Mid-Continent and Illinois Basin areas for a sales price of approximately $550 million. We expect the sale, which will be effective as of April 1, 2010, to close in third quarter 2010. The properties represent approximately 5.7 MBoepd of production and 29 MMBoe of reserves.

Exploration Program Continued investment in significant exploration remains a key component to our strategy. We are in the process of integrating recently-acquired 3-D seismic information for our properties offshore Cameroon, reprocessing seismic information on Blocks O and I offshore Equatorial Guinea, in preparation for future drilling programs, and moving forward on our plans to drill an exploration well at the Leviathan prospect offshore Israel later this year.

Major Development Projects During second quarter 2010, we continued to advance our major development projects at the Aseng oil field, offshore Equatorial Guinea, and the Tamar project, offshore Israel, toward first production on time and on budget. We continued development drilling at Aseng with two drilling rigs working and well completions scheduled for the third quarter 2010, and conversion work is ongoing for the FPSO vessel that will be used in the Aseng development. In addition, we are continuing FEED (front end engineering and design) work for the Alen project and recently submitted the Plan of Development to the government of Equatorial Guinea. In Israel, we are in the process of finalizing a development plan for Tamar and negotiating additional natural gas sales contracts.

Sales Volumes

On a BOE basis, sales volumes were higher second quarter 2010 as compared with second quarter 2009. Production was higher in the onshore US areas due to record production in the Wattenberg field primarily due to the recent acquisition of producing properties. In Equatorial Guinea, crude oil sales volumes were higher due to the timing of liftings, despite the planned shut-in of the Alba field for scheduled facility maintenance and repair. In Israel, there was an increase in demand for natural gas to produce electricity and a higher percentage of the demand was met by production from our properties. Despite downtime related to equipment modifications at the Dumbarton FPSO, there was an increase in volumes lifted in the North Sea, which also contributed to the overall increase. These increases were partially offset by the expected decrease in natural gas sales volumes in Equatorial Guinea due to the planned shut-in of the Alba field discussed above.

Commodity Price Changes and Hedging

Second quarter 2010 average realized crude oil, natural gas and NGL prices have increased significantly from second quarter 2009 due to strengthening commodities markets which are showing benefit from the global economic recovery. During second quarter 2010 we expanded our hedging program with additional basis swaps. We have hedged approximately 43% of our expected world-wide crude oil production and 68% of our expected domestic natural gas production for the remainder of 2010.

Table of Contents

OUTLOOK

Our expected crude oil, natural gas and NGL production for the remainder of 2010 may be impacted by several factors including:

- overall level and timing of capital expenditures which, dependent upon our drilling success and notwithstanding the other factors listed below, are expected to maintain our near-term production volumes (See 2010 Budget discussion below);
- impact of US onshore asset sale, expected to close third quarter 2010, which will reduce production by approximately 5.7 MBoepd;
- 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 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;
- seasonal variations in rainfall in Ecuador that affect our natural gas-to-power project;
- potential hurricane-related volume curtailments in the deepwater Gulf of Mexico and Gulf Coast areas;
- potential winter storm-related volume curtailments in the Northern region of our US operations;
- potential pipeline and processing facility capacity constraints in the Rocky Mountains and deepwater Gulf of Mexico;
- potential volume curtailments in Ecuador due to unsettled economic and political environment;
- impact of asset purchases;
- timing of significant project completion and initial production; and
- impact of sales of non-core operating assets.

2010 Budget   We have updated our business plan for the remainder of 2010 to take into account the impact of the Federal Deepwater Moratorium on our planned deepwater Gulf of Mexico activities. Some uncertainty remains, such as the length of time the Moratorium will continue and whether or not certain activities can be performed on deepwater wells during the Moratorium. Some of our planned activities are being delayed. However, in some cases, we are able to continue with well completion work and non-drilling activities, such as topside work or pipeline installation, that allow us to keep our projects moving forward on schedule. The delay in spending caused by the Moratorium will have a positive effect on our short-term net cash flows.

Our total capital investment program for 2010 is now estimated at $2.2 billion, $300 million less than previously announced, with approximately 37% going toward major project investments, 17% for exploration and appraisal activities, and the remaining 46% for ongoing maintenance and near-term development opportunities. We have planned to spend about $832 million on major project investments, with the majority of capital directed toward the development of Galapagos in the deepwater Gulf of Mexico, Aseng offshore Equatorial Guinea and Tamar offshore Israel. We expect to spend approximately $380 million for exploration activities. The remainder of our budget is focused on liquid-rich and emerging opportunities onshore in the US, as well as near-term development projects in Israel, the North Sea and China.

Excluded from the budget discussed above is the $509 million total purchase price for the DJ Basin asset acquisition on March 1, 2010, as well as $251 million of non-cash capital expected to be accrued for the Aseng FPSO capital lease.

We have a diverse domestic and international portfolio as well as ample liquidity which allow us to engage in activities that mitigate the impact of the drilling moratorium. Numerous opportunities are available to us, and it is possible that we may reallocate capital to US onshore or international locations. We will continue to review our options as the legislative and regulatory response to the Deepwater Horizon Incident unfolds.

We expect that the remaining 2010 budget will be funded primarily from cash flows from operations, cash on hand, and borrowings under our revolving credit facility and/or other financing. We will evaluate the level of capital spending throughout the year based on drilling results, commodity prices, cash flows from operations, the full impact of the Federal Deepwater Moratorium and legislative response, and property acquisitions and divestitures. Our capital spending is integrated with our goal of maintaining a strong balance sheet and ample liquidity. See Liquidity and Capital Resources – Capital Structure/Financing Strategy, below.

