NOBLE ENERGY INC
Form 10-Q
October 24, 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 September 30, 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)
1001 Noble Energy Way	
Houston, Texas	77070
(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 September 30, 2013, there were 359,276,944 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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Revenues				
Oil, Gas and NGL Sales	$1,341	$954	$3,537	$2,925
Income from Equity Method Investees	53	51	150	137
Total	1,394	1,005	3,687	3,062
Costs and Expenses				
Production Expense	221	158	619	492
Exploration Expense	60	95	211	322
Depreciation, Depletion and Amortization	412	368	1,146	987
General and Administrative	109	93	324	286
Gain on Divestitures	—	(157)	(12)	(167)
Asset Impairments	63	—	63	73
Other Operating (Income) Expense, Net	6	(2)	27	19
Total	871	555	2,378	2,012
Operating Income	523	450	1,309	1,050
Other (Income) Expense				
(Gain) Loss on Commodity Derivative Instruments	157	135	69	(46)
Interest, Net of Amount Capitalized	46	36	104	95
Other Non-Operating (Income) Expense, Net	9	4	21	2
Total	212	175	194	51
Income from Continuing Operations Before Income Taxes	311	275	1,115	999
Income Tax Provision	116	111	330	312
Income from Continuing Operations	195	164	785	687
Discontinued Operations, Net of Tax	10	57	58	89
Net Income	$205	$221	$843	$776
Earnings Per Share, Basic				
Income from Continuing Operations	$0.54	$0.46	$2.19	$1.93
Discontinued Operations, Net of Tax	0.03	0.16	0.16	0.25
Net Income	$0.57	$0.62	$2.35	$2.18
Earnings Per Share, Diluted				
Income from Continuing Operations	$0.53	$0.45	$2.17	$1.90
Discontinued Operations, Net of Tax	0.03	0.16	0.16	0.25
Net Income	$0.56	$0.61	$2.33	$2.15
Weighted Average Number of Shares Outstanding				
Basic	359	356	359	356
Diluted	363	359	363	361

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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Net Income	$205	$221	$843	$776
Other Items of Comprehensive Income				
Net Change in Pension and Other	4	4	15	9
Less Tax Benefit	(1)	(1)	(5)	(3)
Other Comprehensive Income	3	3	10	6
Comprehensive Income	$208	$224	$853	$782

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

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

	September 30, 2013	December 31, 2012
ASSETS		
Current Assets		
Cash and Cash Equivalents	$938	$1,387
Accounts Receivable, Net	973	964
Other Current Assets	328	420
Total Current Assets	2,239	2,771
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method of Accounting)	21,969	19,496
Property, Plant and Equipment, Other	437	344
Total Property, Plant and Equipment, Gross	22,406	19,840
Accumulated Depreciation, Depletion and Amortization	(7,049)	(6,289)
Total Property, Plant and Equipment, Net	15,357	13,551
Goodwill	631	635
Other Noncurrent Assets	641	597
Total Assets	$18,868	$17,554
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable - Trade	$1,408	$1,508
Other Current Liabilities	874	1,024
Total Current Liabilities	2,282	2,532
Long-Term Debt	4,352	3,736
Deferred Income Taxes, Noncurrent	2,305	2,218
Other Noncurrent Liabilities	865	810
Total Liabilities	9,804	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; 399 Million and 397 Million Shares Issued, respectively	4	4
Additional Paid in Capital	3,415	3,302
Accumulated Other Comprehensive Loss	(103)	(113)
Treasury Stock, at Cost; 38 Million Shares	(662)	(648)
Retained Earnings	6,410	5,713
Total Shareholders' Equity	9,064	8,258
Total Liabilities and Shareholders' Equity	$18,868	$17,554

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

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

	Nine Months Ended September 30,	
	2013	2012
Cash Flows From Operating Activities		
Net Income	$843	$776
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities		
Depreciation, Depletion and Amortization	1,148	1,020
Asset Impairments	63	73
Dry Hole Cost	22	141
Deferred Income Taxes	168	57
Dividends (Income) from Equity Method Investees, Net	(12)	4
Unrealized (Gain) Loss on Commodity Derivative Instruments	67	(74)
Gain on Divestitures	(67)	(83)
Stock Based Compensation	59	51
Other Adjustments for Noncash Items Included in Income	63	64
Changes in Operating Assets and Liabilities		
(Increase) Decrease in Accounts Receivable	(260)	68
Decrease (Increase) in Other Current Assets	13	(51)
Increase in Accounts Payable	63	122
(Decrease) Increase in Current Income Taxes Payable	(48)	51
(Decrease) in Other Current Liabilities	(20)	(13)
Other Operating Assets and Liabilities, Net	51	(35)
Net Cash Provided by Operating Activities	2,153	2,171
Cash Flows From Investing Activities		
Additions to Property, Plant and Equipment	(3,021)	(2,685)
Additions to Equity Method Investments	(30)	(35)
Proceeds from Divestitures	119	1,161
Other	(5)	—
Net Cash Used in Investing Activities	(2,937)	(1,559)
Cash Flows From Financing Activities		
Exercise of Stock Options	39	28
Excess Tax Benefits from Stock-Based Awards	15	14
Dividends Paid, Common Stock	(146)	(119)
Purchase of Treasury Stock	(14)	(13)
Proceeds from Credit Facilities	800	150
Repayment of Credit Facilities	—	(150)
Repayment of CONSOL Installment Loan	(328)	(328)
Repayment of Capital Lease Obligation	(31)	(32)
Net Cash Provided by (Used in) Financing Activities	335	(450)
(Decrease) Increase in Cash and Cash Equivalents	(449)	162
Cash and Cash Equivalents at Beginning of Period	1,387	1,455
Cash and Cash Equivalents at End of Period	$938	$1,617

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 [1]	Additional Paid in Capital [1]	Accumulated Other Comprehensive Loss	Treasury Stock at Cost	Retained Earnings	Total Shareholders' Equity
December 31, 2012	$4	$3,302	$(113)	$(648)	$5,713	$8,258
Net Income	—	—	—	—	843	843
Stock-based Compensation	—	59	—	—	—	59
Exercise of Stock Options	—	39	—	—	—	39
Tax Benefits Related to Exercise of Stock Options	—	15	—	—	—	15
Dividends (41 cents per share)	—	—	—	—	(146)	(146)
Changes in Treasury Stock, Net	—	—	—	(14)	—	(14)
Net Change in Pension and Other	—	—	10	—	—	10
September 30, 2013	$4	$3,415	$(103)	$(662)	$6,410	$9,064
December 31, 2011	$1,312	$1,841	$(100)	$(638)	$4,850	$7,265
Net Income	—	—	—	—	776	776
Stock-based Compensation	—	51	—	—	—	51
Exercise of Stock Options	—	28	—	—	—	28
Tax Benefits Related to Exercise of Stock Options	—	14	—	—	—	14
Dividends (33 cents per share)	—	—	—	—	(119)	(119)
Changes in Treasury Stock, Net	—	—	—	(13)	—	(13)
Change in Par Value	(1,308)	1,308	—	—	—	—
Net Change in Pension and Other	—	—	6	—	—	6
September 30, 2012	$4	$3,242	$(94)	$(651)	$5,507	$8,008

(1) Amounts restated to reflect impact of 2-for-1 stock split.

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

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Noble Energy, Inc.
Notes to Consolidated Financial Statements

Note 1. Organization and Nature of Operations
Noble Energy, Inc. (Noble Energy, we or us) is a leading independent energy company engaged in worldwide crude oil and natural gas exploration and production. Our core operating areas are onshore 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 September 30, 2013 and December 31, 2012 and for the three and nine months ended September 30, 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 and nine months ended September 30, 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.
Common Stock Split On April 22, 2013, Noble Energy's Board of Directors approved a 2-for-1 split of its common stock to be effected in the form of a stock dividend. The stock dividend was distributed on May 28, 2013 to shareholders of record as of May 14, 2013. Earnings per share and common shares outstanding are reported giving retrospective effect to the common stock split.
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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
(millions)				
Production Expense				
Lease Operating Expense	$137	$103	$393	$309
Production and Ad Valorem Taxes	51	31	137	112
Transportation and Gathering Expense	33	24	89	71
Total	$221	$158	$619	$492
Other Operating (Income) Expense, Net				
Other, Net	6	(2)	27	19
Total	$6	$(2)	$27	$19
Other Non-Operating (Income) Expense, Net				
Deferred Compensation (Income) Expense [1]	$10	$7	$24	$(1)
Other (Income) Expense, Net	(1)	(3)	(3)	3
Total	$9	$4	$21	$2

[1] Amounts represent increases (decreases) in the fair value of shares of our common stock held in a rabbi trust.

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Balance Sheet Information   Other balance sheet information is as follows:

(millions)	September 30, 2013	December 31, 2012
Accounts Receivable, Net		
Commodity Sales	$514	$349
Joint Interest Billings	389	486
Other	80	139
Allowance for Doubtful Accounts	(10)	(10)
Total	$973	$964
Other Current Assets		
Inventories, Current	$116	$90
Commodity Derivative Assets	15	63
Deferred Income Taxes, Net	20	106
Probable Insurance Claims (1)	—	45
Assets Held for Sale (2)	99	45
Prepaid Expenses and Other Current Assets	78	71
Total	$328	$420
Other Noncurrent Assets		
Equity Method Investments	$414	$367
Mutual Fund Investments	113	103
Commodity Derivative Assets	31	21
Other Assets	83	106
Total	$641	$597
Other Current Liabilities		
Production and Ad Valorem Taxes	$102	$113
Commodity Derivative Liabilities	39	7
Income Taxes Payable	155	203
Asset Retirement Obligations	69	69
Interest Payable	41	55
Current Portion of Long Term Debt (3)	200	324
Current Portion of FPSO and Other Capital Lease Obligations	51	48
Liabilities Associated with Assets Held for Sale (2)	44	12
Other	173	193
Total	$874	$1,024
Other Noncurrent Liabilities		
Deferred Compensation Liabilities	$265	$229
Asset Retirement Obligations	348	333
Accrued Benefit Costs	122	116
Other	130	132
Total	$865	$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 oil and gas properties and non-core onshore US properties in New Mexico. 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

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Noble Energy, Inc.
Notes to Consolidated Financial Statements

Note 3. Divestitures

North Sea Properties During the first nine months of 2013, we closed two sales of non-operated working interest properties located in the UK and Netherlands sectors of the North Sea. The sales resulted in a $55 million gain based on net sales proceeds of $54 million for the fields. We also signed a purchase and sale agreement related to our southern North Sea properties in the UK, which is expected to close during the fourth quarter of 2013, and continue to market our remaining North Sea properties.

