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

FORM 10-Q

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

For the quarterly period ended March 31, 2016

OR

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

For the transition period from _____to_____

Commission file number: 001-07964

NOBLE ENERGY, INC.

(Exact name of registrant as specified in its charter)

Delaware	**73-0785597**
(State 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 ☒ No ☐
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes ☒ No ☐
Indicate by check mark 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 ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐
		(Do not check if a smaller reporting company)	

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

As of March 31, 2016, there were 429,592,264 shares of the registrant's common stock,
par value $0.01 per share, outstanding.

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Part I. Financial Information
Item 1. Financial Statements
Noble Energy, Inc.
Consolidated Statements of Operations
(millions, except per share amounts)
(unaudited)

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015
Revenues		
Oil, Gas and NGL Sales	$ 705	$ 749
Income from Equity Method Investees	19	18
Total	724	767
Costs and Expenses		
Production Expense	272	254
Exploration Expense	163	65
Depreciation, Depletion and Amortization	617	454
General and Administrative	91	94
Other Operating (Income) Expense, Net	3	34
Total	1,146	901
Operating Loss	(422)	(134)
Other (Income) Expense		
Gain on Commodity Derivative Instruments	(44)	(150)
Interest, Net of Amount Capitalized	79	57
Other Non-Operating (Income) Expense, Net	(4)	1
Total	31	(92)
Loss Before Income Taxes	(453)	(42)
Income Tax Benefit	(166)	(20)
Net Loss	$ (287)	$ (22)
Loss Per Share, Basic	$ (0.67)	$ (0.06)
Loss Per Share, Diluted	$ (0.67)	$ (0.06)
Weighted Average Number of Shares Outstanding		
Basic	429	370
Diluted	429	370

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

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

	Three Months Ended March 31,	
	2016	2015
Net Loss	$ (287)	$ (22)
Other Items of Comprehensive Loss		
Net Change in Mutual Fund Investment	—	(11)
Less Tax Benefit	—	3
Net Change in Pension and Other	—	1
Other Comprehensive Loss	—	(7)
Comprehensive Loss	$ (287)	$ (29)

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

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

		March 31, 2016		December 31, 2015
ASSETS				
Current Assets				
Cash and Cash Equivalents	$	953	$	1,028
Accounts Receivable, Net		531		450
Commodity Derivative Assets, Current		454		582
Other Current Assets		154		216
Total Current Assets		2,092		2,276
Property, Plant and Equipment				
Oil and Gas Properties (Successful Efforts Method of Accounting)		31,209		31,220
Property, Plant and Equipment, Other		892		858
Total Property, Plant and Equipment, Gross		32,101		32,078
Accumulated Depreciation, Depletion and Amortization		(11,394)		(10,778)
Total Property, Plant and Equipment, Net		20,707		21,300
Other Noncurrent Assets		614		620
Total Assets	$	23,413	$	24,196
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current Liabilities				
Accounts Payable - Trade	$	1,005	$	1,128
Other Current Liabilities		601		677
Total Current Liabilities		1,606		1,805
Long-Term Debt		7,882		7,976
Deferred Income Taxes, Noncurrent		2,640		2,826
Other Noncurrent Liabilities		1,233		1,219
Total Liabilities		13,361		13,826
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; 1 Billion Shares Authorized; 471 Million and 470 Million Shares Issued, respectively		5		5
Additional Paid in Capital		6,378		6,360
Accumulated Other Comprehensive Loss		(33)		(33)
Treasury Stock, at Cost; 38 Million Shares		(696)		(688)
Retained Earnings		4,398		4,726
Total Shareholders' Equity		10,052		10,370
Total Liabilities and Shareholders' Equity	$	23,413	$	24,196

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

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

	Three Months Ended March 31,	
	2016	2015
Cash Flows From Operating Activities		
Net Loss	$ (287)	$ (22)
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities		
Depreciation, Depletion and Amortization	617	454
Asset Impairments	—	27
Dry Hole Cost	93	20
Gain on Extinguishment of Debt	(80)	—
Loss on Asset Due to Terminated Contract	42	—
Deferred Income Tax Benefit	(186)	(30)
Loss from Equity Method Investees, Net of Dividends	(3)	(18)
Gain on Commodity Derivative Instruments	(44)	(150)
Net Cash Received in Settlement of Commodity Derivative Instruments	178	210
Stock Based Compensation	20	21
Other Adjustments for Noncash Items Included in Income	37	11
Changes in Operating Assets and Liabilities		
(Increase) Decrease in Accounts Receivable	(38)	107
Decrease in Accounts Payable	(24)	(71)
(Decrease) Increase in Current Income Taxes Payable	(16)	3
Other Current Assets and Liabilities, Net	(64)	(51)
Other Operating Assets and Liabilities, Net	6	30
Net Cash Provided by Operating Activities	251	541
Cash Flows From Investing Activities		
Additions to Property, Plant and Equipment	(496)	(1,111)
Additions to Equity Method Investments	(6)	(44)
Proceeds from Divestitures and Other	238	119
Net Cash Used in Investing Activities	(264)	(1,036)
Cash Flows From Financing Activities		
Dividends Paid, Common Stock	(41)	(64)
Proceeds from Issuance of Shares of Common Stock to Public, Net of Offering Costs	—	1,112
Proceeds from Term Loan Facility	1,400	—
Repayment of Senior Notes	(1,383)	—
Repayment of Capital Lease Obligation	(13)	(19)
Other	(25)	(8)
Net Cash (Used in) Provided by Financing Activities	(62)	1,021
(Decrease) Increase in Cash and Cash Equivalents	(75)	526
Cash and Cash Equivalents at Beginning of Period	1,028	1,183
Cash and Cash Equivalents at End of Period	$ 953	$ 1,709

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

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

	Common Stock	Additional Paid in Capital	Accumulated Other Comprehensive Loss	Treasury Stock at Cost	Retained Earnings	Total Shareholders' Equity
December 31, 2015	$ 5	$ 6,360	$ (33)	$ (688)	$ 4,726	$ 10,370
Net Loss	—	—	—	—	(287)	(287)
Stock-based Compensation	—	19	—	—	—	19
Dividends (10 cents per share)	—	—	—	—	(41)	(41)
Other	—	(1)	—	(8)	—	(9)
March 31, 2016	$ 5	$ 6,378	$ (33)	$ (696)	$ 4,398	$ 10,052
December 31, 2014	$ 4	$ 3,624	$ (90)	$ (671)	$ 7,458	$ 10,325
Net Loss	—	—	—	—	(22)	(22)
Stock-based Compensation	—	21	—	—	—	21
Dividends (18 cents per share)	—	—	—	—	(64)	(64)
Issuance of Shares of Common Stock to Public, Net of Offering Costs	—	1,112	—	— —	—	1,112
Other	—	4	(7)	(12)	—	(15)
March 31, 2015	$ 4	$ 4,761	$ (97)	$ (683)	$ 7,372	$ 11,357

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

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 (DJ Basin, Marcellus Shale, Eagle Ford Shale, and Permian Basin), deepwater Gulf of Mexico, offshore Eastern Mediterranean and offshore West Africa.

Note 2. Basis of Presentation

Presentation The accompanying unaudited consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the US (US GAAP) for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and notes required by US GAAP for complete financial statements. The accompanying consolidated financial statements at March 31, 2016 and December 31, 2015 and for the three months ended March 31, 2016 and 2015 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. Certain prior-period amounts have been reclassified to conform to the current-period presentation. Operating results for the three months ended March 31, 2016 are not necessarily indicative of the results that may be expected for the year ending December 31, 2016.

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, 2015.

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

Estimates The preparation of consolidated financial statements in conformity with US GAAP requires us to make a number of estimates and assumptions relating to the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ significantly from those estimates. Management evaluates estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic and commodity price environment.

Issuance of Phantom Units On February 1, 2016, we issued cash-settled awards to certain employees under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan in lieu of a portion of restricted stock and stock options. We issued approximately one million awards (phantom units; nomenclature used in accounting literature), a portion of which are subject to the achievement of specific performance goals. These phantom units, once vested, are settled in cash. The phantom units represent a hypothetical interest in the Company and are equivalent in value to the phantom unit value. The phantom unit value is the lesser of the fair market value of a share of common stock of the Company as of the vesting date or four times the fair market value of a share of common stock of the Company as of the grant date, which was $31.65. The Company recognizes the value of our cash-settled awards utilizing the liability method as defined under Accounting Standards Codification Topic 718, *Compensation - Stock Compensation*. The fair value of liability awards is remeasured at each reporting date, based on the fair market value of a share of common stock of the Company as of the reporting date, through the settlement date with the change in fair value recognized as compensation expense over that period. As of March 31, 2016, the fair value remeasurement had a de minimis impact on our consolidated statement of operations and balance sheet. See Note 7. Fair Value Measurements and Disclosures.

Recently Issued Accounting Standards In March 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2016-09 (ASU 2016-09): *Compensation - Stock Compensation*, to reduce complexity and enhance several aspects of accounting and disclosure for share-based payment transactions, including the accounting for income taxes, award forfeitures, and statutory tax withholding requirements, as well as classification in the statement of cash flows. The ASU will be effective for annual and interim periods beginning after December 15, 2016, with earlier application permitted. Certain aspects of this guidance will require retrospective application while other aspects are to be applied prospectively. We are currently evaluating the effect that the guidance will have on our consolidated financial statements and related disclosures.

In March 2016, the FASB issued Accounting Standards Update No. 2016-07 (ASU 2016-07): *Investments - Equity Method and Joint Ventures*, to eliminate retroactive application of equity method accounting when an investment becomes qualified for equity method accounting as a result of an increase in the level of ownership interest or degree of influence. The ASU will be effective for annual and interim periods beginning after December 15, 2016, with earlier application permitted. We are currently evaluating the effect, if any, that the guidance will have on our consolidated financial statements and related disclosures.

Noble Energy, Inc.
Notes to Consolidated Financial Statements

In February 2016, the FASB issued Accounting Standards Update No. 2016-02 (ASU 2016-02): *Leases.* The guidance requires lessees to recognize assets and liabilities on the balance sheet for the rights and obligations created by leases with terms of more than 12 months. This ASU also requires disclosures designed to give financial statement users information on the amount, timing, and uncertainty of cash flows arising from leases. The standard will be effective for annual and interim periods beginning after December 15, 2018, with earlier application permitted. While we are currently evaluating the provisions of this guidance to determine the effects it will have on our consolidated financial statements and related disclosures, we believe it is likely to have a material impact on our balance sheet resulting from an increase in both assets and liabilities relating to our leasing activities.

In July 2015, the FASB issued Accounting Standards Update No. 2015-11 (ASU 2015-11): *Simplifying the Measurement of Inventory*, effective for annual and interim periods beginning after December 15, 2016. ASU 2015-11 changes the inventory measurement principle for entities using the first-in, first out (FIFO) or average cost methods. For entities utilizing one of these methods, the inventory measurement principle will change from lower of cost or market to the lower of cost and net realizable value. We follow the average cost method and are currently evaluating the provisions of ASU 2015-11 and assessing the impact, if any, it may have on our financial position and results of operations.

In February 2015, the FASB issued Accounting Standards Update No. 2015-02 (ASU 2015-02): *Consolidation - Amendments to the Consolidation Analysis*, which changes the guidance as to whether an entity is a variable interest entity (VIE) or a voting interest entity and how related parties are considered in the VIE model. As of March 31, 2016, we have adopted the provisions of ASU 2015-02, which did not impact our consolidated financial statements.

In May 2014, the FASB issued Accounting Standards Update No. 2014-09 (ASU 2014-09), which creates Topic 606, *Revenue from Contracts with Customers*. In summary, the core principle of Topic 606 is that an entity recognizes revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. Additionally, ASU 2014-09 requires enhanced financial statement disclosures over revenue recognition as part of the new accounting guidance. The standard will be effective for annual reporting periods beginning after December 15, 2017, including interim reporting periods within that reporting period. In March 2016, the FASB released certain implementation guidance through ASU 2016-08 to clarify principal versus agent considerations. We are continuing to evaluate the provisions of ASU 2014-09 and have not yet determined the full impact it may have on our financial position and results of operations. At a minimum, we expect we will be required to change from the entitlements method used for certain domestic natural gas sales to the sales method of accounting.

Noble Energy, Inc.
Notes to Consolidated Financial Statements

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

	Three Months Ended March 31,	
(millions)	2016	2015
Production Expense		
Lease Operating Expense	$ 161	$ 157
Production and Ad Valorem Taxes (1)	4	32
Transportation and Gathering Expense (2)	107	65
Total	$ 272	$ 254
Other Operating (Income) Expense, Net		
Loss on Asset Due to Terminated Contract (3)	$ 42	$ —
Marketing and Processing Expense, Net (4)	22	6
Asset Impairments (5)	—	27
Gain on Extinguishment of Debt (6)	(80)	—
Other, Net	19	1
Total	$ 3	$ 34
Other Non-Operating (Income) Expense, Net		
Deferred Compensation Expense (7)	—	$ 2
Other (Income) Expense, Net	(4)	(1)
Total	$ (4)	$ 1

(1) The reduction in production and ad valorem taxes is primarily due to the accrual of a $28 million onshore US severance tax receivable during first quarter 2016.
(2) Certain of our revenue received from purchasers was historically presented with deductions for transportation, gathering, fractionation or processing costs. Beginning in 2016, we have changed our presentation of revenue to no longer include these expenses as deductions from revenue. These costs are now included within production expense and prior year amounts have been reclassified to conform to the current presentation.
(3) Amount relates to the termination of a rig contract offshore Falkland Islands as a result of a supplier's non-performance. See Note 8. Capitalized Exploratory Well Costs and Undeveloped Leasehold and Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Executive Overview - Exploration Program Update.
(4) In 2016, amount includes $16 million of expense due to unutilized firm transportation and shortfalls in delivering or transporting minimum volumes under certain commitments.
(5) Impairments during 2015 were related to facility costs at South Raton (Deepwater Gulf of Mexico) and increases in expected field abandonment cost for the Noa and Pinnacles fields (Eastern Mediterranean).
(6) Amount relates to the tendering of senior notes assumed in the Rosetta Merger. See Note 6. Debt.
(7) Amounts represent decreases in the fair value of shares of our common stock held in a rabbi trust.

