NOBLE ENERGY INC
Form 10-Q
April 25, 2013
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended March 31, 2013

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 ý 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 ý 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 (Do not check if a smaller reporting company)	Smaller reporting company o

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

As of April 8, 2013, there were 179,314,474 shares of the registrant’s common stock, par value $0.01 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,	
	2013	2012
Revenues		
Oil, Gas and NGL Sales	$1,083	$1,037
Income from Equity Method Investees	60	51
Total	1,143	1,088
Costs and Expenses		
Production Expense	187	163
Exploration Expense	61	60
Depreciation, Depletion and Amortization	366	294
General and Administrative	112	97
Other Operating (Income) Expense, Net	(8)	12
Total	718	626
Operating Income	425	462
Other (Income) Expense		
Loss on Commodity Derivative Instruments	72	96
Interest, Net of Amount Capitalized	25	32
Other Non-Operating (Income) Expense, Net	10	(1)
Total	107	127
Income from Continuing Operations Before Income Taxes	318	335
Income Tax Provision	86	86
Income from Continuing Operations	232	249
Discontinued Operations, Net of Tax	29	14
Net Income	$261	$263
Earnings Per Share, Basic		
Income from Continuing Operations	$1.29	$1.40
Discontinued Operations, Net of Tax	0.17	0.08
Net Income	$1.46	$1.48
Earnings Per Share, Diluted		
Income from Continuing Operations	$1.28	$1.39
Discontinued Operations, Net of Tax	0.17	0.08
Net Income	$1.45	$1.47
Weighted Average Number of Shares Outstanding		
Basic	179	177
Diluted	181	180

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

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

	Three Months Ended March 31,	
	2013	2012
Net Income	$261	$263
Other Items of Comprehensive Income		
Net Change in Pension and Other	6	3
Less Tax Benefit	(2)	(1)
Other Comprehensive Income	4	2
Comprehensive Income	$265	$265

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, 2013	December 31, 2012
ASSETS		
Current Assets		
Cash and Cash Equivalents	$1,305	$1,387
Accounts Receivable, Net	776	964
Other Current Assets	370	420
Total Current Assets	2,451	2,771
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method of Accounting)	20,015	19,496
Property, Plant and Equipment, Other	346	344
Total Property, Plant and Equipment, Gross	20,361	19,840
Accumulated Depreciation, Depletion and Amortization	(6,366)	(6,289)
Total Property, Plant and Equipment, Net	13,995	13,551
Goodwill	632	635
Other Noncurrent Assets	632	597
Total Assets	$17,710	$17,554
LIABILITIES AND SHAREHOLDERS’ EQUITY		
Current Liabilities		
Accounts Payable - Trade	$1,388	$1,508
Other Current Liabilities	986	1,024
Total Current Liabilities	2,374	2,532
Long-Term Debt	3,723	3,736
Deferred Income Taxes, Noncurrent	2,249	2,218
Other Noncurrent Liabilities	850	810
Total Liabilities	9,196	9,296
Commitments and Contingencies		
Shareholders’ Equity		
Preferred Stock - Par Value $1.00 per share; 4 Million Shares Authorized, None Issued	—	—
Common Stock - Par Value $0.01 per share; 500 Million Shares Authorized; 199 Million and 198 Million Shares Issued, respectively	2	2
Additional Paid in Capital	3,353	3,304
Accumulated Other Comprehensive Loss	(109)	(113)
Treasury Stock, at Cost; 19 Million Shares	(662)	(648)
Retained Earnings	5,930	5,713
Total Shareholders’ Equity	8,514	8,258
Total Liabilities and Shareholders’ Equity	$17,710	$17,554

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, 2013	2012
Cash Flows From Operating Activities		
Net Income	$261	$263
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities		
Depreciation, Depletion and Amortization	367	312
Deferred Income Taxes	52	32
Dividends (Income) from Equity Method Investees, Net	(35)	(29)
Unrealized Loss on Commodity Derivative Instruments	79	73
Gain on Divestitures	(53)	—
Stock Based Compensation	18	16
Other Adjustments for Noncash Items Included in Income	25	15
Changes in Operating Assets and Liabilities		
Increase in Accounts Receivable	(56)	(135)
(Increase) Decrease in Other Current Assets	20	(5)
Increase in Accounts Payable	82	190
Decrease in Other Current Liabilities	(48)	(26)
Other Operating Assets and Liabilities, Net	(7)	35
Net Cash Provided by Operating Activities	705	741
Cash Flows From Investing Activities		
Additions to Property, Plant and Equipment	(806)	(1,018)
Additions to Equity Method Investments	(20)	(14)
Proceeds from Divestitures	76	—
Other	2	—
Net Cash Used in Investing Activities	(748)	(1,032)
Cash Flows From Financing Activities		
Exercise of Stock Options	22	27
Excess Tax Benefits from Stock-Based Awards	9	12
Dividends Paid, Common Stock	(44)	(39)
Purchase of Treasury Stock	(14)	(13)
Repayment of Capital Lease Obligation	(12)	(8)
Net Cash Used In Financing Activities	(39)	(21)
Decrease in Cash and Cash Equivalents	(82)	(312)
Cash and Cash Equivalents at Beginning of Period	1,387	1,455
Cash and Cash Equivalents at End of Period	$1,305	$1,143

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	Accumulated Other Comprehensive Loss	Treasury Stock at Cost	Retained Earnings	Total Shareholders' Equity
December 31, 2012	$2	$3,304	$(113)	$(648)	$5,713	$8,258
Net Income	—	—	—	—	261	261
Stock-based Compensation	—	18	—	—	—	18
Exercise of Stock Options	—	22	—	—	—	22
Tax Benefits Related to Exercise of Stock Options	—	9	—	—	—	9
Dividends (25 cents per share)	—	—	—	—	(44)	(44)
Changes in Treasury Stock, Net	—	—	—	(14)	—	(14)
Net Change in Pension and Other	—	—	4	—	—	4
March 31, 2013	$2	$3,353	$(109)	$(662)	$5,930	$8,514
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
Dividends (22 cents per share)	—	—	—	—	(39)	(39)
Changes in Treasury Stock, Net	—	—	—	(13)	—	(13)
Net Change in Pension and Other	1	(1)	2	—	—	2
March 31, 2012	$659	$2,549	$(98)	$(651)	$5,074	$7,533

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

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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 US, 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, 2013 and December 31, 2012 and for the three months ended March 31, 2013 and 2012 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, 2013 are not necessarily indicative of the results that may be expected for the year ending December 31, 2013. Certain reclassifications of amounts previously reported have been made to reflect the operations of our North Sea geographical segment as discontinued, as well as to conform to current year presentations. See Note 3. Divestitures.

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, 2012.

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. Management evaluates estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic and commodity price environment.

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

	Three Months Ended March 31,	
	2013	2012
(millions)		
Production Expense		
Lease Operating Expense	$117	$105
Production and Ad Valorem Taxes	43	38
Transportation and Gathering Expense	27	20
Total	$187	$163
Other Operating (Income) Expense, Net		
Gain on Divestitures [1]	(15)	—
Other, Net	7	12
Total	$(8)	$12
Other Non-Operating (Income) Expense, Net		
Deferred Compensation Expense [2]	$10	$3
Other (Income) Expense, Net	—	(4)
Total	$10	$(1)

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

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Notes to Consolidated Financial Statements

Balance Sheet Information   Other balance sheet information is as follows:

(millions)	March 31, 2013	December 31, 2012
Accounts Receivable, Net		
Commodity Sales	$266	$349
Joint Interest Billings	395	486
Other	125	139
Allowance for Doubtful Accounts	(10)	(10)
Total	$776	$964
Other Current Assets		
Inventories, Current	$97	$90
Commodity Derivative Assets	36	63
Deferred Income Taxes, Net	83	106
Probable Insurance Claims (1)	17	45
Assets Held for Sale (2)	63	45
Prepaid Expenses and Other Current Assets	74	71
Total	$370	$420
Other Noncurrent Assets		
Equity Method Investments	$423	$367
Mutual Fund Investments	109	103
Commodity Derivative Assets	13	21
Other Assets, Noncurrent	87	106
Total	$632	$597
Other Current Liabilities		
Production and Ad Valorem Taxes	$107	$113
Commodity Derivative Liabilities	44	7
Income Taxes Payable	202	203
Asset Retirement Obligations	69	69
Interest Payable	40	55
CONSOL Installment Payment (3)	325	324
Current Portion of FPSO Lease Obligation	49	48
Liabilities Associated with Assets Held for Sale (2)	14	12
Other	136	193
Total	$986	$1,024
Other Noncurrent Liabilities		
Deferred Compensation Liabilities	$247	$229
Asset Retirement Obligations	330	333
Accrued Benefit Costs	118	116
Commodity Derivative Liabilities	9	3
Other	146	129
Total	$850	$810

(1) Amounts represent the costs incurred to date of the Leviathan-2 appraisal well and expected well abandonment costs in excess of the insurance deductible less insurance proceeds received to date.