Risk and Insurance Program Update   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 an economically appropriate level of financial protection from significant unfavorable losses 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. We maintain insurance at levels that we believe are appropriate and consistent with industry practice and we regularly review our risks of loss and the cost and availability of insurance and revise our insurance program accordingly.

Table of Contents

We expect the future availability and cost of insurance to be impacted by the recent 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.

Recently, various Congressional committees have begun pursuing legislation to increase or remove liability caps for deepwater drilling. The current $75 million liability limit under the Oil Pollution Act is likely to be materially increased or lifted in its entirety. Such a requirement would ultimately require a company to maintain either an insurance coverage minimum or a significant financial position. The insurance market will be unlikely to provide meaningful coverage enhancements to address any significant increases in liability caps going forward. We anticipate that, at a minimum, less insurance coverage will be available and at a higher cost. If the liability cap is lifted in its entirety, the industry could become relatively un-insurable.

Although the root cause, or causes, of the Deepwater Horizon Incident are unclear at this time, we believe there is a high likelihood of regulatory and/or legislative changes that will impact operations in the Gulf of Mexico. We will continue to monitor the expected regulatory and legislative response and its impact on the insurance market and our overall risk profile, and adjust our risk and insurance program to provide protection, at an economically appropriate level, against disruption to our operations and cash flows.

In accordance with industry practice, 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, 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, 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.

Deepwater drilling entails inherent risks. We have a robust 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 strive to manage our risks 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.

In addition to our insurance coverages related to operations in the Gulf of Mexico, in April 2010, we notified Oil Insurance Limited (OIL), a mutual insurance company of which we are a member, that we would elect to self insure our 2010 windstorm exposure. Due to recent reductions in windstorm coverage by OIL, we now believe it is commercially more reasonable to self insure against this particular risk. Recent abandonment activities on the Gulf of Mexico Shelf have significantly reduced our windstorm exposure as our remaining Gulf of Mexico assets are primarily subsea operations. However, we are now responsible for substantially all windstorm-related damages to these assets.

Table of Contents

RESULTS OF OPERATIONS

Revenues

Revenues were as follows:

(millions)	2010	2009	Increase (Decrease) from Prior Year
Three Months Ended June 30,			
Oil, Gas and NGL Sales	$ 710	$ 460	54 %
Income from Equity Method Investees	24	16	50 %
Other Revenues	17	15	13 %
Total	$ 751	$ 491	53 %
Six Months Ended June 30,			
Oil, Gas and NGL Sales	$ 1,398	$ 866	61 %
Income from Equity Method Investees	50	27	85 %
Other Revenues	36	39	(8 %)
Total	$ 1,484	$ 932	59 %

Changes in revenues are discussed below.

Table of Contents

Oil, Gas and NGL Sales Average daily sales volumes and average realized sales prices were as follows:

	Sales Volumes				Average Realized Sales Prices		
	Crude Oil & Condensate	Natural Gas	NGLs	Total	Crude Oil & Condensate	Natural Gas	NGLs
	(MBpd)	(MMcfpd)	(MBpd)	(MBoepd) (1)	(Per Bbl)	(Per Mcf)	(Per Bbl)
Three Months Ended June 30, 2010							
United States (2)	38	414	13	120	$75.00	$3.89	$39.37
Equatorial Guinea (3) (4)	16	224	-	54	76.10	0.27	-
Israel	-	121	-	20	-	4.33	-
North Sea	9	7	-	10	75.22	4.53	-
Ecuador (5)	-	27	-	4	-	-	-
China	4	-	-	4	76.05	-	-
Total Consolidated Operations	67	793	13	212	75.36	2.91	39.37
Equity Investees (6)	2	-	5	7	74.22	-	50.32
Total Operations	69	793	18	219	$75.33	$2.91	$42.52
Three Months Ended June 30, 2009							
United States (2)	37	394	10	112	$51.85	$3.09	$23.94
Equatorial Guinea (3) (4)	15	244	-	56	51.63	0.27	-
Israel	-	95	-	16	-	2.76	-
North Sea	6	5	-	7	56.57	5.20	-
Ecuador (5)	-	16	-	3	-	-	-
China	5	-	-	5	48.87	-	-
Total Consolidated Operations	63	754	10	199	52.05	2.13	23.94
Equity Investees (6)	2	-	6	7	56.12	-	30.12
Total Operations	65	754	16	206	$52.19	$2.13	$26.24
Six Months Ended June 30, 2010							
United States (2)	39	399	13	118	$74.39	$4.64	$42.12
Equatorial Guinea (3) (4)	12	209	-	47	75.16	0.27	-
Israel	-	104	-	17	-	4.28	-
North Sea	9	7	-	10	76.15	4.97	-
Ecuador (5)	-	28	-	5	-	-	-
China	4	-	-	4	74.24	-	-
Total Consolidated Operations	64	747	13	201	74.77	3.32	42.12
Equity Investees (6)	2	-	5	7	74.96	-	53.33
Total Operations	66	747	18	208	$74.77	$3.32	$45.11
Six Months Ended June 30, 2009							
United States (2)	36	403	10	113	$43.92	$3.52	$24.33
Equatorial Guinea (3) (4)	14	243	-	55	46.19	0.27	-
Israel	-	103	-	17	-	2.78	-
North Sea	7	5	-	8	50.81	6.72	-
Ecuador (5)	-	23	-	4	-	-	-
China	4	-	-	4	43.28	-	-
Total Consolidated Operations	61	777	10	201	45.17	2.39	24.33
Equity Investees (6)	2	-	6	7	50.38	-	28.38
Total Operations	63	777	16	208	$45.32	$2.39	$25.92

(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 differentials, 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 $1.35 per Bbl and $2.29 per Bbl for second quarter 2010 and 2009, respectively, and $1.34 per Bbl and $2.49 per Bbl for the first six months of 2010 and 2009, respectively, from hedging activities.