As of September 30, 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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
(millions)				
Oil and Gas Sales	$11	$54	$32	$194
Income Before Income Taxes	7	38	10	117
Income Tax Expense	(3)	3	7	50
Operating Income (Loss), Net of Tax	10	35	3	67
Gain on Sale, Net of Tax	—	22	55	22
Discontinued Operations, Net of Tax	$10	$57	$58	$89

Onshore US Properties During the first nine months of 2013, we closed the sales of certain crude oil and natural gas properties in Kansas, Oklahoma and the Gulf Coast areas. The information regarding the assets sold is as follows:

	Nine Months Ended September 30, 2013
(millions)	
Sales Proceeds	$60
Less	
Net Book Value of Assets Sold	(53)
Goodwill Allocated to Assets Sold	(4)
Asset Retirement Obligations Associated with Assets Sold	5
Other Closing Adjustments	4
Gain on Divestitures	$12

During September 2013, we signed a purchase and sale agreement related to our non-core onshore US properties in New Mexico. These properties were reclassified as held for sale at September 30, 2013, which resulted in an impairment charge of $16 million. See Note 6. Fair Value Measurements and Disclosures.

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 production. In order to mitigate the effect of commodity price volatility and enhance the predictability of cash flows relating to the marketing of our global crude oil and domestic 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 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 September 30, 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 September 30, 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	37,000	92.67	—	—	—	—
2014	Swaps	Dated Brent	13,000	103.21	—	—	—	—
2014	Three-Way Collars	NYMEX WTI	12,000	—	—	75.67	90.67	100.88
2014	Three-Way Collars	Dated Brent	8,000	—	—	84.38	98.25	121.56
2015	Swaps	NYMEX WTI	16,000	87.66	—	—	—	—
2015	Swaps	Dated Brent	5,000	99.04	—	—	—	—
2015	Three-Way Collars	NYMEX WTI	15,000	—	—	70.67	88.00	94.78
2015	Three-Way Collars	Dated Brent	8,000	—	—	75.00	95.00	109.71

(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 at the time of settlement. If the index price settles at or above the floor price of the put option, we pay only the put option premium at the time of settlement.

As of September 30, 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 September 30, 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	230,000	—	2.83	3.75	4.98
2015	Swaps	NYMEX HH	80,000	4.32	—	—	—
2015	Three-Way Collars	NYMEX HH	120,000	—	3.54	4.25	5.06

[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			
	September 30, 2013		December 31, 2012		September 30, 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	$15	Current Assets	$63	Current Liabilities [1]	$39	Current Liabilities	$7
	Noncurrent Assets	31	Noncurrent Assets	21	Noncurrent Liabilities	2	Noncurrent Liabilities	3
Total		$46		$84		$41		$10

[1] Includes $6 million of deferred put option premium. The premium is paid monthly over the settlement terms.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions)	2013	2012	2013	2012
Realized Mark-to-Market (Gain) Loss				
Crude Oil	$24	$17	$39	$68
Natural Gas	(14)	(13)	(37)	(40)
Total Realized Mark-to-Market (Gain) Loss	10	4	2	28
Unrealized Mark-to-Market (Gain) Loss				
Crude Oil	143	112	60	(97)
Natural Gas	4	19	7	23

Total Unrealized Mark-to-Market (Gain) Loss	147	131	67	(74)
Total (Gain) Loss on Commodity Derivative Instruments	$157	$135	$69	$(46)

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Accumulated other comprehensive loss (AOCL) at September 30, 2013 included deferred losses of $24 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)	September 30, 2013 Debt		Interest Rate		December 31, 2012 Debt		Interest Rate	
Credit Facility, due October 3, 2018 [1]	$800		1.36	%	$—		—	
CONSOL Installment Payment, due September 30, 2013	—		—		328		1.79	% [2]
FPSO and Other Capital Lease Obligations	330		—		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	4,614				4,123			
Unamortized Discount	(11	)			(15	)		
Total Debt, Net of Discount	4,603				4,108			
Less Amounts Due Within One Year								
Current portion of CONSOL Installment Payment, net of discount	—				(324	)		
5¼% Senior Notes, due April 15, 2014, net of discount	(200	)			—			
FPSO and Other Capital Lease Obligations	(51	)			(48	)		
Long-Term Debt Due After One Year	$4,352				$3,736			

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

On October 3, 2013, we amended our Credit Facility to extend the maturity date to October 3, 2018.

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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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
September 30, 2013					
Financial Assets					
Mutual Fund Investments	$113	$—	$—	$—	$113
Commodity Derivative Instruments	—	72	—	(26)	46
Financial Liabilities					
Commodity Derivative Instruments	—	(67)	—	26	(41)
Portion of Deferred Compensation Liability Measured at Fair Value	(190)	—	—	—	(190)
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.

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Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis
Certain assets and liabilities are measured at fair value on a nonrecurring basis in our consolidated balance sheets. The following methods and assumptions were used to estimate the fair values:
Asset Impairments We determined that the carrying amounts of certain assets were not recoverable from future cash flows and, therefore, were impaired. The assets were reduced to their estimated fair values. Information about the impaired assets is as follows:

Description	Fair Value Measurements Using Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Book Value [1]	Total Pre-tax (Non-cash) Impairment Loss
millions					
Three Months Ended September 30, 2013					
Impaired Oil and Gas Properties	$—	$—	$75	$138	$63
Three Months Ended September 30, 2012					
Impaired Oil and Gas Properties	—	—	—	—	—
Nine Months Ended September 30, 2013					
Impaired Oil and Gas Properties	—	—	75	138	63
Nine Months Ended September 30, 2012					
Impaired Oil and Gas Properties	—	—	172	245	73

(1) Amount represents net book value at the date of assessment.

Amounts for 2013 related primarily to our non-core onshore US properties in New Mexico reclassified as held for sale at September 30, 2013 and our Mari-B field, offshore Israel, due to natural field decline.
Amounts for 2012 related primarily to our South Raton development in the deepwater Gulf of Mexico and our Piceance development, onshore US.
The fair values of properties held and used were determined as of the date of the assessment using discounted cash flow models based on management’s expectations for the future. Inputs included estimates of future oil and gas production, commodity prices based on NYMEX commodity price curves as of the date of the estimate, estimated operating and development costs, and a risk-adjusted discount rate of 10%. The fair values of assets held for sale were based on anticipated sales proceeds less costs to sell.
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 our Credit Facility (at September 30, 2013) approximates fair value because the interest rate paid on such debt is set for periods of three months or less. The carrying amount of the CONSOL installment payment (at December 31, 2012) approximates fair value because it is discounted at the prevailing market rate for similar debt instruments. As such, we consider the fair values of our Credit Facility and CONSOL installment payment to be Level 2 measurements on the fair value hierarchy.
See Note 5. Debt. Fair value information regarding our debt is as follows:

	September 30, 2013		December 31, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
(millions)				
Total Debt, Net of Unamortized Discount [1]	$4,273	$4,778	$3,797	$4,570

(1) Excludes FPSO and other capital lease obligations.

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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 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:

	Nine Months Ended September 30, 2013
(millions)	
Capitalized Exploratory Well Costs, Beginning of Period	$900
Additions to Capitalized Exploratory Well Costs Pending Determination of Proved Reserves	586
Reclassified to Proved Oil and Gas Properties Based on Determination of Proved Reserves	(34)
Capitalized Exploratory Well Costs Charged to Expense	(3)
Capitalized Exploratory Well Costs, End of Period	$1,449

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:

	September 30, 2013	December 31, 2012
(millions)		
Exploratory Well Costs Capitalized for a Period of One Year or Less	$732	$355
Exploratory Well Costs Capitalized for a Period Greater Than One Year Since Commencement of Drilling	717	545
Balance at End of Period	$1,449	$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

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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 September 30, 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	19	1	1	17
Offshore Cameroon				
YoYo	48	3	5	40
Offshore Israel				
Leviathan	125	17	67	41
Leviathan-1 Deep	77	49	28	—
Tanin 1	34	2	32	—
Dolphin 1	22	—	22	—
Dalit	23	1	—	22
Offshore Cyprus				
Cyprus A-1	70	13	57	—
Deepwater Gulf of Mexico				
Gunflint	116	64	—	52
Other				
Projects of $10 million or less each	29	20	—	9
Total	$717	$172	$272	$273

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 continue reviewing results of the Carla O-7 and Carla I-7 wells. During the third quarter of 2013, we successfully drilled the Diega I-8 appraisal well and are commencing flow testing. We are currently evaluating regional development scenarios.

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 and working with the government of Equatorial Guinea to assess longer-term natural gas commercialization across the industry.

YoYo   YoYo is a 2007 natural gas and condensate discovery in the YoYo Block. 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 future natural 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 integrating 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.