(2) Assets held for sale consist primarily of North Sea and onshore US oil and gas properties. Liabilities associated with assets held for sale consist primarily of asset retirement obligations related to these assets. See Note 3.

Divestitures.

(3) See Note 5. Debt.

Note 3. Divestitures

North Sea Properties During the first quarter of 2013, we closed the sale of our 13% non-operated working interest in the Cook field located in the UK sector of the North Sea. The sale resulted in a $37 million gain based on net sale proceeds of $38 million for the field.

We continue to market our remaining North Sea properties. As of March 31, 2013, all the properties remaining in our North Sea geographical segment are included in assets held for sale in our consolidated balance sheet. Our consolidated statements of operations have been reclassified for all periods presented to reflect the operations of our North Sea geographical segment as discontinued. Upon reclassification as held for sale, depreciation, depletion, and amortization (DD&A) ceased. Our long-term debt is recorded at the consolidated level; therefore no interest expense has been allocated to discontinued operations.

Summarized results of discontinued operations are as follows:

	Three Months Ended March 31,	
	2013	2012
(millions)		
Oil and Gas Sales	$10	$75
Income (Loss) Before Income Taxes	(1)	39
Income Tax Expense	7	25
Operating Income (Loss), Net of Tax	(8)	14
Gain on Sale, Net of Tax	37	—
Discontinued Operations, Net of Tax	$29	$14

Sale of Onshore US Properties During the first quarter of 2013, we closed the sales of certain crude oil and natural gas properties in the Gulf Coast area with an effective date of November 1, 2012. The information regarding the assets sold is as follows:

	Three Months Ended March 31, 2013
(millions)	
Sale Proceeds	$55
Less	
Net Book Value of Assets Sold	(28)
Goodwill Allocated to Assets Sold	(3)
Asset Retirement Obligations Associated with Assets Sold	5
Other Closing Adjustments [1]	(14)
Gain on Divestitures	$15

[1] Other closing adjustments also include adjustments related to onshore US property sales completed during 2012.

Note 4. Derivative Instruments and Hedging Activities

Objective and Strategies for Using Derivative Instruments We are exposed to fluctuations in crude oil and natural gas prices on the majority of our worldwide production. In order to mitigate the effect of commodity price volatility 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 put options.

During the first quarter of 2013, we restructured our hedge portfolio to better align hedge benchmark prices with our realized crude oil sales prices. We terminated certain of our crude oil swaps and three way collars while entering into new hedging

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Notes to Consolidated Financial Statements

instruments including crude oil swaps and put options. As a result of this restructuring, we recognized a de minimis gain on hedge terminations.

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

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.

Unsettled Derivative Instruments As of March 31, 2013, we had entered into the following crude oil derivative instruments:

				Swaps	Options	Collars		
Settlement Period	Type of Contract	Index	Bbls Per Day	Weighted Average Fixed Price	Put Option Premium	Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
Instruments Entered Into as of March 31, 2013								
2013	Swaps	NYMEX WTI [1]	9,000	$90.16	$—	$—	$—	$—
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	7,000	—	—	63.57	83.57	109.04
2013	Three-Way Collars	Dated Brent	13,000	—	—	81.15	100.75	124.68
2013	Put Options [2]	NYMEX WTI	11,000	—	5.97	—	97.60	—
2014	Swaps	NYMEX WTI	32,000	92.62	—	—	—	—
2014	Swaps	Dated Brent	10,000	103.33	—	—	—	—
2014	Three-Way Collars	NYMEX WTI	9,000	—	—	75.89	90.89	100.44
2014	Three-Way Collars	Dated Brent	5,000	—	—	84.00	97.20	129.70
2015	Swaps	NYMEX WTI	5,000	88.02	—	—	—	—
2015	Swaps	Dated Brent	5,000	99.04	—	—	—	—
2015	Three-Way Collars	NYMEX WTI	10,000	—	—	68.50	88.50	92.87
2015	Three-Way Collars	Dated Brent	5,000	—	—	75.00	95.00	112.53

(1) West Texas Intermediate

(2) For put options, we typically pay a premium to the counterparty in exchange for the sale of the instrument. If the index price is below the floor price of the put option, we receive the difference between the floor price and the index price multiplied by the contract volumes less the option premium. If the index price settles at or above the floor price of the put option, we pay only the option premium.

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As of March 31, 2013, we had entered into the following natural gas derivative instruments:

Settlement Period	Type of Contract	Index	MMBtu Per Day	Swaps Weighted Average Fixed Price	Collars Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
Instruments Entered Into as of March 31, 2013							
2013	Swaps	NYMEX HH [1]	60,000	$4.58	$—	$—	$—
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
2014	Swaps	NYMEX HH	60,000	4.24	—	—	—
2014	Three-Way Collars	NYMEX HH	160,000	—	2.64	3.64	5.02
2015	Swaps	NYMEX HH	30,000	4.25	—	—	—
2015	Three-Way Collars	NYMEX HH	100,000	—	3.50	4.25	5.01

[1] Henry Hub

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, 2013		December 31, 2012		March 31, 2013		December 31, 2012	
(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	$36	Current Assets	$63	Current Liabilities [1]	$44	Current Liabilities	$7
	Noncurrent Assets	13	Noncurrent Assets	21	Noncurrent Liabilities	9	Noncurrent Liabilities	3
Total		$49		$84		$53		$10

[1] Includes $18 million of deferred put option premium.

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

	Three Months Ended March 31,	
(millions)	2013	2012
Realized Mark-to-Market (Gain) Loss		
Crude Oil	$8	$34
Natural Gas	(15)	(11)

Total Realized Mark-to-Market (Gain) Loss	(7)	23
Unrealized Mark-to-Market (Gain) Loss		
Crude Oil	41	92
Natural Gas	38	(19)
Total Unrealized Mark-to-Market Loss	79	73
Total Loss on Commodity Derivative Instruments	$72	$96

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Accumulated other comprehensive loss (AOCL) at March 31, 2013 included deferred losses of $25 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 5. Debt

Our debt consists of the following:

(millions, except percentages)	March 31, 2013 Debt	Interest Rate		December 31, 2012 Debt	Interest Rate	
Credit Facility, due October 14, 2016 [1]	$—	—		$—	—	
CONSOL Installment Payment, due September 30, 2013	328	1.79	% [2]	328	1.79	% [2]
FPSO Lease Obligation	299	—		311	—	
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	4,111			4,123		
Unamortized Discount	(14)			(15)		
Total Debt, Net of Discount	4,097			4,108		
Less Amounts Due Within One Year						
Current portion of CONSOL Installment Payment, net of discount	(325)			(324)		
FPSO Lease Obligation	(49)			(48)		
Long-Term Debt Due After One Year	$3,723			$3,736		

(1) Our Credit Agreement provides for a $4.0 billion unsecured revolving Credit Facility. The Credit Facility is available for general corporate purposes.
(2) Imputed rate based on the prevailing market rates for similar debt instruments at the date of assessment.

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

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.

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Notes to Consolidated Financial Statements

Commodity Derivative Instruments Our commodity derivative instruments consist of variable to fixed price commodity swaps, two-way and three-way collars, and put options. 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 4. Derivative Instruments and Hedging Activities.

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, 2013					
Financial Assets					
Mutual Fund Investments	$109	$—	$—	$—	$109
Commodity Derivative Instruments	—	62	—	(13)	49
Financial Liabilities					
Commodity Derivative Instruments	—	(66)	—	13	(53)
Portion of Deferred Compensation Liability Measured at Fair Value	(174)	—	—	—	(174)
December 31, 2012					
Financial Assets					
Mutual Fund Investments	$103	$—	$—	$—	$103
Commodity Derivative Instruments	—	113	—	(29)	84
Financial Liabilities					
Commodity Derivative Instruments	—	(39)	—	29	(10)
Portion of Deferred Compensation Liability Measured at Fair Value	(160)	—	—	—	(160)

[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 netting clauses within our master 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 amount of the CONSOL installment payment approximates fair value because it is discounted at the prevailing market rate for similar debt instruments. As such, we consider the fair value of our CONSOL installment payment to be a Level 2 measurement on the fair value hierarchy. See Note 5. Debt. Fair value information regarding our debt is as follows:

	March 31, 2013		December 31, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
(millions)				
Total Debt, Net of Unamortized Discount [1]	$3,798	$4,539	$3,797	$4,570

(1) Excludes Aseng FPSO lease obligation. No floating rate debt was outstanding at March 31, 2013 or December 31, 2012.

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 as dry hole cost.

