NOBLE ENERGY INC
Form 10-Q
April 26, 2012

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 March 31, 2012

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 April 6, 2012, there were 177,787,421 shares of the registrant’s common stock, par value $3.33 1/3 per share, outstanding.

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Part I. Financial Information

Item 1. Financial Statements

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

	Three Months Ended March 31, 2012	2011
Revenues		
Oil, Gas and NGL Sales	$1,112	$830
Income from Equity Method Investees	53	48
Other Revenues	-	21
Total	1,165	899
Costs and Expenses		
Production Expense	179	142
Exploration Expense	63	70
Depreciation, Depletion and Amortization	312	221
General and Administrative	98	83
Other Operating (Income) Expense, Net	12	36
Total	664	552
Operating Income	501	347
Other (Income) Expense		
Loss on Commodity Derivative Instruments	96	286
Interest, Net of Amount Capitalized	32	16
Other Non-Operating (Income) Expense, Net	(1)	8
Total	127	310
Income Before Income Taxes	374	37
Income Tax Provision	111	23
Net Income	$263	$14
Earnings Per Share, Basic	$1.48	$0.08
Earnings Per Share, Diluted	1.47	0.08
Weighted Average Number of Shares Outstanding, Basic	177	176
Weighted Average Number of Shares Outstanding, Diluted	180	178

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

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

	Three Months Ended March 31, 2012	2011
Net Income	$263	$14
Other Items of Comprehensive Income (Loss)		
Interest Rate Cash Flow Hedges		
Unrealized Change in Fair Value	-	23
Less Tax Provision	-	(8)
Net Change in Other	2	2
Other Comprehensive Income	2	17
Comprehensive Income	$265	$31

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

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Noble Energy, Inc.

Consolidated Balance Sheets
(millions)
(unaudited)

	March 31, 2012	December 31, 2011
ASSETS		
Current Assets		
Cash and Cash Equivalents	$1,143	$1,455
Accounts Receivable, Net	919	783
Other Current Assets	330	180
Total Current Assets	2,392	2,418
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method of Accounting)	18,527	17,703
Property, Plant and Equipment, Other	317	294
Total Property, Plant and Equipment, Gross	18,844	17,997
Accumulated Depreciation, Depletion and Amortization	(5,460)	(5,215)
Total Property, Plant and Equipment, Net	13,384	12,782
Goodwill	696	696
Other Noncurrent Assets	592	548
Total Assets	$17,064	$16,444
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable - Trade	$1,457	$1,343
Other Current Liabilities	951	925
Total Current Liabilities	2,408	2,268
Long-Term Debt	4,088	4,100
Deferred Income Taxes, Noncurrent	2,216	2,059
Other Noncurrent Liabilities	819	752
Total Liabilities	9,531	9,179
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; 198 Million and 197 Million Shares Issued, Respectively	659	656
Additional Paid in Capital	2,549	2,497
Accumulated Other Comprehensive Loss	(98)	(100)
Treasury Stock, at Cost; 19 Million Shares	(651)	(638)
Retained Earnings	5,074	4,850
Total Shareholders' Equity	7,533	7,265
Total Liabilities and Shareholders' Equity	$17,064	$16,444

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

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Noble Energy, Inc.

Consolidated Statements of Cash Flows
(millions)
(unaudited)

	Three Months Ended March 31, 2012	2011
Cash Flows From Operating Activities		
Net Income	$263	$14
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities		
Depreciation, Depletion and Amortization	312	221
Dry Hole Cost	1	22
Deferred Income Taxes	32	11
Dividends (Income) from Equity Method Investees, Net	(29)	(23)
Unrealized Loss on Commodity Derivative Instruments	73	303
Other Adjustments for Noncash Items Included in Income	30	36
Changes in Operating Assets and Liabilities		
(Increase) in Accounts Receivable	(135)	(9)
(Increase) in Other Current Assets	(5)	(17)
Increase in Accounts Payable	190	28
Increase (Decrease) in Current Income Taxes Payable	5	(71)
(Decrease) in Other Current Liabilities	(26)	(54)
Other Operating Assets and Liabilities, Net	30	23
Net Cash Provided by Operating Activities	741	484
Cash Flows From Investing Activities		
Additions to Property, Plant and Equipment	(1,018)	(578)
Additions to Equity Method Investments	(14)	-
Proceeds from Divestitures	-	3
Net Cash Used in Investing Activities	(1,032)	(575)
Cash Flows From Financing Activities		
Exercise of Stock Options	27	23
Excess Tax Benefits from Stock-Based Awards	12	8
Dividends Paid, Common Stock	(39)	(32)
Purchase of Treasury Stock	(13)	(16)
Proceeds from Credit Facilities	-	120
Repayment of Credit Facilities	-	(470)
Proceeds from Issuance of Senior Long-Term Debt, Net	-	836
Settlement of Interest Rate Derivative Instrument	-	(40)
Repayment of Capital Lease Obligation	(8)	-
Net Cash Provided By (Used In) Financing Activities	(21)	429
Increase (Decrease) in Cash and Cash Equivalents	(312)	338
Cash and Cash Equivalents at Beginning of Period	1,455	1,081
Cash and Cash Equivalents at End of Period	$1,143	$1,419

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

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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 Shareholders' Equity
December 31, 2011	$656	$2,497	$ (100)	$(638)	$4,850	$ 7,265
Net Income	-	-	-	-	263	263
Stock-based Compensation	-	16	-	-	-	16
Exercise of Stock Options	2	25	-	-	-	27
Tax Benefits Related to Exercise of Stock Options	-	12	-	-	-	12
Restricted Stock Awards, Net	1	(1)	-	-	-	-
Dividends (22 cents per share)	-	-	-	-	(39)	(39)
Changes in Treasury Stock, Net	-	-	-	(13)	-	(13)
Net Change in Other	-	-	2	-	-	2
March 31, 2012	$659	$2,549	$ (98)	$(651)	$5,074	$ 7,533
December 31, 2010	$651	$2,385	$ (104)	$(624)	$4,540	$ 6,848
Net Income	-	-	-	-	14	14
Stock-based Compensation	-	14	-	-	-	14
Exercise of Stock Options	2	21	-	-	-	23
Tax Benefits Related to Exercise of Stock Options	-	8	-	-	-	8
Restricted Stock Awards, Net	1	(1)	-	-	-	-
Dividends (18 cents per share)	-	-	-	-	(32)	(32)
Changes in Treasury Stock, Net	-	-	-	(16)	-	(16)
Interest Rate Cash Flow Hedges						
Unrealized Change in Fair Value	-	-	15	-	-	15
Net Change in Other	-	-	2	-	-	2
March 31, 2011	$654	$2,427	$ (87)	$(640)	$4,522	$ 6,876

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

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Noble Energy, Inc.
Notes to Consolidated Financial Statements

Note 1. Organization and Nature of Operations
Noble Energy, Inc. (Noble Energy, we or us) is a leading independent energy company engaged in worldwide crude oil and natural gas exploration and production. Our core operating areas are onshore U.S., primarily in the DJ Basin and Marcellus Shale, in the deepwater Gulf of Mexico, offshore Eastern Mediterranean, and offshore West Africa.

Note 2. Basis of Presentation

Presentation The accompanying unaudited consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the US (US GAAP) 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 GAAP for complete financial statements. The accompanying consolidated financial statements at March 31, 2012 and December 31, 2011 and for the three months ended March 31, 2012 and 2011 contain all normally recurring adjustments considered necessary for a fair presentation of our financial position, results of operations, cash flows and shareholders' equity for such periods. Operating results for the three months ended March 31, 2012 are not necessarily indicative of the results that may be expected for the year ending December 31, 2012. 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, 2011.

Consolidation Our consolidated accounts include our accounts and the accounts of our wholly-owned subsidiaries. In addition, we use the equity method of accounting for investments in entities that we do not control but over which we exert significant influence. All significant intercompany balances and transactions have been eliminated upon consolidation.

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

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

	Three Months Ended March 31,			
		2012		2011
(millions)				
Other Revenues (1)	$	-	$	21
Production Expense				
Lease Operating Expense	$	118	$	92
Production and Ad Valorem Taxes		38		32
Transportation and Gathering Expense		23		18
Total	$	179	$	142
Other Operating (Income) Expense, Net				
Deepwater Gulf of Mexico Moratorium Expense (2)	$	-	$	18
Electricity Generation Expense (1)		-		17
Other, Net		12		1

Total	$	12	$	36
Other Non-Operating (Income) Expense, Net				
Deferred Compensation Expense (3)	$	3	$	10
Interest Income		-		(3)
Other (Income) Expense, Net		(4)		1
Total	$	(1)	$	8

(1) Other revenues for first quarter 2011 consist of electricity sales from the Machala power plant located in Machala, Ecuador. Electricity generation expense includes all operating and non-operating expenses associated with the plant, including depreciation and changes in the allowance for doubtful accounts. In May 2011, we transferred our assets in Ecuador to the Ecuadorian government.

(2) Amount relates to rig stand-by expense incurred prior to receiving a permit to resume drilling activities in the deepwater Gulf of Mexico in 2011.

(3) Amounts represent increases in the fair value of shares of our common stock held in a rabbi trust.

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Noble Energy, Inc.
Notes to Consolidated Financial Statements

Balance Sheet Information   Other balance sheet information is as follows:

(millions)	March 31, 2012	December 31, 2011
Accounts Receivable, Net		
Commodity Sales	$ 467	$ 356
Joint Interest Billings	344	313
Other	117	123
Allowance for Doubtful Accounts	(9)	(9)
Total	$ 919	$ 783
Other Current Assets		
Inventories, Current	$ 77	$ 78
Commodity Derivative Assets, Current	17	10
Deferred Income Taxes, Net, Current (1)	159	41
Probable Insurance Claims (2)	22	15
Prepaid Expenses and Other Current Assets, Current	55	36
Total	$ 330	$ 180
Other Noncurrent Assets		
Equity Method Investments	$ 376	$ 329
Mutual Fund Investments	108	99
Commodity Derivative Assets, Noncurrent	22	37
Other Assets, Noncurrent	86	83
Total	$ 592	$ 548
Other Current Liabilities		
Production and Ad Valorem Taxes	$ 123	$ 121
Commodity Derivative Liabilities, Current	119	76
Income Taxes Payable	131	127
Asset Retirement Obligations, Current	41	33
Interest Payable	41	56
CONSOL Installment Payment (3)	325	324
Current Portion of FPSO Lease Obligation	48	45
Other	123	143
Total	$ 951	$ 925
Other Noncurrent Liabilities		
Deferred Compensation Liabilities, Noncurrent	$ 237	$ 222
Asset Retirement Obligations, Noncurrent	350	344
Accrued Benefit Costs, Noncurrent	90	88
Commodity Derivative Liabilities, Noncurrent	29	7
Other	113	91
Total	$ 819	$ 752

(1) Increase from December 31, 2011 is due to reclassification of deferred income tax assets from long-term to short-term as certain foreign entities are estimated to begin utilizing net operating loss carryforwards in 2012 and 2013.