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 development alternatives.

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 development alternatives.

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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 The Cyprus A-1 is a successful natural gas exploratory well drilled on Block 12 in the fourth quarter of 2011. During the third quarter of 2013, we drilled a successful appraisal well. The A-2 location has successfully defined the northern area of the discovery, and we anticipate additional appraisal activities to further refine the ultimate recoverable resources and optimize field development planning. In addition to the appraisal well, we completed the acquisition phase of a 3D seismic study and are currently processing the results. We are working with the Cyprus government regarding domestic development plans along with possible LNG export options.

Gunflint Gunflint (Mississippi Canyon Block 948/992) is a 2008 crude oil discovery. In July 2012, we drilled a successful Gunflint appraisal well. We completed drilling our second successful Gunflint appraisal well in June 2013. In October 2013, we sanctioned the development plan for Gunflint utilizing a subsea tieback to an existing host facility. First production from Gunflint is targeted for 2016.

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:

	Nine Months Ended September 30,	
	2013	2012
(millions)		
Asset Retirement Obligations, Beginning Balance	$402	$377
Liabilities Incurred	4	24
Liabilities Settled	(15)	(98)
Revision of Estimate	7	30
Accretion Expense [1]	21	21
Other	(2)	(34)
Asset Retirement Obligations, Ending Balance	$417	$320

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

Liabilities incurred in 2013 relate primarily to wells drilled in the DJ Basin and Marcellus Shale, onshore US. Liabilities incurred in 2012 include costs to abandon the Leviathan-2 appraisal well, offshore Israel.

Liabilities settled in 2013 relate primarily to onshore US properties that have been sold. See Note 3. Divestitures. Liabilities settled in 2012 related primarily to certain North Sea and non-core onshore US property sales and the Leviathan-2 appraisal well.

Revisions relate primarily to our Alen development, offshore Equatorial Guinea, in 2013 and China in 2012.

Other includes ARO liabilities associated with properties held for sale, including certain onshore US properties in 2013 and North Sea properties in 2012. The liabilities are included within liabilities associated with assets held for sale. See Note 2. Basis of Presentation.

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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
(millions, except per share amounts)				
Income from Continuing Operations	$195	$164	$785	$687
Earnings Adjustment from Assumed Conversion of Dilutive Shares of Common Stock in Rabbi Trust [1]	—	—	—	(1)
Income from Continuing Operations Used for Diluted Earnings Per Share Calculation	$195	$164	$785	$686
Weighted Average Number of Shares Outstanding, Basic	359	356	359	356
Incremental Shares From Assumed Conversion of Dilutive Stock Options, Restricted Stock and Shares of Common Stock in Rabbi Trust	4	3	4	5
Weighted Average Number of Shares Outstanding, Diluted	363	359	363	361
Earnings from Continuing Operations Per Share, Basic	$0.54	$0.46	$2.19	$1.93
Earnings from Continuing Operations Per Share, Diluted	0.53	0.45	2.17	1.90
Number of antidilutive stock options, shares of restricted stock and shares of common stock in rabbi trust excluded from calculation above	4	6	5	4

(1) Consistent with GAAP, when dilutive, deferred compensation gains or losses, net of tax, are excluded from net income while our common shares held in the rabbi trust are included in the diluted share count. For this reason, the diluted earnings per share calculation for the nine months ended September 30, 2012 excludes deferred compensation gains.

Note 10. Income Taxes

The income tax provision relating to continuing operations consists of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
(millions)				
Current	$53	$37	$161	$138
Deferred	63	74	169	174
Total Income Tax Provision	$116	$111	$330	$312
Effective Tax Rate	37.2 %	40.4 %	29.6 %	31.2 %

Our effective tax rate (ETR) for the first nine months of 2013 decreased as compared with the first nine months of 2012. Concurrent with the filing of our 2012 fiscal year tax return during the third quarter of 2013, we released $25 million of valuation allowance with respect to the utilization of foreign tax credits. The decrease in ETR resulting from the valuation allowance release was partially offset by an increase in ETR resulting from an increase in the Israeli corporate income tax rate, from 25.0% to 26.5%, enacted in July 2013.

During 2012, we established a valuation allowance of $32 million with respect to foreign tax credits available, resulting in a corresponding increase in income tax expense during that year. Additionally, during the third quarter of 2012, we increased our reserve for uncertain tax positions related to prior years by $10 million.

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In our major tax jurisdictions, the earliest years remaining open to examination are as follows: US – 2010, Equatorial Guinea – 2008, Israel – 2008 and China –2010.
See Note 3. Divestitures for income taxes associated with discontinued operations.

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 September 30, 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.

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(millions)	Consolidated	United States	West Africa	Eastern Mediterranean	Other Int'l & Corporate
Three Months Ended September 30, 2013					
Revenues from Third Parties	$1,341	$810	$372	$122	$37
Income from Equity Method Investees	53	—	53	—	—
Total Revenues	1,394	810	425	122	37
DD&A	412	295	72	26	19
Gain on Divestitures	—	—	—	—	—
Asset Impairments	63	16	—	47	—
Loss on Commodity Derivative Instruments [1]	157	115	42	—	—
Income (Loss) from Continuing Operations Before Income Taxes	311	183	223	34	(129)
Three Months Ended September 30, 2012					
Revenues from Third Parties	$954	$593	$280	$48	$33
Income from Equity Method Investees	51	3	48	—	—
Total Revenues	1,005	596	328	48	33
DD&A	368	240	61	49	18
Gain on Divestitures	(157)	(157)	—	—	—
Asset Impairments	—	—	—	—	—
Loss on Commodity Derivative Instruments [1]	135	42	93	—	—
Income (Loss) from Continuing Operations Before Income Taxes	275	337	85	(11)	(136)
Nine Months Ended September 30, 2013					
Revenues from Third Parties	$3,537	$2,209	$935	$274	$119
Income from Equity Method Investees	150	—	150	—	—
Total Revenues	3,687	2,209	1,085	274	119
DD&A	1,146	819	189	81	57
Gain on Divestitures	(12)	(12)	—	—	—
Asset Impairments	63	16	—	47	—
Loss on Commodity Derivative Instruments [1]	69	54	15	—	—
Income (Loss) from Continuing Operations Before Income Taxes	1,115	746	722	93	(446)
Nine Months Ended September 30, 2012					
Revenues from Third Parties	$2,925	$1,674	$995	$121	$135
Income from Equity Method Investees	137	6	131	—	—
Total Revenues	3,062	1,680	1,126	121	135
DD&A	987	670	196	64	57
Gain on Divestitures	(167)	(167)	—	—	—
Asset Impairments	73	73	—	—	—
(Gain) Loss on Commodity Derivative Instruments [1]	(46)	(60)	14	—	—
Income (Loss) from Continuing Operations Before Income Taxes	999	578	767	26	(372)
September 30, 2013					
Total Assets	$18,829	$12,462	$3,300	$2,642	$425

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.

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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. We use common industry terms, such as thousand barrels of oil equivalent per day (MBoe/d) and million cubic feet equivalent per day (MMcfe/d), to discuss production and sales volumes. 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 that balances crude oil, US natural gas and NGLs, and international natural gas. We primarily focus on organic growth from exploration and development drilling within our core operating areas: onshore US (DJ Basin and Marcellus Shale), deepwater Gulf of Mexico, offshore West Africa and offshore Eastern Mediterranean, while seeking potential new core areas. We focus on basins or plays where we have strategic competitive advantage and which we believe generate superior returns.

In pursuit of our strategy, we progressed our exploration program during the third quarter of 2013 with a discovery at Troubadour (deepwater Gulf of Mexico) and a successful appraisal well offshore Cyprus. We achieved record sales volumes of 293 MBoe/d, driven by increased horizontal production in the DJ Basin and a ramp up of our Marcellus Shale drilling program. Our international assets contributed substantially with record production at Tamar in the Eastern Mediterranean, and continued strong performance from our West Africa assets, with uptime reliability of almost 98% at Aseng and increasing production as Alen ramps up to full capacity.

Our financial results for the third quarter of 2013 included:

- net income of $205 million (including $195 million from continuing operations), as compared with $221 million (including $164 million from continuing operations) for third quarter 2012;
- loss on commodity derivative instruments of $157 million (including unrealized mark-to-market loss of $147 million) as compared with a loss on commodity derivative instruments of $135 million (including unrealized mark-to-market loss of $131 million) for third quarter 2012;
- diluted earnings per share of $0.56, as compared with $0.61 for third quarter 2012;
- cash flow provided by operating activities of $909 million, as compared with $924 million for third quarter 2012;
- ending cash balance of $938 million, as compared with $1.4 billion at December 31, 2012;
- capital spending, on a cash basis, of $1.1 billion as compared with $785 million for third quarter 2012; and
- ratio of debt-to-book capital of 34%, as compared with 33% at December 31, 2012.

DJ Basin Acreage Exchange

On October 18, 2013, we closed an acreage exchange agreement with another operator related to our position in the greater Wattenberg area of northern Colorado. Each party contributed around 50,000 net acres to the exchange. The effective date of the transaction is January 1, 2013. The exchange consolidates large contiguous acreage blocks, and will provide the opportunity to optimize drilling, production, and gathering activities and add more extended-reach lateral wells to the program. A short-term reduction in production of approximately 8 MBoe/d is anticipated to be quickly offset with operational efficiencies and cost savings. We received approximately $105 million in cash related to reimbursement of capital expenditures and other normal closing adjustments from the effective date to closing date.