Noble Energy, Inc.
Notes to Consolidated Financial Statements

Balance Sheet Information Other balance sheet information is as follows:

(millions)	March 31, 2016	December 31, 2015
Accounts Receivable, Net		
Commodity Sales	$ 308	$ 298
Joint Interest Billings	51	20
Proceeds Receivable [1]	40	—
Severance Tax Refund [2]	28	—
Other	128	151
Allowance for Doubtful Accounts	(24)	(19)
Total	$ 531	$ 450
Other Current Assets		
Inventories, Materials and Supplies	$ 90	$ 92
Inventories, Crude Oil	27	23
Assets Held for Sale [3]	—	67
Prepaid Expenses and Other Current Assets	37	34
Total	$ 154	$ 216
Other Noncurrent Assets		
Investments in Unconsolidated Subsidiaries	$ 461	$ 453
Mutual Fund Investments	77	90
Commodity Derivative Assets	6	10
Other Assets	70	67
Total	$ 614	$ 620
Other Current Liabilities		
Production and Ad Valorem Taxes	$ 162	$ 166
Income Taxes Payable	71	86
Asset Retirement Obligations	128	128
Interest Payable	94	83
Current Portion of Capital Lease Obligations	54	53
Other	92	161
Total	$ 601	$ 677
Other Noncurrent Liabilities		
Deferred Compensation Liabilities	$ 214	$ 217
Asset Retirement Obligations	872	861
Production and Ad Valorem Taxes	76	68
Other	71	73
Total	$ 1,233	$ 1,219

[1] Amount relates to proceeds to be received from our farm-out of 35% interest in Block 12 offshore Cyprus. See Note 4. Divestitures.
[2] Amount relates to the accrual of a $28 million onshore US severance tax receivable.
[3] Assets held for sale at December 31, 2015 included our Karish and Tanin natural gas discoveries, offshore Israel. The sale closed first quarter 2016. See Note 4. Divestitures.

Note 3. Rosetta Merger

On July 20, 2015, Noble Energy completed the merger of Rosetta Resources Inc. (Rosetta) into a subsidiary of Noble Energy (Rosetta Merger). The results of Rosetta's operations since the merger date are included in our consolidated statements of operations. The merger was effected through the issuance of approximately 41 million shares of Noble Energy common stock in exchange for all outstanding shares of Rosetta common stock using a ratio of 0.542 of a share of Noble Energy common stock for each share of Rosetta common stock and the assumption of Rosetta's liabilities, including approximately $2 billion fair value of outstanding debt. The merger added two new onshore US shale positions to our portfolio including approximately 50,000 net acres in the Eagle Ford Shale and 54,000 net acres in the Permian Basin (45,000 acres in the Delaware Basin and 9,000 acres in the Midland Basin). In connection with the Rosetta Merger, we incurred merger-related costs in 2015 of approximately $81 million, including (i) $66 million of severance, consulting, investment, advisory, legal and other merger-related fees, and (ii) $15 million of noncash share-based compensation expense, all of which were expensed and were included in Other Operating (Income) Expense, Net.

Allocation of Purchase Price The merger has been accounted for as a business combination, using the acquisition method. The following table represents the preliminary allocation of the total purchase price of Rosetta to the assets acquired and the liabilities assumed based on the fair value at the merger date, with any excess of the purchase price over the estimated fair value of the identifiable net assets acquired recorded as goodwill. Certain data necessary to complete the purchase price allocation is not yet available, and includes, but is not limited to, valuation of pre-merger contingencies, final assessment of deferred taxes based upon the underlying tax basis of Rosetta's assets and liabilities, and final appraisals of assets acquired and liabilities assumed. We expect to complete the purchase price allocation during the 12-month period following the merger date, in line with the acquisition method of accounting, during which time the value of the assets and liabilities may be revised as appropriate.

The following table sets forth our preliminary purchase price allocation which was based on fair values of assets acquired and liabilities assumed at the merger date, July 20, 2015, with the excess of the purchase price over the estimated fair value of the identifiable net assets acquired recorded as goodwill:

		(in millions, except stock price)
Shares of Noble Energy common stock issued to Rosetta shareholders		41
Noble Energy common stock price on July 20, 2015	$	36.97
Fair value of common stock issued	$	1,518
Plus: fair value of Rosetta's restricted stock awards and performance awards assumed		10
Plus: Rosetta stock options assumed		1
Total purchase price		1,529
Plus: liabilities assumed by Noble Energy		
Accounts Payable		100
Current Liabilities		37
Long Term Deferred Tax Liability		8
Long-Term Debt		1,992
Other Long Term Liabilities		23
Asset Retirement Obligation		27
Total purchase price plus liabilities assumed	$	3,716
Fair Value of Rosetta Assets		
Cash and Equivalents	$	61
Other Current Assets		76
Derivative Instruments		209
Oil and Gas Properties		
Proved Reserves		1,613
Undeveloped Leaseholds		1,355
Gathering & Processing Assets		207
Asset Retirement Obligation		27
Other Property Plant and Equipment		5
Goodwill		163
Total Asset Value	$	3,716

The fair value measurements of derivative instruments assumed were determined based on published forward commodity price curves as of the date of the merger and represent Level 2 inputs. 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. The fair value measurements of long-term debt were estimated based on published market prices and represent Level 1 inputs.

The fair value measurements of crude oil and natural gas properties and asset retirement obligations are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair values of crude oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of crude oil and natural gas properties included estimates of: (i) recoverable reserves; (ii) production rates; (iii) future operating and development costs; (iv) future commodity prices; and (v) a market-based weighted average cost of capital. These inputs required significant judgments and estimates by management at the time of the valuation and are the most sensitive and may be subject to change.

The results of operations attributable to Rosetta are included in our consolidated statements of operations beginning on July 21, 2015. Revenues of $87 million and pre-tax net loss of $31 million from Rosetta were generated during first quarter 2016.

Proforma Financial Information The following pro forma condensed combined financial information was derived from the historical financial statements of Noble Energy and Rosetta and gives effect to the merger as if it had occurred on January 1, 2015. The below information reflects pro forma adjustments based on available information and certain assumptions that we believe are reasonable, including (i) adjustments to conform Rosetta's historical policy of accounting for its crude oil and natural gas properties from the full cost method to the successful efforts method of accounting, (ii) depletion of Rosetta's fair-valued proved crude oil and natural gas properties, and (iii) the estimated tax impacts of the pro forma adjustments. The pro forma results of operations do not include any cost savings or other synergies that may result from the Rosetta Merger or any estimated costs that have been or will be incurred by us to integrate the Rosetta assets. The pro forma condensed combined financial information has been included for comparative purposes and is not necessarily indicative of the results that might have actually occurred had the Rosetta Merger taken place on January 1, 2015; furthermore, the financial information is not intended to be a projection of future results.

	Three Months Ended March 31,	
(in millions, except per share amounts)	2016 [1]	2015
Revenues	$ 724	$ 894
Net Loss	$ (287)	$ (27)
Loss per share		
Basic	$ (0.67)	$ (0.07)
Diluted	$ (0.67)	$ (0.07)

(1) No pro forma adjustments were made for the period as the acquisition is included in the Company's historical results.

Note 4. Divestitures

Offshore Israel Assets In November 2015, we executed an agreement to divest our 47% interest in the Alon A and Alon C offshore Israel licenses, which include the Karish and Tanin fields, for a total transaction value of $73 million. These assets were held for sale as of December 31, 2015, and the transaction closed in January 2016.

Cyprus Project (Offshore Cyprus) During fourth quarter 2015, we entered into a farm-out agreement with a partner for a 35% interest in Block 12, which includes the Aphrodite natural gas discovery, for $171 million. In first quarter 2016, we received proceeds of $131 million related to the farm-out agreement and expect to receive the remaining consideration of $40 million, subject to post-close adjustments, in 2017. The proceeds were applied to the Cyprus project asset with no gain or loss recognized.

Onshore US Properties During first quarter 2016, we sold certain onshore US crude oil and natural gas properties, generating net proceeds of $20 million. Proceeds were primarily applied to the DJ Basin depletable field, with no recognition of gain or loss.

During first quarter 2015, we sold certain onshore US crude oil and natural gas properties, generating net proceeds of $119 million. Proceeds were primarily applied to the DJ Basin depletable field, with no recognition of gain or loss.

Subsequent Event On May 2, 2016, we entered into a purchase and sale agreement for the divestiture of certain producing and undeveloped crude oil and natural gas interests in approximately 33,100 net acres in Weld County, Colorado for $505 million, subject to customary closing adjustments. The divestiture is expected to close during 2016, with an effective date of April 1, 2016; however, there can be no assurance that the transaction contemplated by the agreement will be consummated.

Note 5. Derivative Instruments and Hedging Activities

Objective and Strategies for Using Derivative Instruments We are exposed to fluctuations in crude oil and natural gas prices. 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.

While these instruments mitigate the cash flow risk of future decreases in commodity prices, they may also curtail benefits from future increases in commodity prices. See Note 7. Fair Value Measurements and Disclosures for a discussion of methods and assumptions used to estimate the fair values of our derivative instruments.

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Unsettled Commodity Derivative Instruments As of March 31, 2016, the following crude oil derivative contracts were outstanding:

				Swaps	Collars		
Settlement Period	Type of Contract	Index	Bbls Per Day	Weighted Average Fixed Price	Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
2Q16 (1)	Swaps	NYMEX WTI	5,000	$ 54.16	$ —	$ —	$ —
2H16 (1)	Call Option (2)	NYMEX WTI	5,000	—	—	—	54.16
2H16 (1)	Swaps	NYMEX WTI	4,000	47.34	—	—	—
2H16 (1)	Two-Way Collars	NYMEX WTI	6,000	—	—	35.00	49.82
2016	Swaps	NYMEX WTI	12,000	74.47	—	—	—
2016	Swaps (3)	(4)	6,000	90.28 —	—	—	—
2016	Two-Way Collars	NYMEX WTI	1,000	—	—	60.00	70.00
2016	Three-Way Collars	NYMEX WTI	6,000	—	61.00	72.50	86.37
2016	Swaps	Dated Brent	9,000	97.96	—	—	—
2016	Three-Way Collars	Dated Brent	8,000	—	72.50	86.25	101.79
1H17 (1)	Swaps	NYMEX WTI	3,000	60.12	—	—	—
1H17 (1)	Two-Way Collars	NYMEX WTI	2,000	—	—	40.00	50.44
1H17 (1)	Swaps	Dated Brent	3,000	62.80	—	—	—
2H17 (1)	Call Option (2)	NYMEX WTI	3,000	—	—	—	60.12
2H17 (1)	Swaptions (5)	Dated Brent	3,000	—	—	—	62.80
2017	Two-Way Collars	NYMEX WTI	7,000	—	—	40.00	53.29
2017	Call Option (2)	NYMEX WTI	3,000	—	—	—	57.00
2017	Swaptions (5)	NYMEX WTI	4,000	—	—	—	47.34

(1) We have entered into NYMEX WTI swap contracts for portions of 2016 and 2017 resulting in the difference in hedge volumes for the full year.

(2) We have entered into crude oil derivative enhanced swaps with strike prices that are above the market value as of trade commencement. To effect the enhanced swap structure, we sold call options to the applicable counterparty to receive the above market terms.

(3) Includes derivative instruments assumed by our subsidiary, NBL Texas, LLC, in connection with the Rosetta Merger.

(4) The index for these derivative instruments is NYMEX WTI and Argus LLS indices.

(5) We have entered into certain derivative contracts (swaptions), which give counterparties the option to extend for an additional 6-month or 12-month period. Options covering a notional volume of 3,000 Bbls/d are exercisable on June 30, 2017. If the counterparties exercise all such options, the notional volume of our existing Dated Brent derivative contracts will increase by 3,000 Bbls/d at a weighted average price of $62.80 per Bbl for each month during the period July 1, 2017 through December 31, 2017. Options covering a notional volume of 4,000 Bbls/d are exercisable on December 30, 2016. If the counterparties exercise all such options, the notional volume of our existing NYMEX WTI derivative contracts will increase by 4,000 Bbls/d at a weighted average price of $47.34 per Bbl for each month during the period July 1, 2017 through December 31, 2017.

As of March 31, 2016, the following natural gas derivative contracts were outstanding:

				Swaps	Collars		
Settlement Period	Type of Contract	Index	MMBtu Per Day	Weighted Average Fixed Price	Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
2H16	Swaps	NYMEX HH	30,000	$ 2.77	$ —	$ —	$ —
2016	Swaps	NYMEX HH	40,000	3.60	—	—	—
2016	Two-Way Collars	NYMEX HH	30,000	—	—	3.00	3.50
2016	Three-Way Collars	NYMEX HH	90,000	—	2.83	3.42	3.90
2016	Swaps (1)	(2)	30,000	4.04	—	—	—
2016	Two-Way Collars (1)	(2)	30,000	—	—	3.50	5.60
2017	Swaptions (3)	NYMEX HH	60,000	—	—	—	3.14

(1) Includes derivative instruments assumed by our subsidiary, NBL Texas, LLC, in connection with the Rosetta Merger.
(2) The index for these derivative instruments includes a combination of Houston Ship Channel and Tennessee Zone 0 indices.
(3) We have entered into certain natural gas derivative contracts (swaptions), which give counterparties the option to extend for an additional 12-month period. Options covering a notional volume of 60,000 MMBtu/d are exercisable on December 22 and 23, 2016. If the counterparties exercise all such options, the notional volume of our existing natural gas derivative contracts will increase by 60,000 MMBtu/d at a weighted average price of $3.14 per MMBtu for each month during the period January 1, 2017 through December 31, 2017.

Fair Value Amounts and (Gain) Loss on Commodity Derivative Instruments The fair values of commodity derivative instruments in our consolidated balance sheets were as follows:

Fair Value of Derivative Instruments

	Asset Derivative Instruments				Liability Derivative Instruments			
	March 31, 2016		December 31, 2015		March 31, 2016		December 31, 2015	
(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	$ 454	Current Assets	$ 582	Current Liabilities	$ 2	Current Liabilities	$ —
	Noncurrent Assets	6	Noncurrent Assets	10	Noncurrent Liabilities	1	Noncurrent Liabilities	—
Total		$ 460		$ 592		$ 3		$ —

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

	Three Months Ended March 31,	
(millions)	2016	2015
Cash Received in Settlement of Commodity Derivative Instruments		
Crude Oil	$ (156)	$ (185)
Natural Gas	(22)	(25)
Total Cash Received in Settlement of Commodity Derivative Instruments	(178)	(210)
Non-cash Portion of Loss on Commodity Derivative Instruments		
Crude Oil	127	55
Natural Gas	7	5
Total Non-cash Portion of Loss on Commodity Derivative Instruments	134	60
Gain on Commodity Derivative Instruments		
Crude Oil	(29)	(130)
Natural Gas	(15)	(20)
Total Gain on Commodity Derivative Instruments	$ (44)	$ (150)

Note 6. Debt

Debt consists of the following:

	March 31, 2016		December 31, 2015	
(millions, except percentages)	Debt	Interest Rate	Debt	Interest Rate
Revolving Credit Facility, due August 27, 2020	$ —	—%	$ —	—%
Capital Lease and Other Obligations	390	—%	403	—%
Term Loan Facility, due January 6, 2019	1,400	1.69%	—	—%
8.25% Senior Notes, due March 1, 2019	1,000	8.25%	1,000	8.25%
5.625% Senior Notes, due May 1, 2021	379	5.625%	693	5.63%
4.15% Senior Notes, due December 15, 2021	1,000	4.15%	1,000	4.15%
5.875% Senior Notes, due June 1, 2022	18	5.875%	597	5.88%
7.25% Senior Notes, due October 15, 2023	100	7.25%	100	7.25%
5.875% Senior Notes, due June 1, 2024	8	5.875%	499	5.88%
3.90% Senior Notes, due November 15, 2024	650	3.90%	650	3.90%
8.00% Senior Notes, due April 1, 2027	250	8.00%	250	8.00%
6.00% Senior Notes, due March 1, 2041	850	6.00%	850	6.00%
5.25% Senior Notes, due November 15, 2043	1,000	5.25%	1,000	5.25%
5.05% Senior Notes, due November 15, 2044	850	5.05%	850	5.05%
7.25% Senior Debentures, due August 1, 2097	84	7.25%	84	7.25%
Total	7,979		7,976	
Unamortized Discount	(24)		(24)	
Unamortized Premium	19		113	
Unamortized Debt Issuance Costs	(38)		(36)	
Total Debt, Net of Unamortized Discount, Premium and Debt Issuance Costs	7,936		8,029	
Less Amounts Due Within One Year				
Capital Lease Obligations	(54)		(53)	
Long-Term Debt Due After One Year	$ 7,882		$ 7,976	

Revolving Credit Facility Our Credit Agreement, as amended, provides for a $4.0 billion unsecured revolving credit facility (Revolving Credit Facility), which is available for general corporate purposes. The Revolving Credit Facility (i) provides for facility fee rates that range from 10 basis points to 25 basis points per year depending upon our credit rating, (ii) provides for interest rates that are based upon the Eurodollar rate plus a margin that ranges from 90 basis points to 150 basis points depending upon our credit rating, and (iii) includes a sub-limit for letters of credit up to an aggregate amount of $500 million ($450 million of which is committed as of March 31, 2016).