Average realized natural gas prices reflect an increase of $0.01 per Mcf for second quarter 2009 and a decrease of $0.01 per Mcf for the first six months of 2010, from hedging activities. The price increase/reduction resulted from hedge gains/losses that were previously deferred in AOCL. The average realized natural gas prices for the second quarter of 2010 and first six months of 2009 were not impacted by hedging activities, as the net deferred gains reclassified from AOCL were de minimis.

(3) Average realized crude oil and condensate prices reflect a reduction of $5.33 per Bbl for second quarter 2009 and $6.11 per Bbl for the first six months of 2009 from hedging activities. The price reduction resulted from hedge losses that were 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) The natural gas-to-power project in Ecuador is 100% owned by our subsidiaries and intercompany natural gas sales are eliminated for accounting purposes. Electricity sales are included in other revenues. See Item 1. Financial Statements – Note 2. Basis of Presentation.

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

Table of Contents

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	
	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)
Three Months Ended June 30,				
United States	$0.12	$0.96	$13.39	$2.00
Equatorial Guinea	(1.81)	-	15.77	-
Total Consolidated Operations	(0.37)	0.52	11.68	1.07
Total Operations	(0.36)	0.52	11.29	1.07
Six Months Ended June 30,				
United States	$(0.20)	$0.51	$17.18	$1.79
Equatorial Guinea	(1.78)	-	19.79	-
Total Consolidated Operations	(0.47)	0.28	14.65	0.95
Total Operations	(0.46)	0.28	14.23	0.95

An analysis of revenues from sales of crude oil, natural gas and NGLs is as follows:

	Sales Revenues			
(millions)	Crude Oil & Condensate	Natural Gas	NGLs	Total
Three Months Ended June 30, 2009	$296	$143	$21	$460
Changes due to				
Increase in Sales Volumes	22	13	8	43
Increase in Sales Prices Before Hedging	131	46	19	196
Change in Amounts Reclassified from AOCL	11	-	-	11
Three Months Ended June 30, 2010	$460	$202	$48	$710
Six Months Ended June 30, 2009	$497	$326	$43	$866
Changes due to				
Increase (Decrease) in Sales Volumes	27	(1)	14	40
Increase in Sales Prices Before Hedging	320	108	42	470
Change in Amounts Reclassified from AOCL	23	(1)	-	22
Six Months Ended June 30, 2010	$867	$432	$99	$1,398

Crude oil and condensate sales – Revenues from crude oil and condensate sales increased during the second quarter and first six months of 2010 as compared with 2009 due to the following:

- an increase in total consolidated average realized prices due to increased demand resulting from the global economic recovery;
-

increased production from the Wattenberg field in the northern region of our US operations due to ongoing development activity;

Table of Contents

- additional production of approximately 3 MBpd for second quarter 2010 from the DJ Basin asset acquisition;
- crude oil production from a sidetrack to a Swordfish natural gas 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 volumes lifted;

partially offset by

- a decrease in deepwater Gulf of Mexico volumes due to natural field decline and third party downstream facility constraints; and
- a decrease in US onshore volumes due to natural field decline in the Mid-Continent and Gulf Coast areas.

In addition, timing of liftings in Equatorial Guinea resulted in an increase in sales volumes for the second quarter of 2010 as compared with the second quarter of 2009. For the first six months of 2010 as compared with the first six months of 2009 sales volumes decreased due to the planned shut-in of the Alba field for scheduled facility maintenance and repair.

In the North Sea, equipment modifications at the Dumbarton FPSO required the field to be shut in for nearly two months during the second quarter 2010. Despite the downtime, total North Sea production was up as compared with the second quarter 2009 as the related upgrades were completed in late May 2010, bringing existing production and a second development well at Lochranza online.

Revenues from crude oil and condensate sales included deferred losses of $4 million and $15 million for second quarter 2010 and 2009, respectively, and $9 million and $32 million for the first six months of 2010 and 2009, respectively, reclassified from AOCL and related to commodity derivative instruments previously accounted for as cash flow hedges.

Natural gas sales – Revenues from natural gas sales increased during the second quarter and first six months of 2010 as compared with 2009 due to the following:

- an increase in US average realized prices due to increased demand resulting from the economic recovery;
- an increase in Israel average realized prices which are tied to the global liquid markets;
- ongoing development activities in the Wattenberg field area in the US;
- additional production of approximately 36 MMcfpd for the second quarter 2010 from the DJ Basin asset acquisition; 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;
- a decrease in sales volumes due to the sidetrack of a Swordfish gas well into an oil zone after the gas zone began producing water; and
- natural field decline in the deepwater Gulf of Mexico, Gulf Coast and Mid-Continent areas.

Revenues from natural gas sales included deferred losses of $1 million for the first six months of 2010 reclassified from AOCL and related to commodity derivative instruments previously accounted for as cash flow hedges. Revenues for the second quarters of 2010 and 2009 and the first six months of 2009 included de minimis amounts reclassified from AOCL.

NGL sales – Most of our US NGL production is from the Wattenberg field and deepwater Gulf of Mexico. NGL sales revenues increased during the second quarter and first six months of 2010 as compared with 2009 due to an increase in sales volumes from the Wattenberg field and an increase in consolidated average realized prices which benefitted from increased demand resulting from the global economic recovery.