(2)

Amounts represent the costs incurred to date of the Leviathan-2 appraisal well in excess of the insurance deductible and insurance proceeds received to date.

(3) See Note 3. Acquisitions and Note 4. Debt.

Changes in Shareholders' Equity On April 24, 2012, our shareholders voted to approve an amendment to the Company's Certificate of Incorporation to (i) increase the number of authorized shares of our common stock from 250 million to 500 million shares and (ii) reduce the par value of the Company's common stock from $3.33 1/3 per share to $0.01 per share.

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Noble Energy, Inc.
Notes to Consolidated Financial Statements

Recently Issued Accounting Standards Updates In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2011-04: Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs (ASU 2011-04). ASU 2011-04 clarifies application of fair value measurement and disclosure requirements and is effective for annual and interim periods beginning after December 15, 2011. As of March 31, 2012, we have adopted the provisions of ASU 2011-04, which did not impact our consolidated financial statements. The only impact was to our fair value disclosures.

In December 2011, the FASB issued Accounting Standards Update No. 2011-11 Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities (ASU 2011-11). ASU 2011-11 requires that an entity disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. ASU 2011-11 is effective for annual periods beginning on or after January 1, 2013. We are currently evaluating the provisions of ASU 2011-11 and assessing the impact, if any, it may have on our financial position and results of operations.

Note 3. Acquisitions

Marcellus Shale Joint Venture On September 30, 2011, we closed an agreement with a subsidiary of CONSOL Energy Inc. (CONSOL) for the development of Marcellus Shale properties in southwest Pennsylvania and northwest West Virginia. Under the agreement, we acquired a 50% interest in approximately 628,000 net undeveloped acres, certain producing properties, and existing infrastructure, such as pipeline and gathering facilities, for approximately $1.3 billion, including post-closing adjustments. We and CONSOL also formed CONE Gathering LLC (CONE) to own and operate the existing and future infrastructure. We have paid a total of $596 million as of March 31, 2012, and, other than post-closing adjustments, the remainder will be paid in two annual installments. See Note 4. Debt.

As part of the joint venture transaction, we agreed to fund one-third of CONSOL's 50% working interest share of future drilling and completion costs, capped at $400 million each year, up to approximately $2.1 billion (CONSOL Carried Cost Obligation), which is expected to be paid out over approximately eight years or more. The CONSOL Carried Cost Obligation is suspended if average Henry Hub natural gas prices fall and remain below $4.00 per MMBtu in any three consecutive month period and will remain suspended until average Henry Hub natural gas prices are above $4.00 per MMBtu for three consecutive months. The CONSOL Carried Cost Obligation is currently suspended due to low natural gas prices.

As a result of the transaction, we recorded the following:

(millions)		March 31, 2012
Unproved Oil and Gas Properties	$	853
Proved Oil and Gas Properties		386
Investment in CONE Gathering LLC		69
Total Assets Acquired (1)	$	1,308

(1) Total reflects impact of $17 million imputed discount on CONSOL installment payments.

We used an income approach to estimate the fair value of the proved oil and gas properties as of the acquisition date. 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 reserves prepared by our qualified petroleum engineers;
- management's estimates of future commodity prices based on NYMEX Henry Hub natural gas futures prices and adjusted for estimated location and quality differentials;
- estimated future production rates based on our experience with similar properties which we operate; and
- estimated timing and amounts of future operating and development costs based on our experience with similar properties which we operate.

We discounted the resulting future net cash flows using a market-based weighted average cost of capital rate determined appropriate at the acquisition date. The fair value of the proved producing properties is considered a Level 3 fair value measurement.

Certain data necessary to complete the final purchase price allocation for proved oil and gas properties 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.

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Noble Energy, Inc.

Notes to Consolidated Financial Statements

Note 4. Debt

Our debt consists of the following:

	March 31, 2012			December 31, 2011		
	Debt	Interest Rate		Debt	Interest Rate	
(millions, except percentages)						
Credit Facility, due October 14, 2016 (1)	$-	-		$-	-	
CONSOL Installment Payments, due September 30, 2012 and 2013	656	1.76	% (2)	656	1.76	% (2)
FPSO Lease Obligation	344	-		355	-	
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	%
4.15% Senior Notes, due December 15, 2021	1,000	4.15	%	1,000	4.15	%
7¼% Senior Notes, due October 15, 2023	100	7.25	%	100	7.25	%
8% Senior Notes, due April 1, 2027	250	8.00	%	250	8.00	%
6% Senior Notes, due March 1, 2041	850	6.00	%	850	6.00	%
7¼% Senior Debentures, due August 1, 2097	84	7.25	%	84	7.25	%
Total	4,484			4,495		
Unamortized Discount	(23)			(26)		
Total Debt, Net of Discount	4,461			4,469		
Less Amounts Due Within One Year						
CONSOL Installment Payment, due September 30, 2012, net of discount	(325)			(324)		
FPSO Lease Obligation	(48)			(45)		
Long-Term Debt Due After One Year	$4,088			$4,100		

(1) Our Credit Agreement provides for a $3.0 billion unsecured five-year revolving credit facility. The Credit Facility is available for general corporate purposes.

(2) Imputed rate.

See Note 6. Fair Value Measurements and Disclosures for a discussion of methods and assumptions used to estimate the fair values of our debt.

Note 5. Derivative Instruments and Hedging Activities

Objective and Strategies for Using Derivative Instruments In order to mitigate the effect of commodity price uncertainty and enhance the predictability of cash flows relating to the marketing of our crude oil and natural gas, we enter into crude oil and natural gas price hedging arrangements with respect to a portion of our expected production. The derivative instruments we use include variable to fixed price commodity swaps, two-way and three-way collars and basis swaps.

The fixed price swap, two-way collar, and basis swap contracts entitle us (floating price payor) to receive settlement from the counterparty (fixed price payor) for each calculation period in amounts, if any, by which the settlement price for the scheduled trading days applicable for each calculation period is less than the fixed strike price or floor price. We would pay the counterparty if the settlement price for the scheduled trading days applicable for each calculation period is more than the fixed strike price or ceiling price. The amount payable by us, if the floating price is above the fixed or ceiling price, is the product of the notional quantity per calculation period and the excess of the floating price over the fixed or ceiling price in respect of each calculation period. The amount payable by the counterparty, if the floating price is below the fixed or floor price, is the product of the notional quantity per calculation period and the excess of the fixed or floor price over the floating price in respect of each calculation period.

A three-way collar consists of a two-way collar contract combined with a put option contract sold by us with a strike price below the floor price of the two-way collar. We receive price protection at the purchased put option floor price of the two-way collar if commodity prices are above the sold put option strike price. If commodity prices fall below the sold put option strike price, we receive the cash market price plus the delta between the two put option strike prices. This type of instrument allows us to capture more value in a rising commodity price environment, but limits our benefits in a downward commodity price environment.

We also may enter into forward contracts to hedge anticipated exposure to interest rate risk associated with public debt financing.

Noble Energy, Inc.
Notes to Consolidated Financial Statements

While these instruments mitigate the cash flow risk of future reductions in commodity prices or increases in interest rates, they may also curtail benefits from future increases in commodity prices or decreases in interest rates.

See Note 6. Fair Value Measurements and Disclosures for a discussion of methods and assumptions used to estimate the fair values of our derivative instruments.

Counterparty Credit Risk   Derivative instruments expose us to counterparty credit risk. Our commodity derivative instruments are currently with a diversified group of highly rated major banks or market participants, and we monitor and manage our level of financial exposure. Our commodity derivative contracts are executed under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net settled at the time of election.

We monitor the creditworthiness of our counterparties. However, we are not able to predict sudden changes in counterparties' creditworthiness. In addition, even if such changes are not sudden, we may be limited in our ability to mitigate an increase in counterparty credit risk. Possible actions would be to transfer our position to another counterparty or request a voluntary termination of the derivative contracts resulting in a cash settlement. Should one of these financial counterparties not perform, we may not realize the benefit of some of our derivative instruments under lower commodity prices or higher interest rates, and could incur a loss.

Interest Rate Derivative Instrument   In January 2010, we entered into an interest rate forward starting swap to effectively fix the cash flows related to interest payments on our anticipated March 2011 debt issuance. During first quarter 2011, the fair value of the swap increased and we recognized a gain of $23 million, net of tax, in AOCL. On February 15, 2011 we settled the interest rate swap, which had a net liability position of $40 million at the time of settlement. Approximately $26 million, net of tax, was recorded in accumulated other comprehensive loss (AOCL) and is being reclassified to interest expense over the term of the notes. The ineffective portion of the interest rate swap was de minimis.

Unsettled Derivative Instruments   As of March 31, 2012, we had entered into the following crude oil derivative instruments:

Settlement Period	Type of Contract	Index	Bbls Per Day	Swaps Weighted Average Fixed Price	Weighted Average Short Put Price	Collars Weighted Average Floor Price	Weighted Average Ceiling Price
Instruments Entered Into as of March 31, 2012							
2012	Swaps	NYMEX WTI (1)	5,000	$91.84	$-	$-	$-
2012	Swaps	Dated Brent	8,000	89.06	-	-	-
2012	Three-Way Collars	NYMEX WTI	23,000	-	61.09	83.04	101.66
2012	Three-Way Collars	Dated Brent	3,000	-	70.00	95.83	105.00
2013	Swaps	Dated Brent	3,000	98.03	-	-	-
2013	Two-Way Collars	NYMEX WTI	5,000	-	-	95.00	115.00

2013	Three-Way Collars	NYMEX WTI	5,000	-	65.00	85.00	113.63
2013	Three-Way Collars	Dated Brent	26,000	-	82.88	100.86	127.32
2014	Swaps	Dated Brent	3,000	107.15	-	-	-
2014	Three-Way Collars	Dated Brent	10,000	-	85.00	98.50	129.24

(1) West Texas Intermediate

As of March 31, 2012, we had entered into the following natural gas derivative instruments:

Settlement Period	Type of Contract	Index	MMBtu Per Day	Swaps Weighted Average Fixed Price	Weighted Average Short Put Price	Collars Weighted Average Floor Price	Weighted Average Ceiling Price
Instruments Entered Into as of March 31, 2012							
2012	Swaps	NYMEX HH (1)	30,000	$5.10	$-	$-	$-
2012	Two-Way Collars	NYMEX HH	40,000	-	-	3.25	5.14
2012	Three-Way Collars	NYMEX HH	110,000	-	4.44	5.25	6.66
2013	Swaps	NYMEX HH	30,000	5.25	-	-	-
2013	Two-Way Collars	NYMEX HH	40,000	-	-	3.25	5.14
2013	Three-Way Collars	NYMEX HH	100,000	-	3.88	4.75	5.63