Colorado Flooding

In September 2013, floodwaters covered a 4,500 square-mile area in Northern Colorado. We have significant operations near the region impacted, as the DJ Basin is one of our core operating areas. We proactively shut-in certain wells in advance of potential flooding impacts. Average net daily production loss for the third quarter of 2013 was approximately 2 MBoe/d, of which 70% represented crude oil, condensate, and natural gas liquids. We continue to return wells to production, and drilling activities have returned to normal levels with all rigs currently operating. Limited access to certain affected locations has resulted in delays to some of our completion activities. The combined impact of wells shut-in due to flooding and delayed

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completion operations is anticipated to impact our fourth quarter 2013 average volumes by approximately 5 to 7 MBoe/d, of which 80% is projected to be liquids volumes.

Exploration Program Update

We continue to evaluate and build upon our significant exploration inventory in our core areas, as well as new venture locations.

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

We were in the process of drilling and/or evaluating significant exploratory wells at September 30, 2013 (See Item 1. Financial Statements – Note 7. Capitalized Exploratory Well Costs), and expect to continue an active exploratory drilling program in the future.

We devote significant capital to our exploration program. Approximately 22% 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 development 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. For example, in the deepwater Gulf of Mexico, while we continue to mature our prospect portfolio, regulations have become more stringent due to the Deepwater Horizon incident in 2010. In some instances, specifically engineered blowout preventers, rigs, and completion equipment may be required for high pressure environments. Regulatory requirements or lack of readily available equipment could prevent us from engaging in future exploration activities during our current lease terms. As a result, in a future period, dry hole cost and/or 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 third quarter of 2013, we successfully drilled the Troubadour exploratory well (Mississippi Canyon Block 699) to a total depth of 19,510 feet, where reservoir and fluid measurement logs identified a high-quality Miocene reservoir. The Troubadour natural gas discovery (60% operated working interest) is located adjacent to our 2012 Big Bend crude oil discovery (54% operated working interest). The combined area, identified as the Rio Grande area, provides another significant development opportunity.

In September 2013, we spud the Dantzler exploratory well on Mississippi Canyon 738/782, and expect to reach total depth during the fourth quarter of 2013. Also during the third quarter of 2013, we transferred a portion of our Dantzler interest to new partners, reducing our working interest to 45%.

Offshore Eastern Mediterranean During the third quarter of 2013, we drilled the successful Cyprus A-2 (70% operated working interest) appraisal well on Block 12, offshore the Republic of Cyprus. The A-2 well was drilled to a total depth of 18,865 feet in 5,575 feet of water and encountered approximately 120 feet of net natural gas pay within the targeted Miocene-aged sand intervals. The second appraisal well has successfully defined the northern area of the discovery, more than four miles from the A-1 location. We anticipate additional appraisal activities to further refine the ultimate recoverable resources and optimize field development planning. In addition to the appraisal well, we completed the acquisition phase of a 3D seismic study and are currently processing the results.

During the second quarter of 2013, we drilled a successful natural gas exploratory well on the Karish prospect in the Alon C license, offshore Israel. The well was drilled to a depth of 15,783 feet, discovering hydrocarbons in the lower Miocene sands. We hold a 47% operated working interest in Karish.

In October 2013, we spud our Tamar SW exploration well (36% operated working interest), offshore Israel, to test an exploration prospect offsetting the main Tamar field. We expect to reach total depth by the end of 2013.

Offshore Nicaragua   In August 2013, we spud our first exploratory well offshore Nicaragua (Paraiso), targeting a crude oil play. We anticipate reaching total depth during the fourth quarter of 2013. As of October 2013, pending government approval, we transfered a portion of our working interest in the block to two new partners, reducing our working interest to 70%.
Offshore Falkland Islands   In March 2013, we assumed operatorship of the Northern Area License from Falkland Oil and Gas Limited and will assume operatorship of the Southern Area License no later than March 2014. We continue to acquire and

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process 3D seismic over the Southern Area License and plan to acquire 3D seismic over the Northern Area License, beginning in the fourth quarter of 2013. The construction of our shore base facility is ongoing in preparation for our next exploratory well.

Northeast Nevada   Based on the 3D seismic acquired during 2012, we spud our first exploratory well in this area during the third quarter of 2013.

Major Development Project Updates

Thus far in 2013, we have successfully brought the Tamar, offshore Israel, and Alen, offshore Equatorial Guinea, projects online as we continue to advance our major development projects. Tamar has significantly increased our production offshore Israel and we are advancing plans for a compression project to expand the Ashdod onshore terminal to facilitate the increased sales volumes from Tamar. Alen began production in late second quarter of 2013, ahead of the original start up date, and utilizes the Aseng FPSO for storage and offloading. We expect these projects to deliver incremental production over the next several years. Updates on our major development projects are as follows:

Sanctioned Ongoing Development Projects

Horizontal Niobrara (Onshore US)   We have increased our horizontal drilling activity targeting the Niobrara formation in the Wattenberg area and our Northern Colorado acreage, resulting in a significant positive impact on our current production volumes. We expect to spud approximately 300 horizontal wells during 2013 and continue to move into areas of higher liquids content. We spud 221 horizontal wells thus far in 2013, including 23 extended-reach lateral wells.

We continue to build out infrastructure projects in the DJ Basin to maximize production efficiencies. Several infrastructure projects will come online over the next year and will significantly improve our flow assurance and reduce our truck traffic in the area. In the fourth quarter of 2013, our new crude oil gathering pipeline will be in service and will allow us to move crude oil from the northern parts of the basin to the center of the basin, which enhances our access to end markets. Additionally, a new rail facility is expected to commence operations during the fourth quarter of 2013 to further enhance the transportation of our crude oil out of the basin.

We will be bringing online our first central processing facility at Wells Ranch during the fourth quarter of 2013. This facility will enable us to efficiently gather and process crude oil, natural gas, and water from a large surrounding area, reducing truck traffic and our overall surface footprint. In the second half of 2014, we will start construction of our second gas processing plant in Northern Colorado where there is minimal infrastructure in place today. This will enhance our ability to develop this liquids-rich part of the basin.

Marcellus Shale (Onshore US)   We continue to delineate the wet gas acreage, while our partner CONSOL Energy continues to develop the dry gas area. We have begun to realize cost efficiencies through longer lateral wells and increased production growth through applied learning, completion design and optimized well placement. We have drilled to total depth 42 wet gas wells and 32 dry gas wells as well as turned 29 wet gas wells and 39 dry gas wells online during 2013. During 2014 we plan to continue to shift the balance of bringing wet and dry gas wells online and maximize the resource through exploration delineation and well spacing tests.

The CONSOL Carried Cost Obligation is currently suspended because average natural gas prices have remained below the contractual threshold. See Liquidity and Capital Resources – Contractual Obligations below.

Unsanctioned Development Projects (As of September 30, 2013)

Gunflint (deepwater Gulf of Mexico)   Gunflint was a 2008 crude oil discovery. We completed drilling our second successful Gunflint appraisal well in June 2013. In October 2013, we sanctioned the development plan for Gunflint utilizing a subsea tieback to an existing host facility. First production from Gunflint is targeted for 2016.

Rio Grande (deepwater Gulf of Mexico) The Rio Grande area is a co-development opportunity for two recent exploration successes in the deepwater Gulf of Mexico, Big Bend and Troubadour. In October 2013, we sanctioned the development plan for Big Bend utilizing a subsea tieback to a third party host facility, with first production targeted for late 2015. We are currently evaluating possible integration of the Troubadour discovery into this development plan.

Leviathan (Offshore Israel)   The successful results from our recent Leviathan-4 appraisal well have enhanced our understanding of the reservoir and we continue our evaluation of multiple development concepts.

We continue working with Woodside Energy Ltd. (Woodside) 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. See Operating Outlook – Update on Israel's Natural Gas Economy, below.

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Carla and Diega (Offshore Equatorial Guinea) We continue reviewing drilling results of the Carla O-7 and the Carla I-7 wells. During the third quarter of 2013, we successfully drilled the Diega I-8 appraisal well and are flow testing. We are currently evaluating regional development scenarios.

See Item 1. Financial Statements – Note 7. Capitalized Exploratory Well Costs for additional information on costs incurred related to these projects.

Sales Volumes

The execution of our strategy has delivered a diversified production growth most recently due to our Tamar and Alen projects coming online in 2013 along with our onshore unconventional developments. On a BOE basis, total sales volumes from continuing operations were 21% higher for the third quarter of 2013 as compared with the third quarter of 2012, and our mix of sales volumes was 43% global liquids, 29% international natural gas, and 28% US natural gas. See Results of Operations – Revenues, below.

Commodity Price Changes and Hedging

US average realized natural gas prices for the third quarter of 2013 increased 37% as compared with the third quarter of 2012. Total consolidated average realized crude oil prices for the third quarter of 2013 increased 6% as compared with the third quarter of 2012.

In order to mitigate the effect of commodity price volatility and enhance the predictability of cash flows, we have hedged approximately 49% of our expected global crude oil production and 55% of our expected domestic natural gas production for the remainder of 2013. See Item 1. Financial Statements – Note 4. Derivative Instruments and Hedging Activities.

Non-Core Divestiture Program

Our divestiture program for non-core assets is winding down with certain smaller onshore US property packages remaining to be sold. Divestitures of non-core properties allow us to allocate capital and employee resources to high-value and high-growth areas. Since January 1, 2012, the program has generated net proceeds of $1.3 billion providing additional flexibility for the continued growth of our five core areas.

During the first nine months of 2013, we closed two sales of non-operated working interests located in the UK and Netherlands sectors of the North Sea. The sales resulted in a $55 million gain based on total net sale proceeds of $54 million. We also closed the sale of certain crude oil and natural gas properties in Kansas, Oklahoma and the Gulf Coast areas for a $12 million gain based on total net sale proceeds of $60 million. We also signed purchase and sale agreements related to our southern North Sea properties in the UK and our onshore US properties in New Mexico and Wyoming (deep drilling rights only). All transactions are expected to close during the fourth quarter of 2013. 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 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.