Income from Equity Method Investees We have a 45% interest in Atlantic Methanol Production Company, LLC, which owns and operates a methanol plant and related facilities and a 28% interest in Alba Plant LLC, which owns and operates a liquefied petroleum gas processing plant. Both plants are located onshore in Equatorial Guinea. Equity method investments are included in other noncurrent assets in our consolidated balance sheets, our share of earnings is reported as income from equity method investees in our consolidated statements of operations, and our share of dividends is reported within cash flows from operating activities in our consolidated statements of cash flows.

The increase in income from equity method investees for the second quarter and first six months of 2010 as compared with 2009 was due to an increase in average realized condensate, LPG and methanol prices from increased demand due to the global economic recovery. Condensate and LPG sales volumes and average realized prices are included in the average daily sales volumes and average realized sales prices table above. Methanol sales volumes and prices were as follows:

Table of Contents

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Methanol Sales Volumes in MMgal	34	41	69	76
Methanol Sales Prices	$ 0.84	$ 0.49	$ 0.83	$ 0.47

The increase in dividends from equity method investees to $48 million for the first six months of 2010 as compared with $5 million for the first six months of 2009 was due to their increased profitability.

Other Revenues   Other revenues include electricity sales and other revenues from operating activities. See Item 1. Financial Statements – Note 2. Basis of Presentation.

Operating Costs and Expenses

Operating costs and expenses were as follows:

	2010	2009	Increase (Decrease) from Prior Year
(millions)			
Three Months Ended June 30,			
Production Expense	$ 150	$ 129	16 %
Exploration Expense	52	33	58 %
Depreciation, Depletion and Amortization	215	196	10 %
General and Administrative	63	60	5 %
Other Operating (Income) Expense, Net	41	(3)	N/M
Total	$ 521	$ 415	26 %
Six Months Ended June 30,			
Production Expense	$ 289	$ 260	11 %
Exploration Expense	132	75	76 %
Depreciation, Depletion and Amortization	431	396	9 %
General and Administrative	129	119	8 %
Asset Impairments	-	437	(100 %)
Other Operating (Income) Expense, Net	55	(11)	N/M
Total	$ 1,036	$ 1,276	(19 %)

(N/M) The percentage is so large that it is not meaningful.

Table of Contents

Changes in operating costs and expenses are discussed below.

Production Expense Components of production expense were as follows:

	Total per BOE (1)	Total	United States	Equatorial Guinea	Israel	North Sea	Other Int'l, Corporate
(millions, except unit rate)							
Three Months Ended June 30, 2010							
Lease Operating Expense (2)	$ 5.18	$ 100	$ 68	$ 13	$ 3	$ 11	$ 5
Production and Ad Valorem Taxes	1.75	34	28	-	-	-	6
Transportation Expense	0.87	16	15	-	-	1	-
Total Production Expense	$ 7.80	$ 150	$ 111	$ 13	$ 3	$ 12	$ 11
Three Months Ended June 30, 2009							
Lease Operating Expense (2)	$ 5.17	$ 93	$ 65	$ 11	$ 3	$ 9	$ 5
Production and Ad Valorem Taxes	1.29	23	20	-	-	-	3
Transportation Expense	0.73	13	11	-	-	1	1
Total Production Expense	$ 7.19	$ 129	$ 96	$ 11	$ 3	$ 10	$ 9
Six Months Ended June, 2010							
Lease Operating Expense (2)	$ 5.15	$ 188	$ 133	$ 20	$ 4	$ 22	$ 9
Production and Ad Valorem Taxes	1.84	67	57	-	-	-	10
Transportation Expense	0.93	34	30	-	-	3	1
Total Production Expense	$ 7.92	$ 289	$ 220	$ 20	$ 4	$ 25	$ 20
Six Months Ended June, 2009							
Lease Operating Expense (2)	$ 5.34	$ 193	$ 142	$ 20	$ 4	$ 19	$ 8
Production and Ad Valorem Taxes	1.14	42	38	-	-	-	4
Transportation Expense	0.68	25	21	-	-	2	2
Total Production Expense	$ 7.16	$ 260	$ 201	$ 20	$ 4	$ 21	$ 14

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

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

For the second quarter and first six months of 2010, total production expense increased as compared with 2009 due to the following:

- an increase in production taxes in the US and China due to higher commodity prices;
- an increase in transportation expense in the Wattenberg field due to increased crude oil and condensate production and the use of a new interstate crude oil transportation pipeline system to market production; and
- an increase in North Sea lease operating expense due to higher sales volumes;

partially offset by

- reductions in US lease operating expense due to the abandonment of our remaining Gulf of Mexico shelf properties at Main Pass, reductions in third-party costs and operating supplies and services, and reduced workover expense in the Mid-Continent area.

Table of Contents

Oil and Gas Exploration Expense   Components of oil and gas exploration expense were as follows:

(millions)	Total	United States	West Africa (1)	Eastern Mediter-ranean (2)	North Sea	Other Int'l, Corporate (3)
Three Months Ended June 30, 2010						
Dry Hole Cost	$15	$15	$-	$ -	$-	$-
Seismic	13	7	4	2	-	-
Staff Expense	19	5	1	1	-	12
Other	5	5	-	-	-	-
Total Exploration Expense	$52	$32	$5	$ 3	$-	$12
Three Months Ended June 30, 2009						
Dry Hole Cost	$7	$7	$-	$ -	$-	$-
Seismic	7	5	-	2	-	-
Staff Expense	17	3	3	-	-	11
Other	2	2	-	-	-	-
Total Exploration Expense	$33	$17	$3	$ 2	$-	$11
Six Months Ended June 30, 2010						
Dry Hole Cost	$54	$51	$3	$ -	$-	$-
Seismic	35	29	4	2	-	-
Staff Expense	34	8	3	1	1	21
Other	9	9	-	-	-	-
Total Exploration Expense	$132	$97	$10	$ 3	$1	$21
Six Months Ended June 30, 2009						
Dry Hole Cost	$9	$6	$4	$ -	$-	$(1)
Seismic	30	28	-	2	-	-
Staff Expense	32	6	6	-	1	19
Other	4	4	-	-	-	-
Total Exploration Expense	$75	$44	$10	$ 2	$1	$18

(1) West Africa includes Equatorial Guinea and Cameroon.