Term Loan Agreement and Completed Tender Offers On January 6, 2016, we entered into a term loan agreement (Term Loan Facility) with Citibank, N.A., as administrative agent, Mizuho Bank, Ltd., as syndication agent, and certain other financial institutions party thereto, which provides for a three-year term loan facility for a principal amount of $1.4 billion. Provisions of the Term Loan Facility are consistent with those in the Revolving Credit Facility. Borrowings under the Term Loan Facility may be prepaid prior to maturity without premium. The Term Loan Facility will accrue interest, at our option, at either (a) a base rate equal to the highest of (i) the rate announced by Citibank, N.A., as its prime rate, (ii) the Federal Funds Rate plus 0.5%, and (iii) a London interbank offered rate plus 1.0%, plus a margin that ranges from 10 basis points to 75 basis points depending upon our credit rating, or (b) a London interbank offered rate, plus a margin that ranges from 100 basis points to 175 basis points depending upon our credit rating. The interest rate for our Term Loan Facility is 1.69% as of March 31, 2016.

In connection with the Term Loan Facility, we launched cash tender offers for the 5.875% Senior Notes due June 1, 2024, 5.875% Senior Notes due June 1, 2022 and 5.625% Senior Notes due May 1, 2021, all of which were assumed in the Rosetta Merger. The borrowings under the Term Loan Facility were used solely to fund the tender offers. Approximately $1.38 billion of notes were validly tendered and accepted by us, with a corresponding amount borrowed under the new Term Loan Facility. As a result, we recognized a gain of $80 million which is reflected in other operating (income) expense, net in our consolidated statements of operations.

See Note 7. Fair Value Measurements and Disclosures for a discussion of methods and assumptions used to estimate the fair values of debt.

Note 7. Fair Value Measurements and Disclosures

Assets and Liabilities Measured at Fair Value on a Recurring Basis

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

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

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

Commodity Derivative Instruments Our commodity derivative instruments may include variable to fixed price commodity swaps, two-way collars, three-way collars, swaptions and enhanced swaps. We estimate the fair values of these instruments using 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 and the contract floors and ceilings using an option pricing model which takes into account market volatility, market prices and contract terms. See Note 5. 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.

Phantom Units The fair value of phantom unit awards is measured based on the fair market value of our common stock on the date of grant. We recognize the value of these awards utilizing the liability method whereby these liability awards are remeasured at each reporting date, based on the fair market value of a share of common stock of the Company as of the reporting date, through the settlement date with the change in fair value recognized as compensation expense over that period. See Note 2. Basis of Presentation.

Measurement information for assets and liabilities that are measured at fair value on a recurring basis was as follows:

	Fair Value Measurements Using				
	Quoted Prices in Active Markets (Level 1) (1)	Significant Other Observable Inputs (Level 2) (2)	Significant Unobservable Inputs (Level 3) (3)	Adjustment (4)	Fair Value Measurement
(millions)					
March 31, 2016					
Financial Assets					
Mutual Fund Investments	$ 77	$ —	$ —	$ —	$ 77
Commodity Derivative Instruments	—	472	—	(12)	460
Financial Liabilities					
Commodity Derivative Instruments	—	(15)	—	12	(3)
Portion of Deferred Compensation Liability Measured at Fair Value	(96)	—	—	—	(96)
Portion of Stock Based Compensation Liability Measured at Fair Value	(1)	—	—	—	(1)
December 31, 2015					
Financial Assets					
Mutual Fund Investments	$ 90	$ —	$ —	$ —	$ 90
Commodity Derivative Instruments	—	600	—	(8)	592
Financial Liabilities					
Commodity Derivative Instruments	—	(8)	—	8	—
Portion of Deferred Compensation Liability Measured at Fair Value	(98)	—	—	—	(98)

(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 provisions within our master agreements that allow us to net cash settle asset and liability positions with the same counterparty.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

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

Asset Impairments Information about impaired assets is as follows:

	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 March 31, 2016					
Impaired Oil and Gas Properties	$ —	$ —	$ —	$ —	$ —
Three Months Ended March 31, 2015					
Impaired Oil and Gas Properties	—	—	—	27	27

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

The fair value of impaired crude oil and natural gas properties was determined as of the date of the assessment using a discounted cash flow model based on management's expectations of future production prior to abandonment date, commodity prices based on NYMEX WTI, NYMEX Henry Hub, and Brent futures price curves as of the date of the estimate, estimated operating and abandonment costs, and a risk-adjusted discount rate. First quarter 2015 impairments were due primarily to increases in asset carrying values associated with increases in estimated abandonment costs.

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.

Our Term Loan Facility is variable-rate, non-public debt. The fair value is estimated based on significant other observable inputs. As such, we consider the fair value of our Term Loan Facility to be a Level 2 measurement on the fair value hierarchy. See Note 6. Debt.

Fair value information regarding our debt is as follows:

	March 31, 2016		December 31, 2015	
(millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt, Net [1]	$ 7,546	$ 7,334	$ 7,626	$ 7,105

[1] Net of unamortized discount, premium and debt issuance costs and excludes capital lease and other obligations.

Note 8. Capitalized Exploratory Well Costs and Undeveloped Leasehold

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. On a quarterly basis, we review the status of suspended exploratory well costs and assess the development of these projects. 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:

(millions)	Three Months Ended March 31, 2016
Capitalized Exploratory Well Costs, Beginning of Period	$ 1,353
Additions to Capitalized Exploratory Well Costs Pending Determination of Proved Reserves	22
Divestitures [1]	(143)
Reclassified to Proved Oil and Gas Properties Based on Determination of Proved Reserves	(2)
Capitalized Exploratory Well Costs Charged to Expense [2]	(56)
Capitalized Exploratory Well Costs, End of Period	$ 1,174

[1] Represents our farm-out of a 35% interest in Block 12 offshore Cyprus to a new partner.
[2] Includes $42 million relating to the termination of a rig contract offshore Falkland Islands as a result of a supplier's non-performance.

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

(millions)	March 31, 2016	December 31, 2015
Exploratory Well Costs Capitalized for a Period of One Year or Less	$ 63	$ 95
Exploratory Well Costs Capitalized for a Period Greater Than One Year Since Commencement of Drilling	1,111	1,258
Balance at End of Period	$ 1,174	$ 1,353
Number of Projects with Exploratory Well Costs That Have Been Capitalized for a Period Greater Than One Year Since Commencement of Drilling	14	14

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The following table includes exploratory well costs that have been capitalized for a period greater than one year since the commencement of drilling as of March 31, 2016:

(millions)	Total by Project	Progress
Country/Project:		
Deepwater Gulf of Mexico		
Troubadour	49	Evaluating development scenarios for this 2013 natural gas discovery including subsea tieback to existing infrastructure.
Katmai	93	Commenced drilling of an appraisal well in April 2016 to test the resource potential of this 2014 crude oil discovery.
Offshore Equatorial Guinea (Blocks I and O)		
Diega (Block I) and Carmen (Block O)	235	Evaluating regional development scenarios for this 2008 crude oil discovery. We drilled subsequent appraisal wells. During 2014, we conducted additional seismic activity over Blocks I and O and are interpreting and evaluating the acquired seismic data.
Carla (Block O)	180	Evaluating regional development scenarios for this 2011 crude oil discovery. We drilled subsequent appraisal wells. During 2014, we conducted additional seismic activity over Blocks I and O and are interpreting and evaluating the acquired seismic data.
Yolanda/Felicita	66	Evaluating regional development plans for these 2007/2008 condensate and natural gas discoveries. Natural gas development teams are working with the governments of Equatorial Guinea and Cameroon to evaluate natural gas monetization options and finalize data exchange agreements between the two countries.
Offshore Cameroon		
YoYo	52	Working with the government to assess commercialization of this 2007 condensate and natural gas discovery. A natural gas development team is working with the governments of Equatorial Guinea and Cameroon to evaluate natural gas monetization options and finalize a data exchange agreement between the two countries. Our 50% working interest partner has given notice to us and the Cameroon government of their intention to exit this acreage position. Once the assignment process is finalized, we will hold 100% operating working interest. We have begun efforts to market this additional working interest.
Offshore Israel		
Leviathan	194	We are engaged in natural gas marketing activities for both export and domestic Israeli customers. We have submitted a Plan of Development to the Government of Israel and continue to pursue financing arrangements to support development. The Natural Gas Framework was enacted in 2015 and subsequently affirmed by the Israeli Supreme Court, with the exception of the stability provisions. The Court concluded that the Government of Israel should provide stability assurances and provisions through an alternate legal mechanism and provided the Government up to one year to resolve this matter. In first quarter 2016, Israel's National Planning Commission approved the platform location and gas interconnect.
Leviathan-1 Deep	82	Well did not reach the target interval; developing future drilling plans to test this deep oil concept, which is held by the Leviathan Development and Production Leases. We are working on potential well design and placement. See also Leviathan, above, for discussion of Natural Gas Framework.

Dalit	28	Submitted a development plan to the government to develop this 2009 natural gas discovery as a tie-in to existing infrastructure.
Dolphin 1	26	Reviewing regional development scenarios for this 2011 natural gas discovery, including a potential tieback to Leviathan. We have applied to the government for a commerciality ruling and our license has been extended to second quarter 2016.
Offshore Cyprus		
Cyprus	84	We continue to work with the Government of Cyprus to obtain approval of the development plan and the subsequent issuance of an Exploitation License. Receiving an Exploitation License will enable us and our partners to perform the necessary engineering and design studies and progress the project to final investment decision. During fourth quarter 2015, we farmed-out a 35% working interest.
Other		
Individual Projects Less than $20 million	22	Continuing to assess and evaluate wells.
Total	$ 1,111	

Undeveloped Leasehold Costs As of March 31, 2016, we had capitalized undeveloped leasehold costs of $2.3 billion, of which approximately $2 billion relates to our core operating areas onshore US and is included in our quarterly impairment testing for these areas. In addition, we have capitalized undeveloped leasehold of $57 million relating to international operations,and $255 million relating to deepwater Gulf of Mexico.

Significant undeveloped leases, primarily in deepwater Gulf of Mexico, are individually assessed for impairment. While none of our undeveloped leases were impaired as of March 31, 2016, if, based upon a change in exploration plans, availability of capital and suitable rig and drilling equipment, resource potential, changing regulations and/or other factors, an impairment is indicated, a valuation allowance will be provided. Costs of individually insignificant leases are combined and amortized over their lease term. Expense associated with either impairment or amortization of undeveloped leases is included in exploration expense in our consolidated statement of operations.

Note 9. Asset Retirement Obligations

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

	Three Months Ended March 31,	
(millions)	2016	2015
Asset Retirement Obligations, Beginning Balance	$ 989	$ 751
Liabilities Incurred	2	10
Liabilities Settled	(8)	(8)
Revision of Estimate	5	24
Accretion Expense [1]	12	10
Asset Retirement Obligations, Ending Balance	$ 1,000	$ 787

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

For the three months ended March 31, 2016 Liabilities incurred were due to new wells and facilities for onshore US. Liabilities settled primarily related to onshore US property abandonments.

Revisions of estimates relate to changes in cost estimates of $5 million for Equatorial Guinea.

For the three months ended March 31, 2015 Liabilities incurred were due to new wells and facilities and included $4 million for onshore US and $6 million for deepwater Gulf of Mexico. Liabilities settled in 2015 relate primarily to non-core US properties classified as held for sale.

Revisions in estimate for 2015 relate to changes in cost estimates for Eastern Mediterranean.

Note 10. Loss Per Share

Basic loss per share of common stock is computed using the weighted average number of shares of common stock outstanding during each period. The following table summarizes the calculation of basic and diluted loss per share:

	Three Months Ended March 31,	
(millions, except per share amounts)	2016	2015
Net Loss	$ (287)	$ (22)
Weighted Average Number of Shares Outstanding, Basic [1]	429	370
Weighted Average Number of Shares Outstanding, Diluted[2]	429	370
Loss Per Share, Basic	**$ (0.67)**	**$ (0.06)**
Loss Per Share, Diluted	**(0.67)**	**(0.06)**
Number of Antidilutive Stock Options, Shares of Restricted Stock, and Shares of Common Stock in Rabbi Trust Excluded from Calculation Above	15	9

(1) The weighted average number of shares outstanding includes the weighted average shares of common stock issued in connection with the underwritten public offering of 24.15 million shares of Noble Energy common stock in first quarter 2015 and issued in connection with the exchange of approximately 41 million shares for all outstanding shares of Rosetta common stock on July 20, 2015.

(2) For the three months ended March 31, 2016 and March 31, 2015, all outstanding options and non-vested restricted shares have been excluded from the calculation of diluted loss per share as Noble Energy incurred a net loss. Therefore, inclusion of outstanding options and non-vested restricted shares in the calculation of diluted loss per share would be anti-dilutive.

Note 11. Income Taxes

The income tax benefit consists of the following:

	Three Months Ended March 31,	
(millions)	2016	2015
Current	$ 20	$ 10
Deferred	(186)	(30)
Total Income Tax Benefit	$ (166)	$ (20)
Effective Tax Rate	36.6%	47.6%

Accumulated Undistributed Earnings of Foreign Subsidiaries As of December 31, 2015, we no longer consider our foreign subsidiaries' undistributed earnings to be indefinitely reinvested outside the United States and, accordingly, recorded additional deferred income taxes, net of estimated foreign tax credits.