(1) Henry Hub

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As of March 31, 2012, we had entered into the following natural gas basis swaps:

Settlement Period	Index	Index Less Differential	MMBtu Per Day	Weighted Average Differential
2012	IFERC CIG (1)	NYMEX HH	150,000	$ (0.52)

(1) Colorado Interstate Gas – Northern System

Fair Value Amounts and Gains and Losses on Derivative Instruments   The fair values of derivative instruments in our consolidated balance sheets were as follows:

	Fair Value of Derivative Instruments							
	Asset Derivative Instruments				Liability Derivative Instruments			
	March 31, 2012		December 31, 2011		March 31, 2012		December 31, 2011	
(millions)	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity Derivative Instruments	Current Assets	$ 17	Current Assets	$ 10	Current Liabilities	$ 119	Current Liabilities	$ 76
	Noncurrent Assets	22	Noncurrent Assets	37	Noncurrent Liabilities	29	Noncurrent Liabilities	7
Total		$ 39		$ 47		$ 148		$ 83

The effect of derivative instruments on our consolidated statements of operations was as follows:

	Three Months Ended March 31,	
(millions)	2012	2011
Realized Mark-to-Market (Gain) Loss	$ 23	$ (17)
Unrealized Mark-to-Market Loss	73	303
Total Loss on Commodity Derivative Instruments	$ 96	$ 286

AOCL at March 31, 2012 included deferred losses of $26 million, net of tax, related to interest rate derivative instruments. This amount will be reclassified to earnings as an adjustment to interest expense over the terms of our senior notes due April 2014 and March 2041. Approximately $2 million of deferred losses (net of tax) will be reclassified to earnings during the next 12 months and will be recorded as an increase in interest expense.

Note 6. Fair Value Measurements and Disclosures

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Certain assets and liabilities are measured at fair value on a recurring basis in our consolidated balance sheets. The following methods and assumptions were used to estimate the fair values:

Cash, Cash Equivalents, Accounts Receivable and Accounts Payable The carrying amounts approximate fair value due to the short-term nature or maturity of the instruments.

Mutual Fund Investments Our mutual fund investments, which primarily include assets held in a rabbi trust, consist of various publicly-traded mutual funds that include investments ranging from equities to money market instruments. The fair values are based on quoted market prices for identical assets.

Commodity Derivative Instruments Our commodity derivative instruments consist of variable to fixed price commodity swaps, two-way and three-way collars, and basis swaps. We estimate the fair values of these instruments based on published forward commodity price curves as of the date of the estimate. The discount rate used in the discounted cash flow projections is based on published LIBOR rates, Eurodollar futures rates and interest swap rates. The fair values of commodity derivative instruments in an asset position include a measure of counterparty nonperformance risk, and the fair values of commodity derivative instruments in a liability position include a measure of our own nonperformance risk, each based on the current published credit default swap rates. In addition, for collars, we estimate the option values of the put options sold (for three-way collars) and the contract floors and ceilings (for two-way and three-way collars) using an option pricing model which takes into account market volatility, market prices and contract terms. See Note 5. Derivative Instruments and Hedging Activities.

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Deferred Compensation Liability The value is dependent 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				
(millions)	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
March 31, 2012					
Financial Assets					
Mutual Fund Investments	$108	$-	$ -	$-	$ 108
Commodity Derivative Instruments	-	105	-	(66)	39
Financial Liabilities					
Commodity Derivative Instruments	-	(214)	-	66	(148)
Portion of Deferred Compensation Liability Measured at Fair Value	(172)	-	-	-	(172)
December 31, 2011					
Financial Assets					
Mutual Fund Investments	$99	$-	$ -	$-	$ 99
Commodity Derivative Instruments	-	99	-	(52)	47
Financial Liabilities					
Commodity Derivative Instruments	-	(135)	-	52	(83)
Portion of Deferred Compensation Liability Measured at Fair Value	(162)	-	-	-	(162)

(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.

Additional Fair Value Disclosures

Debt The fair value of fixed-rate, public debt is estimated based on the published market prices for the same or similar issues. As such, we consider the fair value of our public fixed rate debt to be a level 1 measurement on the fair value hierarchy. The carrying amounts of floating-rate debt approximate fair value because the interest rate paid on such debt was set for periods of three months or less. The carrying amounts of the CONSOL installment payments approximate fair value because they have been discounted at the prevailing market rates for similar instruments. As such, we consider the fair value of our floating-rate debt and CONSOL installment payments to be level 2 measurements on the fair value hierarchy. See Note 4. Debt. Fair value information regarding our debt is as follows:

	March 31, 2012		December 31, 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
(millions)				
Long-Term Debt, Net of Unamortized Discount (1)	$4,117	$4,606	$4,114	$4,733

(1) Excludes Aseng FPSO lease obligation. No floating rate debt was outstanding at March 31, 2012 or December 31, 2011. See Note 4. Debt.

Note 7. Capitalized Exploratory Well Costs

We capitalize exploratory well costs until a determination is made that the well has found proved reserves or is deemed noncommercial. If a well is deemed to be noncommercial, the well costs are immediately charged to exploration expense.

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

(millions)	Three Months Ended March 31, 2012
Capitalized Exploratory Well Costs, Beginning of Period	$696
Additions to Capitalized Exploratory Well Costs Pending Determination of Proved Reserves	93
Reclassified to Proved Oil and Gas Properties Based on Determination of Proved Reserves	-
Capitalized Exploratory Well Costs Charged to Expense	-
Capitalized Exploratory Well Costs, End of Period	$789

The following table provides an aging of capitalized exploratory well costs based on the date that drilling commenced, and the number of projects that have been capitalized for a period greater than one year:

(millions)	March 31, 2012	December 31, 2011
Exploratory Well Costs Capitalized for a Period of One Year or Less	$ 345	$ 318
Exploratory Well Costs Capitalized for a Period Greater Than One Year Since Commencement of Drilling	444	378
Balance at End of Period	$ 789	$ 696
Number of Projects with Exploratory Well Costs That Have Been Capitalized for a Period Greater Than One Year Since Commencement of Drilling	10	9

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 commencement of drilling as of March 31, 2012:

		Suspended Since		
(millions)	Total	2011	2010	2009 & Prior
Country/Project				
Offshore Equatorial Guinea				
Blocks O and I	$ 114	$ 2	$ 6	$ 106
Offshore Cameroon				
YoYo	41	1	2	38
Offshore Israel				
Leviathan	86	45	41	-
Dalit	22	-	1	21
Deepwater Gulf of Mexico				
Gunflint	70	11	3	56
Deep Blue	75	2	54	19

North Sea							
Selkirk		22		-		1		21
Other								
3 projects of $10 million or less each		14		6		8		-
Total	$	444	$	67	$	116	$	261

Blocks O and I   Blocks O and I are crude oil, natural gas and natural gas condensate discoveries. During the second quarter of 2011, we drilled the successful Diega appraisal well which encountered both crude oil and natural gas. We have drilled two sidetracks, each of which encountered hydrocarbons. We are currently finalizing our appraisal of Diega and are evaluating regional development scenarios.

YoYo   YoYo is a 2007 natural gas and condensate discovery. During 2011 we acquired and processed additional 3-D seismic information and are continuing evaluations for future drilling potential.

Leviathan   Leviathan is a 2010 natural gas discovery. We are continuing to evaluate the discovery with the successful drilling of the Leviathan-3 appraisal well. We will require an additional one or two appraisal wells to further define Leviathan’s natural gas areal extent in order to determine the best development option including subsea tieback to existing shallow water platform, semi-submersible platform, FPSO, or LNG.

In January 2012, we resumed drilling at the Leviathan-1 well in order to evaluate two additional intervals for the existence of crude oil. Results from these deeper tests are expected during the second quarter of 2012.

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Dalit   Dalit is a 2009 natural gas discovery. We are currently working with our partners on a cost-effective development plan.

Gunflint   Gunflint (Mississippi Canyon Block 948) is a 2008 crude oil discovery. We are currently drilling the first of up to three appraisal wells that we anticipate drilling to fully evaluate the extent of the reservoir. We are also reviewing host platform options including subsea tieback to an existing third-party host and construction of a new facility.

Deep Blue   Deep Blue (Green Canyon Block 723) was a significant test well which began drilling in 2009. When the Deepwater Moratorium was announced in May 2010, we were required to suspend side track drilling activities. We resumed drilling activities and found additional hydrocarbons in high quality reservoirs in 2011. We have completed the analysis of the data obtained from the side track well and are working with our existing and potential new partners regarding their participation in an appraisal well.

Selkirk   The Selkirk project is located in the UK sector of the North Sea. Capitalized costs to date primarily consist of the cost of drilling an exploratory well. We are currently working with our partners on a cost-effective development plan, including selection of a host facility.

Note 8. 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:

	Three Months Ended March 31,	
(millions)	2012	2011
Asset Retirement Obligations, Beginning Balance	$ 377	$ 253
Liabilities Incurred	6	1
Liabilities Settled	(2)	(9)
Revision of Estimate	3	4
Accretion Expense	7	5
Asset Retirement Obligations, Ending Balance	$ 391	$ 254

Liabilities settled in 2011 related primarily to Deepwater Gulf of Mexico and Gulf of Mexico shelf properties.

Accretion expense is included in depreciation, depletion and amortization (DD&A) expense in the consolidated statements of operations.

Note 9. Basic and Diluted Earnings Per Share

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

	Three Months Ended March 31,	
	2012	2011
(millions, except per share amounts)		
Net Income	$ 263	$ 14
Weighted Average Number of Shares Outstanding, Basic	177	176
Incremental Shares From Assumed Conversion of Dilutive Stock Options and Restricted Stock	3	2
Weighted Average Number of Shares Outstanding, Diluted	180	178
Earnings Per Share, Basic	$ 1.48	$ 0.08
Earnings Per Share, Diluted	1.47	0.08
Number of antidilutive stock options, shares of restricted stock and shares of common stock in rabbi trust excluded from calculation above	2	2

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Notes to Consolidated Financial Statements

Note 10. Income Taxes

The income tax provision consists of the following:

(millions)	Three Months Ended March 31, 2012	2011
Current	$ 79	$ 12
Deferred	32	11
Total Income Tax Provision	$ 111	$ 23
Effective Tax Rate	30 %	62 %

Our effective tax rate decreased for the first quarter of 2012 as compared with the first quarter of 2011. During the first quarter of 2011, we increased the valuation allowance against our deferred tax asset for foreign tax credits by $11 million resulting in a corresponding increase in income tax expense, which was primarily responsible for the difference in the quarterly effective tax rates.

