NOBLE ENERGY INC
Form 10-Q
August 03, 2017
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2017

OR

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

For the transition period from _____to_____

Commission file number: 001-07964

NOBLE ENERGY, INC.	
(Exact name of registrant as specified in its charter)	
Delaware	73-0785597
(State or other jurisdiction of incorporation or organization)	(I.R.S. employer identification number)
1001 Noble Energy Way	
Houston, Texas	77070
(Address of principal executive offices)	(Zip Code)
(281) 872-3100	
(Registrant's telephone number, including area code)	

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes ý No o
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes ý No o
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller
reporting company or an emerging growth company. See the definitions of "large accelerated filer", "accelerated filer", "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer x	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o	Emerging growth company o

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. o

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

As of June 30, 2017, there were 486,545,041 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 and Comprehensive Loss
(millions, except per share amounts)
(unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Revenues				
Oil, NGL and Gas Sales	$1,017	$823	$2,011	$1,528
Income from Equity Method Investees and Other	42	24	84	43
Total	1,059	847	2,095	1,571
Costs and Expenses				
Production Expense	283	280	586	556
Exploration Expense	30	89	72	252
Depreciation, Depletion and Amortization	503	622	1,031	1,239
Loss on Marcellus Shale Upstream Divestiture	2,322	—	2,322	—
General and Administrative	103	107	202	198
Other Operating Expense, Net	118	11	147	10
Total	3,359	1,109	4,360	2,255
Operating Loss	(2,300)	(262)	(2,265)	(684)
Other Expense (Income)				
(Gain) Loss on Commodity Derivative Instruments	(57)	151	(167)	107
Interest, Net of Amount Capitalized	96	78	183	157
Other Non-Operating (Income) Expense, Net	(5)	7	(6)	3
Total	34	236	10	267
Loss Before Income Taxes	(2,334)	(498)	(2,275)	(951)
Income Tax Benefit	(836)	(183)	(824)	(349)
Net Loss and Comprehensive Loss Including Noncontrolling Interests	(1,498)	(315)	(1,451)	(602)
Less: Net Income and Comprehensive Income Attributable to Noncontrolling Interests	14	—	25	—
Net Loss and Comprehensive Loss Attributable to Noble Energy	$(1,512)	$(315)	$(1,476)	$(602)
Net Loss Attributable to Noble Energy per Common Share				
Basic and Diluted	$(3.20)	$(0.73)	$(3.27)	$(1.40)
Weighted Average Number of Common Shares Outstanding				
Basic and Diluted	472	430	452	429

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

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

	June 30, 2017	December 31, 2016
ASSETS		
Current Assets		
Cash and Cash Equivalents	$540	$ 1,180
Accounts Receivable, Net	699	615
Other Current Assets	338	160
Total Current Assets	1,577	1,955
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method of Accounting)	29,928	30,355
Property, Plant and Equipment, Other	911	909
Total Property, Plant and Equipment, Gross	30,839	31,264
Accumulated Depreciation, Depletion and Amortization	(12,563)	(12,716)
Total Property, Plant and Equipment, Net	18,276	18,548
Goodwill	1,289	—
Other Noncurrent Assets	432	508
Total Assets	$21,574	$ 21,011
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable - Trade	$1,086	$ 736
Other Current Liabilities	509	742
Total Current Liabilities	1,595	1,478
Long-Term Debt	7,133	7,011
Deferred Income Taxes	1,469	1,819
Other Noncurrent Liabilities	1,279	1,103
Total Liabilities	11,476	11,411
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; 529 Million and 471 Million Shares Issued, respectively	5	5
Additional Paid in Capital	8,399	6,450
Accumulated Other Comprehensive Loss	(30)	(31)
Treasury Stock, at Cost; 39 Million and 38 Million Shares, respectively	(727)	(692)
Retained Earnings	1,988	3,556
Noble Energy Share of Equity	9,635	9,288
Noncontrolling Interests	463	312
Total Equity	10,098	9,600
Total Liabilities and Equity	$21,574	$ 21,011