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;
- increases in and timing of production from the Tamar project, offshore Israel, the Alen project, offshore Equatorial Guinea, horizontal drilling in the Niobrara formation in the DJ Basin and drilling in the Marcellus Shale;

- Israeli demand for electricity which affects demand for natural gas as fuel for power generation, industrial market growth, and production rates from Tamar, Mari-B and Noa fields, offshore Israel;
- variations in West Africa crude oil and condensate sales volumes due to potential Aseng FPSO downtime and timing of liftings, and variations in natural gas sales volumes related to potential downtime at the methanol, LPG and/or LNG plants;

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- natural field decline in the deepwater Gulf of Mexico and non-core onshore US areas, the Mari-B and Noa fields offshore Israel, and the Alba and Aseng fields offshore Equatorial Guinea;
- potential weather-related volume curtailments due to hurricanes in the deepwater Gulf of Mexico, heat in the Rocky Mountain area of our US operations, or winter storms and flooding in the DJ Basin, Marcellus Shale and/or Rocky Mountain areas;
- reliability of third party facilities and/or potential pipeline and processing facility capacity constraints which may cause restrictions or interruptions in mid-stream processing in the DJ Basin, Marcellus Shale and/or Rocky Mountain areas of our US operations;
- potential shut-in of US producing properties if storage capacity becomes unavailable;
- potential drilling and/or completion permit delays due to future regulatory changes; and
- potential purchases of producing properties or divestments of non-core operating assets.

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% to 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 22% of total capital.

The 2013 capital investment program will exceed operating cash flows and the difference is expected to be funded from cash on hand, borrowings under our Credit Facility, and/or other financing such as an issuance of long-term debt. Funding may also be provided by proceeds from divestment of non-core assets. See Liquidity and Capital Resources – Financing Activities below.

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

- commodity prices, including price realizations on specific crude oil, natural gas and NGL production;
- cash flows from operations;
- operating and development costs and service contractor market conditions;
- drilling results;
- CONSOL Carried Cost Obligation (See Liquidity and Capital Resources – Contractual Obligations, below);
- property acquisitions and divestitures;
- increase in exploration activities in new areas, including Northeast Nevada, Nicaragua and the Falkland Islands;
- availability of financing;
- potential legislative or regulatory changes;
- potential changes in the fiscal regimes of the US and other countries in which we operate; and
- impact of new laws and regulations.

Potential for Asset Impairments

Commodity prices remain volatile. A decline in future 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 along with operating and development costs, market outlook on forward commodity prices, 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.

We are currently marketing certain non-core properties. As of September 30, 2013, we signed a purchase and sale agreement related to our New Mexico onshore US assets, which resulted in a $16 million impairment charge. Management and the Board of Directors had not committed to any other specific plans to sell additional properties as of September 30, 2013. If properties are reclassified as assets held for sale in the future, 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. In addition, a further loss on sale could occur.

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 recently experienced mechanical issues, which are being remediated. We expect production to be restored in the fourth quarter of 2013; however, there is no assurance that such mechanical issues would not recur in the future or that future remediation efforts would be successful. South Raton had a net book value of approximately $115 million at September 30, 2013.

Update on Hydraulic Fracturing

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, on May 16, 2013, the US Department of the Interior issued proposed rules

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governing hydraulic fracturing on federal lands. The proposed rules would affect drilling operations on the 700 million acres of federally-owned minerals administered by the Bureau of Land Management, as well as 56 million acres of Native American-owned minerals.

The proposed rules would require companies to:

- disclose chemicals they inject by using an online database, with an exception for chemicals deemed to be trade secrets;
- verify that wells are drilled properly so that toxic fluids do not contaminate groundwater; and
- submit plans for managing drilling wastewater in lined pits or storage tanks.

The proposed rules could see further revision. Because oil and gas drilling and development activities, including hydraulic fracturing practices, are already regulated at the state level, compliance with federal hydraulic fracturing regulations may result in additional costs and reporting burdens.

In Nevada, the State Assembly recently adopted legislation that requires the development of a program to regulate the use of hydraulic fracturing in Nevada. State regulators will soon begin to develop a program to regulate hydraulic fracturing in the state.

In Colorado, there has been recent activity on oil and gas policy on multiple fronts. This includes several local ballot initiatives and ordinances, regulatory efforts, litigation, and statewide legislative efforts. For example, the city council of Fort Collins has enacted an ordinance that bans the use of hydraulic fracturing within city limits, and the voters of the city of Longmont have approved a charter amendment to ban hydraulic fracturing and other oil and gas practices within municipal boundaries. In addition, in November 2013, moratoria on hydraulic fracturing and other restrictions on oil and natural gas development are on ballots in municipalities including Broomfield, Fort Collins, Boulder and Lafayette. Some previously-enacted bans are being litigated by the state and industry as being in conflict with state law.

Because our operations are focused in Weld County, Colorado, we do not have active drilling programs in any of the areas currently experiencing bans or ballot initiatives. However, a state-wide moratorium or ban on hydraulic fracturing activities in Colorado or another state in which we conduct business could result in substantial incremental operating, capital and compliance costs as well as delay our ability to develop oil and gas reserves.

We continue to monitor these voter initiatives, as well as proposed legislation and regulations, to assess the potential impact on our operations and to develop and implement strategies for managing these risks. See also Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2012 – Federal or state hydraulic fracturing legislation could increase our costs or restrict our access to oil and gas reserves.

Update on Israel's Natural Gas Economy

Antitrust Authority   The Israeli Antitrust Commissioner has been actively engaged to encourage competition in developing Israel's natural gas resources. The Antitrust Commissioner ruled that all domestic natural gas sales contracts are subject to review and approval of the Antitrust Authority and has intervened regarding the terms used in long term contracts with certain end users. In addition, the Antitrust Commissioner has alleged that the Leviathan license acquisition agreement is a restrictive arrangement and has 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. We continue to engage with the Israeli government on this matter. Antitrust Commissioner decisions and actions to increase competition could result in a requirement to divest assets, reduce or relinquish revenue interests, and/or implement the marketing of our working interest share of production.

Natural Gas Export   The Israeli government is also in the process of developing a natural gas export policy. In September 2012, the Tzemach Committee issued its final recommendations on government policy for developing the natural gas economy (the Tzemach Report). See Items 1 and 2. Business and Properties – Regulations – Israeli Interministerial Committee in our Annual Report on Form 10-K for the year ended December 31, 2012.

On June 23, 2013, the Israeli Cabinet approved a plan for natural gas exports and other natural gas development related matters. However, certain members of the Knesset, the Israeli parliament, have demanded that natural gas policy, including exports, be legislated by the Knesset as opposed to a Cabinet ruling. This matter was appealed to the Israeli High Court of Justice (High Court). The High Court rejected the appeal on October 21, 2013.

With our partners, we are continuing to study the official export and natural gas development policies and are monitoring any additional developments to assess the possible impact, positive or negative, of any resulting laws or regulations on our future development activities in Israel. Certain changes in Israel's fiscal and/or regulatory regimes or energy policies occurring as a result of Antitrust Authority rulings or government policy on natural gas development and/or exports could: delay or reduce the profitability of our Tamar and/or Leviathan development projects; delay closing of a farm-out agreement which we are currently negotiating with Woodside or preclude such an agreement entirely; and/or render future exploration and development

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projects uneconomic. We continue to work with the Israeli government in support of establishing a stable investment climate to allow for future development of Israel's natural gas economy, which we believe will bring significant economic benefits to the state and citizens of Israel.

See also Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2012 – Our international operations may be adversely affected by economic and political developments.

Update on Cyber Security

In 2013, cyber attacks against US corporations have escalated, and we believe that cyber attackers are actively looking for ways to gain access to the networks and information of US oil and gas companies, including Noble Energy. While some attacks on US companies have resulted in theft of intellectual property or financial assets, other attacks have included infiltration, denial of service efforts, business disruption, or surveillance and control of computer systems with an apparent hostile intent. For example, it has been reported that hackers were able to gain access to control-system software that could allow manipulation of oil or gas pipeline operations. Such manipulation could include the deletion of important data or the disabling of key safety features.

Information technology and infrastructure may also be breached due to employee or contractor error or malfeasance or by other disruptions that could result in unauthorized disclosure or loss of information.

We continuously look for ways to enhance our cyber security controls and procedures, including the deployment of additional personnel and protection technologies, employee awareness and training, and application of learnings and best practices gained from other companies and government engagement.

We continue to face cyber threats, as do general industry and the oil and gas sector. Specifically, we are aware that we are at risk of cyber threats from hackers that are hostile to countries in which we operate. As these and other cyber threats evolve, we expect to expend additional financial or employee resources to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

See also Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2012 – A cyber incident could result in information theft, data corruption, operational disruption, and/or financial loss.

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 revised for the property and business interruption programs, as well as the excess liability program, in the first half of the year.

We carry some business interruption insurance for loss of production income arising from physical damage to our major facilities. The coverage is subject to customary deductibles, waiting periods and recovery limits. We also maintain credit insurance to mitigate commodity receivables concentration risk.

Availability of insurance coverage, subject to customary deductibles and recovery limits, 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; however, the amount of financial recovery through the fund is not guaranteed.

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. As a result, we currently believe it is more cost-effective for us to self-insure, or absorb any physical loss or damage to these assets, including any business interruption attributable to windstorm exposures. We continually assess our offshore insurance needs in response to our changing business requirements.

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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 $800 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 $600 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.

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.