Years Remaining Open to Examination In our major tax jurisdictions, the earliest years remaining open to examination are as follows: US – 2008, Equatorial Guinea – 2007, Israel – 2008, UK – 2010, the Netherlands – 2009, and China – 2006.

Note 11. Segment Information

We have operations throughout the world and manage our operations by country. The following information is grouped into five components that are all primarily in the business of crude oil and natural gas exploration, development, and acquisition: the United States; West Africa (Equatorial Guinea, Cameroon, Senegal/Guinea-Bissau); Eastern Mediterranean (Israel and Cyprus); the North Sea (UK and the Netherlands); and Other International and Corporate. Other International includes China, Ecuador (in first quarter 2011), and new ventures.

(millions)	Consolidated	United States	West Africa	Eastern Mediter-ranean	North Sea	Other Int'l and Corporate
Three Months Ended March 31, 2012						
Revenues from Third Parties	$ 1,112	$554	$383	$44	$75	$56
Income from Equity Method Investees	53	2	51	-	-	-
Total Revenues	1,165	556	434	44	75	56
DD&A	312	198	73	5	18	18
(Gain) Loss on Commodity Derivative Instruments	96	(9)	105	-	-	-
Income (Loss) Before Income Taxes	374	193	227	32	40	(118)

Three Months Ended March 31, 2011						
Revenues from Third Parties	$ 851	$505	$130	$52	$114	$50
Income from Equity Method Investees	48	-	48	-	-	-
Total Revenues	899	505	178	52	114	50
DD&A	221	167	10	4	28	12
Loss on Commodity Derivative Instruments	286	192	94	-	-	-
Income (Loss) Before Income Taxes	37	(37)	74	39	68	(107)
March 31, 2012						
Goodwill	$ 696	$696	$-	$-	$-	$-
Total Assets	17,064	11,220	2,948	2,107	458	331
December 31, 2011						
Goodwill	696	696	-	-	-	-
Total Assets	16,444	11,201	2,728	1,751	544	220

Note 12. 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.

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During 2011, we received two Notices of Alleged Violation (NOAV) from the Colorado Oil and Gas Conservation Commission (COGCC) regarding the reporting of the presence of hydrogen sulfide to the COGCC and local government designee within certain areas of our Piceance Basin and Grover field operations. At this time, the COGCC has not established a proposed penalty for either NOAV. Given the inherent uncertainty in administrative actions of this nature, we are unable to predict the ultimate outcome of this action at this time. However, we believe that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on our financial position, results of operations or cash flows.

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

Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) is intended to provide a narrative about our business from the perspective of our management. Our MD&A is presented in the following major sections:

- Executive Overview;
- Operating Outlook;
- Results of Operations; and
- Liquidity and Capital Resources.

The preceding consolidated financial statements, including the notes thereto, contain detailed information that should be read in conjunction with our MD&A.

EXECUTIVE OVERVIEW

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

Our financial results for first quarter 2012 included:

- net income of $263 million, as compared with $14 million for first quarter 2011;
- loss on commodity derivative instruments of $96 million (including unrealized mark-to-market loss of $73 million) as compared with a loss on commodity derivative instruments of $286 million (including unrealized mark-to-market loss of $303 million) for first quarter 2011;
- diluted earnings per share of $1.47, as compared with $0.08 for first quarter 2011;
- cash flow provided by operating activities of $741 million, as compared with $484 million for first quarter 2011;
- ending cash balance of $1.1 billion, as compared with $1.5 billion at December 31, 2011;
- capital spending, on a cash basis, of $1 billion, as compared with $578 million for first quarter of 2011; and
- ratio of debt-to-book capital of 37% as compared with 38% at December 31, 2011.

Operational events for first quarter 2012 included:

Overall

- record total sales volume of 243 MBoe/d, up 10 MBoe/d over the fourth quarter of 2011; and
- liquids represent 47% of total sales volumes, up from 40% in the fourth quarter of 2011;

United States

- horizontal production from the DJ Basin averaged 18 MBoe/d net, or 25% of the total DJ Basin volumes;
- expanded the Northern Colorado acreage position by 48,000 net acres to 230,000 net acres, where recent Company horizontal Niobrara results indicate recoveries comparable to Wattenberg; and
- assumed operatorship in the wet gas area of the Marcellus Shale joint venture acreage;

International

gross daily crude oil production from the Aseng field, offshore Equatorial Guinea, achieved 60 MBbl/d;
signed a natural gas sales contract with Israel Electric Corporation Limited for 2.7 Tcf of natural gas; and
announced the Tanin discovery offshore Israel.

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Exploration Program Update

We have significant remaining exploration potential in the onshore US, deepwater Gulf of Mexico, offshore West Africa, offshore Eastern Mediterranean and other international areas where we hold acreage positions. Significant exploratory wells were in progress at March 31, 2012, such as Deep Blue and the deep crude oil test at Leviathan-1 (See Item 1. Financial Statements – Note 7. Capitalized Exploratory Well Costs), and we expect to continue an active exploratory drilling program during the remainder of 2012. We do not always find proved reserves through our drilling activities. In addition, we may find hydrocarbons but subsequently reach a decision, through additional analysis or appraisal drilling, that a project is not economically or operationally viable. We are currently conducting, or planning to conduct, appraisal activities at several of our discoveries. In the event we conclude that one of our discoveries is not economically or operationally viable, the associated capitalized exploratory well costs would be charged to expense. As a result, in a future period, dry hole cost could be significant.

Updates of our significant exploration activities are as follows:

DJ Basin (Onshore US) We continue to acquire 3-D seismic information and appraise our acreage in Northern Colorado and Wyoming.

Deep Blue (Deepwater Gulf of Mexico) We have completed the analysis of the data obtained from the side track well and are working with our existing and potential new partners regarding their participation in an appraisal well.

Leviathan (Offshore Israel) In late 2010, we announced a significant natural gas discovery at the Leviathan-1 well in the Levant Basin. Additionally, we will require one or two appraisal wells to further define Leviathan's natural gas areal extent in order to determine the best development option. See Major Development Projects Update – Leviathan below.

In January 2012, we returned to drilling at the Leviathan-1 well, which was suspended during 2011, in order to evaluate additional intervals for the existence of crude oil. Although the geological likelihood of success is low, the drilling results, which are expected in the second quarter of 2012, will yield valuable information about this new basin.

Tanin 1 (Offshore Israel) In February 2012 we announced a natural gas discovery at the Tanin prospect, approximately 13 miles northwest of the Tamar field.

Additionally, we have acquired approximately 330,000 net acres in the state of Nevada. We are currently planning 3-D seismic testing in 2012 and exploration drilling in 2013.

Major Development Projects Update

During the first quarter of 2012, we continued to advance our major development projects, which we expect to deliver significant growth over the next several years. Updates on our significant development projects are as follows:

Horizontal Niobrara (Onshore US) We have increased our horizontal drilling activity targeting the Niobrara formation, completing 30 horizontal wells during the quarter. We recently added another horizontal drilling rig to our program and are currently running six horizontal drilling rigs.

Marcellus Shale (Onshore US) During the first quarter of 2012, we took over operatorship of our first rig in the wet gas area of the Marcellus Shale, bringing the total rig count operating in the joint venture properties to seven. We drilled five horizontal wells reaching target depth during the quarter. By the end of the year, we expect to operate three rigs in the wet gas area while our partner CONSOL expects to operate two rigs in the dry gas area.

Galapagos (Deepwater Gulf of Mexico) Installation of topside equipment at the host facility and subsea tiebacks for Santa Cruz, Isabela and Santiago have been completed and we are working with the host platform operator to perform final commissioning work. We expect production to commence in the second quarter of 2012.

Gunflint (Deepwater Gulf of Mexico) We are currently drilling an appraisal well at Gunflint. We currently anticipate drilling up to two additional appraisal wells to fully evaluate the extent of the reservoir. We are also reviewing host platform options, including subsea tieback to an existing third-party host and construction of a new facility, which will likely lead to sanctioning of a development project.

Alen (Offshore Equatorial Guinea) All sub-sea trees have been installed and sub-sea fabrication is underway. The production and injection wells are also on schedule and first production is expected to commence in the fourth quarter of 2013.

Diega (Offshore Equatorial Guinea) We are currently finalizing our appraisal of Diega and are evaluating regional development scenarios.

Carla (Offshore Equatorial Guinea) In late 2011, we drilled the Carla well, a successful oil appraisal well in Block O, offshore Equatorial Guinea. We are evaluating drilling results from our Carla discovery well and reviewing development options and formulating a development plan for these areas.

Tamar (Offshore Israel) Tamar development drilling and platform fabrication are ongoing. Pipeline installation is essentially complete, and the project remains on schedule for commissioning beginning in late 2012 and first sales in the second quarter of 2013. We also finalized several natural gas sales and purchase agreements during the quarter. See Israel Delivery Commitments below.

Noa/Pinnacles (Offshore Israel) The Noa field is being developed as a subsea tieback to the Mari-B platform. Two development wells have been drilled, FEED (front end engineering and design) work has been completed, and installation and fabrication are progressing on schedule. In addition to Noa, we drilled the Pinnacles-1 well and are currently in the process of completing and tying the well back to the Mari-B platform. Noa and Pinnacles will help meet Israeli natural gas demands until the Tamar field begins producing. We expect production from both Noa and Pinnacles to commence in the third quarter of 2012. See Israel Delivery Commitments below.

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Leviathan (Offshore Israel) We have project and commercial teams in place and are considering our natural gas commercialization options. Due to the size of the field, economic viability depends on the ability to export via pipeline or LNG. Engineering design and planning work are currently underway for a potential first phase of development; however, we have not yet sanctioned a development project.

Block 12 (Offshore Cyprus) We are in the process of evaluating our commercialization options, including LNG, for the Block 12 natural gas discovery.

Northern Region Transportation Curtailments

The marketability of our production depends in part upon the availability, proximity and capacity of pipelines, natural gas gathering systems and processing facilities. Although we have some contractual control over the transportation of our production through firm transportation arrangements, third-party systems and facilities may be temporarily unavailable due to market conditions, mechanical or other reasons. In addition, continued drilling activity in concentrated areas, such as the DJ Basin and Marcellus Shale, can result in production growth outstripping available transportation and gathering capacity.

Due to both scheduled and unscheduled curtailments of third party pipeline services for significant equipment repairs and upgrades, we expect our Wattenberg area production to be impacted for the second quarter of 2012.

Recent Developments in the Marcellus Shale

Well Impact Fee During the first quarter of 2012, the Pennsylvania legislature enacted an annual well impact fee which will be used by local governments, counties and state agencies to support the infrastructure and regulatory framework necessary to sustain effective development of natural gas resources in the Marcellus Shale. The well impact fee is a variable rate based on natural gas prices and the year a well is drilled. Due to the early stage of our Marcellus Shale development activities, the fee did not have a significant impact on our results of operations for the first quarter of 2012.