(2) Eastern Mediterranean includes Israel and Cyprus.

(3) Other International includes China, Ecuador and other amounts spent in support of various international new ventures.

Oil and gas exploration expense for the second quarter and first six months of 2010 increased 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. US seismic expense was incurred in support of Central Gulf of Mexico lease sales and West Africa seismic expenditures represented the acquisition of 3-D seismic information for Cameroon.

Table of Contents

Depreciation, Depletion and Amortization   DD&A expense was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
(millions, except unit rate)				
DD&A Expense	$210	$192	$422	$389
Accretion of Discount on Asset Retirement Obligations	5	4	9	7
Total DD&A Expense	$215	$196	$431	$396
Unit Rate per BOE (1)	$11.13	$10.88	$11.81	$10.95

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

Total DD&A expense for the second quarter and first six months of 2010 increased as compared with 2009 due to the following:

- higher production in the Wattenberg, Piceance and Western Oklahoma areas of our US operations, which have high DD&A rates relative to production from Equatorial Guinea and Israel which have lower DD&A rates;
- ongoing capital spending in the Northern region of our US operations;
- higher sales volumes in the North Sea; and
- impact of lower year-end 2009 commodity prices on oil and gas reserves;

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 held for sale.

The unit rate per BOE increased for the second quarter and first six months of 2010 as compared with 2009 due to the change in mix of production, including decreases in lower-cost sales volumes from Equatorial Guinea and the impact of lower year-end 2009 commodity prices on oil and gas reserves, offset by a lower rate for the Mid-Continent area and the cessation of DD&A associated with assets held for sale.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
G&A Expense (millions)	$63	$60	$129	$119
Unit Rate per BOE (1)	$3.26	$3.35	$3.54	$3.29

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

G&A expense for the second quarter and first six months of 2010 increased as compared with 2009 primarily due to additional expenses relating to personnel and office costs in support of our major projects.

Asset Impairments   Asset impairment expense for the first six months of 2009 was related to Granite Wash, an onshore US area where we have significantly reduced investments beginning in 2007, and our Gulf of Mexico Main Pass asset which had been reclassified from held-for-sale to held-and-used.

Other Operating (Income) Expense, Net   Other operating (income) expense, net includes rig contract termination expense related to the Federal Deepwater Moratorium, electricity generation expense and other items of operating income or expense. See Item 1. Financial Statements – Note 2. Basis of Presentation and Note 3. Impact of Federal Deepwater Moratorium.

Table of Contents

Other (Income) Expense

Other (income) expense was as follows:

(millions)	2010	2009	Increase (Decrease) from Prior Year
Three Months Ended June 30,			
(Gain) Loss on Commodity Derivative Instruments	$ (96)	$ 139	N/M
Interest, Net of Amount Capitalized	19	23	(17 %)
Other Non-Operating (Income) Expense, Net	(13)	4	N/M
Total	$ (90)	$ 166	N/M
Six Months Ended June 30,			
(Gain) Loss on Commodity Derivative Instruments	$ (242)	$ 66	N/M
Interest, Net of Amount Capitalized	39	41	(5 %)
Other Non-Operating (Income) Expense, Net	(13)	12	N/M
Total	$ (216)	$ 119	N/M

(N/M) The percentage is so large that it is not meaningful.

(Gain) Loss on Commodity Derivative Instruments (Gain) loss on commodity derivative instruments is a result of mark-to-market accounting. See Item 1. Financial Statements – Note 6. Derivative Instruments and Hedging Activities and Note 7. Fair Value Measurements and Disclosures.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions, except unit rate)	2010	2009	2010	2009
Interest Expense	$35	$35	$70	$59
Capitalized Interest	(16)	(12)	(31)	(18)
Interest Expense, Net	$19	$23	$39	$41
Unit Rate, per BOE (1)	$0.99	$1.29	$1.06	$1.13

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

Interest expense increased for the first six months of 2010, as compared with 2009. The increase in interest expense primarily relates to our $1 billion 8¼% senior unsecured notes due March 1, 2019, which we issued on February 27, 2009. The higher rate on the senior unsecured notes replaced the substantially lower rate applicable to our revolving credit facility. See also Liquidity and Capital Resources – Financing Activities below.

The increases in the amount of interest capitalized are due to higher work in progress amounts related to major long-term projects in West Africa, the deepwater Gulf of Mexico and Israel and the higher interest rate associated with our $1 billion 8¼% senior unsecured notes due March 1, 2019.

Other Non-operating (Income) Expense, Net   Other non-operating (income) expense, net includes deferred compensation (income) expense, interest income and other (income) expense. The decrease was due to a reduction in deferred compensation expense and increases in interest and other income. See Item 1. Financial Statements – Note 2. Basis of Presentation.

Income Tax Provision (Benefit)

See Item 1. Financial Statements – Note 13. Income Taxes for a discussion of the change in our effective tax rate during the first six months of 2010 as compared with 2009.