Effective Tax Rate (ETR) Our ETR decreased first quarter 2016 as compared with first quarter 2015. This is primarily due to a higher income tax benefit as compared with the change in the components of the overall net loss from period to period, which is impacted by certain income items with different tax rates.

Also, during first quarter 2016, the change in our permanent reinvestment assumption, noted above, resulted in additional deferred income tax expense (net of estimated foreign tax credits) being recorded on certain income items, including income from equity method investees and increased earnings in our foreign jurisdictions with rates that vary from the US statutory rate. This additional deferred income tax expense had the result of offsetting our income tax benefit to a greater extent in first quarter 2016 thereby driving the ETR lower than it would have been if additional deferred taxes had not been recorded.

In our major tax jurisdictions, the earliest years remaining open to examination are as follows: US – 2012, Equatorial Guinea – 2010 and Israel – 2011.

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Note 12. Segment Information

We have operations throughout the world and manage our global 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, Gabon and Sierra Leone (which we exited in second quarter 2015); Eastern Mediterranean (Israel and Cyprus); and Other International and Corporate. Other International includes the North Sea, Falkland Islands, Suriname, Nicaragua (which we exited in first quarter 2015) and new ventures.

(millions)	Consolidated	United States	West Africa	Eastern Mediterranean	Other Int'l & Corporate
Three Months Ended March 31, 2016					
Revenues from Third Parties	$ 705	$ 489	$ 90	$ 126	$ —
Income from Equity Method Investees	19	16	3	—	—
Total Revenues	724	505	93	126	—
DD&A	617	530	55	20	12
Gain on Commodity Derivative Instruments	(44)	(37)	(7)	—	—
Income (Loss) Before Income Taxes	(453)	(292)	9	84	(254)
Three Months Ended March 31, 2015					
Revenues from Third Parties	$ 749	$ 487	$ 138	$ 120	$ 4
Income from Equity Method Investees	18	11	7	—	—
Total Revenues	767	498	145	120	4
DD&A	454	357	77	15	5
Asset Impairments	27	3	—	24	—
Gain on Commodity Derivative Instruments	(150)	(105)	(45)	—	—
Income (Loss) Before Income Taxes	(42)	(1)	74	51	(166)
March 31, 2016					
Total Assets	$ 23,413	$ 18,387	$ 2,233	$ 2,459	$ 334
December 31, 2015					
Total Assets	24,196	18,831	2,299	2,677	389

Note 13. Commitments and Contingencies

CONSOL Carried Cost Obligation In accordance with our Marcellus Shale joint venture arrangement with a subsidiary of CONSOL Energy Inc. (CONSOL), we agreed to fund one-third of CONSOL's 50% working interest share of future drilling and completion costs, capped at $400 million each year (CONSOL Carried Cost Obligation). The remaining obligation totaled approximately $1.6 billion at March 31, 2016.

The CONSOL Carried Cost Obligation is suspended if average Henry Hub natural gas prices fall and remain below $4.00 per MMBtu in any three consecutive month period and remain suspended until average Henry Hub natural gas prices equal or exceed $4.00 per MMBtu for three consecutive months. Due to low natural gas prices, the CONSOL Carried Cost Obligation was suspended from the end of 2011 until February 28, 2014. We began funding a portion of CONSOL's working interest share of certain drilling and completion costs as of March 1, 2014; however, the funding was suspended again in November 2014 due to lower natural gas prices. Based on the March 31, 2016 NYMEX Henry Hub natural gas price curve, we expect that the CONSOL Carried Cost Obligation will be suspended for the next 12 months.

Delivery and Firm Transportation Commitments We have commitments to deliver approximately 437 Bcf of natural gas produced onshore US (primarily in the Marcellus Shale) and have also entered into various long-term gathering, processing and transportation contracts for some of our onshore US crude oil and natural gas production (in the Marcellus Shale, DJ Basin and Eagle Ford Shale).

We enter into long-term contracts to provide production flow assurance in over-supplied markets and/or markets with limited infrastructure. This strategy provides for optimization of transportation and processing costs. As properties are undergoing development activities, we may experience temporary delivery or transportation shortfalls until production volumes grow to meet or exceed the minimum volume commitments. During first quarter 2016, we incurred expense of approximately $16 million related to deficiencies and/or unutilized commitments. We expect to continue to incur deficiency and/or unutilized costs in the near-term as development activities continue. Should commodity prices continue to decline or if we are unable to continue to develop our properties as planned, or certain wells become uneconomic and are shut-in, we could incur additional shortfalls in delivering or transporting the minimum volumes and we could be required to make payments in the event that these commitments are not otherwise offset.

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.

Colorado Air Matter In April 2015, we entered into a joint consent decree (Consent Decree) with the US Environmental Protection Agency, US Department of Justice, and State of Colorado to improve emission control systems at a number of our condensate storage tanks that are part of our upstream crude oil and natural gas operations within the Non-Attainment Area of the DJ Basin. The Consent Decree was entered by the Court on June 2, 2015.

The Consent Decree, which alleges violations of the Colorado Air Pollution Prevention and Control Act and Colorado's federal approved State Implementation Plan, specifically Colorado Air Quality Control Commission Regulation Number 7, requires us to perform certain injunctive relief activities to complete mitigation projects and supplemental environmental projects (SEP), and pay a civil penalty. Costs associated with the settlement consist of $4.95 million in civil penalties which were paid in 2015. Mitigation costs of $4.5 million and SEP costs of $4 million are being expended in accordance with schedules established in the Consent Decree. Costs associated with the injunctive relief are not yet precisely quantifiable as they will be determined in accordance with the outcome of evaluations on the adequate design, operation, and maintenance of certain aspects of tank systems to handle potential peak instantaneous vapor flow rates between now and mid-2017.

Compliance with the Consent Decree could result in the temporary shut in or permanent plugging and abandonment of certain wells and associated tank batteries. The Consent Decree sets forth a detailed compliance schedule with deadlines for achievement of milestones through early 2019. The Consent Decree contains additional obligations for ongoing inspection and monitoring beyond that which is required under existing Colorado regulations. Inspection and monitoring findings may influence decisions to temporarily shut in or permanently plug and abandon wells and associated tank batteries.

We have concluded that the penalties, injunctive relief, and mitigation expenditures that resulted from this settlement did not have, and based on currently available information will not have, a material adverse effect on our financial position, results of operations or cash flows.

Colorado Air Compliance Order on Consent In December 2015, we received a proposed Compliance Order on Consent (COC) from the Colorado Department of Public Health and Environment's Air Pollution Control Division to resolve allegations of noncompliance associated with certain engines subject to various General Permit 02 conditions and/or individual permit conditions as well as certain emission control devices subject to various individual permit conditions. The COC, which provided for an opportunity to further discuss the offer of settlement, has not yet been executed. At present, the revised COC seeks completion of compliance testing, modification of certain permits, submission of a notice and payment of a reduced penalty of $223,475, of which up to 80% may be mitigated by pursuing a SEP or SEPs. Given the inherent uncertainty in administrative actions of this nature, we are unable to predict the ultimate outcome of this action at this time. However, we believe that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on our financial position, results of operations or cash flows.

Item 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 globally diversified explorer and producer of crude oil, natural gas and natural gas liquids. We aim to achieve sustainable growth in value and cash flow through the development of a high-quality and diverse, worldwide portfolio of assets with investment flexibility between onshore unconventional developments and offshore exploration leading to major development projects. Our portfolio is further diversified through US and international projects and production mix among crude oil, natural gas, and NGLs. Our core operating areas include onshore US, primarily the DJ Basin, Marcellus Shale, Eagle Ford Shale and Permian Basin; offshore US Gulf of Mexico; West Africa; and Eastern Mediterranean. In these areas we believe we have a strategic competitive advantage and will generate attractive returns throughout oil and gas business cycles.

Our portfolio is further complimented through the pursuit of certain exploration opportunities as we seek to establish potential new core areas, such as Suriname, Falkland Islands and Gabon. We may also conclude that an exploration area is not commercially viable and, therefore, may exit locations, such as we did in 2015 with Nevada, Sierra Leone and Nicaragua.

The following discussion highlights significant operating and financial results. This discussion includes operating results associated with our Rosetta Merger, which closed in third quarter of 2015, and should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2015, which includes disclosures regarding our critical accounting policies as part of "Management's Discussion and Analysis of Financial Condition and Results of Operations."

First Quarter 2016 Significant Operating Highlights Included:

- maintained cost reduction efforts in capital, lease operating expense and general and administrative areas and continued to pursue further reductions to align spending with operational cash flows in the current commodity price environment (see Cost Reduction Efforts, below);
- continued progression of the Natural Gas Framework (Framework) in Israel;
- set a first quarter record 266 million MMcf/d, net, of natural gas in Israel, reflecting enhanced dispatch of natural gas to fuel power generation;
- averaged 416 MBoe/d total sales volumes;
- recorded first full quarter sales volumes for Big Bend and Dantzler combined of 19 MBoe/d, net, in deepwater Gulf of Mexico;
- improved and enhanced well completion designs in the DJ Basin leading to capital efficiencies;
- initiated production on our first two Briscoe Ranch wells in the Eagle Ford Shale and first two Delaware Basin wells in the Permian Basin;
- installed the Alba B3 compression platform and initiated hook-up and commissioning activities; and
- entered into a purchase and sale agreement on May 2, 2016, subsequent to quarter-end, for the divestiture of certain producing and undeveloped crude oil and natural gas interests in approximately 33,500 net acres in Weld County, Colorado for $505 million. See Item 1. Financial Statements – Note 4. Divestitures.

First Quarter 2016 Financial Results Included:

- net loss of $287 million, as compared with net loss of $22 million for first quarter 2015;
- net gain on commodity derivative instruments of $44 million as compared with net gain on commodity derivative instruments of $150 million for first quarter 2015;
- reduced unit costs by 23% in lease operating expense and 27% in general and administrative expense as compared to first quarter 2015;
- dry hole expense of $95 million related to the Silvergate exploration well in deepwater Gulf of Mexico;

- other expense of $42 million related to the termination of a rig contract offshore Falkland Islands as a result of a supplier's non-performance;
- diluted loss per share of $0.67, as compared with diluted loss per share of $0.06 for first quarter 2015;
- cash flow provided by operating activities of $251 million, as compared with $541 million for first quarter 2015;
- cash proceeds from non-core divestitures and other of $238 million, as compared with $119 million for first quarter 2015;
- capital expenditures of $374 million, as compared with $919 million for first quarter 2015; and
- entered into the $1.4 billion Term Loan Facility and utilized borrowings under the Term Loan Facility to tender $1.38 billion of senior notes assumed in the Rosetta Merger resulting in a gain of $80 million.

Quarter-End Key Financial Metrics Included:

- ending cash balance of $953 million, as compared with $1.0 billion at December 31, 2015;
- total liquidity of approximately $5.0 billion at March 31, 2016, as compared with $5.0 billion at December 31, 2015; and
- ratio of debt-to-book capital of 44% at March 31, 2016, as compared with 43% at December 31, 2015.

Impact of Current Commodity Prices on our Business

The upstream oil and gas business is cyclical and we are currently operating in a period of low commodity prices. Commodity prices began declining sharply during fourth quarter 2014 and continued to decline throughout 2015. Thus far in 2016, crude oil prices have remained volatile ranging below $30.00 per barrel to upwards of $43.00 per barrel. Current commodity prices continue to negatively impact our revenues, profitability, and cash flows. In response to the commodity price environment, we have reduced our 2016 capital spending program to less than $1.5 billion, approximately 50% lower than 2015 and approximately 70% lower than 2014. See Operating Outlook – 2016 Capital Investment Program, below.

Positioning for the Future

We have taken steps to sustain our business in the volatile and low commodity price environment that has evolved. We have adopted a comprehensive effort to spend within cash flow and maintain our strong balance sheet. To this end, we plan to defer certain activity to protect our liquidity position and have adopted a 2016 capital program more closely aligned with expected cash flow. In addition, we adjusted the quarterly dividend to 10 cents per common share in first and second quarter 2016, representing a reduction of 8 cents, or 44%, from 2015 quarterly dividends which aligns the dividend yield with historical levels and further enhances our liquidity. We also intend to reduce leverage in this environment and have engaged in debt refinancing activities in first quarter 2016. The dividend reduction and debt refinancing are expected to provide approximately $200 million annually in support of balance sheet management efforts.

We believe we have positioned the Company for sustainability, operational efficiency, and long-term success throughout the oil and gas business cycle. However, if the industry downturn continues for an extended period, or becomes more severe, we could experience additional material negative impacts on our revenues, profitability, cash flows, liquidity and proved reserves, and in response, we may consider additional reductions in our capital program or dividends, and further asset sales and/or additional organizational changes. Our production and our stock price could decline further as a result of these potential developments.

Cost Reduction Efforts

For 2016, we continue to focus on maintaining our strong safety culture, driving operational efficiencies and productivity and reducing our cost structure. Cost reduction initiatives, including both operational enhancements and new pricing arrangements with suppliers, have resulted in total lease operating expense and general and administrative expense being flat as compared to first quarter 2015 while sales volumes increased nearly 100 MBoe/d. Our global portfolio provides significant optionality, allowing us to reduce our capital spending by nearly 60% for the first three months of 2016, as compared to the same period of 2015. As the majority of our onshore US assets are held by production, the investment and financial flexibility of our portfolio allows us to defer certain activity to protect our liquidity position.

Sales Volumes

On a BOE basis, total sales volumes were 31% higher for first quarter 2016 as compared with first quarter 2015, and our mix of sales volumes was 45% global liquids, 19% international natural gas, and 36% US natural gas. On a BOE basis and excluding the impact of the Rosetta Merger, total sales volumes were 12% higher for first quarter 2016 as compared with first quarter 2015, and our mix of sales volumes was 42% global liquids, 36% US natural gas and 22% international natural gas. See Results of Operations – Revenues, below.

Commodity Price Changes

Crude oil prices are driven by global crude oil supply and demand factors. During 2014, crude oil became oversupplied as production from non-OPEC producers increased, primarily driven by US crude oil production growth from tight formations and the de-bottlenecking of transportation infrastructure, while global crude oil demand growth was muted on lower global economic growth, especially in Europe, coupled with slower growth in China.

The outlook for crude oil prices during 2016 depends primarily on supply and demand dynamics and global security concerns in crude oil-producing nations. In April 2016, OPEC and other major oil producers convened to discuss efforts to reduce the oversupply and re-balance the market, but failed to reach an agreement to limit crude oil production. On the demand side, recent projections have reduced anticipated global crude oil demand growth for 2016 and Chinese economic indicators have weakened, which continue to exacerbate the current oversupply situation and resulting soft pricing environment.