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

	Three Months Ended March 31, 2013
(millions)	
Capitalized Exploratory Well Costs, Beginning of Period	$900
Additions to Capitalized Exploratory Well Costs Pending Determination of Proved Reserves	178
Reclassified to Proved Oil and Gas Properties Based on Determination of Proved Reserves	(8)
Capitalized Exploratory Well Costs, End of Period	$1,070

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:

	March 31, 2013	December 31, 2012
(millions)		
Exploratory Well Costs Capitalized for a Period of One Year or Less	$453	$355
Exploratory Well Costs Capitalized for a Period Greater Than One Year Since Commencement of Drilling	617	545
Balance at End of Period	$1,070	$900
Number of Projects with Exploratory Well Costs That Have Been Capitalized for a Period Greater Than One Year Since Commencement of Drilling	13	14

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, 2013:

		Suspended Since		
	Total	2012	2011	2010 & Prior
(millions)				
Country/Project:				
Offshore Equatorial Guinea				
Carla	$12	$—	$12	$—
Diega	106	1	46	59
Felicita	36	1	2	33
Yolanda	18	—	1	17
Offshore Cameroon				
YoYo	47	2	5	40
Offshore Israel				
Leviathan	113	5	67	41
Leviathan-1 Deep	55	27	28	—
Tanin 1	33	2	31	—
Dolphin 1	22	—	22	—
Dalit	22	—	—	22
Offshore Cyprus				
Cyprus A-1	64	7	57	—
Deepwater Gulf of Mexico				
Gunflint	77	23	—	54
Other				
Projects of $10 million or less each	12	3	—	9
Total	$617	$71	$271	$275

Carla/Diega Carla is a 2011 crude oil discovery on Block O, Diega (formerly Carmen) is a 2008 condensate and crude oil discovery on Blocks O and I. We are continuing our appraisal program for our Carla discovery. During first quarter of 2013, we spud the Carla I-7 well and continue to review the drilling results of the Carla O-7 well. Further appraisal drilling of Diega is planned for the second half of 2013. We are currently evaluating regional development scenarios for these two discoveries, which includes possible sanctioning of Carla during 2013.

Felicita/Yolanda Felicita is a 2008 condensate and natural gas discovery on Block O. Yolanda is a 2008 condensate and natural gas discovery on Block I. We are currently evaluating regional natural gas development options for these discoveries.

YoYo YoYo is a 2007 natural gas and condensate discovery. During 2011 we acquired and processed additional 3D seismic information and are continuing evaluations for future drilling potential. We are also working with the government of Cameroon to assess gas commercialization options.

Leviathan Leviathan is a 2010 natural gas discovery. During 2012, we continued to evaluate the discovery with the successful drilling of both the Leviathan-3 and Leviathan-4 appraisal wells. We have project and commercial teams in place and are in the process of screening multiple development concepts. In 2012, we announced that the partners in the Leviathan Project had agreed in principle on a proposal to sell a 30% working interest in the Leviathan licenses to Woodside Energy Ltd. (Woodside).

Leviathan-1 Deep In January 2012, we returned to the Leviathan-1 well and began drilling toward two deeper intervals in order to evaluate them for the existence of crude oil (Leviathan-1 Deep). We are continuing our evaluation of Leviathan-1 Deep and will integrate the data from the Leviathan-1 Deep well into our model to update our analysis and design a drilling plan specifically to test the deep oil concept. We have secured a drillship with the capabilities

necessary to reach the target objective. The drillship is scheduled to arrive in the Eastern Mediterranean at the end of 2013, and we plan to begin drilling an exploratory well shortly after its arrival.
Tanin 1 Tanin 1 is a 2011 natural gas discovery located in the Alon A block, offshore Israel. We and our partners are currently reviewing alternatives for the development of reserves from this asset.

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Dolphin 1 Dolphin 1 is a 2011 natural gas discovery located in the Hanna license, southwest of the Tamar gas field. We and our partners are currently reviewing alternatives for the development of reserves from this asset.
Dalit Dalit is a 2009 natural gas discovery. We and our partners are working on a development plan which would include tie-in to the Tamar platform and have submitted a development plan to the Israeli government.
Cyprus During the fourth quarter of 2011, we drilled a successful natural gas exploration well (A-1) in Block 12. We submitted an appraisal plan to the Cyprus government and are reviewing locations for appraisal drilling activities. We plan to drill the A-2 appraisal well during the second half of 2013.
Gunflint Gunflint (Mississippi Canyon Block 948) is a 2008 crude oil discovery. In July 2012, we drilled a successful Gunflint appraisal well. We have commenced drilling the second Gunflint appraisal well and continue to proceed towards sanctioning a scalable development project in the second half of 2013. First production from Gunflint is targeted for 2015 if we utilize a subsea tieback to an existing host facility or 2017 if a standalone facility is required.

Note 8. Asset Retirement Obligations

Asset retirement obligation (ARO) consists primarily of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. Changes in ARO are as follows:

	Three Months Ended March 31,	
	2013	2012
(millions)		
Asset Retirement Obligations, Beginning Balance	$402	$377
Liabilities Incurred	1	6
Liabilities Settled	(10)	(2)
Revision of Estimate	(1)	3
Accretion Expense [1]	7	7
Asset Retirement Obligations, Ending Balance	$399	$391

[1] Accretion expense is included in DD&A expense in the consolidated statements of operations.

Liabilities settled in 2013 relate primarily to onshore US properties sold. See Note 3. Divestitures.

Note 9. 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,	
	2013	2012
(millions, except per share amounts)		
Income from Continuing Operations	$232	$249
Weighted Average Number of Shares Outstanding, Basic	179	177
Incremental Shares From Assumed Conversion of Dilutive Stock Options, Restricted Stock and Shares of Common Stock in Rabbi Trust	2	3
Weighted Average Number of Shares Outstanding, Diluted	181	180
Earnings from Continuing Operations Per Share, Basic	$1.29	$1.40
Earnings from Continuing Operations Per Share, Diluted	1.28	1.39
Number of antidilutive stock options, shares of restricted stock and shares of common stock in rabbi trust excluded from calculation above	3	2

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Common Stock Split   On April 22, 2013, Noble Energy's Board of Directors approved a two-for-one split of its common stock to be effected in the form of a stock dividend. The stock dividend will be distributed on May 28, 2013 to shareholders of record as of May 14, 2013. Pro forma earnings per share and common shares outstanding, giving retrospective effect to the stock split, is as follows:

	Three Months Ended March 31,			
	2013		2012	
	As Reported	Pro Forma	As Reported	Pro Forma
(millions, except per share amounts)				
Earnings Per Share, Basic				
Income from Continuing Operations	$1.29	$0.65	$1.40	$0.70
Discontinued Operations, Net of Tax	0.17	0.08	0.08	0.04
Net Income	$1.46	$0.73	$1.48	$0.74
Earnings Per Share, Diluted				
Income from Continuing Operations	$1.28	$0.64	$1.39	$0.69
Discontinued Operations, Net of Tax	0.17	0.08	0.08	0.04
Net Income	$1.45	$0.72	$1.47	$0.73
Weighted Avg Number of Shares Outstanding				
Basic	179	358	177	355
Diluted	181	362	180	359

Note 10. Income Taxes
The income tax provision relating to continuing operations consists of the following:

	Three Months Ended March 31,			
	2013		2012	
(millions)				
Current	$36		$44	
Deferred	50		42	
Total Income Tax Provision	$86		$86	
Effective Tax Rate	27.1	%	25.8	%

Our effective tax rate for the first three months of 2013 increased as compared with the first three months of 2012. This increase is primarily due to a tax contingency recognized during the first quarter of 2013.
In our major tax jurisdictions, the earliest years remaining open to examination are as follows: US – 2008, Equatorial Guinea – 2007, Israel – 2008 and China –2010.
See Note 3. Divestitures for income taxes related to discontinued operations.

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Note 11. Segment Information

We have operations throughout the world and manage our operations by country. The following information is grouped into four components that are all in the business of crude oil and natural gas exploration, development, production, and acquisition: the United States; West Africa (Equatorial Guinea, Cameroon, Sierra Leone and Senegal/Guinea-Bissau, which we exited in the third quarter of 2012); Eastern Mediterranean (Israel and Cyprus); and Other International and Corporate. Other International includes China, Falkland Islands, Nicaragua and new ventures. As of March 31, 2013, our remaining North Sea assets were reclassified to assets held for sale, and prior year amounts have been reclassified to exclude the North Sea geographical segment. See Note 3. Divestitures.