In May, we successfully led a full-scale deployment of critical well control equipment to assess our ability to respond to a potential subsea blowout in the deepwater Gulf of Mexico. The drill was a collaborative test between the Department of the Interior's Bureau of Safety and Environmental Enforcement (BSEE), the U.S. Coast Guard, Louisiana Offshore Coordinator's Office and all 15 member companies of the HWCG consortium. Activation of the HWCG rapid response system and deployment of the HWCG capping stack to pressurization requirements met all objectives and marked the successful completion of the exercise.

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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 September 30,				
Oil, Gas and NGL Sales	$1,341	$954	41	%
Income from Equity Method Investees	53	51	4	%
Total	$1,394	$1,005	39	%
Nine Months Ended September 30,				
Oil, Gas and NGL Sales	$3,537	$2,925	21	%
Income from Equity Method Investees	150	137	9	%
Total	$3,687	$3,062	20	%

Changes in revenues are discussed below.

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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 September 30, 2013							
United States	64	489	13	159	$103.59	$3.57	$31.26
Equatorial Guinea (2)	37	257	—	80	107.67	0.27	—
Israel (3)	—	255	—	43	—	5.08	—
China	4	—	—	4	101.58	—	—
Total Consolidated Operations	105	1,001	13	286	104.95	3.11	31.26
Equity Investees (4)	2	—	6	7	104.45	—	64.74
Total Continuing Operations	107	1,001	19	293	$104.94	$3.11	$41.34
Three Months Ended September 30, 2012							
United States	52	440	16	141	$93.67	$2.61	$29.71
Equatorial Guinea (2)	27	251	—	70	108.90	0.27	—
Israel	—	116	—	19	—	4.43	—
China	3	—	—	3	107.61	—	—
Total Consolidated Operations	82	807	16	233	99.30	2.14	29.71
Equity Investees (4)	2	—	7	9	93.09	—	61.34
Total Continuing Operations	84	807	23	242	$99.18	$2.14	$39.05
Nine Months Ended September 30, 2013							
United States	61	434	15	148	$98.03	$3.64	$33.60
Equatorial Guinea (2)	31	251	—	73	106.78	0.27	—
Israel (3)	—	196	—	33	—	5.03	—
China	4	—	—	4	103.00	—	—
Total Consolidated Operations	96	881	15	258	101.08	3.00	33.60
Equity Investees (4)	2	—	6	8	105.03	—	67.59
Total Continuing Operations	98	881	21	266	$101.15	$3.00	$43.18
Nine Months Ended September 30, 2012							
United States	47	435	16	135	$96.20	$2.44	$34.87
Equatorial Guinea (2)	32	232	—	71	110.68	0.27	—
Israel	—	95	—	16	—	4.67	—
China	4	—	—	4	117.44	—	—
Total Consolidated Operations	83	762	16	226	102.90	2.06	34.87
Equity Investees (4)	2	—	6	8	104.09	—	63.93
Total Continuing Operations	85	762	22	234	$102.92	$2.06	$42.60

(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, an LNG plant and a power generation plant. The methanol and LPG plants are owned by affiliated entities accounted for under the equity method of accounting.

(3) Israel's weighted average natural gas price for third quarter 2013 represents 207 MMcf/d sold at an average price of $5.46 per Mcf under Tamar gas sale and purchase agreements (GSPAs) and 48 MMcf/d sold at an average price of $3.43 per Mcf under Mari-B GSPAs.

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Israel's weighted average natural gas price for the nine months ending September 30, 2013 represents 133 MMcf/d sold at an average price of $5.32 per Mcf under Tamar GSPAs and 63 MMcf/d sold at an average price of $4.44 per Mcf under Mari-B GSPAs.

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

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 September 30, 2012	$751	$159	$44	$954
Changes due to				
Increase (Decrease) in Sales Volumes	211	38	(8)	241
Increase in Sales Prices	55	89	2	146
Three Months Ended September 30, 2013	$1,017	$286	$38	$1,341
Nine Months Ended September 30, 2012	$2,339	$429	$157	$2,925
Changes due to				
Increase (Decrease) in Sales Volumes	391	66	(17)	440
Increase (Decrease) in Sales Prices	(47)	224	(5)	172
Nine Months Ended September 30, 2013	$2,683	$719	$135	$3,537

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

- higher sales volumes in the DJ Basin attributable to our horizontal drilling program;
- the addition of sales volumes of 7 MBoe/d from Alen, offshore Equatorial Guinea, which began producing in late second quarter of 2013;
- an increased number of liftings at Alba field, offshore Equatorial Guinea, due to timing; and
- higher average realized prices onshore US;

partially offset by:

- Colorado flooding impact of approximately 2 MBoe/d in the DJ Basin;
- decreases in sales volumes due to sales of certain onshore US properties in the third quarter of 2012; and
- decreases in sales volumes from Aseng, offshore Equatorial Guinea, of 4 MBoe/d due to natural production declines.

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

- higher sales volumes in the DJ Basin attributable to our horizontal drilling program;
- the addition of sales volumes from Galapagos, deepwater Gulf of Mexico, which began producing in the second quarter of 2012; and
- the addition of sales volumes from Alen, offshore Equatorial Guinea, which began producing in late second quarter of 2013;

partially offset by:

- a reduced number of liftings at Alba field, offshore Equatorial Guinea, due to timing;
- natural field decline at Aseng, offshore Equatorial Guinea;
- 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 certain onshore US properties in the third quarter of 2012.

Natural gas sales – Revenues from natural gas sales increased during the third quarter and first nine months 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 Israel from two full quarters of sales from Tamar, which contributed 207 Mmcf/d during the third quarter of 2013 and 133 Mmcf/d during the first nine months of 2013;

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- higher sales volumes of 397 Mmcf/d in the DJ Basin and Marcellus Shale primarily attributable to our horizontal drilling programs;

partially offset by:

- lower sales volumes due to divestitures of certain onshore US properties in the third quarter of 2012, which has continued during the first nine months of 2013; and
- lower sales volumes due to natural field decline from Mari B, Noa and Pinnacles, offshore Israel, which contributed a combined 63 Mmcf/d for the first nine months of 2013, compared with 95 Mmcf/d for the first nine months of 2012.

NGL sales – The majority of our US NGL production is currently from the DJ Basin. NGL sales revenues decreased during the third quarter and first nine months of 2013 as compared with 2012, primarily due to declines in sales volumes. NGL sales in the DJ Basin decreased by 2 Mboe/d during the third quarter of 2013 as compared with 2012, and recent sales of our non-core onshore US properties have reduced sales volumes by 1 Mboe/d as compared with the third quarter of 2012. Additionally, sales prices have declined for the first nine months of 2013, compared to the first nine months of 2012 due to high US NGL supply, which has exerted downward pressure on prices.

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.

Operating Costs and Expenses

Operating costs and expenses were as follows:

(millions)	2013	2012	Increase (Decrease) from Prior Year
Three Months Ended September 30,			
Production Expense	$221	$158	40 %
Exploration Expense	60	95	(37)%
Depreciation, Depletion and Amortization	412	368	12 %
General and Administrative	109	93	17 %
Gain on Divestitures	—	(157)	(100)%
Asset Impairments	63	—	N/M
Other Operating (Income) Expense, Net	6	(2)	N/M
Total	$871	$555	57 %
Nine Months Ended September 30,			
Production Expense	$619	$492	26 %
Exploration Expense	211	322	(34)%
Depreciation, Depletion and Amortization	1,146	987	16 %
General and Administrative	324	286	13 %
Gain on Divestitures	(12)	(167)	(93)%
Asset Impairments	63	73	(14)%
Other Operating (Income) Expense, Net	27	19	42 %
Total	$2,378	$2,012	18 %

N/M – Amount is not meaningful

Changes in operating costs and expenses are discussed below.

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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 September 30, 2013						
Lease Operating Expense [2]	$5.21	$137	$81	$30	$13	$13
Production and Ad Valorem Taxes	1.94	51	43	—	—	8
Transportation and Gathering Expense	1.26	33	32	—	—	1
Total Production Expense	$8.41	$221	$156	$30	$13	$22
Three Months Ended September 30, 2012						
Lease Operating Expense [2]	$4.82	$103	$68	$21	$6	$8
Production and Ad Valorem Taxes	1.43	31	24	—	—	7
Transportation and Gathering Expense	1.11	24	23	—	—	1
Total Production Expense	$7.36	$158	$115	$21	$6	$16
Nine Months Ended September 30, 2013						
Lease Operating Expense [2]	$5.56	$393	$260	$77	$33	$23
Production and Ad Valorem Taxes	1.94	137	112	—	—	25
Transportation and Gathering Expense	1.26	89	86	—	—	3
Total Production Expense	$8.76	$619	$458	$77	$33	$51
Nine Months Ended September 30, 2012						
Lease Operating Expense [2]	$4.98	$309	$207	$64	$13	$25
Production and Ad Valorem Taxes	1.81	112	83	—	—	29
Transportation and Gathering Expense	1.14	71	68	—	—	3
Total Production Expense	$7.93	$492	$358	$64	$13	$57

(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 third quarter and first nine months of 2013, total production expense increased as compared with 2012 due to the following:

- additional operating costs at Galapagos, deepwater Gulf of Mexico, which began production in the second quarter of 2012;
- additional operating costs related to Tamar's start-up and two full quarters of production at Tamar, offshore Israel;
- additional operating costs related to Alen's start-up, which began in late second quarter of 2013, offshore Equatorial Guinea;
- mechanical repairs related to Swordfish, deepwater Gulf of Mexico;
- a change in the US production mix as DJ Basin volumes grew while we have divested non-core properties;
- an increase in transportation and gathering expense due to higher natural gas production in the Marcellus Shale; and
- an increase in production and ad valorem taxes in the US due to higher volumes from the DJ Basin and the Pennsylvania well impact fee offset by a decrease associated with divestitures.