LIQUIDITY AND CAPITAL RESOURCES

Capital Structure/Financing Strategy
We strive to employ a capital structure, emphasizing a strong balance sheet, and financing strategy designed to provide ample liquidity throughout the commodity price cycle, sufficient to fund growth and major project development. Specifically, we strive to retain the ability to fund long-cycle, capital intensive development projects while also maintaining the capability for financially attractive periodic mergers and acquisitions activity, such as the DJ Basin asset acquisition on March 1, 2010. We endeavor to maintain an investment grade debt rating in support 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 operations and cash flows. See Risk and Insurance Program Update, above.

Table of Contents

We have planned to spend approximately $1 billion per year in 2010 and 2011 for major project development with funding provided by cash flows from operations, cash on hand and borrowings under our revolving credit facility and/or other financing. Cash may also be generated by occasional sales of non-strategic crude oil and natural gas properties.

As a result of the Federal Deepwater Moratorium, a portion of our spending related to exploratory and development activities in the deepwater Gulf of Mexico may be delayed. Additional delays in spending could occur, if, at the end of the Moratorium, drilling rigs, support vessels and equipment, or other oilfield services are in short supply. A delay in spending will have a positive effect on our cash flows in the short term, to the extent we do not redeploy capital to US onshore or international areas. Once the Moratorium ends and we are re-engaged in our planned activities in the deepwater Gulf of Mexico, we may see a negative impact on cash flows due to higher drilling, operating and insurance costs.

Delays and price volatility are inherent in our business. Our capital structure approach has been to maintain a strong liquidity position which allows us to manage uncertainty by providing alternative courses of action. At June 30, 2010, we had over $1 billion in cash and significant remaining capacity under our credit facility for a total liquidity of $2.3 billion. This strong financial capacity will provide flexibility as we decide how best to manage the current situation in the deepwater Gulf of Mexico.

Information regarding cash and debt balances was as follows:

(millions, except percentages)	June 30, 2010	December 31, 2009
Cash and Cash Equivalents	$1,017	$ 1,014
Amount Available to be Borrowed Under Credit Facility	1,280	1,718
Total Liquidity	$2,297	$ 2,732
Total Debt (Excluding Unamortized Discount)	$2,591	$ 2,045
Total Shareholders' Equity	6,541	6,157
Debt-to-Capital Ratio (1)	28 %	25 %

(1) 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 billion in cash and cash equivalents at June 30, 2010, primarily denominated in US dollars and invested in money market funds and short-term deposits with major financial institutions. A majority of this cash is attributable to our foreign subsidiaries and most would be subject to US income taxes if repatriated. We currently intend to use our international cash to fund international projects, including the planned developments in Equatorial Guinea and Israel.

Credit Facility We have 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 ended second quarter 2010 with $1.3 billion remaining available for borrowing.

Derivative Instruments We use various derivative instruments 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, collars and basis swaps. 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. Except for certain minor derivative contracts that we enter into from time to time in order to market third-party natural gas, none of our counterparty agreements contain margin requirements. 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.

Commodity derivative instruments are recorded at fair value in our consolidated balance sheets, and changes in fair value are recorded in earnings in the period in which the change occurs. As of June 30, 2010 the fair value of our commodity derivative assets was $122 million and the fair value of our commodity derivative liabilities was $5 million (after consideration of netting agreements). Interest rate derivative instruments, which are designated as cash flow hedges, are recorded at fair value in our consolidated balance sheets, and 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 notes. As of June 30, 2010 the fair value of our interest rate derivative liability was $94 million. See Item 1. Financial Statements – Note 6. Derivative Instruments and Hedging Activities for a discussion of counterparty credit risk and Note 7. Fair Value Measurements and Disclosures for a description of the methods we use to estimate the fair values of derivative instruments.

Table of Contents

Cash Flows

Cash flow information is as follows:

	Six Months Ended June 30,	
(millions)	2010	2009
Total Cash Provided By (Used in)		
Operating Activities	$844	$498
Investing Activities	(1,248)	(777)
Financing Activities	407	95
Increase (Decrease) in Cash and Cash Equivalents	$3	$(184)

Operating Activities   Net cash provided by operating activities for the first six months of 2010 increased as compared with the first six months of 2009 due primarily to increases in commodity prices, the refund of deepwater Gulf of Mexico royalties and an increase in dividends received from equity method investees.

Investing Activities   Our investing activities include capital spending on a cash basis for oil and gas properties, which may be offset by proceeds from property sales. Net cash used in investing activities increased by $471 million during the first six months of 2010 as compared with the first six months of 2009, primarily due to the DJ Basin asset acquisition. See Item 1. Financial Statements – Note 4. Acquisitions and Divestitures. See also Investing Activities – Acquisition, Capital and Exploration Expenditures below.

Financing Activities   Our financing activities include the issuance or repurchase of our common stock, payment of cash dividends on our common stock, the borrowing of cash and the repayment of borrowings. During the first six months of 2010, $438 million of funds were provided by net increases in borrowings under our revolving credit facility and used to fund the DJ Basin asset acquisition and other capital expenditures. Funds were also provided by cash proceeds from, and tax benefits related to, the exercise of stock options ($44 million). We used cash to pay dividends on our common stock ($63 million) and to repurchase shares of our common stock ($12 million).

In comparison, during the first six months of 2009, funds were provided by net proceeds from the issuance of our 8¼% senior notes ($989 million) and cash proceeds from, and tax benefits related to, the exercise of stock options ($16 million). We used cash for net repayments of amounts outstanding under our revolving credit facility ($821 million), to pay dividends on our common stock ($63 million), and to repurchase shares of our common stock ($1 million).