	Consolidated	United States	West Africa	Eastern Mediterranean	Other Int'l & Corporate
(millions)					
Three Months Ended March 31, 2013					
Revenues from Third Parties	$1,083	$716	$273	$51	$43
Income from Equity Method Investees	60	—	60	—	—
Total Revenues	1,143	716	333	51	43
DD&A	366	266	54	28	18
Loss on Commodity Derivative Instruments [1]	72	49	23	—	—
Income (Loss) from Continuing Operations Before Income Taxes	318	243	231	15	(171)
Three Months Ended March 31, 2012					
Revenues from Third Parties	$1,037	$554	$383	$44	$56
Income from Equity Method Investees	51	—	51	—	—
Total Revenues	1,088	554	434	44	56
DD&A	294	198	73	5	18
Gain (Loss) on Commodity Derivative Instruments [1]	96	(9)	105	—	—
Income (Loss) from Continuing Operations Before Income Taxes	335	193	227	32	(117)
March 31, 2013					
Total Assets	$17,667	$11,398	$3,183	$2,631	$455
December 31, 2012					
Total Assets	17,509	11,199	3,063	2,572	675

[1] See Note 4. Derivative Instruments and Hedging Activities.

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.

West Virginia Matter In March 2013, we received seven Notices of Violation (NOV) and two Administrative Orders (Orders) from the West Virginia Department of Environmental Protection Office of Oil and Gas (OOG) regarding the unintentional discharge of a mixture of freshwater and produced water that occurred on or about the evening of February 22, 2013 from one of our permitted water storage facilities in Marshall County, West Virginia. At this time, the OOG has not established a proposed penalty for these NOVs or Orders. Given the 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.

Colorado Matter On April 16, 2013, we received a proposed Early Settlement Agreement (ESA) from Colorado Department of Public Health and Environment's Air Pollution Control Division to resolve allegations of noncompliance with our 2011 Ozone and Non-Ozone season spreadsheet submissions pursuant to Air Quality Control Commission Regulation 7. The ESA, which provides for an opportunity to further discuss the offer of settlement, has not yet been executed. At present, the ESA seeks payment of a reduced penalty of $112,000. 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 worldwide producer of crude oil and natural gas. We aim to achieve sustainable growth in value and cash flow through exploration success and the development of a high-quality, diversified, growing portfolio of assets that is balanced between US and international projects, while maintaining a strong balance sheet and ample liquidity levels. We primarily focus on organic growth from exploration and development drilling and augment that with a periodic, opportunistic new business development (mergers and acquisition) capability. We manage the portfolio for superior returns and to ensure geographic portfolio diversification, with periodic divestments of non-core assets. We focus on basins or plays where we have strategic competitive advantage and which we believe generate superior returns.

Our core operating areas are the onshore US (DJ Basin and Marcellus Shale), deepwater Gulf of Mexico, offshore West Africa and offshore Eastern Mediterranean.

Our major development projects typically offer long life, sustained cash flows after investment and attractive financial returns. We maintain a diversified portfolio between US and international assets and strive to maintain a balanced geographic and political risk profile. We also maintain a geographical diversity of production mix among crude oil, US natural gas, and international natural gas.

Our financial results for the first quarter of 2013 included:

- net income of $261 million (including $232 million from continuing operations), as compared with $263 million (including $249 million from continuing operations) for first quarter 2012;
- loss on commodity derivative instruments of $72 million (including unrealized mark-to-market loss of $79 million) as compared with a loss on commodity derivative instruments of $96 million (including unrealized mark-to-market loss of $73 million) for first quarter 2012;
- diluted earnings per share of $1.45, as compared with $1.47 for first quarter 2012;
- cash flow provided by operating activities of $705 million, as compared with $741 million for first quarter 2012;
- ending cash balance of $1.3 billion, as compared with $1.4 billion at December 31, 2012;
- capital spending, on a cash basis, of $806 million as compared with $1.0 billion for first quarter 2012; and
- ratio of debt-to-book capital of 33%, unchanged from December 31, 2012.

Key highlights for the first quarter of 2013 included:

- first production established at Tamar, offshore Israel;
- record net sales volumes of 92 MBoe/d from the DJ Basin with 45 MBoe/d from the horizontal program;
- drilled extended reach lateral well of 9,978 feet in the DJ Basin, the longest in Colorado history;
- signed sales agreements on three non-core divestment packages with expected proceeds exceeding $105 million; and
- successful appraisal well at Leviathan, offshore Israel.

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Tamar Startup

Initial sales from Tamar commenced on March 31, 2013. Just over four years from discovery, the Tamar project is fully operational and delivering significant volumes of natural gas to Israel and represents the first of two major projects targeted for completion in 2013. The natural gas flows from the field through the longest subsea tieback in the world, more than 90 miles to the Tamar platform and then to the Ashdod onshore terminal. Tamar was successfully brought online during the first quarter and currently all five of the subsea wells are producing at stable rates. Each of the five subsea wells is capable of flowing 250 MMcf/d of natural gas. The development is designed to deliver natural gas rates up to one Bcf/d. Volumes will likely reach this maximum capacity during the peak summer demand in the third quarter this year. Tamar is a technological and commercial milestone and will make a significant contribution to our continuing production growth. Sales commenced under a temporary permit and we are working with the government to obtain a final permit as soon as practicable. Our largest purchaser, the Israel Electric Corporation Ltd., recently exercised its option to increase sales over the 15-year contract period from approximately 2.7 Tcf (approximately 1.0 Tcf net) to approximately 3.5 Tcf (approximately 1.3 Tcf net).

Exploration Program Update

We continue to evaluate and build upon our significant exploration inventory in the onshore US, deepwater Gulf of Mexico, offshore West Africa, offshore Eastern Mediterranean and other new venture locations.

We continually evaluate our exploration inventory to provide additional growth opportunities and potential new core areas. In addition, each of our existing core areas has significant remaining exploration upside. We continue to leverage existing activities to improve our exploratory programs in these core areas.

We were in the process of drilling and/or evaluating significant exploratory wells at March 31, 2013 (See Item 1. Financial Statements – Note 7. Capitalized Exploratory Well Costs), and we expect to continue an active exploratory drilling program in the future.

We devote significant capital to our exploration program; approximately 19% of our $3.9 billion capital investment program in 2013 is dedicated to exploration and associated appraisal activities, including leasehold acquisitions. However, we do not always encounter hydrocarbons 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.

As discussed below, we are currently conducting, or planning to conduct, exploratory drilling activities in previously unexplored areas as well as appraisal activities at several of our discoveries. In the event we conclude that one of our exploratory wells did not encounter hydrocarbons or that a discovery is not economically or operationally viable, the associated capitalized exploratory well costs would be charged to expense. Additionally, we may not conduct exploration activities prior to lease expirations. As a result, in a future period, dry hole cost and leasehold impairment charges could be significant.

Updates of our significant exploration activities are as follows:

Deepwater Gulf of Mexico   We hold significant exploration potential in the deepwater Gulf of Mexico. During the first quarter of 2013, we participated in the Central Gulf of Mexico Lease Sale 227 and were high bidder on five deepwater blocks. During the second half of 2013, we plan to drill the Troubadour exploration well (Mississippi Canyon Block 699), an offset to our Big Bend discovery, and spud an additional exploration prospect.

Karish (Offshore Israel) We spud our first exploratory well on the Karish prospect in the Alon C license. Karish is expected to reach total depth in the second quarter of 2013.

Offshore Nicaragua We continue to evaluate our undeveloped acreage and currently plan to spud our first exploration well (Paraiso), targeting an oil play, in the third quarter of 2013. During the first quarter of 2013, we began hosting potential partners in our Houston data room in anticipation of a working interest farmout by the time we spud Paraiso.

Offshore Falkland Islands In March 2013, we assumed operatorship from Falkland Oil and Gas Limited (FOGL) of the Northern Area License and will assume operatorship of the Southern Area License no later than March 2014. We continue to acquire 3D seismic over the Southern Area License as part of the exploration program.

Major Development Project Updates

During the first quarter of 2013, we successfully brought the Tamar project online as we continue to advance our major development projects, many of which have resulted from our exploration success. We expect these projects to deliver significant growth in production over the next several years. Updates on our significant development projects are as follows:

Sanctioned Development Projects

Horizontal Niobrara (Onshore US) We have increased our horizontal drilling activity by targeting the Niobrara formation in the Wattenberg area, resulting in a significant positive impact on our current production volumes. We expect to drill over 300 horizontal

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wells during 2013 and we continue to move into areas of higher liquids content. We spud 56 horizontal wells during the first quarter of 2013, including ten extended-reach lateral wells.

We continue to expand our horizontal Niobrara development activities into northern Colorado, where recent results indicate recoveries comparable to those in the Wattenberg area. We plan to spud over 60 wells during 2013 as we work to delineate our remaining acreage position in northern Colorado.

Marcellus Shale (Onshore US) We continue developing the field with longer lateral wells, enhanced completion design and optimal well placements. We have drilled to total depth 15 wet gas wells thus far in 2013.

Although we have reduced drilling in the dry gas area due to the current natural gas price environment, the dry gas portion of the program continues to deliver economically attractive returns due to strong production performance, high net revenue interests, and access to market. The CONSOL Carried Cost Obligation is currently suspended due to low natural gas prices. See Liquidity and Capital Resources - Contractual Obligations below.