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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 September 30, 2013					
Dry Hole Cost	$(1)	$(1)	$—	$—	$—
Seismic	16	7	1	7	1
Staff Expense	33	11	2	2	18
Other	12	11	—	—	1
Total Exploration Expense	$60	$28	$3	$9	$20
Three Months Ended September 30, 2012					
Dry Hole Cost	$23	$3	$20	$—	$—
Seismic	7	7	—	—	—
Staff Expense	58	5	43	2	8
Other	7	7	—	—	—
Total Exploration Expense	$95	$22	$63	$2	$8
Nine Months Ended September 30, 2013					
Dry Hole Cost	$22	$14	$8	$—	$—
Seismic	66	20	3	13	30
Staff Expense	91	23	6	3	59
Other	32	32	—	—	—
Total Exploration Expense	$211	$89	$17	$16	$89
Nine Months Ended September 30, 2012					
Dry Hole Cost	$141	$120	$21	$—	$—
Seismic	53	47	—	—	6
Staff Expense	110	13	47	4	46
Other	18	17	1	—	—
Total Exploration Expense	$322	$197	$69	$4	$52

(1) West Africa includes Equatorial Guinea, Cameroon, and Sierra Leone, as well as 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 Falkland Islands and Nicaragua.

Exploration expense for the third quarter and first nine months of 2013 included the following:

- dry hole cost related primarily to the deeper exploration objective of the second Gunflint appraisal well, deepwater Gulf of Mexico, and the side track portion of the Carla I-7 appraisal well, offshore Equatorial Guinea;
- seismic expense related to our offshore Cyprus exploration program;
- other international seismic expense related to 3D seismic in the Falkland Islands; and
- staff expense associated with new ventures and corporate expenditures.

Exploration expense for the third quarter and first nine months of 2012 included the following:

- exploration expense of $40 million related to the non-operated AGC Profond block offshore Senegal/Guinea-Bissau;
- dry hole cost of $20 million incurred through September 30, 2012, related to the Trema exploratory well (offshore Cameroon);
- dry hole cost of $118 million related to the Deep Blue exploratory well (deepwater Gulf of Mexico);
- acquisition of seismic information for the deepwater Gulf of Mexico lease sale; and
- staff expense associated with new ventures and corporate expenditures.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
DD&A Expense (millions) [1]	$412	$368	$1,146	$987
Unit Rate per BOE [2]	$15.67	$17.16	$16.22	$15.92

[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 third quarter and first nine months of 2013 increased as compared with 2012 due to the following:

- higher sales volumes combined with development growth in the DJ Basin and Marcellus Shale;
- additional DD&A from the start up of Alen, offshore Equatorial Guinea, which began production in late second quarter of 2013; Galapagos, deepwater Gulf of Mexico, which began production in the second quarter of 2012; and Tamar, offshore Israel, which began production in late first quarter of 2013;

partially offset by:

- the impact of divestitures of non-core onshore US properties in 2012;
- lower DD&A from Mari-B, offshore Israel, due to natural field decline and decreased book value from 2012 impairment;
- lower DD&A from Raton South, deepwater Gulf of Mexico, due to decreased book value from 2012 impairment; and
- downtime at Swordfish, deepwater Gulf of Mexico, due to mechanical repairs in 2013.

Changes in the unit rate per BOE for the third quarter 2013 as compared with 2012 were primarily due to start-up of Tamar field, offshore Israel, and the Alen field, offshore Equatorial Guinea, as both these areas have comparatively lower DD&A rates, along with increased activity in the DJ Basin, which has a higher DD&A rate.

Changes in the unit rate per BOE for the first nine months 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, which have comparatively higher DD&A rates.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
G&A Expense (millions)	$109	$93	$324	$286
Unit Rate per BOE [1]	$4.14	$4.31	$4.59	$4.61

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

G&A expense for the third quarter and first nine months 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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
(millions)				
Gain on Divestitures	$—	$(157)	$(12)	$(167)

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

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Asset Impairment Expense Asset impairment expense was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
(millions)				
Asset Impairments	$63	$—	$63	$73

See Item 1. Financial Statements – Note 6. Fair Value Measurements and Disclosures.

Other Operating (Income) Expense, Net. See Item 1. Financial Statements – Note 2. Basis of Presentation

Other (Income) Expense

Other (income) expense was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
(millions)				
(Gain) Loss on Commodity Derivative Instruments	$157	$135	$69	$(46)
Interest, Net of Amount Capitalized	46	36	104	95
Other Non-Operating (Income) Expense, Net	9	4	21	2
Total	$212	$175	$194	$51

(Gain) Loss on Commodity Derivative Instruments (Gain) Loss on commodity derivative instruments is a result of mark-to-market accounting. Many factors impact our (gain) loss on commodity derivative instruments including: increases and decreases in the commodity forward curves compared to our executed hedging arrangements; increases in hedged future volumes; and the mix of hedge arrangements between NYMEX WTI, Dated Brent and NYMEX HH commodities. 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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
(millions, except unit rate)				
Interest Expense	$68	$69	$204	$207
Capitalized Interest	(22)	(33)	(100)	(112)
Interest Expense, Net	$46	$36	$104	$95
Unit Rate per BOE [1]	$1.74	$1.68	$1.47	$1.52

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

The decrease in capitalized interest is primarily due to the completion of major projects, such as Alen, offshore West Africa and Tamar, offshore Israel, partially offset by higher work in progress amounts related to major long-term projects in the deepwater Gulf of Mexico, offshore West Africa, and offshore Israel.

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 third quarter and first nine months of 2013 as compared with 2012.

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Discontinued Operations

Summarized results of discontinued operations were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
(millions)				
Oil and Gas Sales	$11	$54	$32	$194
Less:				
Production Expense	4	14	16	39
DD&A Expense	—	1	2	33
Other (Income) Expense, Net	—	1	4	5
Income Before Income Taxes	7	38	10	117
Income Tax Expense	(3)	3	7	50
Operating Income (Loss), Net of Tax	10	35	3	67
Gain on Sale, Net of Tax	—	22	55	22
Income From Discontinued Operations	$10	$57	$58	$89
Key Statistics:				
Daily Production				
Crude Oil & Condensate (MBbl/d)	1	5	1	6
Natural Gas (MMcf/d)	3	3	3	4
Average Realized Price				
Crude Oil & Condensate (Per Bbl)	$110.13	$106.03	$108.51	$113.11
Natural Gas (Per Mcf)	10.49	8.37	10.59	8.31

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.

We strive to maintain a minimum liquidity level to address volatility and risk. Traditional sources of our liquidity are cash flows from operations, available borrowing capacity under our Credit Facility, cash on hand, 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 the capital markets to ensure adequate liquidity exists in the form of unutilized capacity under our Credit Facility, under which we had borrowed $800 million at September 30, 2013, and to refinance scheduled debt maturities. We have $200 million of scheduled current maturities due by the end of the second quarter of 2014. See Credit Facility below.

As we ramp up the development of our major projects, as well as our planned exploration and appraisal drilling activities, we recognize that over the near term our capital expenditures will exceed cash flows from operating activities. During the first nine months of 2013, our cash balance decreased $449 million.

The extent to which capital investment will continue to 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. Our financial capacity, coupled with our balanced and diversified portfolio, provides

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us with flexibility in our investment decisions including execution of our major development projects and increased exploration activity.

To support our investment program, we expect that higher production resulting from our horizontal Niobrara development program combined with new production from Tamar, which began producing late in the first quarter of 2013, and Alen, which began producing late in the second quarter of 2013, 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, Cameroon, Nicaragua and the deepwater Gulf of Mexico for reimbursement of our capital spending in these areas. In addition, our current liquidity level and balance sheet, along with our ability to access the capital markets, 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, FPSO, 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.

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

	September 30, 2013	December 31, 2012
(millions, except percentages)		
Cash and Cash Equivalents	$938	$1,387
Amount Available to be Borrowed Under Credit Facility [(1)]	3,200	4,000
Total Liquidity	$4,138	$5,387
Total Debt [(2)]	$4,614	$4,123
Total Shareholders' Equity	9,064	8,258
Ratio of Debt-to-Book Capital [(3)]	34 %	33 %

(1) See Credit Facility below.

(2) Total debt includes FPSO and other capital lease obligations and the remaining CONSOL installment payment (at December 31, 2012) 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 $938 million in cash and cash equivalents at September 30, 2013, primarily denominated in US dollars and invested in money market funds and short-term deposits with major financial institutions. Approximately $755 million of this cash is attributable to our foreign subsidiaries and a portion would be subject to US income taxes if repatriated.

We are currently developing our 2014 capital investment program. If the 2014 capital investment program is expected to exceed operating cash flows, the difference could be funded from a variety of sources including cash on hand, borrowings under our Credit Facility, other financing such as an issuance of long-term debt, or proceeds from non-core asset divestment. In addition, we may consider repatriation possibilities.

Credit Facility   We have an unsecured revolving Credit Facility that matures on October 3, 2018. The commitment is $4.0 billion through the maturity date of the Credit Facility. On October 3, 2013, we amended the Credit Facility by extending the maturity date from October 14, 2016 to October 3, 2018.

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

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margin requirements. We have also used derivative instruments to manage interest rate risk by entering into forward contracts or swap agreements to minimize the impact of interest rate fluctuations associated with fixed or floating rate borrowings. However, we currently have no 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 September 30, 2013, the fair value of our commodity derivative assets was $46 million and the fair value of our commodity derivative liabilities was $41 million (after consideration of netting clauses within our master agreements). See Item 1. Financial Statements –Note 6. Fair Value Measurements and Disclosures for a description of the methods we use to estimate the fair values of derivative instruments and Counterparty Credit Risk, below, for a discussion of credit risk.