Longer term, we expect supply and demand to re-balance. If prices remain at lower levels, we expect producers will reduce investment which will, over time, reduce production, helping to balance supply and demand in the crude oil market.

We plan for commodity price cyclicality in our business and believe we are well positioned to withstand current and future commodity price volatility due to the following:

- we have a high-quality, globally diversified portfolio of assets, the majority of which are held by production and provide investment flexibility;
- we have achieved sustainable cost reductions impacting both operating expenses and capital expenditures, including a substantially reduced capital investment program which allows us to respond to changing commodity price conditions in 2016, thereby positively impacting operating cash flows;
- we are well hedged for 2016, and partially hedged for 2017;
- we have a strong balance sheet with a ratio of debt-to-book capital of 44% at March 31, 2016; and
- we have robust liquidity of approximately $5.0 billion at March 31, 2016 and ability to access capital markets.

Major Development Project Updates

We continue to advance our major development projects, which we expect to deliver incremental production over the next several years. Updates on major development projects are as follows:

Sanctioned Ongoing Development Projects

A "sanctioned" development project is one for which a final investment decision has been made.

DJ Basin (Onshore US) During the quarter, we operated three drilling rigs (reducing to two rigs in February), drilled 24 wells and commenced production on 36 wells. We continued to improve and enhance our completion designs and were able to deliver higher production at lower capital and lease operating expense costs than first quarter of 2015.

Marcellus Shale (Onshore US) Currently, we have no operated or non-operated rigs running in the Marcellus Shale. For 2016, we and CONSOL have agreed to operate within cash flow and have agreed to a plan which will focus on well completions. As such, our allocated capital to be invested in the Marcellus Shale will be limited to the completion of certain previously-drilled wells primarily located in non-operated dry gas areas. During the quarter, we commenced production on eight operated wells and our joint venture partner commenced production on 17 wells.

Eagle Ford Shale and Permian Basin (Onshore US) During the quarter, we operated one drilling rig, drilled two horizontal wells and commenced production on eight wells in the Eagle Ford Shale. In the Permian Basin, we operated one drilling rig, drilled two horizontal wells and commenced production on our first two horizontal wells.

Gunflint (Deepwater Gulf of Mexico) Development is on track for the Gunflint (31% operated working interest) crude oil discovery, utilizing a two-well subsea tieback to the Gulfstar One spar. Topsides modifications and facilities upgrades are in the process of being completed, and we are targeting first production for mid-2016.

Alba Field (Offshore Equatorial Guinea) The Alba B3 compression platform was successfully installed in first quarter 2016. Hook-up and commissioning activities are underway and are expected to be completed in mid-year 2016, with first production from the compression project expected in third quarter 2016.

Tamar Southwest We continue to work with the Government of Israel to obtain regulatory approval of our development plan, which is intended to utilize current Tamar infrastructure. To ensure project continuity, we have petitioned the Israeli courts to expedite the needed approvals. Timely development of Tamar Southwest is important to maintain well capacity and reliability for our overall Tamar project. See Update on Israel Natural Gas Regulatory Framework, below.

Unsanctioned Development Projects

Tamar Expansion Project (Offshore Israel) We have engaged in the planning phase for an expansion project which would expand Tamar field deliverability to approximately 2.1 Bcf/d, a quantity that would allow for regional export. Expansion would include a third flow line component and additional producing wells. Timing of project sanction depends on satisfactory resolution of regulatory matters as well as progression of marketing efforts. See Update on Israel Natural Gas Regulatory Framework, below.

Leviathan Project (Offshore Israel) The marketing and development of natural gas is intended to serve both domestic demand and regional export. We have been engaged in natural gas marketing activities and executed our first natural gas sales and purchase agreement in early 2016. We also submitted a Plan of Development to the Government of Israel. However, timing of project sanction depends on satisfactory resolution of regulatory matters that we and our partners face in developing our offshore assets. Project financing will also be required. See Update on Israel Natural Gas Regulatory Framework, below.

Cyprus Project (Offshore Cyprus) During fourth quarter 2015, we entered into a farm-out agreement with a partner for a 35% interest in Block 12, which includes the Aphrodite natural gas discovery, for $171 million. In first quarter 2016, we received proceeds of $131 million related to the farm-out agreement and expect to receive the remaining consideration of $40 million, subject to post-close adjustments, in 2017. The proceeds were applied to the Cyprus project asset with no gain or loss recognized. We will continue to operate with a 35% interest. Also, as part of the farm-out process, we negotiated a waiver of our remaining exploration well obligation.

During 2015, we submitted a Declaration of Commerciality and a Development Plan to the Government of Cyprus. We continue to work with the Government of Cyprus to obtain approval of the development plan and the issuance of an Exploitation License for the Aphrodite field. Receiving an Exploitation License, in conjunction with securing markets for Aphrodite gas, will allow us and our partners to perform the necessary front-end engineering design (FEED) studies and progress the project to final investment decision. In preparation for FEED, we and our partners are currently performing preliminary engineering and design (pre-FEED) for the potential development of Aphrodite field that, as currently planned, would deliver natural gas to potential customers in Cyprus and Egypt.

See Item 1. Financial Statements – Note 8. Capitalized Exploratory Well Costs and Undeveloped Leasehold.

Exploration Program Update

Our 2016 exploration budget has been substantially reduced compared to prior years, but provides flexibility to respond to commodity price changes. While we expect to conduct limited exploratory activities in the current year, our core areas provide for exploration opportunities and we have increased our evaluation of new venture opportunities in both US and international locations.

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. 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 recorded as dry hole expense.

Additionally, we may not be able to conduct exploration activities prior to lease expirations. As a result, in a future period, dry hole cost and/or leasehold abandonment expense could be significant. See Item 1. Financial Statements – Note 8. Capitalized Exploratory Well Costs and Undeveloped Leasehold and Operating Outlook – Potential for Future Impairment, Dry Hole or Lease Abandonment Expense, below.

Updates on significant exploration activities are as follows:

Deepwater Gulf of Mexico In first quarter 2016, drilling operations were completed at our Silvergate exploration well in deepwater Gulf of Mexico. The well did not encounter commercial hydrocarbons and has been plugged and abandoned. In first quarter 2016, we recorded dry hole expense of $95 million associated with this well. Our exploration and appraisal program for 2016 also includes an appraisal well (38% operated working interest) at our Katmai discovery made during third quarter 2014 (Green Canyon Block 40, 50% operated working interest) to test the remaining resource potential and further define potential development scenarios.

Offshore West Africa We are interpreting and evaluating recently acquired 3D seismic data across Equatorial Guinea Blocks I and O which will aid in advancing exploration and development opportunities, including the Diega/Carmen and Carla discoveries.

Offshore Cameroon We have an interest in approximately 167,800 gross undeveloped acres offshore Cameroon in our YoYo mining concession (50% operating working interest). Petronas holds the other 50% operating working interest and has given notice to us and the Cameroon government of their intention to exit this acreage position. Once the assignment process is finalized, we will hold 100% operating working interest in the YoYo mining concession. We have begun efforts to market this additional working interest. The YoYo-1 exploratory well was drilled in 2007, discovering natural gas and condensate. We are working with the government of Cameroon to evaluate natural gas development options and are negotiating with the Cameroon government to convert the YoYo mining concession to a production sharing contract. We have completed reprocessing of 3D seismic data over our YoYo mining concession and are currently evaluating the data. In April 2016, we gave notice to the Cameroon government of our intention to exit our acreage position in the Tilapia block (46.67% operating working interest) which covered an area of approximately 900,000 gross acres.

Offshore Eastern Mediterranean See Update on Israel Natural Gas Regulatory Framework, below.

Offshore Falkland Islands In 2015, we experienced material operational issues with a drilling rig while drilling the Humpback well. The same drilling rig was scheduled to drill another prospect but due to significant safety and operational concerns, the drilling contract was terminated in first quarter 2016. We have been and will continue to work closely with our partners and the Falkland Islands Government to evaluate a path forward that includes retaining flexibility for any possible prospects. In first quarter 2016, we expensed $42 million of capitalized rig costs relating to pre-drill activities. These costs are reflected in Other Non-Operating (Income) Expense, Net in the consolidated statements of operations.

Offshore Suriname The initial phase of exploration on Block 54 requires acquisition of a 3D seismic survey, which has been completed and is currently being processed. Evaluation of the seismic survey will determine if a commitment to a subsequent exploration phase to drill an exploration well is warranted.

Offshore Gabon We are the operator of Block F15 (60% working interest), an undeveloped, deep water area. Our exploration commitment includes a 3D seismic obligation which is currently being acquired.

Update on Israel Natural Gas Regulatory Framework

We have been progressing plans to develop the Leviathan field and expand the currently producing Tamar field. Historically we have had to address certain fiscal, antitrust and other regulatory challenges in Israel. These challenges were addressed with the enactment of a comprehensive regulatory natural gas framework (Natural Gas Framework) by the Government of Israel in 2015. The Natural Gas Framework provides clarity on numerous matters concerning resource development which we will rely upon to support a final investment decision and upon which we can develop our resources while ensuring economic benefits to the state of Israel and its citizens. Among other items, the Natural Gas Framework provides for the following:

- the timely approval of asset development permits and plans and export permits;
- benchmarking future domestic contract pricing for an interim period until market competition is established, whereby such contracts are indexed to existing domestic and export contracts;
- resolution of antitrust and competition concerns, whereby we recently divested our Karish and Tanin discoveries and will reduce our ownership in Tamar to 25% within six years;
- the de-linking of Tamar export timing from Leviathan, enabling Tamar expansion to move forward; and
- support for investment and industry growth through stabilization assurance.

The Natural Gas Framework also enables marketing of Leviathan natural gas to Israeli customers for the first time. The development of Leviathan will substantially expand our capacity to deliver natural gas to Israel and the region, as well as provide a second source of domestic natural gas supply and redundancy of infrastructure for the people of Israel.

Since its enactment, the Natural Gas Framework (Framework) has been subject to ongoing legal challenges. The Israel Supreme Court held hearings in February 2016 to consider the challenges, including the Government of Israel's enactment of Section 52 of the Restrictive Trade Practices Act and constitutional aspects of the stability undertakings. Execution of Section 52 resolves and provides exemption from claims of the Anti-trust Authority with respect to the Leviathan joint venture partners' acquisition of petroleum rights in the underlying permits.

The Court subsequently affirmed the Framework, including the anti-trust exemption, the Framework's price transparency and export provisions. However, the Court did not approve the stability provisions.

Regarding the stability provisions, the Court concluded that the Government of Israel should provide stability assurances and provisions through an alternate legal mechanism and provided the Government up to one year to resolve this matter. The Government continues to evaluate a number of alternatives to provide for this stability clause and instill investment confidence. Stable fiscal and contract terms and the regulatory Framework are required to support long-term investment in such major energy infrastructure. We cannot predict the outcome of this process, the impact on timing of sanction or start-up of production of the Leviathan project.

Pending Master Limited Partnership

On October 22, 2015, Noble Midstream Partners LP (Noble Midstream), a wholly owned subsidiary of Noble Energy, filed a registration statement on Form S-1 with the U.S. Securities and Exchange Commission (SEC) relating to a proposed master limited partnership. On April 1, 2016, Noble Midstream filed an amendment to the Form S-1. Under the proposed structure, Noble Midstream will own, operate and develop our DJ Basin crude oil, natural gas and water-related midstream infrastructure, and Noble Energy will own the general partner of Noble Midstream and retain a majority of limited partnership interests in the proposed master limited partnership. As of the date of this report, the registration statement is not effective. The completion of the proposed offering is subject to numerous conditions, including capital market conditions, and we can provide no assurance that it will be successfully completed.

Non-Core Divestiture Program

We periodically divest non-core, non-strategic assets. During first quarter 2016, we continued our non-core asset divestiture program with the sale of certain smaller onshore US property packages resulting in net proceeds of $20 million. Divestitures of non-core properties allow us to allocate capital and other resources to high-value and high-growth areas and enhances our balance sheet strength. We continue to evaluate divestment opportunities of certain non-core onshore properties located in the Rocky Mountain and Bowdoin (north central Montana) areas. As of March 31, 2016, the net book value of these non-core assets totaled $86 million, of which $65 million was related to our Bowdoin assets located in north central Montana.

See Item 1. Financial Statements – Note 4. Divestitures and Operating Outlook - Potential for Future Impairment, Dry Hole or Lease Abandonment Expense, below.

Update on Regulations

US Offshore Regulatory Developments On April 14, 2016, the BSEE issued a final rule establishing updated standards for blowout prevention systems and other well controls for offshore oil and gas activities conducted in US federal waters, including the Gulf of Mexico. Although the final rule incorporates some of the changes recommended by the oil and gas industry, it imposes a number of new requirements relating to well design, well control, casing, cementing, real-time well monitoring and subsea containment. For example, the new rule requires double sets of shear rams on all deepwater blowout preventers (BOPs), periodic inspections of BOPs and outside audits of equipment, and real-time well monitoring requirements. The new rule will likely increase the costs associated with well design, drilling and completion operations.

On March 17, 2016, the BOEM proposed a new air quality monitoring rule that would significantly broaden the scope of air emissions that operators in US federal waters, including the Gulf of Mexico, must measure, monitor and control. Among other things, the proposed rule would expand the types of emissions that must be measured, require operators to measure emissions more frequently, and increase the scope of facilities that must be monitored. If adopted as proposed, the new rule would likely increase the cost associated with our activities in the Gulf of Mexico.

Colorado Crude Oil and Natural Gas Regulation In 2014, by executive order, Colorado Governor Hickenlooper created a 21-member Oil and Gas Task Force (Task Force) made up of representatives of local governments, civic entities, environmental organizations and industry for the purpose of making recommendations regarding oil and gas development in communities. After 18-months, the Task Force, which included a representative from Noble Energy, concluded its activities on February 27, 2015. Nine recommendations were sent to the governor, seven of which were unanimously supported. These recommendations have all been adopted by legislation or regulation. The Colorado Oil and Gas Conservation Commission recently completed work on new rules which govern the siting of large oil and gas operations in urban areas and require greater coordination of drilling operations with local governments. These new rules took effect in March 2016 and there is strong public support for them to be implemented.

Recently the state of Colorado approved for signature gathering four ballot measures which would impact oil and gas operations. Measure 40 would grant local communities self-governance and the opportunity to ban certain businesses from operating in their jurisdictions. Measure 63 would establish a constitutional right to a healthy environment and provide local governments the obligation to protect the environment. Measure 75 would grant local governments control over oil and gas development, notwithstanding state law. Measure 78 would require that all new oil and gas facilities be located 2,500 feet from occupied structures and an expansive list of landscape features called ‘areas of special concern.’ Measure 78 would significantly impact future oil and gas operations and has strong opposition from the oil and gas industry, the governor and the business community.

All of these measures are available for signature gathering and the proponents have until August 8, 2016 to gather 98,492 signatures to qualify for the November 2016 ballot.