Butler v. Powers On September 7, 2011, an intermediate appellate court (Superior Court) in Pennsylvania issued an opinion in Butler v. Powers regarding the interpretation of a deed. As a result, traditional views of how ownership of shale gas is determined in that state have been called into question. The issue raised by the case is whether shale gas is different from other natural gas and should be considered part of mineral rights, rather than oil and gas rights, because shale gas is contained inside non-porous shale rock. An appeal of the decision was subsequently filed with the Pennsylvania Supreme Court. The Pennsylvania Supreme Court recently announced its decision to hear the appeal. Written arguments in the case are due by May 15, 2012.

At this time, no case law or interpretation of existing law has changed, nor has there been an indication that either the Superior Court or the Pennsylvania Supreme Court will seek to change existing law. Based upon our initial review, we believe that any adverse decision in the pending case would have minimal adverse impact upon the assets acquired from CONSOL and our Marcellus Shale joint venture operations.

Recent Developments Onshore US

Researchers from the U.S. Geological Survey recently reported that they have observed an increase in seismic activity in the Midcontinent region and have indicated that the seismic activity may be attributable to injection wells that handle wastewater from oil and gas drilling activities. The researchers cite a series of examples for which an uptick in seismic activity is observed in areas where the disposal of wastewater through deep-well injection increased significantly. Regulators in Ohio and Arkansas are also looking at a possible connection between minor seismic events and disposal of wastewater in injection wells.

Minor and imperceptible seismic activity is extremely common in areas of oil and gas development. Historically, such activity has rarely caused damage. In addition, there are safeguards in place to reduce the likelihood of seismic activity caused by oil and gas drilling activities, including the disposal of wastewater. For example, we study the seismicity of the areas where we operate and design plans for each well based on our understanding of the specific geology. Steps taken to prevent seismic events include limiting increases in well pressure by reducing either the volume of wastewater pumped into the wells or the rate at which it is pumped. We also comply with requirements for injection well construction, operation, and closure set by the Underground Injection Control (UIC) Program, which was established under the provisions of the Safe Drinking Water Act of 1974.

Recent Developments Offshore France

We and our partner have applied to the French government for an extension of our offshore exploratory license until November 2015. The French government has thus far not responded officially to this application, even though the regulatory period for reply has passed. The current political climate is not favorable to our application, and we are unable to predict the ultimate outcome. Regardless of the final result, any curtailment of exploration activities offshore France would have no material impact on our financial position or results of operations.

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Recent Developments in West Africa

We currently have an interest in the AGC Profond block covering 2.4 million gross (724,000 net) undeveloped acres offshore Senegal/Guinea-Bissau. On March 26, 2012, a new president of Senegal was elected in a peaceful, democratic election. Conversely, on April 13, 2012, the interim government of Guinea-Bissau was deposed by military forces. The military and the opposition subsequently agreed to form a transitional council, but have not announced specific plans. We will continue to monitor these developments, and we currently cannot predict the impact these events may have on our future exploration plans in this area.

Israel Delivery Commitments

During 2011, due to multiple interruptions in imported gas supplies from Egypt, Mari-B natural gas volumes were delivered at very high rates to support Israel's growing natural gas and power demands. As a result, we experienced accelerated depletion of the Mari-B field. In January 2012, we announced a cut back in production at Mari-B, which is nearing the end of its expected production life, to prudently manage the reservoir. We are currently working closely with our Israeli customers to manage demand from the Mari-B field and continue production from it while wells from Noa and Pinnacles are drilled, completed and tied back to the Mari-B platform. We expect production to commence from Noa and Pinnacles during the third quarter of 2012 and the Tamar field during the second quarter of 2013.

On March 14, 2012, we and our Tamar partners entered into a Gas Sale and Purchase Agreement (GSPA) with the Israel Electric Corporation Limited (IEC). Under the terms of the GSPA, we have agreed to sell approximately 2.7 Tcf of natural gas produced from the Tamar field to IEC over an approximate 15-year period. At IEC's option, this amount can be increased to 3.5 Tcf, under certain conditions. The term of the GSPA begins upon commissioning of the Tamar project. The sales price is based on an initial base price and will be subject to an inflation adjustment. The GSPA is attached as Exhibit 10.1 to this Quarterly Report on Form 10-Q.

As of April 15, 2012, we and our partners have also signed GSPAs with other Israeli customers, including independent power, cogeneration and manufacturing companies, to supply approximately 1.3 Tcf of natural gas over a 16 to 17 year period beginning in late 2013. These contracts provide for an initial base price, subject to an inflation adjustment, and some of the contracts provide for increases or decreases in total quantities. We continue to negotiate additional GSPAs with other potential customers.

Sales Volumes

On a BOE basis, total sales volumes were 13% higher for the first quarter of 2012 as compared with the first quarter of 2011, and our mix of sales volumes was 47% global liquids, 23% international natural gas, and 30% US natural gas. US sales volumes increased due to continued acceleration of our horizontal drilling programs in Wattenberg along with our Marcellus Shale program, which began at the end of the third quarter of 2011. International crude oil sales volumes were higher in Equatorial Guinea due to the commencement of crude oil production at Aseng in the fourth quarter of 2011. Israel natural gas sales volumes were lower as we have reduced the rate of production from the Mari-B field in order to manage the reservoir. See Israel Delivery Commitments above and Results of Operations – Revenues below.

Commodity Price Changes and Hedging

Total consolidated average realized crude oil prices for the first three months of 2012 increased 14% as compared with the first three months of 2011. The increase was driven by the continued global economic recovery and continued threats to the global oil supply system.

US natural gas prices remain weak. Average realized natural gas prices for the first three months of 2012 decreased 36% as compared with the first three months of 2011 primarily due to abundant supply and above average levels of natural gas in storage. As long as US natural gas development activity continues at, or near, the current level and there is no significant increase in demand, production growth will continue to outstrip growth in transportation and storage capacity, likely resulting in downward pressure on natural gas prices (See Potential for Future Asset Impairments below).

We have hedged approximately 41% of our expected global crude oil production and 39% of our expected domestic natural gas production for the remainder of 2012. See Item 1. Financial Statements – Note 5. Derivative Instruments and Hedging Activities.

OPERATING OUTLOOK

Our expected crude oil, natural gas and NGL production for 2012 may be impacted by several factors including:

- overall level and timing of capital expenditures which, as discussed below and dependent upon our drilling success, are expected to maintain our near-term production volumes;
- timing of major development project completion and initial production;
- ongoing development activity in the Wattenberg area and horizontal drilling in the Niobrara formation in the DJ Basin;
- ramp-up of development activity in the Marcellus Shale;
- natural field decline in the deepwater Gulf of Mexico, Gulf Coast and Mid-Continent areas of our US operations, in the North Sea and the Mari-B field in Israel, where we reduced production to manage the reservoir (See Israel Delivery Commitments, above);
- variations in sales volumes of natural gas from the Alba field in Equatorial Guinea related to scheduled field maintenance and potential downtime at the methanol, LPG and/or LNG plants;

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- 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 and commencement of production from the Noa field and Pinnacles project, offshore Israel;
- variations in West Africa and North Sea sales volumes due to potential FPSO downtime and timing of liftings;
- potential hurricane-related volume curtailments in the deepwater Gulf of Mexico and Gulf Coast areas;
- potential winter storm-related volume curtailments in the Rocky Mountain and/or Marcellus Shale areas of our US operations;
- potential pipeline and processing facility capacity constraints in the Rocky Mountain and/or Marcellus Shale areas of our US operations (see Northern Region Transportation Curtailments above);
- potential drilling and/or hydraulic fracturing permit delays due to future regulatory changes;
- potential purchases of producing properties and/or divestments of non-core operating assets; and
- potential shut-in of US producing properties if storage capacity becomes unavailable.

2012 Capital Investment Program

Our total capital investment program for 2012 is estimated at $3.5 billion. The capital investment program allocates approximately 50% to onshore US and the remainder to offshore deepwater Gulf of Mexico, Eastern Mediterranean, and West Africa. Exploration and appraisal activity within these geographic areas is expected to receive approximately 20% of total capital.

We expect that the 2012 capital investment program will be funded from cash flows from operations, cash on hand, and borrowings under our revolving credit facility and/or other financing such as an issuance of long-term debt. Funding may also be provided by proceeds from divestment of non-core assets. See Liquidity and Capital Resources – Financing Activities below.

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

- commodity prices, including price realizations on specific crude oil and natural gas production including the impact of NGLs;
- cash flows from operations;
- operating and development costs and possible inflationary pressures;
- permitting activity in the deepwater Gulf of Mexico;
- drilling results;
- CONSOL Carried Cost Obligation (See Contractual Obligations below);
- property acquisitions and divestitures;
- availability of financing;
- potential legislative or regulatory changes regarding the use of hydraulic fracturing;
- potential changes in the fiscal regimes of the US and other countries in which we operate; and
- impact of new laws and regulations, including implementation of the Dodd-Frank Wall Street Reform and Consumer Protection Act, on our business practices.

Marketing of North Sea and Onshore US Assets

We occasionally divest non-core, non-strategic properties from our portfolio to generate organizational and operational efficiencies as well as cash for use in our capital investment program. We are in the process of marketing our North Sea properties along with certain non-core onshore US properties and are currently soliciting bids. However, at this time, the Board of Directors and management have not committed to any specific plans to sell the assets, individually or as packaged groups. See Potential for Future Asset Impairments below.

Potential for Future Asset Impairments

The US natural gas market remains weak. A decrease from the March 31, 2012 forward natural gas prices could result in impairment charges. Certain of our onshore US properties have significant natural gas reserves and therefore are sensitive to declines in natural gas prices. These properties are at risk of impairment if future NYMEX Henry Hub natural gas prices experience further decline. The cash flow model that we use to assess proved properties for impairment includes numerous assumptions, such as management's estimates of future oil and gas production, market outlook on forward commodity prices, operating and development costs, and discount rates. All inputs to the cash flow model must be evaluated at each date of estimate. However, a decrease in forward natural gas prices alone could result in an impairment of properties that are sensitive to declines in natural gas prices.

Additionally, we are currently marketing certain non-core onshore US properties. If the properties are reclassified as assets held for sale, they will be valued at the lower of net book value or anticipated sales proceeds less costs to sell. Impairment expense would be recorded for any excess of net book value over anticipated sales proceeds less costs to sell.

The onshore US properties discussed above have a combined net book value of approximately $1 billion at March 31, 2012.