U. S. 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 increasing taxes on the oil and gas industry, specifically the elimination of expense treatment of intangible drilling and development costs. The discussions of a full tax reform continue 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 fallout from 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. Some countries have implemented austerity measures including raising taxes and reducing entitlements, but are still struggling to pay off their debts, and the major bailout fund, the European Stability Mechanism, has limited lending capacity. In many cases, the banking community across the region has undergone consolidation, restructuring and increased regulatory governance. 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 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, letters of credit or credit insurance; 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. Based on the September 30, 2013 NYMEX Henry Hub natural gas price curve, we forecast our CONSOL Carried Cost Obligation will remain suspended for the next 12 months.

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Cash Flows

Cash flow information is as follows:

	Nine Months Ended September 30,	
	2013	2012
(millions)		
Total Cash Provided By (Used in)		
Operating Activities	$2,153	$2,171
Investing Activities	(2,937)	(1,559)
Financing Activities	335	(450)
Increase (Decrease) in Cash and Cash Equivalents	$(449)	$162

Operating Activities   Net cash provided by operating activities for the first nine months of 2013 remained flat as compared with 2012. Higher natural gas sales prices and an increase in crude oil and natural gas sales volumes were offset by slightly lower crude oil sales prices and increases in production expenses and general and administrative expense. See Item 1. Financial Statements – Consolidated Statements of Cash Flows.

Investing Activities   Our investing activities include capital spending on a cash basis for oil and gas properties and investments in unconsolidated subsidiaries accounted for by the equity method. These investing activities may be offset by proceeds from property sales or dispositions, 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 increased by $336 million during the first nine months of 2013 as compared with 2012, primarily due to increased development in the DJ Basin and Marcellus Shale and corporate building improvements, partially offset by a decline in spending based on the project life cycle of recently-completed major projects offshore West Africa and offshore Israel. We received $119 million net proceeds primarily from non-core asset divestitures during the first nine months of 2013 as compared with $1.2 billion from divestiture activity during the first nine 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 nine months of 2013, funds were provided by cash proceeds from, and tax benefits related to the exercise of stock options ($54 million) and cash proceeds from our Credit Facility ($800 million). We used cash to make the final CONSOL installment payment ($328 million), pay dividends on our common stock ($146 million), make principal payments related to the Aseng FPSO capital lease obligation ($31 million) and repurchase shares of our common stock ($14 million).

In comparison, during the first nine months of 2012, funds were provided by cash proceeds from, and tax benefits related to, the exercise of stock options ($42 million). We also used cash to make the first CONSOL installment payment ($328 million), pay dividends on our common stock ($119 million), make principal payments related to the Aseng FPSO capital lease obligation ($32 million) and repurchase shares of our common stock ($13 million).

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

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Investing Activities

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
(millions)				
Acquisition, Capital and Exploration Expenditures				
Unproved Property Acquisition	$34	$(38)	$168	$49
Exploration	275	95	660	316
Development	795	648	2,169	2,102
Corporate and Other	35	19	159	44
Total	$1,139	$724	$3,156	$2,511
Other				
Investment in Equity Method Investee	$8	$—	$30	$35
Increase in Capital Lease Obligations	18	—	54	—

2013   Unproved property acquisition costs for the first nine months of 2013 were primarily related to acquisitions that strengthened our positions in the DJ Basin, Marcellus Shale and deepwater Gulf of Mexico.

2012   Unproved property acquisition costs for the first nine months of 2012 included downward adjustments related to the Marcellus Shale acquisition, offset by acquisitions that strengthened our positions in the DJ Basin and deepwater Gulf of Mexico along with entry into a license offshore Sierra Leone (West Africa).

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.

The increase in capital lease obligations represents estimated construction in progress to date on US operating assets. See Item 1. Financial Statements – Note 5. Debt.

Financing Activities

Long-Term Debt   Our principal source of liquidity is a Credit Facility that matures October 3, 2018. We utilized the Credit Facility to engage in short-term borrowing arrangements during the first nine months of 2013.

In addition, at September 30, 2013, we had $800 million outstanding under the Credit Facility, leaving $3.2 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 FPSO and other capital lease obligations) totaled approximately $3.5 billion at September 30, 2013. The weighted average interest rate on fixed-rate debt was 6.28%, with maturities ranging from April 2014 to August 2097. Approximately $200 million of our fixed rate debt is scheduled to mature by the end of the second quarter of 2014.

Dividends   We paid total cash dividends of 41 cents per share of our common stock during the first nine months of 2013 and 33 cents per share during the first nine months of 2012 (as adjusted for the 2-for-1 stock split during the second quarter of 2013). 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 $39 million during the first nine months of 2013 and $28 million during the first nine 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 247,985 shares with a value of $14 million during the first nine months of 2013 and 264,968 shares with a value of $13 million during the first nine months of 2012.

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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 September 30, 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 asset position with a fair value of $5 million. Based on the September 30, 2013 published commodity futures price curves for the underlying commodities, a hypothetical price increase of $1.00 per Bbl for crude oil would decrease the fair value of our net commodity derivative asset by approximately $37 million. A hypothetical price increase of $0.10 per MMBtu for natural gas would decrease the fair value of our net commodity derivative asset by approximately $12 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 Credit Facility and the amount of interest we earn on our short-term investments.

At September 30, 2013, we had approximately $4.3 billion (excluding FPSO and other capital lease obligations) of long-term debt outstanding. Of this amount, $3.5 billion was fixed-rate debt with a weighted average interest rate of 6.28%. Although near term changes in interest rates may affect the fair value of our fixed-rate debt, they do not expose us to the risk of earnings or cash flow loss.

The remainder of our long-term debt, $800 million at September 30, 2013, was variable-rate debt. Variable-rate debt exposes us to the risk of earnings or cash flow loss due to increases in market interest rates. We estimate that a hypothetical 25 basis point change in the floating interest rates applicable to the September 30, 2013 balance of our variable-rate debt would result in a change in annual interest expense of approximately $2 million.

We occasionally enter into interest rate derivative instruments such as forward contracts or swap agreements to hedge exposure to interest rate risk. Changes in fair value of interest rate derivative instruments used as cash flow hedges are reported in AOCL, to the extent the hedge is effective, until the forecasted transaction occurs, at which time they are recorded as adjustments to interest expense. At September 30, 2013, AOCL included $24 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 September 30, 2013, our cash and cash equivalents totaled approximately $938 million, approximately 49% of which was invested in money market funds and short-term investments with major financial institutions. A hypothetical 25 basis point change in the floating interest rates applicable to the amount invested as of September 30, 2013 would result in a change in annual interest income of approximately $1 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 third quarter and the first nine months of 2013. Net transaction gains (losses) totaled $2 million for the third quarter and ($4) million for the first nine months of 2012. The losses were primarily related to the changes in exchange rates between the US dollar and Israeli new shekel. Transaction (gains) losses are included in other (income) expense, net in the consolidated statements of operations.

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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 those 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 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.

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 Matters 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 submissions pursuant to Air Quality Control Commission Regulation 7. The ESA sought payment of a reduced penalty of $112,000. On June 18, 2013, we accepted the reduced penalty and executed a Compliance Order on Consent (COC). Under the terms and conditions of the COC, we agreed to pursue a supplemental environmental project (SEP) to mitigate $89,600 of the total penalty and submitted payment of $22,400 as an administrative penalty. On September 5, 2013, we provided $89,600 to the Colorado Energy Office to serve as funding for the development and implementation of an energy efficiency educational outreach program for students. All penalties associated with this matter have now been paid.

In July 2013, we received a proposed Compliance Order on Consent (COC) from Colorado Department of Public Health and Environment's Air Pollution Control Division to resolve allegations of noncompliance with our 2012 Ozone Season submissions pursuant to Air Quality Control Commission Regulation 7. The COC sought payment of a reduced penalty of $156,450. On August 7, 2013, we accepted the reduced penalty and executed the COC. Under the terms and conditions of the COC, we agreed to pursue a supplemental environmental project (SEP) to mitigate $125,160 of the total penalty and submitted payment of $31,290 as an administrative penalty. The SEP's $125,160 is currently intended to assist with the American Lung Association of Colorado's development and implementation of its Clear the Air Challenge, which is a pollution prevention and environmental education program that focuses on the reduction and/or elimination of pollutants, to help preserve the region's air quality through conservation of transportation related energy.

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)
7/1/2013 - 7/31/2013	186	$63.93	—	—
8/1/2013 - 8/31/2013	324	63.48	—	—
9/1/2013 - 9/30/2013	491	66.62	—	—

Total	1,001	$65.11	—	—

(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.

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Item 3. Defaults Upon Senior Securities
None.

Item 4. Mine Safety Disclosures
Not applicable.

Item 5. Other Information
None.

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

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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 October 24, 2013	/s/ Kenneth M. Fisher Kenneth M. Fisher Executive 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 as Exhibit 3.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2013 and incorporated herein by reference.
3.2	By-Laws of Noble Energy, Inc. (as amended through April 23, 2013), filed as Exhibit 3.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2013 and incorporated herein by reference.
10.1	First Amendment to Credit Agreement, dated October 3, 2013, by and among Noble Energy, Inc., JPMorgan Chase Bank, N.A., as administrative agent, Citibank N.A., as syndication agent, and Bank of America, N.A., Bank of Tokyo-Mitsubishi UFJ, Ltd., Mizuho Bank, Ltd. and DNB Bank ASA as documentation agents, and the other commercial lending institutions party thereto (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: October 3, 2013), filed October 9, 2013 and incorporated herein by reference).
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