In addition to the above, we will continue to monitor proposed and new regulations and legislation in all our operating jurisdictions to assess the potential impact on our company. Concurrently, we are engaged in extensive public education and outreach efforts with the goal of engaging and educating the general public and communities about the energy, economic and environmental benefits of safe and responsible crude oil and natural gas development.

Recently Issued Accounting Standards

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

OPERATING OUTLOOK

2016 Production We have adopted a comprehensive effort to spend within cash flow, manage the Company's balance sheet and position ourselves for future growth. To this end, we plan to defer certain activities to protect our liquidity position and adopted a 2016 capital program more closely aligned with expected cash flow. Therefore, our total crude oil, natural gas and NGL production for 2016 may not grow at a rate consistent with prior years and potentially could decline. Production may be impacted by factors including:

- commodity prices which, if subject to further decline, could result in current production becoming uneconomic;
- overall level and timing of capital expenditures which, as discussed below and dependent upon our drilling success, will impact near-term production volumes;

- timing of start-up of the Gunflint project (deepwater Gulf of Mexico) and Alba compression project (offshore Equatorial Guinea);
- Israeli demand for electricity, which is impacted by unseasonable weather and conversion of the Israeli electricity portfolio from coal to natural gas;
- Israeli industrial demand for natural gas;
- 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;
- natural field decline in the onshore US, deepwater Gulf of Mexico and offshore Equatorial Guinea;
- potential weather-related volume curtailments due to hurricanes in the deepwater Gulf of Mexico, or winter storms and flooding impacting onshore US operations;
- reliability of support equipment and facilities and/or potential pipeline and processing facility capacity constraints which may cause restrictions or interruptions in production and/or mid-stream processing;
- timing and completion of planned maintenance, including turnarounds, of processing facilities serving our DJ Basin assets;
- 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.

2016 Capital Investment Program Given the current commodity price environment, we have designed a substantially reduced and flexible capital investment program that is part of our comprehensive effort to spend within cash flow and manage the Company's balance sheet. Our updated 2016 capital investment program will accommodate an investment level of less than $1.5 billion, or approximately 50% lower than our 2015 program. The program allocates two-thirds of total investment to core onshore US assets and the remaining one-third to offshore development and exploration.

See Liquidity and Capital Resources – Financing Activities.

Potential for Future Dry Hole Cost, Lease Abandonment Expense or Property Impairments

Exploration Activities Our exploratory drilling program seeks to provide long-term growth from existing and potential new core areas. In the event we conclude that an exploratory well 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. For example, in first quarter 2016, we recorded dry hole costs of $95 million associated with our Silvergate exploratory well. The well did not encounter commercial hydrocarbons and has been plugged and abandoned. See Item 1. Financial Statements - Note 8. Capitalized Exploratory Well Costs and Undeveloped Leasehold.

Additionally, we may not conduct exploration activities prior to lease expirations. For example, in the deepwater Gulf of Mexico, we continue to mature our prospect portfolio. However, 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. In addition, the current commodity price environment may render certain prospects economically less attractive and we may not conduct exploration activities before lease expiration.

We currently have capitalized undeveloped leasehold cost of approximately $255 million related to deepwater Gulf of Mexico prospects that have not yet been drilled. These leases will expire over the years 2016 - 2024. While none of our undeveloped leases were impaired as of March 31, 2016, changes in exploration plans, availability of capital and suitable rig and drilling equipment, resource potential, changing regulations and/or other factors, could result in future impairment. In the deepwater Gulf of Mexico, some leases may become impaired if production is not established, we do not take action to extend the terms of the leases, or the leases become uneconomic due to low commodity prices, costs of complying with new regulations, or other factors.

As a result of our exploration activities, future exploration expense, including leasehold expense, could be significant. See Results of Operations - Oil and Gas Exploration Expense, below. See also Item 1A. Risk Factors.

Producing Properties In 2016, commodity prices, including WTI, Brent and HH, have continued to trade in a low range and remain volatile. A further decline in future crude oil, natural gas or NGL prices could result in some of our properties becoming uneconomic, resulting in additional impairment charges, decrease in proved reserves and/or shut-in of currently producing wells.

In addition, in certain onshore US areas, transportation bottlenecks caused by oversupply and/or lack of infrastructure can reduce the amount of production reaching premium markets, resulting in less favorable basis differentials, or differences between WTI and HH pricing and the average prices we actually receive. A widening of these basis differentials could also reduce cash flows and result in property 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 crude oil and natural 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 commodity prices, or widening of basis differentials, alone could result in an impairment.

In addition, well decommissioning programs, especially in deepwater or remote locations, are often complex and expensive. It may be difficult to estimate timing of actual abandonment activities, which are subject to regulatory approval and the availability of rigs and services. It may be difficult to estimate costs as rigs and services become more expensive in periods of higher demand. Therefore, our ARO estimates may change, sometimes significantly, and could result in asset impairment.

Divestments We are currently marketing certain non-core onshore US properties. 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.

RESULTS OF OPERATIONS

Revenues

Revenues were as follows:

(millions)	2016	2015	(Decrease) / Increase from Prior Year
Three Months Ended March 31,			
Oil, Gas and NGL Sales	$ 705	$ 749	(6)%
Income from Equity Method Investees	19	18	6 %
Total	$ 724	$ 767	(6)%

Changes in revenues are discussed below.

Oil, Gas and NGL Sales

We generally sell crude oil, natural gas, and NGLs under two types of agreements common in our industry. Both types of agreements may include transportation charges. One type of agreement is a netback agreement, under which we sell crude oil and natural gas at the wellhead and receive a price, net of transportation expense incurred by the purchaser. In the case of NGLs, we may receive a price from the purchaser, which is net of fractionation and processing costs. Historically, we have recorded revenue at the net price we had received from the purchaser, net of transportation, fractionation or processing costs. Beginning in 2016, we changed our presentation of revenue to no longer include expenses netted from revenue by the purchaser. Crude oil, natural gas and NGL sales are now shown without deductions relating to transportation, fractionation or processing costs, which are now recorded as production expense. Prior year amounts, including revenues, expenses, average realized sales prices and average production costs per BOE, have been reclassified to conform to the current presentation. Amounts reclassified in first quarter 2015 totaled $9 million relating to NGL sales; respective crude oil and natural gas sales amounts were de minimis.

In addition, commodity prices we receive may be reduced by location basis differentials, which can be significant. As a result of location basis differentials, our reported sales prices may differ significantly from published commodity price benchmarks for the same period.

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

	Sales Volumes				Average Realized Sales Prices		
	Crude Oil & Condensate (MBbl/d)	Natural Gas (MMcf/d)	NGLs (MBbl/d)	Total (MBoe/d) [1]	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)	NGLs (Per Bbl)
Three Months Ended March 31, 2016							
United States	102	910	53	306	$ 30.14	$ 1.90	$ 11.18
Equatorial Guinea [2]	27	195	—	60	34.49	0.27	—
Israel	—	266	—	45	—	5.19	—
Total Consolidated Operations	129	1,371	53	411	31.04	2.30	11.18
Equity Investees [3]	1	—	4	5	33.30	—	22.19
Total	130	1,371	57	416	$ 31.06	$ 2.30	$ 12.01
Three Months Ended March 31, 2015							
United States	73	619	25	201	$ 44.39	$ 2.72	$ 18.80
Equatorial Guinea [2]	30	231	—	68	49.65	0.27	—
Israel	—	242	—	40	—	5.45	—
Other International [4]	1	—	—	1	52.89	—	—
Total Consolidated Operations	104	1,092	25	310	45.96	2.81	18.80
Equity Investees [3]	2	—	6	8	48.63	—	30.17
Total	106	1,092	31	318	$ 46.01	$ 2.81	$ 20.99

(1) Natural gas is converted on the basis of six Mcf of gas per one barrel of crude oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency. Given commodity price disparities, the price for a barrel of crude oil equivalent for US natural gas and NGLs are significantly less than the price for a barrel of crude oil. In Israel, we sell natural gas under contracts where the majority of the price is fixed, resulting in less commodity price disparity.
(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 in part by affiliated entities accounted for under the equity method of accounting.
(3) Volumes represent sales of condensate and LPG from the LPG plant in Equatorial Guinea. See *Income from Equity Method Investees,* below.
(4) Other International includes de minimis North Sea sales volumes with last production in May 2015.

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

	Sales Revenues			
(millions)	Crude Oil & Condensate	Natural Gas	NGLs	Total
Three Months Ended March 31, 2015	$ 431	$ 276	$ 42	$ 749
Changes due to				
Increase in Sales Volumes	110	75	48	233
Decrease in Sales Prices	(176)	(64)	(37)	(277)
Three Months Ended March 31, 2016	$ 365	$ 287	$ 53	$ 705

Crude Oil and Condensate Sales – Revenues from crude oil and condensate sales decreased during first quarter 2016 as compared with 2015 due to the following:

- decreases in average realized prices primarily due to the decline in global commodity prices that began in the second half of 2014;

partially offset by:

- higher sales volumes in the deepwater Gulf of Mexico due to production from the Big Bend and Dantzler development projects, which began producing in fourth quarter 2015, with each project contributing 8 MBbl/d, net, in first quarter 2016; and
- sales volumes contributed by our Eagle Ford Shale and Permian Basin assets acquired in third quarter 2015, which contributed 10 MBbl/d and 7 MBbl/d, net, respectively, in first quarter 2016.

Natural Gas Sales – Revenues from natural gas sales increased during first quarter 2016 as compared with 2015 due to the following:

- higher sales volumes in the Marcellus Shale due to commencing production on eight operated wells, our joint venture partner commencing production on 17 wells, and the recognition of efficiencies in base production performance; and
- sales volumes contributed by our Eagle Ford Shale and Permian Basin assets acquired in third quarter 2015, which contributed 121 MMcf/d and 9 MMcf/d, net, respectively, in first quarter 2016;

partially offset by:

- decreases in average realized prices primarily due to the decline in global commodity prices that began in the second half of 2014; and
- a widening of location basis differentials in the Marcellus Shale due to an oversupply of natural gas in the region.

NGL Sales – Revenues from NGL sales increased during first quarter 2016 as compared with 2015 due to the following:

- higher sales volumes in the Marcellus Shale due to commencing production on eight operated wells, our joint venture partner commencing production on 17 wells, and the recognition of efficiencies in base production performance;
- higher sales volumes in the DJ Basin due to increased activity in East Pony and Wells Ranch; and
- sales volumes contributed by our Eagle Ford Shale and Permian Basin assets acquired in third quarter 2015, which contributed 20 MBbl/d and 2 MBbl/d, net, respectively, in first quarter 2016;

partially offset by:

- decreases in average realized prices primarily driven by oversupply.

Income from Equity Method Investees We have interests in equity method investees that operate midstream assets onshore US and West Africa. 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, activity is reflected within cash flows provided by operating activities and cash flows provided by (used in) investing activities.

Income from equity method investees increased $1 million during the first three months of 2016 as compared with 2015. The increase primarily includes a $6 million increase from AMPCO, our methanol investee, which experienced a 45-day plant turnaround during first quarter 2015; an $11 million decrease from Alba Plant, our LPG investee, due to lower sales volumes and lower realized prices; an increase of $4 million from our investments in CONE Gathering LLC and CONE Midstream Partners due primarily to higher throughput volumes; and an increase of $2 million from other investments.

Operating Costs and Expenses

Operating costs and expenses were as follows:

(millions)	2016	2015	Increase / (Decrease) from Prior Year
Three Months Ended March 31,			
Production Expense	$ 272	$ 254	7 %
Exploration Expense	163	65	151 %
Depreciation, Depletion and Amortization	617	454	36 %
General and Administrative	91	94	(3)%
Other Operating Expense, Net	3	34	(91)%
Total	$ 1,146	$ 901	27 %

Changes in operating costs and expenses are discussed below.

Production Expense Components of production expense were as follows:

(millions, except unit rate)	Total per BOE [1]	Total	United States	Equatorial Guinea	Israel	Corporate
Three Months Ended March 31, 2016						
Lease Operating Expense [2]	$ 4.31	$ 161	$ 120	$ 29	$ 10	$ 2
Production and Ad Valorem Taxes	0.11	4	4	—	—	—
Transportation and Gathering Expense [3]	2.86	107	107	—	—	—
Total Production Expense	$ 7.28	$ 272	$ 231	$ 29	$ 10	$ 2
Total Production Expense per BOE		$ 7.28	$ 8.29	$ 5.34	$ 2.46	N/M
Three Months Ended March 31, 2015						
Lease Operating Expense [2]	$ 5.61	$ 157	$ 103	$ 34	$ 12	$ 8
Production and Ad Valorem Taxes	1.16	32	32	—	—	—
Transportation and Gathering Expense [3]	2.32	65	65	—	—	—
Total Production Expense	$ 9.09	$ 254	$ 200	$ 34	$ 12	$ 8
Total Production Expense per BOE		$ 9.09	$ 11.05	$ 5.55	$ 3.27	N/M

N/M amount is not meaningful.

(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.
(3) Certain of our revenue received from purchasers was historically presented with deduction for transportation, fractionation or processing costs. Beginning in 2016, we have changed our presentation of revenue to no longer include these expenses as deductions from revenue. These costs are now included within production expense and prior year amounts have been reclassified to conform to the current presentation.

For first quarter of 2016, total production expense increased as compared with 2015 due to the following:

- an increase onshore US lease operating, transportation and gathering expense due to higher onshore US production, including the addition of production from our Eagle Ford Shale and Permian Basin assets in third quarter 2015;

partially offset by:

- a decrease in lease operating expense due to continued focus on cost reduction and efficiency initiatives;
- a decrease in production and ad valorem taxes due to the accrual of a $28 million onshore US severance tax receivable recorded in first quarter 2016; and
- a decrease in production and ad valorem taxes due to lower revenues resulting from the decline in commodity prices in the US.

The unit rate per BOE for total production expense decreased for 2016 as compared with 2015 primarily due to an increase in production of nearly 100 MBoe/d, net, lower production and ad valorem taxes as a result of the pricing environment as well as the impact of cost reduction initiatives in lease operating expense. The decrease in unit rate per BOE was partially offset by the increase in transportation and gathering expense primarily due to the addition of our Eagle Ford Shale and Permian Basin assets in third quarter 2015 and an increase in production in the Marcellus Shale.