Alen (Blocks O and I, Offshore Equatorial Guinea) The production and injection wells have been completed and platform and subsea installations continue on schedule. First production is expected to commence in the third quarter of 2013 at 18 MBbl/d, net. Alen will be our second major project to be completed in 2013.

Unsanctioned Development Projects

Gunflint (Deepwater Gulf of Mexico) We have commenced drilling the second Gunflint appraisal well and continue to proceed towards sanctioning a scalable development project in the second half of 2013. First production from Gunflint is targeted for 2015 if we utilize a subsea tieback to an existing host facility or 2017 if a standalone facility is required.

Big Bend (Deepwater Gulf of Mexico) We anticipate sanctioning a development plan for Big Bend during 2013 with first production targeted in late 2015 or early 2016.

Leviathan (Offshore Israel) The Leviathan #4 appraisal well was drilled to total depth and encountered 454 net feet of natural gas pay in multiple intervals, the thickest net pay of any well drilled to date at Leviathan. The results have enhanced our understanding of the reservoir and we continue our evaluation of multiple development concepts.

We continue working with Woodside Energy Ltd. towards reaching a definitive agreement to sell a 30% working interest in the Leviathan licenses. Each of the current Leviathan partners is expected to participate as a seller to Woodside. We expect to convey a 9.66% working interest, reducing our working interest to 30%, and continue as upstream operator.

Carla and Diega (Offshore Equatorial Guinea) We continue our appraisal program for our Carla discovery where we are reviewing drilling results of the Carla O-7 and have spud the Carla I-7 during the first quarter of 2013. Further appraisal drilling of Diega is planned for the second half of 2013.

Non-Core Divestiture Program

Our non-core divestiture program is designed to generate organizational and operational efficiencies as well as cash for use in our capital investment program. Divestitures of non-core properties allow us to allocate capital and employee resources to high-value and high-growth areas. Further, proceeds from divestitures will provide additional flexibility in the implementation of our international and deepwater Gulf of Mexico exploration and development programs and our horizontal drilling activities in the DJ Basin and Marcellus Shale.

During the first quarter of 2013, we closed the sale of our 13% non-operated working interest in the Cook field located in the UK sector of the North Sea. The sale resulted in a $37 million gain based on total net sale proceeds of $38 million for the field. We also closed the sale of certain crude oil and natural gas properties in the Gulf Coast area for total sale proceeds of $55 million. We continue to market packages of non-core onshore US properties and our remaining North Sea properties. See Item 1. Financial Statements – Note 3. Divestitures.

On occasion we will withdraw from all operations in a country. The reasons for withdrawing from a country vary. It may be based on a decision to allocate resources to other projects, or result from government action such as the Ecuadorian government's termination of our Block 3 PSC in 2010. Some exploration programs simply do not result in the discovery of a commercial quantity of reserves. Withdrawing from a country usually involves two parallel processes: concluding exploration and production operations; and winding up local business activities. Winding up local business activities may involve completing outstanding tax audits and filing final tax returns, resolving employment related matters, settling claims and dissolving local entities such as subsidiaries or branches.

We are currently planning to withdraw from the United Kingdom and the Dutch North Sea and are winding up local business activities in Ecuador and Argentina. At this time, we do not believe that any of the activities associated with these areas will have a material effect on our financial position, results of operations or cash flows.

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Sales Volumes

On a BOE basis, total sales volumes from continuing operations were 4% higher for the first quarter of 2013 as compared with the first quarter of 2012, and our mix of sales volumes was 48% global liquids, 24% international natural gas, and 28% US natural gas. Onshore US sales volume increases were due to our horizontal drilling programs in the DJ Basin and the Marcellus Shale. In the deepwater Gulf of Mexico, South Raton was offline for an extended period during the quarter due to mechanical issues and Swordfish production was impacted by a temporary loss of power. Also, we had lower sales volumes from Alba, offshore Equatorial Guinea, due to fewer liftings in first quarter of 2013. See Results of Operations – Revenues below.

Commodity Price Changes and Hedging

US natural gas prices began to increase during the quarter; US average realized natural gas prices for the first quarter of 2013 increased 26% as compared with the first quarter of 2012. Total consolidated average realized crude oil prices for the first quarter of 2013 decreased 8% as compared with the first quarter of 2012.

We have hedged approximately 45% of our expected global crude oil production and 44% of our expected domestic natural gas production for the remainder of 2013. See Item 1. Financial Statements – Note 4. Derivative Instruments and Hedging Activities.

OPERATING OUTLOOK

2013 Production Our expected crude oil, natural gas and NGL production for 2013 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 ramp up of the Tamar field and other major development projects completion and initial production, including Alen, offshore Equatorial Guinea, which is scheduled to begin producing in the third quarter of 2013;
- ongoing development activity in the Wattenberg area and horizontal drilling in the Niobrara formation in the DJ Basin;
- pace of increase of development activity in both wet gas and dry gas areas of the Marcellus Shale;
- divestments of non-core operating assets;
- natural field decline in the deepwater Gulf of Mexico and Mid-Continent areas of our US operations, the Mari-B, Noa and Pinnacles fields offshore Israel, and Alba and Aseng fields offshore Equatorial Guinea;
- variations in sales volumes of natural gas from the Alba field in Equatorial Guinea related to potential downtime at the methanol, LPG and/or LNG plants;
- Israeli demand for electricity which affects demand for natural gas as fuel for power generation, market growth, and production rates from Tamar, Mari-B, Noa and Pinnacles fields, offshore Israel;
- variations in West Africa sales volumes due to potential FPSO downtime and timing of liftings;
- potential hurricane-related volume curtailments in the deepwater Gulf of Mexico;
- potential winter storm-related volume curtailments in the Rocky Mountain and/or Marcellus Shale areas of our US operations;
- third party facilities reliability in the Wattenberg and/or Rocky Mountain areas of our US properties which may cause restrictions or interruptions in mid-stream processing facilities;
- potential pipeline and processing facility capacity constraints in the Rocky Mountain and/or Marcellus Shale areas of our US operations;
- potential drilling and/or hydraulic fracturing permit delays due to future regulatory changes;
- potential purchases of producing properties; and
- potential shut-in of US producing properties if storage capacity becomes unavailable.

2013 Capital Investment Program Our total capital investment program for 2013 is estimated at $3.9 billion. The capital investment program allocates approximately 60% to onshore US, 6% for deepwater Gulf of Mexico, 10% to the Eastern Mediterranean, 15% to West Africa and 9% to corporate and other. Exploration and appraisal activity within these geographic areas is expected to receive 19% of total capital.

The 2013 capital investment program will exceed operating cash flows and is expected to 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.

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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 Liquidity and Capital Resources - Contractual Obligations);
- property acquisitions and divestitures;
- increase in exploration activities in new areas, including offshore Sierra Leone, Nicaragua and the Falkland Islands;
- 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, which has resulted in significant derivatives regulations and disclosure requirements, on our business practices.

Potential for Asset Impairments

Commodity prices remain volatile. A decline in future NYMEX crude oil or natural gas prices could result in impairment charges. 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 interest rates. All inputs to the cash flow model must be evaluated at each date of estimate. However, a decrease in forward crude oil or natural gas prices alone could result in impairment.

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.

Occasionally, well mechanical problems arise, which can reduce production and potentially result in reductions in proved reserves estimates. For example, our South Raton development in the deepwater Gulf of Mexico is currently experiencing mechanical issues and we are conducting remediation efforts. South Raton had a net book value of approximately $115 million at March 31, 2013.

Hydraulic Fracturing Update

The practice of hydraulic fracturing in shale formations is the subject of significant focus among some environmentalists, local, state, and federal policy makers, and the general public.

Although hydraulic fracturing is regulated primarily at the state level, local governments and the federal government are increasingly active on the matter. For example, the Federal Bureau of Land Management is presently developing new regulations related to hydraulic fracturing processes on federal lands. Additionally, in 2012 the City of Longmont, Colorado voted to ban hydraulic fracturing activities within city limits. And, in March 2013, the Fort Collins, Colorado, City Council also voted to ban hydraulic fracturing activities within city limits. The State of Colorado, through the Colorado Oil and Gas Conservation Commission, and with oil and gas industry support, has opposed such bans.

Our current activities are focused outside these jurisdictions, primarily in Weld County, Colorado. The local initiatives referenced above represent a focused effort by those who oppose oil and gas development to impact public policy decisions and direction. Therefore, they remain a concern for us because their efforts could lead to statewide initiatives related to hydraulic fracturing.

An outright ban on hydraulic fracturing or a significant increase in local regulation in the State of Colorado would have a negative impact on us, and it would also significantly impact the State of Colorado via a reduction in private investment, employment opportunities, and state and local government revenues. We continue to monitor new and proposed legislation and regulations to assess the potential impact on our operations. We are currently evaluating the possible impact any proposed rules, such as those described above, could have on our business. Certain federal, state or local restrictions on hydraulic fracturing that may be imposed in areas in which we conduct business could potentially result in substantial incremental operating, capital and compliance costs as well as delay our ability to develop oil and gas reserves.