Investing Activities

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions)	2010	2009	2010	2009
Acquisition, Capital and Exploration Expenditures				
Unproved Property Acquisition	$62	$46	$208	$62
Proved Property Acquisition	-	-	363	-
Exploration	56	50	171	145
Development	363	198	637	429
Corporate and Other	38	29	58	73

Total	$519	$323	$1,437	$709
Increase in FPSO Lease Obligation	$68	$-	$108	$-

2010 Unproved property acquisition costs for the first six months of 2010 include $36 million of lease bonuses paid on deepwater Gulf of Mexico lease blocks and $146 million related to the DJ Basin asset acquisition and the remainder primarily for other onshore US lease acquisitions. Proved property acquisition costs are the result of the DJ Basin asset acquisition. See Item 1. Financial Statements – Note 4. Acquisitions and Divestitures.

The obligation under FPSO lease represents the increase in estimated construction in progress to date on an FPSO to be used in the development of the Aseng field in Equatorial Guinea. See Item 1. Financial Statements – Note 5. Debt.

2009 Unproved property acquisition costs include primarily lease bonuses on deepwater Gulf of Mexico lease blocks.

Table of Contents

Financing Activities

Long-Term Debt 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. 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 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 is with certain commercial lending institutions and is available for general corporate purposes.

At June 30, 2010, borrowings outstanding under the credit facility totaled $820 million, leaving approximately $1.3 billion available for use. The weighted average interest rate applicable to borrowings under the credit facility at June 30, 2010 was 0.66%.

Our outstanding fixed-rate debt totaled $1.6 billion at June 30, 2010. The weighted average interest rate on fixed-rate debt was 7.73%, with maturities ranging from 2014 to 2097.

Our ratio of debt-to-book capital was 28% at June 30, 2010 and 25% at December 31, 2009. 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.

Short-Term Borrowings Our committed credit facility may be 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. There were no amounts outstanding under uncommitted credit lines at June 30, 2010 or December 31, 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.

Dividends We paid total cash dividends of 36 cents per share of our common stock during the first six months of each of 2010 and 2009. On July 27, 2010, our Board of Directors declared a quarterly cash dividend of 18 cents per common share, payable August 23, 2010 to shareholders of record on August 9, 2010. 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.

Exercise of Stock Options We received cash proceeds of $28 million from the exercise of stock options during the first six months of 2010 as compared with $13 million during the first six months of 2009.

Common Stock Repurchases We receive shares of 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 163,388 shares with a value of $12 million during the first six months of 2010 and 17,510 shares with a value of $1 million during the first six months of 2009.

Table of Contents

Item 3. 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 June 30, 2010, we had entered into variable to fixed price commodity swaps, collars and basis swaps related to crude oil and natural gas sales. Our open commodity derivative instruments were in a net receivable position with a fair value of $117 million. Based on the June 30, 2010 published commodity futures price strips for the underlying commodities, a hypothetical price increase of $1.00 per Bbl for crude oil would decrease the fair value of our net commodity derivative receivable by approximately $10 million. A hypothetical price increase of $0.10 per MMBtu for natural gas would decrease the fair value of our net commodity derivative receivable by approximately $11 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 cash settled at the time of election. See Item 1. Financial Statements – Note 6. 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 June 30, 2010, we had $2.5 billion (excluding the FPSO lease 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, $820 million at June 30, 2010, was variable-rate debt drawn under our credit facility. 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 June 30, 2010 balance of our variable-rate debt would result in a change in annual interest expense of approximately $2 million.

We occasionally enter into interest rate derivative instruments such as forward contracts or swap agreements to hedge exposure to interest rate risk. Changes in fair value of interest rate derivative instruments 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 June 30, 2010, AOCL included $63 million, net of tax, related to interest rate derivative instruments. Of this amount, $2 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 ($61 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 June 30, 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 $33 million.

See Item 8. Financial Statements and Supplementary Data – Note 6. 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 June 30, 2010, our cash and cash equivalents totaled $1 billion, approximately 72% of which was invested in money market funds and short-term investments with major financial institutions. A hypothetical 25 basis point change in the floating interest rates applicable to the amount invested as of June 30, 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 (income) expense, net in the consolidated statements of operations.

In the UK sector of our North Sea operations, significant future capital commitments and certain operating expenses are expected to be denominated in British pounds. Therefore, our cash flows could be impacted by future changes in the exchange rate between the US dollar and the British pound. We currently have no foreign currency derivative instruments outstanding. However, we may enter into foreign currency derivative instruments (such as forward contracts, costless collars or swap agreements) in the future if we determined that it is necessary to invest in such instruments in order to mitigate our foreign currency exchange risk.

Table of Contents

Disclosure Regarding Forward-Looking Statements

This quarterly report on Form 10-Q contains 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 and development 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,” “estimate” ar similar words, although some forward-looking statements may be expressed differently. These forward-looking statements are made based upon our 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 included herein, if any, and included in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2010, and our Annual Report on Form 10-K for the year ended December 31, 2009, which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements. Our Quarterly Report on Form 10-Q for the quarter ended March 31, 2010, and our Annual Report on Form 10-K for the year ended December 31, 2009 are available on our website at www.nobleenergyinc.com.

Item 4. Controls and Procedures

Based on the evaluation of our disclosure controls and procedures by our principal executive officer and our principal financial officer, as of the end of the period covered by this quarterly report, each of them has concluded that our disclosure controls and procedures, as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended, are effective. There were no changes in internal control over financial reporting that occurred during the quarter covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

See Item I. Financial Statements – Note 16. Commitments and Contingencies.