Exploration Expense Components of exploration expense were as follows:

(millions)	Total	United States	West Africa (1)	Eastern Mediter-ranean (2)	Other Int'l, Corporate (3)
Three Months Ended March 31, 2016					
Leasehold Impairment and Amortization	$ 15	$ 15	$ —	$ —	$ —
Dry Hole Expense	93	95	—	—	(2)
Seismic, Geological and Geophysical	9	—	—	—	9
Staff Expense	18	1	1	1	15
Other (4)	28	13	—	7	8
Total Exploration Expense	$ 163	$ 124	$ 1	$ 8	$ 30
Three Months Ended March 31, 2015					
Leasehold Impairment and Amortization	$ 16	$ 11	$ —	$ 5	$ —
Dry Hole Expense	20	17	—	—	3
Seismic, Geological and Geophysical	10	2	—	—	8
Staff Expense	17	5	—	—	12
Other (4)	2	—	(3)	2	3
Total Exploration Expense	$ 65	$ 35	$ (3)	$ 7	$ 26

(1) West Africa includes Equatorial Guinea, Cameroon, Sierra Leone (which we exited in second quarter 2015), and Gabon.
(2) Eastern Mediterranean includes Israel and Cyprus.
(3) Other International, Corporate includes the Falkland Islands, other new ventures and corporate expenditures.
(4) Includes lease rentals and other exploratory costs.

Exploration expense for first quarter 2016 included:

- US dry hole cost represents the Silvergate exploratory well, deepwater Gulf of Mexico;
- US Other cost includes lease rentals of $12 million primarily related to Permian Basin leases; and
- salaries and related expenses for corporate exploration and new ventures personnel.

Exploration expense for first quarter 2015 included the following:

- $13 million of dry hole cost related primarily to onshore US exploratory wells; and
- salaries and related expenses for corporate exploration and new ventures personnel.

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

	Three Months Ended March 31,	
	2016	2015
DD&A Expense (millions) (1)	$ 617	$ 454
Unit Rate per BOE (2)	$ 16.52	$ 16.24

(1) For DD&A expense by geographical area, see Item 1. Financial Statements – Note 12. Segment Information.
(2) Consolidated unit rates exclude sales volumes and expenses attributable to equity method investees.

Total DD&A expense for first quarter 2016 increased as compared with 2015 due to the following:

- the addition of Eagle Ford Shale and Permian Basin production in third quarter 2015, resulting in $40 million and $11 million in DD&A expense respectively, in first quarter 2016;
- an increase in the Marcellus Shale, Eastern Mediterranean and deepwater Gulf of Mexico due to higher sales volumes;
- a reduction in proved reserves in fourth quarter 2015 primarily due to downward price revisions in DJ Basin and Marcellus Shale;

partially offset by:

- a decrease in sales volumes offshore Equatorial Guinea due to downtime installing the B3 compression platform and scheduled maintenance in the Alba field; and
- the impact of lower net book value as a result of a fourth quarter 2015 impairment offshore Equatorial Guinea properties.

The increase in the unit rate per BOE for the first quarter 2016 as compared with 2015 was due primarily to higher-cost production volumes in the deepwater Gulf of Mexico, reductions in proved reserves in fourth quarter 2015 due to downward price revisions, offset by increased lower-cost production volumes from the Tamar field.

Significant changes to the proved reserves at December 31, 2015 include; additions of 269 MMBoe resulting from the Rosetta Merger during the third quarter 2015 offset by downward revisions of 307 MMBoe that were commodity price driven. Estimates of proved reserves significantly affect our DD&A expense. Holding other factors constant, a decline in proved reserves estimates caused by decreases in the 12-month average commodity prices, will result in an increase in DD&A expense in future periods, which would reduce earnings.

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

	Three Months Ended March 31,	
	2016	2015
G&A Expense (millions)	$ 91	$ 94
Unit Rate per BOE [(1)]	$ 2.44	$ 3.36

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

G&A expense for first quarter of 2016 decreased as compared with 2015 primarily due to cost savings initiatives, including reduced use of contractors and consultants and decreased special projects and other discretionary expenses, and decreases in employee personnel costs, partially offset by the addition of Rosetta employees in the third quarter of 2015.

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

	Three Months Ended March 31,	
(millions)	2016	2015
Loss on Asset Due to Terminated Contract	$ 42	$ —
Marketing and Processing Expense, Net	22	6
Asset Impairments	—	27
Gain on Extinguishment of Debt	(80)	—
Other, Net	19	1
Total	$ 3	$ 34

See Item 1. Financial Statements – Note 2. Basis of Presentation for discussion of the above components of other operating (income) expense.

Other (Income) Expense

Other (income) expense was as follows:

	Three Months Ended March 31,	
(millions)	2016	2015
Gain on Commodity Derivative Instruments	$ (44)	$ (150)
Interest, Net of Amount Capitalized	79	57
Other Non-Operating (Income) Expense, Net	(4)	1
Total	$ 31	$ (92)

Gain on Commodity Derivative Instruments Gain on commodity derivative instruments is a result of mark-to-market accounting. Many factors impact a gain or loss on commodity derivative instruments including: increases and decreases in the commodity forward price curves compared to the terms of our executed commodity instruments; increases in notional volumes; and the mix of instruments between NYMEX WTI, Dated Brent and NYMEX Henry Hub commodities. See Item 1. Financial Statements – Note 5. Derivative Instruments and Hedging Activities and Note 7. Fair Value Measurements and Disclosures.

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

	Three Months Ended March 31,	
(millions, except unit rate)	2016	2015
Interest Expense, Gross	$ 106	$ 93
Capitalized Interest	(27)	(36)
Interest Expense, Net	$ 79	$ 57
Unit Rate per BOE [1]	$ 2.11	$ 2.05

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

The increase in interest expense, gross, for first quarter 2016 as compared with 2015 is due to the senior notes assumed by us in the Rosetta Merger during third quarter 2015.

The decrease in capitalized interest for first quarter 2016 as compared with 2015 is primarily due to lower work in progress amounts related to major long-term projects in deepwater Gulf of Mexico, offshore Cyprus, onshore US, and offshore Falkland Islands. See Item 1. Financial Statements - Note 5. Derivative Instruments and Hedging Activities.

Income Tax Provision

See Item 1. Financial Statements – Note 11. Income Taxes for a discussion of the change in our effective tax rate for first quarter 2016 as compared with 2015.

LIQUIDITY AND CAPITAL RESOURCES

Capital Structure/Financing Strategy

In seeking to effectively fund and monetize our discovered hydrocarbons, we employ a capital structure and financing strategy designed to provide sufficient liquidity throughout the volatile commodity price cycle, including the current commodity price environment. Specifically, we strive to retain the ability to fund long cycle, multi-year, capital intensive development projects throughout a range of scenarios, while also funding a continuing exploration program and maintaining capacity to capitalize on financially attractive periodic mergers and acquisitions activity.

We endeavor to maintain a strong balance sheet and investment grade debt rating in service of these objectives. We 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, cash on hand, available borrowing capacity under our Revolving Credit Facility, and proceeds from sales of non-core properties.

We occasionally access the capital markets to ensure adequate liquidity exists in the form of unutilized capacity under our Revolving Credit Facility or to refinance scheduled debt maturities. On January 6, 2016, we entered into the Term Loan Facility which provides for a three-year term loan facility for a principal amount of $1.4 billion. In connection with the Term Loan Facility, we launched cash tender offers for certain Senior Notes assumed in the Rosetta Merger. The borrowings under the Term Loan Facility were used solely to fund the tender offers. Collectively, the result of these transactions provides for significant future interest expense savings with a shorter term debt maturity. While we have no near-term debt maturities, we may seek to access the capital markets to refinance a portion of our outstanding indebtedness. As of March 31, 2016, we had $7.5 billion of long-term debt outstanding, $2.4 billion of which is due first quarter 2019. See Item 1. Financial Statements – Note 6. Debt.

In addition, we evaluate potential strategic farm-out arrangements of our working interests for reimbursement of our capital spending and may consider non-core asset sales or other sources of funding. During first quarter 2016, we received cash proceeds of over $190 million from our Cyprus farm-out and the sale of our Karish and Tanin discoveries offshore Israel and divested of certain non-core onshore US assets.

Cash on hand at March 31, 2016 totaled approximately $1.0 billion, which includes both domestic and foreign cash, and there were no amounts outstanding under our Revolving Credit Facility. See Item 1. Financial Statements – Note 6. Debt and *Revolving Credit Facility,* below.

Our nearly 60% reduction in capital spending in first quarter 2016 as compared to the same period of 2015, coupled with operating efficiencies to increase production at lower costs, has significantly strengthened our position to align capital spending with our operating cash flows. We will continue our effort to invest capital at a level aligned with current operating cash flows. Our financial capacity and lack of near-term debt maturities, coupled with our diversified global portfolio, provides us with flexibility in our investment decisions including execution of our major development projects and exploration activity.

To support our investment program, we expect that production resulting from our core onshore US development programs, combined with new production from the Big Bend and Dantzler development projects, which began producing in fourth quarter 2015, and from the Gunflint development, which is expected to begin producing in 2016, as well as increased peak deliverability resulting from the Tamar compression project, and presuming no significant further deterioration of prices, will result in an increase in cash flows which will be available to meet a portion of future capital commitments in 2016 and subsequent years. See Results of Operations above.

We are currently evaluating potential development and/or financing scenarios for our significant natural gas discoveries offshore Eastern Mediterranean. The magnitude of these discoveries presents technical and financial challenges for us due to the large-scale development requirements. Each of these development options, including the development of Leviathan Phase 1, would require a multi-billion dollar investment and require a number of years to complete. We are currently working with the Government of Israel to resolve stability measures to enable Leviathan and other development to move forward. See Update on Israel Natural Gas Regulatory Framework, above.

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

(millions, except percentages)	March 31, 2016	December 31, 2015
Cash and Cash Equivalents	$ 953	$ 1,028
Amount Available to be Borrowed Under Revolving Credit Facility (1)	4,000	4,000
Total Liquidity	$ 4,953	$ 5,028
Total Debt (2)	$ 7,979	$ 7,976
Total Shareholders' Equity	10,052	10,370
Ratio of Debt-to-Book Capital (3)	44%	43%

(1) See *Revolving Credit Facility,* below.
(2) Total debt includes capital lease obligations and excludes unamortized debt discount/premium.
(3) We define our ratio of debt-to-book capital as total debt (which includes long-term debt excluding unamortized discount, the current portion of long-term debt, and short-term borrowings) divided by the sum of total debt plus shareholders' equity.

Cash and Cash Equivalents We had approximately $1.0 billion in cash and cash equivalents at March 31, 2016, primarily denominated in US dollars and invested in money market funds and short-term deposits with major financial institutions. Approximately $435 million of this cash is attributable to our foreign subsidiaries. We have recorded a related deferred tax liability on undistributed foreign earnings for the future additional US tax liability for the US and foreign tax rate differences, net of estimated foreign tax credit.

Revolving Credit Facility Our Revolving Credit Facility matures on August 27, 2020. The commitment is $4.0 billion through the maturity date of the Revolving Credit Facility. As of March 31, 2016, no amounts were outstanding under the

Revolving Credit Facility. Borrowings under our Revolving Credit Facility subject us to interest rate risk. See Item 1. Financial Statements – Note 6. Debt and Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Commodity 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 may include variable to fixed price commodity swaps, two-way collars, three-way collars, swaptions and enhanced swaps.

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 netting provisions within the master agreements. None of our counterparty agreements contain margin requirements.

Commodity derivative instruments are recorded at fair value in our consolidated balance sheets, and changes in fair value are recorded in earnings in the period in which the change occurs. As of March 31, 2016, the fair value of our commodity derivative assets was $460 million and the fair value of our commodity derivative liabilities was $3 million (after consideration of netting provisions within our master agreements). See Item 1. Financial Statements – Note 7. Fair Value Measurements and Disclosures, for a description of the methods we use to estimate the fair values of commodity derivative instruments, and *Credit Risk,* below.

Credit Risk We monitor the creditworthiness of our trade creditors, joint venture partners, hedge counterparties, and financial institutions on an ongoing basis. Counterparty credit downgrades or liquidity problems could result in a delay in our receiving proceeds from commodity sales, reimbursement of joint venture costs, and potential delays in our major development projects. As operator of the joint ventures, we pay joint venture expenses and make cash calls on our nonoperating partners for their respective shares of joint venture costs. Our projects are capital cost intensive and, in some cases, a nonoperating partner may experience a delay in obtaining financing for its share of the joint venture costs or have liquidity problems resulting in slow payment of joint venture costs. In addition, in the event of bankruptcy or insolvency of a joint venture partner, we may be required to complete their share of remediation activities or fulfill their lease obligations which could result in significant financial losses.

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.

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. In addition, we maintain credit insurance associated with specific purchasers. However, nonperformance by a trade creditor, joint venture partner, hedge counterparty or financial institution could result in significant financial losses.

Contractual Obligations

Marcellus Shale Joint Development Agreement The joint development agreement for our jointly owned Marcellus Shale acreage provides for a multi-year drilling and development plan (default plan). We and CONSOL have agreed to an annual plan that provides for fewer wells to be drilled than the number of wells that was provided for in the default plan, and, for 2016, the amount of capital investment allocated to the Marcellus Shale core area will be less than the amount provided for in the default plan. Each of us has a non-consent right, which is the right to elect not to participate in all (but not less than all) of the operations provided for the following year. If one of us elects to exercise the non-consent right, then the other partner, in its sole discretion, may determine the number of wells, if any, it will drill in such year, which may be significantly less than the number of wells that was provided for in the default plan, or none at all. In the event we elect to exercise our non-consent right for a given year, we would still have to pay the carried costs that are contemplated by the development plan for that non-consent year. Under the joint development agreement, this non-consent right may be exercised by each partner twice (in non-consecutive years) prior to the termination of the default plan at the end of 2020. Neither of us has exercised the non-consent right, and thus, each of us may still elect to exercise the non-consent right twice prior to the end of 2020.

CONSOL Carried Cost Obligation See Item 1. Financial Statements - Note 13. Commitments and Contingencies.

Exploration Commitments The terms of some of our production sharing contracts, licenses or concession agreements may require us to conduct certain exploration activities, including drilling one or more exploratory wells or acquiring seismic data, within specific time periods. These obligations can extend over periods of several years, and failure to conduct such exploration activities within the prescribed periods could lead to loss of leases or exploration rights. Our exploration commitments currently include a 3D seismic obligation offshore Gabon.

Continuous Development Obligations Although the majority of our assets are held by production, certain of our onshore US assets are held through continuous development obligations. Therefore, we are contractually obligated to fund a level of development activity in these areas and failure to meet these obligations may result in the loss of a lease.

Delivery and Firm Transportation Agreements We have entered into various long-term gathering, processing, transportation and delivery contracts for some of our onshore US natural gas production. These contracts may commit us to deliver minimum volumes and require us to make payments for any shortfalls in delivering or transporting the minimum volumes under the commitments. We may use long-term contracts such as these to provide flow assurance for production in over-supplied markets with limited infrastructure, such as the Marcellus Shale, to enable our production to reach higher priced out-of-basin markets.