Update on Israel's Natural Gas Economy

The Israeli Antitrust Commissioner (Commissioner) has been actively engaged to encourage competition in developing Israel's natural gas resources. The Commissioner ruled that all domestic natural gas sales contracts are subject to review and approval

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of the antitrust authority and has intervened in the terms of long term contracts with certain consumers. In addition, we are in discussions with the antitrust authority relating to an alleged restrictive arrangement with respect to the acquisition agreement of the Leviathan licenses. The Commissioner has also publicly expressed concerns regarding ownership concentration in exploration blocks and development projects and its potential impacts on a competitive domestic natural gas price environment and end user electricity costs. Commissioner decisions and actions to increase competition could result in our being required to divest certain assets, reduce or relinquish revenue interests, and implement equity marketing of production.

In addition, the government is in the process of finalizing an export policy. We are monitoring current policy-making activities to assess the possible impact, positive or negative, of any resulting laws or regulations on our business. Certain changes in Israel's fiscal and/or regulatory regimes occurring as a result of Antitrust Commission rulings or government policy on exports could delay or reduce the profitability of our Tamar and/or Leviathan development projects and render future exploration and development projects uneconomic. Our dependency on the Israeli government to make decisions to reduce these uncertainties may have an impact on the expected timing of our developments.

In addition, certain regulatory changes could lead to a reduction in oil and gas exploration and development activities offshore Israel, resulting in lower domestic production, lower government revenues for the State of Israel, and higher energy costs for consumers.

Risk and Insurance Program

Our business is subject to all of the inherent and unplanned operating risks normally associated with the exploration, production, gathering, processing, transportation and marketing of crude oil and natural gas. Such risks include hurricanes, blowouts, well cratering, fire, loss of well control, pipeline disruptions, 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 income), employer's liability, third party 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 the company's ability to sustain uninsured losses, and revise our insurance program accordingly. Limits and deductibles were recently revised for the property and business interruption programs, effective March 1, 2013.

We carry some business interruption insurance for loss of production income arising from physical damage to our major facilities. Business interruption coverage was recently expanded as part of the recent insurance renewal. The coverage is subject to customary deductibles, waiting periods and recovery limits.

Availability of insurance coverage for certain perils such as war or political risk is often excluded or limited within property policies. In Israel and Equatorial Guinea, we insure against acts of war and terrorism in addition to providing insurance coverage for normal operating hazards facing our business. Additionally, as being part of critical national infrastructure, the Israel offshore and onshore assets are included in a special property coverage afforded under the Israeli government's Property Tax and Compensation Fund law.

In the Gulf of Mexico, we self-insure for windstorm related exposures. Currently, our Gulf of Mexico assets are primarily subsea operations; therefore, our direct windstorm exposure is limited. However, we do have some exposure through the use of third party production platforms. 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 for windstorm exposures.

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 more than $700 million in insurance protection, depending on our ownership interest, for potential financial losses occurring as a result of events such as the Deepwater Horizon Incident of 2010. This protection consists of more than $500 million of well control, pollution cleanup and consequential damages coverage and more than $200 million of additional pollution cleanup and consequential damages coverage, which also covers third-party personal injury and death.

We have contracts with third-party service providers to perform hydraulic fracturing operations for us. The master service agreements signed by hydraulic fracturing contractors contain indemnification provisions similar to those noted above. Our liability insurance policies do not contain any specific exclusion 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.

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We expect the future availability and cost of insurance to be impacted by the various catastrophic events and large losses that insurers have incurred over the past several years. Impacts could include tighter underwriting standards, limitations on scope and amount of coverage, and higher premiums.

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 also use third party consultants to help us identify and quantify our risk exposures at major facilities. 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.

Oil Spill Response Preparedness

We maintain membership in Clean Gulf Associates (CGA), a nonprofit association of production and pipeline companies operating in the Gulf of Mexico for surface spill response. We are a member of HWCG, a deepwater well containment group, which has contracted with Helix Energy Solutions Group (HESG) for the provision of subsea intervention, containment, capture and shut-in capacity for deepwater Gulf of Mexico wells. The system, known as the Helix Fast Response System (HFRS), at full production capacity, can contain well leaks up to 55 MBbl/d of oil, 70 MBbl/d of liquids and 95 MMcf/d of natural gas, at 10,000 pounds per square inch (psi) in water depths to 10,000 feet. Resources also include a 15,000 psi-gauge intervention capping stack designed to shut-in wells in water depths to 10,000 feet, including extremely high-pressure, deeper wells in the deepwater Gulf of Mexico.

We are leading a one week capping stack deployment drill for HWCG set to commence in the second quarter of 2013. The Bureau of Safety and Environmental Enforcement will oversee the deployment to ensure that the capping stack can be effectively deployed and can function in deepwater in the event of a subsea well blowout.

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RESULTS OF OPERATIONS

In the discussion below, prior year amounts have been reclassified to reflect the North Sea segment as discontinued operations. See Discontinued Operations, below.

Revenues

Revenues were as follows:

(millions)	2013	2012	Increase from Prior Year	
Three Months Ended March 31,				
Oil, Gas and NGL Sales	$1,083	$1,037	4	%
Income from Equity Method Investees	60	51	18	%
Total	$1,143	$1,088	5	%

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, 2013							
United States	63	409	16	146	$95.70	$3.31	$39.19
Equatorial Guinea (2)	27	246	—	68	111.79	0.27	—
Israel	—	111	—	19	—	5.15	—
China	4	—	—	4	109.22	—	—
Total Consolidated Operations	94	766	16	237	100.90	2.60	39.19
Equity Investees (3)	2	—	6	8	108.63	—	74.19
Total Continuing Operations	96	766	22	245	$101.07	$2.60	$49.29
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	—
China	5	—	—	5	126.10	—	—
Total Consolidated Operations	82	771	17	227	109.89	2.18	41.62
Equity Investees (3)	2	—	7	9	110.09	—	68.02
Total Continuing Operations	84	771	24	236	$109.90	$2.18	$49.34

(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.

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

	Sales Revenues			
	Crude Oil & Condensate	Natural Gas	NGLs	Total
(millions)				
Three Months Ended March 31, 2012	$820	$153	$64	$1,037
Changes due to				
Increase (Decrease) in Sales Volumes	105	(3)	(6)	96
Increase (Decrease) in Sales Prices	(76)	29	(3)	(50)
Three Months Ended March 31, 2013	$849	$179	$55	$1,083

Crude oil and condensate sales – Revenues from crude oil and condensate sales increased during the first quarter of 2013 as compared with 2012 due to the following:

- higher sales volumes in the DJ Basin attributable to our horizontal drilling programs;
- the addition of sales volumes from Galapagos, deepwater Gulf of Mexico, which began production in the second quarter of 2012;

partially offset by:

- a reduced number of liftings at Alba, offshore Equatorial Guinea, due to timing;
- decreases in average realized prices due to, among other factors, concerns over economic recovery in the Eurozone; and
- decreases in sales volumes due to sales of onshore US properties in the third quarter of 2012.

Natural gas sales – Revenues from natural gas sales increased during the first quarter of 2013 as compared with 2012 due to the following:

- increases in total consolidated average realized prices primarily due to increased demand from expectations of cooler weather and higher-than-expected inventory withdrawals;
- higher sales volumes in the DJ Basin and Marcellus Shale attributable to our horizontal drilling programs; and
- the addition of sales volumes from Galapagos, deepwater Gulf of Mexico, which began production in the second quarter of 2012;

partially offset by:

- lower sales volumes due to sales of onshore US properties in the third quarter of 2012.

NGL sales – Most of our US NGL production is currently from the DJ Basin. NGL sales revenues decreased significantly during the first quarter of 2013 as compared with the first quarter of 2012 as a result of the sale of non-core onshore US properties. Our average realized sales prices declined 6% during the first quarter of 2013 as compared with the first quarter of 2012 primarily due 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.

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.