Item 1A. Risk Factors

There have been no material changes from the risk factors disclosed in Item 1A. Risk Factors of our quarterly report on Form 10-Q for the quarter ended March 31, 2010 or our annual report on Form 10-K for the year ended December 31, 2009, other than the following:

Our operations in the deepwater Gulf of Mexico, as well as in U.S. onshore and international locations, could be adversely affected by changes in laws and regulations which are expected to occur as a result of the Deepwater Horizon Incident.

In April 2010, the deepwater Gulf of Mexico drilling rig Deepwater Horizon was engaged in drilling operations for another operator and sank after an apparent blowout and fire. The accident resulted in the loss of life and a significant oil spill. On May 27, 2010, in response to the Incident, the President of the United States announced a six-month moratorium on drilling in the deepwater Gulf of Mexico and imposed new restrictions on permitting activities on the Outer Continental Shelf. In conjunction therewith, the Department of the Interior issued a directive calling for additional safety and performance standards as well as rigorous monitoring and testing requirements. More recently, various Congressional committees have begun pursuing legislation to regulate drilling activities and increase liability. The legislature and regulatory response may not be limited to the U.S.; other countries could respond to the Incident as well.

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:

Table of Contents

- 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;
- increase or remove liability caps for claims of damages from oil spills;
- limit our ability to obtain additional insurance coverage on commercially reasonable terms to protect against any increase in liability.

Any of the above factors may result in a reduction of our cash flows, profitability, and the fair value of our properties.

Our major projects at Galapagos and Gunflint in the deepwater Gulf of Mexico may be adversely affected by our partnership with BP Exploration & Production Inc., a wholly-owned subsidiary of BP America Inc.

We are partners with BP at two major development projects in the deepwater Gulf Mexico, Galapagos and Gunflint. At Galapagos, we are the operator for the Santa Cruz and Santiago wells, and BP is the operator for the Isabela well. At Gunflint, we are the operator. Each project requires significant capital investments.

As a result of BP's involvement in the Deepwater Horizon Incident, its ability to participate effectively as a partner in the Galapagos and Gunflint projects may be negatively impacted. For example, manpower and material resources have been diverted to addressing the Incident and resultant cleanup. Further, BP's credit rating has recently been downgraded. In addition, its assets could be encumbered by governmental agencies, and/or its operating and development activities could be subject to heightened regulatory review or a reduction in scope. BP may have to sell assets or reduce capital expenditures in order to satisfy its oil-spill claims. These actions could limit BP's liquidity and financial flexibility and leave it unable to fund its share of project costs on a timely basis. As a result, these projects could become subject to increased costs and/or delays which could decrease our cash flows and profitability.

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.

In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act) was passed by Congress and signed into law. The Act 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 (the CFTC) to promulgate rules to define these terms, but we do not know the definitions that the CFTC will actually promulgate nor 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 crude oil and natural gas. We also 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 collateral with our dealer counterparties for our commodities and interest rate derivative transactions. Such a requirement could have a significant impact on our business by reducing our ability to execute derivative transactions to reduce commodity price and interest rate uncertainty and to protect cash flows. Requirements to post collateral would cause significant liquidity issues by reducing our ability to use cash for investment or other corporate purposes, or would require us to increase our level of debt. In addition, a requirement for our counterparties to post collateral would likely result in additional costs being passed on to us, thereby decreasing the effectiveness of our hedges and our profitability.

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

We operate in the US and other countries whose tax and fiscal regimes may change over time. The application of fiscal regimes through laws and regulations governing royalty payments and/or income taxes results in an increase or decrease in the amount of revenues a government collects, and a corresponding decrease or increase in the revenues of an oil and gas company operating in that particular country.

Historically, royalty and income tax laws and regulations have changed in certain jurisdictions, and the implementation of new, or the modification of existing, laws or regulations could negatively impact our operations. For example, the UK Finance Act of 2006 increased the income tax rate on our UK operations effective January 1, 2006. The China Petroleum Special Profits Tax, enacted in 2006, imposed an excise tax on crude oil produced in the country.

Table of Contents

The proposed US federal budget for fiscal year 2011, as originally submitted, as well as other proposed legislation currently before Congress, included provisions which could effectively raise taxes for US oil and gas operations.

In Israel, the finance ministry recently announced the establishment of a committee to study Israel's tax policy for the upstream oil and natural gas sector, as well as various options, including an increase in taxes and royalties.

Tax policy changes could result in increases in royalties or other taxes. If these or similar proposals are enacted, our taxes will increase, which would have a negative impact on our net income and cash flows. This could also reduce our drilling activities. Since none of these proposals have yet to become law, we do not know the ultimate impact they may have on our financial condition, results of operations or cash flows.

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 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 becomes effective in 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, and actual or alleged violations could damage our reputation and impair our ability to do business.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

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)
04/01/10 - 04/30/10	1,271	$77.05	-	-
05/01/10 - 05/31/10	636	59.78	-	-
06/01/10 - 06/30/10	34	57.65	-	-
Total	1,941	$71.05	-	-

(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.

Item 3. Defaults Upon Senior Securities

None.

Item 4. (Removed and Reserved)

Item 5. Other Information

None.

Item 6. Exhibits

The information required by this Item 6 is set forth in the Index to Exhibits accompanying this quarterly report on Form 10-Q.

Table of Contents

Signatures

Pursuant to the requirements 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 July 29, 2010	/s/ Kenneth M. Fisher Kenneth M. Fisher Senior Vice President, Chief Financial Officer

Table of Contents

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).
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.
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