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Israeli Interministerial Committee

In 2011, the Interministerial Committee to Examine Government Policy Regarding the Natural Gas Industry in Israel (the Committee) was charged with the task of proposing a government policy for developing the natural gas economy. Objectives include the following:

- ensuring energy security in the economy;
- providing a framework for substantial resource exports;
- designating a certain percentage of production from each field for the domestic natural gas market;
- maintaining competition in the different sectors of the local economy;
- maximizing economic and political benefits; and
- leveraging environmental advantages with respect to the use of natural gas.

The Committee was also asked to examine, among other items, the desired policy to maintain reserves to supply local demand and export of natural gas. The Committee issued Interim Recommendations on April 5, 2012, which included, among others:

- requiring a minimum 25-year supply of gas to the domestic market;
- allowing for a redetermination of market needs after the year 2018;
- requiring regulatory approval for export;
- determining that an Israeli natural gas export facility be under Israeli control and within the jurisdiction of Israel's economic waters;
- taking steps to increase competition in the natural gas market; and
- requiring infrastructure redundancy, physical connection of all reservoirs to the domestic market, third party access to infrastructure, and the development of statutory procedures to define infrastructures.

The Committee's timeline includes a public hearing on May 20, 2012 and submission of a final report on June 7, 2012. We are participating in the process and monitoring the activities of the Committee and the impact of its Interim Recommendations. However, at this time, we cannot predict the ultimate outcome of the Committee's Interim Recommendations or the possible impact any resulting laws or regulations could have on our business. Certain changes in Israel's market, fiscal, and/or regulatory regimes occurring as a result of the Committee's recommendations could delay or reduce the profitability of our Tamar and/or Leviathan development projects and render future exploration and development projects uneconomic.

EPA Final Emissions Standards

On April 18, 2012, the U.S. Environmental Protection Agency (EPA) announced that it has finalized standards related to emissions associated with crude oil and natural gas production, including natural gas wells that are hydraulically fractured. The required technologies and processes, while reducing emissions, will also enable companies to collect additional natural gas that can be sold. The EPA's final standards also address emissions from storage tanks and other equipment.

The final rules establish a phase-in period that will ensure that manufacturers have time to make and broadly distribute the required emissions reduction technology. During the first phase, until January 2015, owners and operators must either flare their emissions or use emissions reduction technology called "green completions," technologies that are already widely deployed at wells. In 2015, all newly fractured wells will be required to use green completions.

We are currently evaluating the EPA's final rules and assessing the impact on our business. The reduction of greenhouse gas emissions (GHG) is already one of our Company's priorities and we have been working to improve our methods to reduce GHGs through operational and business practices. We use green completions or flaring on a number of our wells to comply with COGCC rules. Additionally we've undertaken emission reduction projects such as our US Vapor Recovery Unit (VRU) program, where we have installed VRUs to capture gas that would otherwise be flared on a substantial number of our tank batteries.

Risk and Insurance Program

Our business is subject to all of the operating risks normally associated with the exploration, production, gathering, processing and transportation of crude oil and natural gas, including hurricanes, blowouts, well cratering, fire, loss of well control, mishandling of fluids and chemicals and possible underground migration of hydrocarbons and chemicals, any of which could result in damage to, or destruction of, crude oil and natural gas wells or formations or production facilities and other property, environmental pollution, injury to persons, or loss of life. As protection against financial loss resulting from many, but not all of these operating hazards, we maintain insurance coverage, including certain physical damage, business interruption (loss of production), employer's liability, comprehensive general liability and worker's compensation insurance. We maintain insurance at levels that we believe are appropriate and consistent with industry practice and we regularly review our potential risks of loss and the cost and availability of insurance and revise our insurance program accordingly. We have limited or no insurance coverage for certain risks such as war or political risk. In addition, coverage is generally limited or not available to us for pollution events that are considered gradual.

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

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In the Gulf of Mexico, we self-insure for windstorm related exposures. Our Gulf of Mexico assets are primarily subsea operations; therefore, our windstorm exposure is limited. In addition, the cost of windstorm insurance continues to be very expensive and coverage amounts are limited. We believe it is more cost-effective for us to self-insure these assets.

As is customary with industry practice, crude oil and natural gas well owners generally indemnify drilling rig contractors against certain risks, such as those arising from property and environmental losses, pollution from sources such as oil spills, or contamination resulting from well blowout or fire or other uncontrolled flow of hydrocarbons. Most of our US and international drilling contracts contain such indemnification clauses. In addition, crude oil and natural gas well owners typically assume all costs of well control in the event of an uncontrolled well. We currently carry insurance protection for our net share of any potential financial losses occurring as a result of events such as the Deepwater Horizon Incident. This protection consists of $550 million of well control, pollution cleanup and consequential damages coverage and $326 million of additional pollution cleanup and consequential damages coverage, which also covers third-party personal injury and death. Consequently if we were to experience an accident similar to the Deepwater Horizon Incident, our total coverage for cleanup and consequential damages would cover a gross loss of at least $876 million depending on our ownership interest and subject to reduction for claims related to well control and third-party damages.

We have contracts with third-party service providers to perform hydraulic fracturing operations for us. The master service agreements signed by hydraulic fracturing providers contain indemnification provisions similar to those noted above. Our liability insurance policies do not contain any specific exclusions for liabilities from hydraulic fracturing operations and we believe our policies would cover third party claims related to hydraulic fracturing operations and associated legal expenses, in accordance with, and subject to, the terms of such policies. We do not have insurance for gradual pollution nor do we have coverage for penalties or fines that may be assessed by a governmental authority.

We expect the future availability and cost of insurance to be impacted by the various catastrophic events which occurred in 2011. 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. We anticipate that ongoing changes in the types of coverage available in the insurance market may result in lower effective coverages and/or the incurrence of higher premiums to achieve past levels of coverage.

We continue to monitor the legislative and regulatory response to the Deepwater Horizon Incident and other recent international incidents in Brazil and the North Sea, and their impact on the insurance market and our overall risk profile. We anticipate that, at a minimum, less effective liability coverage will be available at a higher cost. Accordingly, we may adjust our risk and insurance program to provide protection at insured levels that reflect our perception of the cost of risk relative to frequency and severity of the exposure.

Insurance Recoveries In May 2011, we ended drilling operations at the Leviathan-2 appraisal well offshore Israel when we identified water flowing to the sea floor from the wellbore. We are continuing to monitor the wellbore and there are no indications of any hydrocarbons in the produced water. Drilling did not reach the depth of the targeted gas intervals discovered in the Leviathan-1 well. We are working with the Israeli government to determine appropriate abandonment activities.

The incident was a covered event under our well control insurance. At this time, we expect to recover most of the costs from insurance, subject to a deductible. Our partners have insurance coverage, but may not have sufficient coverage to cover all possible outcomes and may have to rely on other financial resources. We do not expect any delays in our insurance claim recovery process to have a significant impact on our cash flows or liquidity. See Item 1. Financial Statements – Note 2. Basis of Presentation.

Our business entails inherent risks. We have a risk assessment program that analyzes safety and environmental hazards and establishes procedures, work practices, training programs and equipment requirements, including monitoring and maintenance rules, for continuous improvement. We have a robust prevention program and continue to manage our risks and operations such that we believe the likelihood of a significant event is remote. However, if an event occurs that is not covered by insurance, not fully protected by insured limits or our non-operating partners are not fully insured, it could have a material adverse impact on our financial condition, results of operations and cash flows.

Recently Issued Accounting Standards Update

See Item 1. Financial Statements – Note 2. Basis of Presentation.

RESULTS OF OPERATIONS

Revenues

Revenues were as follows:

		2012		2011	Increase (Decrease) from Prior Year	
(millions)						
Three Months Ended March 31,						
Oil, Gas and NGL Sales	$	1,112	$	830	34	%
Income from Equity Method Investees		53		48	10	%
Other Revenues		-		21	(100	%)
Total	$	1,165	$	899	30	%

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Changes in revenues are discussed below.

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 (MBbl/d)	Natural Gas (MMcf/d)	NGLs (MBbl/d)	Total (MBoe/d) (1)	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)	NGLs (Per Bbl)
Three Months Ended March 31, 2012							
United States	42	433	17	131	$101.21	$2.62	$41.62
Equatorial Guinea (2)	35	230	-	73	118.04	0.27	-
Israel	-	108	-	18	-	4.51	-
North Sea	6	5	-	7	122.44	7.88	-
China	5	-	-	5	126.10	-	-
Total Consolidated Operations	88	776	17	234	110.80	2.22	41.62
Equity Investees (3)	2	-	7	9	110.09	-	68.02
Total Operations	90	776	24	243	$110.78	$2.22	$49.34
Three Months Ended March 31, 2011							
United States	37	382	14	114	$92.25	$4.07	$47.80
Equatorial Guinea (2)	13	248	-	55	103.49	0.27	-
Israel	-	140	-	23	-	4.19	-
North Sea	11	8	-	12	106.26	7.30	-
China	4	-	-	4	95.28	-	-
Total Consolidated Operations	65	778	14	208	97.15	2.91	47.80
Equity Investees (3)	2	-	5	7	103.93	-	75.71
Total Operations	67	778	19	215	$97.32	$2.91	$55.43

(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 commodity price differentials, the price for a barrel of oil equivalent for natural gas is significantly less than the price for a barrel of oil.

(2) 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.

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

If the realized gains and losses on commodity derivative instruments, which are included in 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)			
	2012		2011	
	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)
Three Months Ended March 31,				
United States	$ (2.40)	$ 0.28	$ (2.75)	$ 0.76
Equatorial Guinea	(7.84)	-	-	-
Total Consolidated Operations	(4.26)	0.16	(1.56)	0.37
Total Operations	(4.17)	0.16	(1.52)	0.37

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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 March 31, 2011	$ 569	$ 203	$ 58	$ 830
Changes due to				
Increase in Sales Volumes	211	2	16	229
Increase (Decrease) in Sales Prices	110	(48)	(9)	53
Three Months Ended March 31, 2012	$ 890	$ 157	$ 65	$ 1,112

Crude oil and condensate sales – Revenues from crude oil and condensate sales increased during the first three months of 2012 as compared with 2011 due to the following:

- increases in average realized prices;
- higher sales volumes in the DJ Basin attributable to the acceleration of our horizontal drilling programs in the Wattenberg area; and
- higher sales volumes in Equatorial Guinea due to the commencement of oil production at Aseng during fourth quarter 2011, which impacted our sales volumes by approximately 18 MBbl/d in the first three months of 2012 as compared with 2011;

partially offset by:

- lower sales volumes in non-core onshore US and deepwater Gulf of Mexico areas due to natural field decline; and
- lower North Sea sales volumes due to maintenance downtime at the Dumbarton field.