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Operating Costs and Expenses

Operating costs and expenses were as follows:

(millions)	2013	2012	Increase (Decrease) from Prior Year
Three Months Ended March 31,			
Production Expense	$187	$163	15 %
Exploration Expense	61	60	2 %
Depreciation, Depletion and Amortization	366	294	24 %
General and Administrative	112	97	15 %
Gain on Divestitures	(15)	—	100 %
Other Operating (Income) Expense, Net	7	12	(42)%
Total	$718	$626	15 %

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	Other Int'l, Corporate
Three Months Ended March 31, 2013						
Lease Operating Expense [2]	$5.49	$117	$89	$20	$1	$7
Production and Ad Valorem Taxes	2.02	43	34	—	—	9
Transportation and Gathering Expense	1.30	27	27	—	—	—
Total Production Expense	$8.81	$187	$150	$20	$1	$16
Three Months Ended March 31, 2012						
Lease Operating Expense [2]	$5.11	$105	$71	$23	$4	$7
Production and Ad Valorem Taxes	1.81	38	26	—	—	12
Transportation and Gathering Expense	0.98	20	19	—	—	1
Total Production Expense	$7.90	$163	$116	$23	$4	$20

(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 quarter of 2013, total production expense increased as compared with 2012 due to the following:

- an increase in US lease operating, transportation and gathering expenses due to higher sales volumes from the DJ Basin due to ongoing development activities;
- additional operating costs from Galapagos, deepwater Gulf of Mexico, which began production in the second quarter of 2012;
- mechanical repairs related to Swordfish, deepwater Gulf of Mexico;
- an increase in transportation and gathering expense due to securing firm pipeline capacity for natural gas in the Marcellus Shale; and
- an increase in US taxes due to increased volumes from the DJ Basin ($10 million) and Pennsylvania impact fee ($2 million) offset by a decrease associated with divestitures ($5 million).

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Exploration Expense Components of exploration expense were as follows:

(millions)	Total	United States	West Africa [1]	Eastern Mediterranean [2]	Other Int'l, Corporate [3]
Three Months Ended March 31, 2013					
Seismic	$25	$6	$—	$—	$19
Staff Expense	28	7	1	3	17
Other	8	9	—	—	(1)
Total Exploration Expense	$61	$22	$1	$3	$35
Three Months Ended March 31, 2012					
Seismic	28	26	—	—	2
Staff Expense	24	4	2	1	17
Other	8	6	2	—	—
Total Exploration Expense	$60	$36	$4	$1	$19

(1) West Africa includes Equatorial Guinea, Cameroon, Sierra Leone, and Senegal/Guinea-Bissau, which we exited in the third quarter of 2012.

(2) Eastern Mediterranean includes Israel and Cyprus.

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

Exploration expense for the first quarter of 2013 included the following:

- $17 million of 3D seismic in the Falkland Islands; and
- staff expense associated with new ventures and corporate expenditures.

Exploration expense for the first quarter 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.

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

	Three Months Ended March 31, 2013	2012
DD&A Expense (millions) [1]	$366	$294
Unit Rate per BOE [2]	$17.18	$14.19

(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 quarter of 2013 increased as compared with 2012 due to the following:

- higher sales volumes in the DJ Basin and Marcellus Shale; and
- additional DD&A from Galapagos, deepwater Gulf of Mexico, which began production in the second quarter of 2012 and Noa and Pinnacles, offshore Israel, which began production in the third quarter of 2012. These fields have higher DD&A rates;

partially offset by:

- lower sales volumes from Alba, offshore Equatorial Guinea; and
- the impact of sales of non-core onshore US properties in 2012.

Changes in the unit rate per BOE for the first quarter of 2013 as compared with 2012 were due to changes in the mix of production, primarily due to volumes from the start-up of the Noa, Pinnacles and Galapagos projects and increased horizontal drilling activity, which have comparatively higher DD&A rates.

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

	Three Months Ended March 31, 2013	2012
G&A Expense (millions)	$112	$97
Unit Rate per BOE [1]	$5.28	$4.70

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

G&A expense for the first quarter of 2013 increased as compared with 2012 primarily due to additional expenses relating to personnel, office, and information technology costs in support of our major development projects and increased exploration activities.

Gain on Divestitures Gain on divestitures was as follows:

	Three Months Ended March 31, 2013	2012
(millions)		
Gain on Divestitures	$(15)	$—

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

Other (Income) Expense

Other (income) expense was as follows:

	Three Months Ended March 31, 2013	2012
(millions)		
Loss on Commodity Derivative Instruments	$72	$96
Interest, Net of Amount Capitalized	25	32
Other Non-Operating (Income) Expense, Net	10	(1)
Total	$107	$127

Loss on Commodity Derivative Instruments   Loss on commodity derivative instruments is a result of mark-to-market accounting.   See Item 1. Financial Statements – Note 4. 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, 2013	2012
(millions, except unit rate)		
Interest Expense	$67	$69
Capitalized Interest	(42)	(37)
Interest Expense, Net	$25	$32
Unit Rate per BOE [1]	$1.19	$1.55

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

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, offshore West Africa, and offshore Israel.

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

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 quarter of 2013 as compared with 2012.

Discontinued Operations

Summarized results of discontinued operations were as follows:

	Three Months Ended March 31,	
	2013	2012
(millions)		
Oil and Gas Sales	$10	$75
Less:		
Production Expense	8	14
DD&A Expense	1	18
Other (Income) Expense, Net	2	4
Income (Loss) Before Income Taxes	(1)	39
Income Tax Expense	7	25
Operating Income (Loss), Net of Tax	(8)	14
Gain on Sale, Net of Tax	37	—
Income From Discontinued Operations	$29	$14
Key Statistics:		
Daily Production		
Crude Oil & Condensate (MBbl/d)	1	6
Natural Gas (MMcf/d)	3	5
Average Realized Price		
Crude Oil & Condensate (Per Bbl)	$113.97	$122.44
Natural Gas (Per Mcf)	10.03	7.88

Our long-term debt is recorded at the consolidated level and is not reflected by each component. Thus, we have not allocated interest expense to discontinued operations.

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

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 throughout a range of scenarios, while also maintaining the capability to execute a robust exploration program and capitalize on financially attractive periodic mergers and acquisitions activity. We endeavor to maintain an investment grade debt rating in service of these objectives, while delivering competitive returns and a growing dividend. We also utilize a commodity price hedging program to reduce the impacts of commodity price volatility and enhance the predictability of cash flows along with a risk and insurance program to protect against disruption to our cash flows and the funding of our business.

Our current line-up of major development projects, as well as our planned exploration and appraisal drilling activities, will result in capital expenditures exceeding cash flows from operating activities over the near term. The amount by which capital investment will exceed operating cash flows depends on our success in sanctioning future development projects, the results of our exploration activities, and new business opportunities as well as external factors such as commodity prices among others.

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To support our investment program, we expect that higher production resulting from our horizontal Niobrara development program combined with new production from Tamar and Alen will result in an increase in cash flows which will be available to meet a substantial portion of future capital commitments. We also evaluate potential strategic farm-out arrangements of our working interests in Israel, Cyprus, Nicaragua and the deepwater Gulf of Mexico for reimbursement of our capital spending in these areas or incremental cash inflows. In addition, our current liquidity level and balance sheet provide flexibility. We believe that we are well-positioned to fund our long-term growth plans. See Available Liquidity, below.

We are currently evaluating potential development scenarios for our significant natural gas discoveries offshore Eastern Mediterranean, including Leviathan and Cyprus Block 12. The magnitude of these discoveries presents financial and technical challenges for us due to the large-scale development requirements. Potential development scenarios may include the construction of LNG terminals, floating LNG, subsea pipeline or other options. Each of these development options would require a multi-billion dollar investment and a number of years to complete. We have announced a potential strategic partner for Leviathan, Woodside, who could provide midstream expertise as well as LNG project execution and marketplace expertise. We are in the process of negotiating a definitive agreement.

We strive to maintain a minimum liquidity level to address volatility and risk. Traditional sources of our liquidity are cash on hand, cash flows from operations, available borrowing capacity under our credit facility, and proceeds from sales of non-core properties, such as certain onshore US and North Sea properties in 2013 and 2012. We may also access debt and/or capital markets for additional financing, such as an issuance of long-term debt or project finance, for our large development projects. See Credit Facility below.

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:

	March 31, 2013	December 31, 2012
(millions, except percentages)		
Cash and Cash Equivalents	$1,305	$1,387
Amount Available to be Borrowed Under Credit Facility [1]	4,000	4,000
Total Liquidity	$5,305	$5,387
Total Debt [2]	$4,111	$4,123
Total Shareholders' Equity	8,514	8,258
Ratio of Debt-to-Book Capital [3]	33 %	33 %

(1) See Credit Facility below.

(2) Total debt includes Aseng FPSO lease obligation and remaining CONSOL installment payment 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 $1.3 billion in cash and cash equivalents at March 31, 2013, primarily denominated in US dollars and invested in money market funds and short-term deposits with major financial institutions. Approximately $1.0 billion 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 to fund international projects, including the planned developments in West Africa and the Eastern Mediterranean.

Credit Facility   We have an unsecured revolving credit facility (Credit Facility) that matures on October 14, 2016. The commitment is $4.0 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 put options. Our practice has been to hedge up to 50% of our forecasted hedgeable crude oil and natural gas production, for the current year plus two additional calendar years. The limit was recently increased to up to 75% of forecasted hedgeable global crude oil production for the years 2014 and 2015.