Although we strive to schedule well completion activities to meet the minimum volumes under the commitments, we may experience temporary delivery or transportation shortfalls. During first quarter 2016, we incurred expense of approximately $16 million related to deficiencies and/or unutilized commitments. We expect to continue to incur deficiency and/or unutilized costs in the near-term as development activities continue. For full year 2016, we estimate these costs could range from approximately $40 million to $50 million. Should commodity prices continue to decline or we are unable to continue to develop our properties as planned, or certain wells become uneconomic and are shut-in, we could incur additional shortfalls in delivering or transporting the minimum volumes and we could be required to make payments in the event that these commitments are not otherwise offset. Although long-term shortfalls are unknown, we continually seek to optimize any short-term under-utilized assets through capacity release and third-party arrangements as well as by shifting transportation of production from rail cars to pipelines where we receive a higher netback price.

Credit Rating Events We do not have any triggering events on our corporate debt that would cause a default in case of a downgrade of our credit rating. In addition, there are no existing ratings triggers in any of our commodity hedging agreements that would require the posting of collateral. However, a series of downgrades or other negative rating actions could increase our cost of financing, and may increase our requirements to post collateral as financial assurance of performance under certain other contractual arrangements such as pipeline transportation contracts, crude oil and natural gas sales contracts, work commitments and certain abandonment obligations. A requirement to post collateral could have a negative impact on our liquidity.

Cash Flows

Cash flow information is as follows:

	Three Months Ended March 31,	
(millions)	2016	2015
Total Cash Provided By (Used in)		
Operating Activities	$ 251	$ 541
Investing Activities	(264)	(1,036)
Financing Activities	(62)	1,021
Increase (Decrease) in Cash and Cash Equivalents	$ (75)	$ 526

Operating Activities Net cash provided by operating activities for the first three months of 2016 decreased significantly as compared with 2015. Decreases in average realized commodity prices were partially offset by increases in sales volumes and more favorable settlements of commodity derivatives. Working capital changes contributed $136 million of negative operating cash flow in the first three months of 2016 as compared with a positive impact of $18 million in the first three months of 2015.

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-out arrangements, which may result in reimbursement for capital spending that had occurred in prior periods. Capital spending for property, plant and equipment decreased by $615 million during the first three months of 2016 as compared with 2015, primarily due to a reduced capital spending program. Investing activities included $6 million in CONE Gathering LLC during the first three months of 2016 as compared with $44 million in the first three months of 2015. We received $238 million in proceeds from asset divestitures during the first three months of 2016, as compared with $119 million during the same period in 2015.

Financing Activities Our financing activities include the issuance or repurchase of our common stock, payment of cash dividends on our common stock, the borrowing of cash and the repayment of borrowings. During the first three months of 2016, funds were provided by cash proceeds from the term loan acquisition ($1.4 billion). We used cash to pay dividends on our common stock ($41 million), fund the purchase of certain of our outstanding senior notes ($1.38 billion), and make principal payments related to capital lease obligations ($13 million).

In comparison, during the first three months of 2015, funds were provided by cash proceeds from the issuance of shares of Company common stock to the public ($1.1 billion). We used cash to pay dividends on our common stock ($64 million) and make principal payments related to capital lease obligations ($19 million).

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

Investing Activities

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

	Three Months Ended March 31,	
(millions)	2016	2015
Acquisition, Capital and Exploration Expenditures		
Unproved Property Acquisition (1)	$ 19	$ 26
Exploration	98	69
Development	228	699
Midstream	15	58
Corporate and Other	8	23
Total	$ 368	$ 875
Other		
Investment in Equity Method Investee (2)	$ 6	$ 44
Increase in Capital Lease Obligations	$ —	$ 20

(1) Unproved property acquisition cost for 2016 includes $10 million in the DJ Basin and $6 million in the Marcellus Shale. Unproved property acquisition cost for 2015 includes $11 million in the DJ Basin and $15 million in the Marcellus Shale.

(2) Investment in equity method investee represents primarily contributions to CONE Gathering LLC which owns and operates the natural gas gathering infrastructure associated with our Marcellus Shale joint venture.

Total expenditures decreased during the first three months of 2016 as compared with 2015 due to our reduced capital spending program. See Operating Outlook – 2016 Capital Investment Program, above.

Financing Activities

Long-Term Debt Our principal source of liquidity is our Revolving Credit Facility that matures August 27, 2020. At March 31, 2016, there were no borrowings outstanding under the Revolving Credit Facility, leaving $4.0 billion available for use. We may rely on our Revolving Credit Facility to help fund our capital investment program, and may periodically borrow amounts for working capital purposes. On January 6, 2016, we entered into the Term Loan Facility with Citibank, N.A., as administrative agent, Mizuho Bank, Ltd., as syndication agent, and certain other financial institutions party thereto, which provides for a three-year term loan facility for a principal amount of $1.4 billion. In connection with the Term Loan Facility, we launched cash tender offers for certain Senior Notes assumed in the Rosetta Merger. The borrowings under the Term Loan Facility were used solely to fund the tender offers. See Item 1. Financial Statements – Note 6. Debt.

Our outstanding fixed-rate debt (excluding capital lease obligations) totaled approximately $6.1 billion at March 31, 2016. The weighted average interest rate on fixed-rate debt was 5.69%, with maturities ranging from March 2019 to August 2097.

Dividends During first quarter 2016, our Board of Directors adjusted the quarterly dividend to align the dividend yield with historical levels and to further enhance our liquidity. We paid total cash dividends of 10 cents per share of common stock during first quarter 2016 as compared with 18 cents per share during first quarter 2015.

On April 25, 2016, the Board of Directors declared a quarterly cash dividend of 10 cents per common share, which will be paid on May 23, 2016 to shareholders of record on May 9, 2016. 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 $5 million during the first three months of 2016 and $4 million during the first three months of 2015.

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 228,917 shares with a value of $8 million during the first three months of 2016 and 249,122 shares with a value of $12 million during the first three months of 2015.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

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

At March 31, 2016, we had various open commodity derivative instruments related to crude oil and natural gas. 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 $457 million. Based on the March 31, 2016 published commodity futures price curves for the underlying commodities, a hypothetical price increase of $10.00 per Bbl for crude oil would decrease the fair value of our net commodity derivative asset by approximately $154 million. A hypothetical price increase of $0.50 per MMBtu for natural gas would decrease the fair value of our net commodity derivative asset by approximately $19 million. Our derivative instruments are executed under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net cash settled at the time of election. See Item 1. Financial Statements – Note 5. Derivative Instruments and Hedging Activities.

Interest Rate Risk

Changes in interest rates affect the amount of interest we pay on borrowings under our Revolving Credit Facility and Term Loan Facility and the amount of interest we earn on our short-term investments.

At March 31, 2016, we had approximately $7.5 billion (excluding capital lease obligations) of long-term debt, net, outstanding. Of this amount, $6.1 billion was fixed-rate debt, net, with a weighted average interest rate of 5.69%. Although near term changes in interest rates may affect the fair value of our fixed-rate debt, they do not expose us to interest rate risk or cash flow loss.

However, we are exposed to interest rate risk related to our interest-bearing cash and cash equivalents balances. As of March 31, 2016, our cash and cash equivalents totaled nearly $1.0 billion, approximately 30% of which was invested in money market funds and short-term investments with major financial institutions. In addition, borrowings under the Term Loan Facility are subject to variable interest rates which expose us to the risk of earnings or cash flow loss due to potential increases in market interest rates. A change in the interest rate applicable to our variable-rate debt could expose us to additional interest cost. While we currently have no interest rate derivative instruments as of March 31, 2016, we may invest in such instruments in the future in order to mitigate interest rate risk. A change in the interest rate applicable to our short-term investments would have a de minimis impact.

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 first quarter of each of 2016 and 2015.

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, 2015, 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, 2015 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) and Rule 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act)), are effective. There were no changes in internal control over financial reporting (as defined in Exchange Act Rule 13a-15(f) and 15d-15(f)) that occurred during the quarter covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

See discussion of legal proceedings in Part I. Financial Information, Item 1. Financial Statements - Note 13. Commitments and Contingencies of this Form 10-Q, which is incorporated by reference into this Part II. Item 1, as well as discussion in Item 3. Legal Proceedings, of our Annual Report on Form 10-K for the year ended December 31, 2015.

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, 2015.

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

The following table sets forth, for the periods indicated, our share repurchase activity:

Period	Total Number of Shares Purchased (1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
				(in thousands)
1/1/2016 - 1/31/2016	99,341	$ 33.15	—	—
2/1/2016 - 2/28/2016	110,073	31.65	—	—
3/1/2016 - 3/31/2016	19,503	31.48	—	—
Total	228,917	$ 32.29	—	—

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

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Item 6. Exhibits

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

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 May 4, 2016

/s/ Kenneth M. Fisher

Kenneth M. Fisher
Executive Vice President, Chief Financial Officer

Table of Contents

Index to Exhibits

Exhibit Number	Exhibit
2.1	Asset Acquisition Agreement dated August 17, 2011 between CNX Gas Company LLC and Noble Energy, Inc. including Appendix I (Definitions) thereto (filed as Exhibit 2.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2011 and incorporated herein by reference).
2.2	Agreement and Plan of Merger, dated as of May 10, 2015, by and among Noble Energy, Inc., Bluebonnet Merger Sub Inc. and Rosetta Resources Inc. (filed as Exhibit 2.1 of the Registrant's Current Report on Form 8-K (Date of Report: May 10, 2015) filed on May 11, 2015 and incorporated herein by reference).
3.1	Certificate of Incorporation of the Registrant (as amended through April 29, 2015), filed as Exhibit 3.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2015 and incorporated herein by reference.
3.2	By-Laws of Noble Energy, Inc. (as amended through October 20, 2015), filed as Exhibit 3.1 to the Registrant's Current Report on Form 8-K (Date of Event: October 20, 2015) filed on October 22, 2015 and incorporated herein by reference.
10.1	Term Loan Agreement as of January 6, 2016 among Noble Energy, Inc., Citibank, N.A., as administrative agent, Mizuho Bank, Ltd., as syndication agent and certain financial institutions as are or may become parties thereto (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Report: January 6, 2016) filed on January 6, 2016 and incorporated herein by reference).
10.2*	Form of Stock Option Agreement under the Noble Energy, Inc. 2015 Non-Employee Director Stock Plan (filed as Exhibit 10.7 to the Registrant's Current Report on Form 8-K (Date of Report: January 25, 2016) filed January 29, 2016 and incorporated herein by reference).
10.3*	Form of Restricted Stock Agreement under the Noble Energy, Inc. 2015 Non-Employee Director Stock Plan (filed as Exhibit 10.6 to the Registrant's Current Report on Form 8-K (Date of Report: January 25, 2016) filed January 29, 2016 and incorporated herein by reference).
10.4*	Form of Non-Qualified Stock Option Agreement under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (effective February 1, 2016) (filed as Exhibit 10.5 to the Registrant's Current Report on Form 8-K (Date of Report: January 25, 2016) filed January 29, 2016 and incorporated herein by reference).
10.5*	Form of Restricted Stock Agreement (two-year time vested for non-PEO executive officers) under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (effective February 1, 2016) (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K (Date of Report: January 25, 2016) filed January 29, 2016 and incorporated herein by reference).
10.6*	Form of Restricted Stock Agreement (two-year time vested for principal executive officer) under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (effective February 1, 2016) (filed as Exhibit 10.3 to the Registrant's Current Report on Form 8-K (Date of Report: January 25, 2016) filed January 29, 2016 and incorporated herein by reference).
10.7*	Form of Performance Award Agreement (three-year performance vested stock and cash) under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (effective February 1, 2016) (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Report: January 25, 2016) filed January 29, 2016 and incorporated herein by reference).
10.8*	Form of Restricted Stock Agreement (three-year performance vested stock) under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (effective February 1, 2016) (filed as Exhibit 10.8 to the Registrant's Current Report on Form 8-K/A (Date of Report: January 25, 2016) filed February 4, 2016 and incorporated herein by reference).

10.9*	Form of Cash Award Agreement (two-year vested) under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (effective February 1, 2016) (filed as Exhibit 10.4 to the Registrant's Current Report on Form 8-K (Date of Report: January 25, 2016) filed January 29, 2016 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), furnished 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), furnished herewith.
101.INS	XBRL Instance Document
101.SCH	XBRL Schema Document
101.CAL	XBRL Calculation Linkbase Document
101.LAB	XBRL Label Linkbase Document
101.PRE	XBRL Presentation Linkbase Document
101.DEF	XBRL Definition Linkbase Document

* Management contract or compensatory plan or arrangement required to be filed as an exhibit hereto.

** Copies of exhibits will be furnished upon prepayment of 25 cents per page. Requests should be addressed to the Executive Vice President and Chief Financial Officer, Noble Energy, Inc., 1001 Noble Energy Way, Houston, Texas 77070.

EXHIBIT 12.1

Noble Energy, Inc.

Calculation of Ratio of Earnings to Fixed Charges

	Three Months Ended March 31,	Year Ended December 31,			
	2016	2015	2014	2013	2012
(millions)					
Income (Loss) From Continuing Operations Before Income Tax and Income From Equity Investees	$ (472)	$ (2,309)	$ 1,540	$ 1,138	$ 1,170
Add (Deduct)					
Fixed Charges	113	435	349	296	288
Capitalized Interest	(27)	(144)	(116)	(121)	(151)
Distributed Income From Equity Investees	16	77	382	204	204
Earnings as Defined	$ (370)	$ (1,941)	$ 2,155	$ 1,517	$ 1,511
Net Interest Expense	79	263	210	158	125
Capitalized Interest	27	144	116	121	151
Interest Portion of Rental Expense	7	28	23	17	12
Fixed Charges as Defined	$ 113	$ 435	$ 349	$ 296	$ 288
Ratio of Earnings to Fixed Charges	—	—	6.2	5.1	5.2
Amount by Which Earnings Were Insufficient to Cover Fixed Charges	$ 483	$ 2,376	$ —	$ —	$ —

Exhibit 31.1

Certification Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002
(18 U.S.C. Section 7241)

I, David L. Stover, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Noble Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting, which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 4, 2016

/s/ David L. Stover

David L. Stover
Chief Executive Officer

Exhibit 31.2

Certification Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002
(18 U.S.C. Section 7241)

I, Kenneth M. Fisher, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Noble Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting, which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 4, 2016

/s/ Kenneth M. Fisher

Kenneth M. Fisher
Chief Financial Officer

Exhibit 32.1

Certification Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002
(18 U.S.C. Section 1350)

In connection with the accompanying Quarterly Report of Noble Energy, Inc. (the "Company") on Form 10-Q for the period ended March 31, 2016 (the "Report"), I, David L. Stover, Chief Executive Officer of the Company, hereby certify that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date:	May 4, 2016	*/s/ David L. Stover*
		David L. Stover
		Chief Executive Officer

Exhibit 32.2

Certification Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002
(18 U.S.C. Section 1350)

In connection with the accompanying Quarterly Report of Noble Energy, Inc. (the "Company") on Form 10-Q for the period ended March 31, 2016 (the "Report"), I, Kenneth M. Fisher, Chief Financial Officer of the Company, hereby certify that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: May 4, 2016

/s/ Kenneth M. Fisher

Kenneth M. Fisher
Chief Financial Officer