Natural gas sales – Revenues from natural gas sales decreased during the first three months of 2012 as compared with 2011 due to the following:

- a 24% decrease in total consolidated average realized prices (36% decrease in US average realized prices) primarily due to oversupply and above average levels of natural gas in storage;
- lower sales volumes in non-core onshore US and deepwater Gulf of Mexico areas due to natural field decline;
- decrease in sales volumes in Israel due to a reduction in the rate of production from the Mari-B field in order to manage the reservoir ; and
- lower sales volumes in the North Sea due to maintenance downtime at the Dumbarton field;

partially offset by:

- higher sales volumes in the DJ Basin attributable to the acceleration of our horizontal drilling programs in the Wattenberg area; and
- sales volumes from Marcellus Shale producing properties which we acquired September 30, 2011 and which added 68 MMcf/d to our first quarter 2012 sales volumes.

NGL sales – Most of our US NGL production is from the Wattenberg area. NGL sales revenues increased during the first three months of 2012 as compared with 2011 primarily due to the continued acceleration of our horizontal drilling programs. US NGL average realized sales prices declined by 13%, due primarily to higher supplies of NGLs resulting from increased wet gas drilling activities.

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 on Bioko Island in Equatorial Guinea. We also have a 50% interest in CONE Gathering LLC (CONE) which owns and operates the infrastructure associated with our Marcellus Shale joint venture. During first quarter 2012, we contributed $14 million to CONE.

Equity method investments are included in other noncurrent assets in our consolidated balance sheets, and our share of earnings is reported as income from equity method investees in our consolidated statements of operations. Within our consolidated statements of cash flows, our share of dividends is reported within cash flows from operating activities and our share of investments is reported within cash flows from investing activities.

The increase in income from equity method investees for the first three months of 2012 as compared with 2011 was due to increases in condensate, LPG and methanol sales volumes, offset by a 10% decrease in average realized liquids prices.

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Methanol sales volumes and prices were as follows:

	Three Months Ended March 31,	
	2012	2011
Methanol Sales Volumes (Mmgal)	41	40
Methanol Sales Prices (per gallon)	$ 1.04	$ 1.03

Operating Costs and Expenses

Operating costs and expenses were as follows:

	Three Months Ended March 31,		Increase (Decrease) from Prior Year
(millions)	2012	2011	
Production Expense	$179	$142	26 %
Exploration Expense	63	70	(10 %)
Depreciation, Depletion and Amortization	312	221	41 %
General and Administrative	98	83	18 %
Other Operating (Income) Expense, Net	12	36	(67 %)
Total	$664	$552	20 %

Changes in operating costs and expenses are discussed below.

Production Expense   Components of production expense were as follows:

(millions, except unit rate)	Total per BOE (1)	Total	United States	Equatorial Guinea	Israel	North Sea	Other Int'l, Corporate
Three Months Ended March 31, 2012							
Lease Operating Expense (2)	$ 5.53	$ 118	$ 71	$ 23	$ 4	$ 13	$ 7
Production and Ad Valorem Taxes	1.76	38	26	-	-	-	12
Transportation and Gathering Expense	1.10	23	21	-	-	1	1
Total Production Expense	$ 8.39	$ 179	$ 118	$ 23	$ 4	$ 14	$ 20
Three Months Ended March 31, 2011							
Lease Operating Expense (2)	$ 4.89	$ 92	$ 62	$ 9	$ 3	$ 12	$ 6
Production and Ad Valorem Taxes	1.71	32	25	-	-	-	7
Transportation and Gathering Expense	0.94	18	16	-	-	2	-
Total Production Expense	$ 7.54	$ 142	$ 103	$ 9	$ 3	$ 14	$ 13

(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 first three months of 2012, total production expense increased as compared with 2011 due to the following:

- an increase in US lease operating, transportation and gathering expenses due to higher sales volumes from the Wattenberg area due to ongoing development activities and new production from the Marcellus Shale joint venture;
- an increase in Equatorial Guinea lease operating expense associated with the Aseng field which began producing in November 2011; and
- an increase in China production and ad valorem taxes due to increases in sales volumes and prices.

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Exploration Expense   Components of 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 March 31, 2012						
Dry Hole Cost	$ 1	$ -	$ 1	$ -	$ -	$ -
Seismic	28	26	-	-	-	2
Exploration Expense	27	4	2	1	3	17
Other	7	6	1	-	-	-
Total Exploration Expense	$ 63	$ 36	$ 4	$ 1	$ 3	$ 19
Three Months Ended March 31, 2011						
Dry Hole Cost	$ 22	$ 22	$ -	$ -	$ -	$ -
Seismic	26	16	-	-	-	10
Exploration Expense	18	5	1	-	-	12
Other	4	4	-	-	-	-
Total Exploration Expense	$ 70	$ 47	$ 1	$ -	$ -	$ 22

(1) West Africa includes Equatorial Guinea, Cameroon, and Senegal/Guinea-Bissau.

(2) Eastern Mediterranean includes Israel and Cyprus.

(3) Other International includes various international new ventures such as offshore Nicaragua.

Exploration expense for the first three months of 2012 included the following:

- acquisition of seismic information for the deepwater Gulf of Mexico; and
- staff expense associated with new ventures and corporate expenditures.

Exploration expense for the first three months of 2011 included the following:

- dry hole cost associated with exploratory drilling in the US Rocky Mountain area;
- acquisition of seismic information for Wattenberg, Rocky Mountain and deepwater Gulf of Mexico areas in the US, and international new ventures; and
- staff expense associated with new ventures and corporate expenditures.

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

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
DD&A Expense (millions) (1)	$ 312	$ 221
Unit Rate per BOE (2)	$ 14.60	$ 11.81

(1) For DD&A expense by geographical area, see Item 1. Financial Statements – Note 11. Segment Information.

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

Total DD&A expense for the first three months of 2012 increased as compared with 2011 due to the following:

- an increase of approximately $33 million due primarily to higher sales volumes in the DJ Basin onshore US and the addition of DD&A expense related to the Marcellus Shale joint venture;
- an increase of approximately $61 million due to the startup of the Aseng field which includes the Aseng FPSO in its depreciation base; and
- the impact of negative reserves revisions at December 31, 2011, due to revised performance expectations in the North Sea and China;

partially offset by:

- lower sales volumes in non-core onshore US and deepwater Gulf of Mexico areas resulting from natural field decline; and
- lower North Sea sales volumes.

Changes in the unit rate per BOE for the first three months of 2012 as compared with 2011 were due to changes in the mix of production, primarily due to volumes from the start-up of the Aseng field, which has a higher DD&A rate.

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

	Three Months Ended March 31,	
	2012	2011
G&A Expense (millions)	$ 98	$ 83
Unit Rate per BOE (1)	$ 4.60	$ 4.43

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

G&A expense for the first three months of 2012 increased as compared with 2011 primarily due to additional expenses relating to personnel, office, and information technology costs in support of our major development projects and increased exploration activities.

Other Operating (Income) Expense, Net Other operating (income) expense, net was as follows:

	Three Months Ended March 31,	
	2012	2011
(millions)		
Deepwater Gulf of Mexico Moratorium Expense	$ -	$ 18
Electricity Generation Expense	-	17
Other, Net	12	1
Total	$ 12	$ 36

See Item 1. Financial Statements – Note 2. Basis of Presentation.

Other (Income) Expense

Other (income) expense was as follows:

	Three Months Ended March 31,	
	2012	2011
(millions)		
Loss on Commodity Derivative Instruments	$ 96	$ 286
Interest, Net of Amount Capitalized	32	16
Other Non-Operating (Income) Expense, Net	(1)	8
Total	$ 127	$ 310

Loss on Commodity Derivative Instruments   Loss on commodity derivative instruments is a result of mark-to-market accounting.   See Item 1. Financial Statements – Note 5. Derivative Instruments and Hedging Activities and Note 6. Fair Value Measurements and Disclosures.

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

	Three Months Ended March 31,	
	2012	2011

(millions, except unit rate)		
Interest Expense	$ 69	$ 41
Capitalized Interest	(37)	(25)
Interest Expense, Net	$ 32	$ 16
Unit Rate per BOE (1)	$ 1.49	$ 0.86

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

Interest expense prior to the reduction for capitalized interest increased for the first three months of 2012 as compared with 2011. The increase mainly resulted from our November 2011 debt issuance, an additional month of interest for our February 2011 debt issuance and interest related to our Aseng FPSO lease obligation.

The increase in capitalized interest is mainly due to higher work in progress amounts related to major long-term projects in the deepwater Gulf of Mexico, West Africa, and Israel.

Other Non-Operating (Income) Expense, Net Other non-operating (income) expense, net includes deferred compensation expense, interest income and other (income) expense. See Item 1. Financial Statements – Note 2. Basis of Presentation.

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Income Tax Provision

See Item 1. Financial Statements – Note 10. Income Taxes for a discussion of the change in our effective tax rate for the first three months of 2012 as compared with 2011.

LIQUIDITY AND CAPITAL RESOURCES

Capital Structure/Financing Strategy

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

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

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

Available Liquidity Information regarding cash and debt balances was as follows:

(millions, except percentages)	March 31, 2012	December 31, 2011
Cash and Cash Equivalents	$1,143	$1,455
Amount Available to be Borrowed Under Credit Facility (1)	3,000	3,000
Total Liquidity	$4,143	$4,455
Total Debt (2)	$4,484	$4,495
Total Shareholders' Equity	7,533	7,265
Ratio of Debt-to-Book Capital (3)	37 %	38 %

(1) See Credit Facility below.

(2) Total debt includes Aseng FPSO lease obligation and remaining CONSOL installment payments and excludes unamortized debt discount.

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

Cash and Cash Equivalents We had approximately $1.1 billion in cash and cash equivalents at March 31, 2012, primarily denominated in US dollars and invested in money market funds and short-term deposits with major financial institutions. Approximately $760 million of this cash is attributable to our foreign subsidiaries and most would be subject to US income taxes if repatriated. We currently expect to use a significant amount of cash during 2012 to fund international projects, including the planned developments in West Africa and the Eastern Mediterranean.

Credit Facility   We have an unsecured revolving credit facility that matures on October 14, 2016. The commitment is $3.0 billion through the maturity date of the credit facility. See Financing Activities – Long-Term Debt below.

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 price commodity swaps, two and three-way 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. None of our counterparty agreements contain margin requirements. We have also used 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. However, we currently have no such instruments.

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 March 31, 2012, the fair value of our commodity derivative assets was $39 million and the fair value of our commodity derivative liabilities was $148 million (after consideration of netting agreements). See Item 1. Financial Statements – Note 5. Derivative Instruments and Hedging Activities for a discussion of derivative counterparty credit risk and Note 6. Fair Value Measurements and Disclosures for a description of the methods we use to estimate the fair values of derivative instruments.

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European Debt Crisis The debt crisis is ongoing and continues to have a negative impact on the European economy, with risks to the global banking system and overall global economy and financial system. During the first quarter of 2012, Moody's Investors Service announced rating actions affecting numerous financial institutions, and the ratings of a number of European banks were placed on review for downgrade.