Current period settlements on commodity derivative instruments impact our liquidity, since we are either paying cash to, or receiving cash from, our counterparties. We net settle by counterparty based on master netting agreements. The net settlements take into account deferred premiums we have agreed to pay for put options. 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

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agreements to minimize the impact of interest rate fluctuations associated with fixed or floating rate borrowings. However, we currently have no interest rate derivative 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, 2013, the fair value of our commodity derivative assets was $49 million and the fair value of our commodity derivative liabilities was $53 million (after consideration of netting agreements). See Item 1. Financial Statements – Note 4. 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.

US Fiscal Environment The 2014 Presidential budget proposes the elimination of specific tax incentives related to oil, natural-gas and coal companies. The President remains focused on reducing tax benefits for the oil and gas industry, specifically the deferral of expensing intangible drilling and development costs (IDC). The discussions of a full tax reform continues with Congress and the Obama Administration divided over these issues. We continue to monitor these events and any potential impacts to our business.

European Debt Crisis The European debt crisis continues to have a negative impact on the European economy, with risks to the global financial system and overall global economy. Countries have raised taxes and reduced entitlements, but are still struggling to pay off their debts, and the major bailout fund, the European Stability Mechanism, has limited lending capacity. In March 2013, Cyprus, a country where we currently have exploration and appraisal activities, reached a bailout agreement with the International Monetary Fund. The agreement requires closure of the country's second largest bank and a tax on bank deposits at the largest lender in Cyprus. Our cash balances in Cyprus were not affected by the banking sector restructuring.

Some of the European banks are counterparties in our commodity hedging program and lenders in our credit facility. If these institutions receive credit downgrades, our internal risk guidelines could preclude further hedging activities with them. At this time, we believe our current balance sheet and financial flexibility enhance our ability to react to European events as they unfold.

Counterparty Credit Risk We monitor the creditworthiness of our trade creditors, joint venture partners, hedging counterparties, and financial institutions on an ongoing basis. Some of these entities are not as creditworthy as we are and may experience credit downgrades, as noted above, or liquidity problems. Credit downgrades or liquidity problems could result in a delay in our receiving proceeds from commodity sales or reimbursement of joint venture costs.

The current uncertain economic and commodity price environment increases the risk of a sudden negative change in liquidity, which could impair a party's ability to perform under the terms of a contract. We are unable to predict sudden changes in a party's creditworthiness or ability to perform. Even if we do accurately predict such sudden changes, our ability to negate these risks may be limited and we could incur significant financial losses.

In addition, nonoperating partners often must obtain financing for their share of capital cost for development projects. For example, our Eastern Mediterranean partners must obtain financing for their share of significant development expenditures at Leviathan, offshore Israel, which potentially includes an LNG project and/or major underwater pipeline. In conjunction with our negotiations with Woodside, we are assisting our current Leviathan partners to obtain appropriate financing for their share of development costs and considering providing a limited amount of financial backstop to them. 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 form of parental guarantees or letters of credit; however, not all of our counterparty credit is protected through guarantees or credit support. Nonperformance by a trade creditor, joint venture partner, hedging counterparty or financial institution 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 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. The CONSOL Carried Cost Obligation is currently suspended due to low natural gas prices. Based on the March 31, 2013 NYMEX Henry Hub natural gas price curve, we forecast our CONSOL Carried Cost Obligation will begin in the second half of 2013.

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Cash Flows

Cash flow information is as follows:

(millions)	Three Months Ended March 31, 2013	2012
Total Cash Provided By (Used in)		
Operating Activities	$705	$741
Investing Activities	(748)	(1,032)
Financing Activities	(39)	(21)
Decrease in Cash and Cash Equivalents	$(82)	$(312)

Operating Activities   Net cash provided by operating activities for the first three months of 2013 decreased as compared with 2012. Lower liquids sales prices, decrease in natural gas sales volumes and increases in production expenses, general and administrative expense and interest expense were offset by higher liquids sales volumes and natural gas prices. 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, including farm-in arrangements, which may result in reimbursement for capital spending that had been previously incurred by us. Capital spending for property, plant and equipment decreased by $212 million during the first three months of 2013 as compared with 2012, primarily due to a decline in the spending based on the project life cycle of major projects offshore West Africa and offshore Israel nearing completion, partially offset by increased development in the DJ Basin and Marcellus Shale. We received $76 million net proceeds from non-core asset divestitures during the first three months of 2013 as compared with no divestiture activity during the first three months of 2012.

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 2013, funds were provided by cash proceeds from, and tax benefits related to, the exercise of stock options ($31 million). We used cash to pay dividends on our common stock ($44 million), make principal payments related to the Aseng FPSO capital lease obligation ($12 million) and repurchase shares of our common stock ($14 million).

In comparison, 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 also 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).

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:

(millions)	Three Months Ended March 31, 2013	2012
Acquisition, Capital and Exploration Expenditures		
Unproved Property Acquisition	$37	$73
Exploration	188	129
Development	630	735
Corporate and Other	35	12
Total	$890	$949
Other		
Investment in Equity Method Investee	$20	$14

Unproved property acquisition costs for the first three months of both 2013 and 2012 were mainly related to acquisitions that strengthened our position in the DJ Basin along with other miscellaneous onshore US lease acquisitions.

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Investment in equity method investees represents funding of our investment in CONE Gathering LLC (CONE) which owns and operates the infrastructure associated with our Marcellus Shale joint venture.

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 short-term borrowing arrangements during the first three months of 2013.

At March 31, 2013, there were no borrowings outstanding under the Credit Facility, leaving $4.0 billion available for use. We expect to use the Credit Facility to fund our capital investment program, and we may periodically borrow amounts for working capital purposes. See Item 1 Financial Statements - Note 5. Debt.

Our outstanding fixed-rate debt (excluding the Aseng FPSO lease obligation) totaled approximately $3.8 billion at March 31, 2013. The weighted average interest rate on fixed-rate debt was 5.89%, with maturities ranging from September 2013 to August 2097. Approximately $528 million of our fixed rate debt is scheduled to mature by April 15, 2014.

Dividends We paid total cash dividends of 25 cents per share of our common stock during the first three months of 2013 and 22 cents per share during the first three months of 2012. 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 $22 million during the first three months of 2013 and $27 million during the first three months of 2012.

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 122,830 shares with a value of $14 million during the first three months of 2013 and 131,868 shares with a value of $13 million during the first three months of 2012.

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 volatility 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, 2013, we had entered into variable to fixed price commodity swaps, collars and put options 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 liability position with a fair value of $4 million. Based on the March 31, 2013 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 liability by approximately $32 million. A hypothetical price increase of $0.10 per MMBtu for natural gas would increase the fair value of our net commodity derivative liability by approximately $11 million. Our derivative instruments are executed under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net cash settled at the time of election. See Item 1. Financial Statements – Note 4. 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, 2013, we had approximately $3.8 billion (excluding the Aseng FPSO lease obligation) of long-term debt outstanding. All debt outstanding was fixed-rate debt with a weighted average interest rate of 5.89%. 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.

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, 2013, AOCL included $25 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 15, 2014 and 6% senior notes due March 1, 2041. See Item 1. Financial Statements – Note 4. 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, 2013, our cash and cash equivalents totaled approximately $1.3 billion, approximately 52% of which was invested in money market

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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, 2013 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 taxes payable in foreign tax jurisdictions, are settled in the foreign local 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.

Net transaction gains and losses were de minimis for the first quarters of both 2013 and 2012.

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.

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, 2012, 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, 2012 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.

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Part II. Other Information

Item 1. Legal Proceedings

West Virginia Matter In March 2013, we received seven Notices of Violation (NOV) and two Administrative Orders (Orders) from the West Virginia Department of Environmental Protection Office of Oil and Gas (OOG) regarding the unintentional discharge of a mixture of freshwater and produced water that occurred on or about the evening of February 22, 2013 from one of our permitted water storage facilities in Marshall County, West Virginia. At this time, the OOG has not established a proposed penalty for these NOVs or Orders. Given the 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.

Colorado Matter In April 2013, we received a proposed Early Settlement Agreement (ESA) from Colorado Department of Public Health and Environment's Air Pollution Control Division to resolve allegations of noncompliance with our 2011 Ozone and Non-Ozone season spreadsheet submissions pursuant to Air Quality Control Commission Regulation 7. The ESA, which provides for an opportunity to further discuss the offer of settlement, has not yet been executed. At present, the ESA seeks payment of a reduced penalty of $112,000. 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.

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, 2012.

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)
1/1/2013 - 1/31/2013	—	$—	—	—
2/1/2013 - 2/28/2013	121,956	108.76	—	—
3/1/2013 - 3/31/2013	874	109.64	—	—
Total	122,830	$108.76	—	—

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

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

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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.

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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 25, 2013	/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 of the Registrant (as amended through April 23, 2013), filed herewith.
3.2	By-Laws of Noble Energy, Inc. (as amended through April 23, 2013), filed herewith.
10.1	Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (as amended through April 23, 2013), filed herewith.
12.1	Calculation of ratio of earnings to fixed charges, filed herewith.
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