Some of our commodity derivatives counterparties, as well as some of our lenders in our $3.0 billion Credit Facility, are international banks. These institutions could potentially be affected by the European debt crisis and be unable to participate in our drawdowns. In addition, credit downgrades of these institutions could result in a change in our counterparties with whom we execute hedging transactions according to our internal risk guidelines.

We believe our current balance sheet and financial flexibility enhance our ability to react to Eurozone events as they unfold.

Accounts Receivable Some of our purchasers and joint venture partners are not as creditworthy as we are and may experience credit downgrades or liquidity problems. For example, Standard & Poor’s Ratings Services recently placed IEC’s credit rating on CreditWatch negative.

Counterparty liquidity problems could result in a delay in our receiving proceeds from commodity sales or reimbursement of joint venture costs. A partner’s inability to obtain financing could result in a delay of one of our joint development projects. Credit enhancements have been obtained from some parties in the way of parental guarantees or letters of credit, including our largest crude oil purchaser; however, not all of our trade credit is protected through guarantees or credit support. Nonperformance by a trade creditor or joint venture partner could result in significant financial losses.

Contractual Obligations

CONSOL Carried Cost Obligation The CONSOL Carried Cost Obligation represents our agreement to fund up to approximately $2.1 billion of CONSOL’s future drilling and completion costs. The CONSOL Carried Cost Obligation is expected to extend over eight years or more. It is capped at $400 million in each calendar year and is suspended if average Henry Hub natural gas prices fall and remain below $4.00 per MMBtu in any three consecutive month period and will remain suspended until average Henry Hub natural gas prices are above $4.00 per MMBtu for three consecutive months. Therefore, specific payment dates for the funding of the CONSOL Carried Cost Obligation cannot be determined at this time. The CONSOL Carried Cost Obligation is currently suspended due to low natural gas prices. Based on the March 31, 2012 Henry Hub natural gas price curve, we forecast our CONSOL Carried Cost Obligation will be suspended throughout the remainder of the 2012 fiscal year.

Cash Flows

Cash flow information is as follows:

	Three Months Ended March 31	
	2012	2011
(millions)		
Total Cash Provided By (Used in)		
Operating Activities	$ 741	$ 484
Investing Activities	(1,032)	(575)
Financing Activities	(21)	429
Increase (Decrease) in Cash and Cash Equivalents	$ (312)	$ 338

Operating Activities   Net cash provided by operating activities for the first three months of 2012 increased as compared with 2011 primarily due to higher revenues, which benefitted from increases in crude oil prices and production. The increase in cash flow was partially offset by lower natural gas prices, increases in production expenses, general and administrative expense and interest expense. See Item 1. Financial Statements – Consolidated Statements of Cash Flows.

Investing Activities   Our investing activities include capital spending on a cash basis for oil and gas properties and investments in unconsolidated subsidiaries accounted for by the equity method. These investing activities may be offset by proceeds from property sales or dispositions. Capital spending for property, plant and equipment increased by $440 million during the first three months of 2012 as compared with 2011, primarily due to increased major project development activity in the Wattenberg area, the Marcellus Shale, offshore West Africa, and offshore Israel. We also invested $14 million in CONE during first quarter 2012.

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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 three months of 2012, funds were provided by cash proceeds from, and tax benefits related to, the exercise of stock options ($39 million). We used cash to pay dividends on our common stock ($39 million), make principal payments related to the Aseng FPSO capital lease obligation ($8 million) and repurchase shares of our common stock ($13 million).

In comparison, during the first three months of 2011, funds were provided by net cash proceeds from borrowings under our revolving credit facility ($120 million) and the issuance of 6% senior notes due 2041 ($836 million). Funds were also provided by cash proceeds from, and tax benefits related to, the exercise of stock options ($31 million). We used a portion of the proceeds from the issuance of senior notes to repay amounts outstanding under our credit facility ($470 million). We also used cash to settle an interest rate lock ($40 million), pay dividends on our common stock ($32 million) and repurchase shares of our common stock ($16 million)

See Item 1. Financial Statements – Consolidated Statements of Cash Flows.

Investing Activities

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

	Three Months Ended March 31,	
	2012	2011
(millions)		
Acquisition, Capital and Exploration Expenditures		
Unproved Property Acquisition	$ 73	$ 15
Exploration	129	122
Development	735	374
Corporate and Other	12	34
Total	$ 949	$ 545
Other		
Investment in Equity Method Investee	$ 14	$ -
Increase in FPSO Lease Obligation	-	34

2012 Unproved property acquisition costs were mainly related to an acquisition that strengthened our position in the DJ Basin along with other miscellaneous onshore US lease acquisitions. The increase in development costs is due to increased capital spending on major development projects located in the DJ Basin, Marcellus Shale, offshore Equatorial Guinea and offshore Israel.

2011 Unproved property acquisition costs for the first three months of 2011 related to onshore US lease acquisitions.

See Item 1. Financial Statements – Note 3. Acquisitions.

Financing Activities

Long-Term Debt Our principal source of liquidity is an unsecured revolving credit facility that matures October 14, 2016. We did not engage in any activities under the Credit Facility, or other short-term borrowing arrangements during the first quarter of 2012.

The Credit Facility (i) provides for an initial commitment of $3.0 billion with an option to increase the overall commitment amount by up to an additional $1.0 billion, subject to the consent of any increasing lenders, (ii) will mature on October 14, 2016, (iii) provides for facility fee rates that range from 12.5 basis points to 30 basis points per year depending upon our credit rating, (iv) includes sub-facilities for short-term loans and letters of credit up to an aggregate amount of $500 million under each sub-facility and (v) provides for interest rates that are based upon the Eurodollar rate plus a margin that ranges from 100 basis points to 145 basis points depending upon our credit rating.

At March 31, 2012, there were no borrowings outstanding under the Credit Facility, leaving $3.0 billion available for use. We expect to use the Credit Facility to fund our capital investment program, and we periodically borrow amounts under provision (iv) above for working capital purposes. See Item 1. Financial Statements – Note 4. Debt.

Our outstanding fixed-rate debt, including the remaining CONSOL installment payments, totaled almost $4.1 billion at March 31, 2012. The weighted average interest rate on fixed-rate debt was 5.56%, with maturities ranging from 2012 to 2097. Approximately 21% of our fixed rate debt will mature within the next five years.

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Our ratio of debt-to-book capital was 37% at March 31, 2012 as compared with 38% at December 31, 2011. 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.

Dividends   We paid total cash dividends of 22 cents per share of our common stock during the first three months of 2012 and 18 cents per share during the first three months of 2011. The amount of future dividends will be determined on a quarterly basis at the discretion of our Board of Directors and will depend on earnings, financial condition, capital requirements and other factors.

Exercise of Stock Options   We received cash proceeds from the exercise of stock options of $27 million during the first three months of 2012 and $23 million during the first three months of 2011.

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 131,868 shares with a value of $13 million during the first three months of 2012 and 178,499 shares with a value of $16 million during the first three months of 2011.

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 March 31, 2012, we had entered into variable to fixed price commodity swaps, collars and basis swaps related to crude oil and natural gas sales. Changes in fair value of commodity derivative instruments are reported in earnings in the period in which they occur. Our open commodity derivative instruments were in a net payable position with a fair value of $109 million. Based on the March 31, 2012 published commodity futures price curves for the underlying commodities, a hypothetical price increase of $1.00 per Bbl for crude oil would increase the fair value of our net commodity derivative payable by approximately $20 million. A hypothetical price increase of $0.10 per MMBtu for natural gas would increase the fair value of our net commodity derivative payable by approximately $5 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 5. 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 March 31, 2012, we had approximately $4.1 billion (excluding the Aseng FPSO lease obligation and unamortized debt discount) of long-term debt outstanding. All debt outstanding was fixed-rate debt with a weighted average interest rate of 5.56%. 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. See Item 1. Financial Statements – Note 4. Debt.

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 March 31, 2012, AOCL included $26 million, net of tax, related to interest rate derivative instruments. This amount is currently being reclassified to earnings as adjustments to interest expense over the terms of our 5¼% senior notes due April 2014 and 6% senior notes due March 1, 2041. See Item 1. Financial Statements – Note 5. 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 March 31, 2012, our cash and cash equivalents totaled approximately $1.1 billion, approximately 83% 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 March 31, 2012 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. A reduction in the value of the US dollar against currencies of other countries in which we have material operations could result in the use of additional cash to settle operating, administrative, and tax liabilities. This risk may be mitigated to the extent commodity prices increase in response to a devaluation of the US dollar.

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.

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 determine that it is necessary to invest in such instruments in order to mitigate our foreign currency exchange risk.

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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;
- the impact of governmental fiscal terms and/or regulation, such as that involving the protection of the environment or marketing of production, as well as other regulations; and
- access to resources.

Forward-looking statements are typically identified by use of terms such as “may,” “will,” “expect,” “believe,” “anticipate,” “estimate,” “intend,” and 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 Annual Report on Form 10-K for the year ended December 31, 2011, which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements. Our Annual Report on Form 10-K for the year ended December 31, 2011 is 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

During 2011, we received two Notices of Alleged Violation (NOAV) from the Colorado Oil and Gas Conservation Commission (COGCC) regarding the reporting of the presence of hydrogen sulfide to the COGCC and local government designee within certain areas of our Piceance Basin and Grover field operations. At this time, the COGCC has not established a proposed penalty for either NOAV. Given the inherent uncertainty in administrative actions of this nature, we are unable to predict the ultimate outcome of this action at this time. However, we believe that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on our financial position, results of operations or cash flows.

See Item 1. Financial Statements – Note 12. 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 Annual Report on Form 10-K for the year ended December 31, 2011.

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

The following table sets forth, for the periods indicated, the Company's share repurchase activity:

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)
01/01/12 - 01/31/12	68,223	$ 100.13	-	-
02/01/12 - 02/29/12	57,994	101.25	-	-
03/01/12 - 03/31/12	5,651	99.74	-	-
Total	131,868	$ 100.61	-	-

(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. Mine Safety Disclosures

Not applicable.

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.

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 April 26, 2012

/s/ Kenneth M. Fisher
Kenneth M. Fisher
Senior Vice President, Chief Financial Officer

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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 20, 2009 and incorporated herein by reference).
10.1	Gas Sale and Purchase Agreement dated March 14, 2012, by and between Noble Energy Mediterranean Ltd. and Isramco Negev 2 Limited Partnership, Delek Drilling Limited Partnership, Avner Oil Exploration Limited Partnership, and Dor Gas Exploration Limited Partnership (Sellers) and The Israel Electric Corporation Limited (Purchaser), filed herewith. (1)
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

(1) Pursuant to a request for confidential treatment, portions of this exhibit have been redacted and have been provided separately to the Securities and Exchange Commission.