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

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

	Six Months Ended June 30,	
	2017	2016
Cash Flows From Operating Activities		
Net Loss Including Noncontrolling Interests	$(1,451)	$(602)
Adjustments to Reconcile Net Loss to Net Cash Provided by Operating Activities		
Depreciation, Depletion and Amortization	1,031	1,239
Loss on Marcellus Shale Upstream Divestiture	2,322	—
Deferred Income Tax Benefit	(873)	(414)
Dry Hole Cost	—	114
Gain on Extinguishment of Debt	—	(80)
(Gain) Loss on Commodity Derivative Instruments	(167)	107
Net Cash Received in Settlement of Commodity Derivative Instruments	14	322
Stock Based Compensation	67	40
Other Adjustments for Noncash Items Included in Income	33	95
Changes in Operating Assets and Liabilities		
Increase in Accounts Receivable	(123)	(6)
Increase (Decrease) in Accounts Payable	120	(232)
Decrease in Current Income Taxes Payable	(42)	(51)
Other Current Assets and Liabilities, Net	(42)	(51)
Other Operating Assets and Liabilities, Net	(12)	(41)
Net Cash Provided by Operating Activities	877	440
Cash Flows From Investing Activities		
Additions to Property, Plant and Equipment	(1,215)	(812)
Proceeds from Marcellus Shale Upstream Divestiture	1,028	—
Clayton Williams Energy Acquisition	(616)	—
Other Acquisitions	(321)	—
Additions to Equity Method Investments	(68)	(6)
Proceeds from Divestitures and Other	101	767
Net Cash Used in Investing Activities	(1,091)	(51)
Cash Flows From Financing Activities		
Dividends Paid, Common Stock	(92)	(86)
Proceeds from Noble Midstream Services Revolving Credit Facility	195	—
Repayment of Noble Midstream Services Revolving Credit Facility	(5)	—
Proceeds from Term Loan Facility	—	1,400
Issuance of Noble Midstream Partners Common Units, Net of Offering Costs	138	—
Proceeds from Revolving Credit Facility	1,310	—
Repayment of Revolving Credit Facility	(1,310)	—
Repayment of Clayton Williams Energy Long-term Debt	(595)	—
Repayment of Senior Notes	—	(1,383)
Other	(67)	(48)
Net Cash Used in Financing Activities	(426)	(117)
(Decrease) Increase in Cash and Cash Equivalents	(640)	272
Cash and Cash Equivalents at Beginning of Period	1,180	1,028
Cash and Cash Equivalents at End of Period	$540	$1,300

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

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

	Attributable to Noble Energy						
	Common Stock	Additional Paid in Capital	Accumulated Other Comprehensive Loss	Treasury Stock at Cost	Retained Earnings	Non-controlling Interests	Total Equity
December 31, 2016	$5	$ 6,450	$ (31)	$ (692)	$ 3,556	$ 312	$ 9,600
Net (Loss) Income	—	—	—	—	(1,476)	25	(1,451)
Clayton Williams Energy Acquisition	—	1,876	—	(25)	—	—	1,851
Stock-based Compensation	—	65	—	—	—	—	65
Dividends (20 cents per share)	—	—	—	—	(92)	—	(92)
Issuance of Noble Midstream Partners Common Units, Net of Offering Costs	—	—	—	—	—	138	138
Distributions to Noncontrolling Interest Owners	—	—	—	—	—	(12)	(12)
Other	—	8	1	(10)	—	—	(1)
June 30, 2017	$5	$ 8,399	$ (30)	$ (727)	$ 1,988	$ 463	$ 10,098
December 31, 2015	$5	$ 6,360	$ (33)	$ (688)	$ 4,726	$ —	$ 10,370
Net Loss	—	—	—	—	(602)	—	(602)
Stock-based Compensation	—	36	—	—	—	—	36
Dividends (20 cents per share)	—	—	—	—	(86)	—	(86)
Other	—	2	1	(8)	—	—	(5)
June 30, 2016	$5	$ 6,398	$ (32)	$ (696)	$ 4,038	$ —	$ 9,713

The accompanying notes are an integral part of these 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 historical operating areas include: US onshore, primarily the DJ Basin, Delaware Basin, Eagle Ford Shale and Marcellus Shale (until June 2017); US offshore Gulf of Mexico; Eastern Mediterranean; and West Africa. Our Midstream segment owns, operates, develops and acquires domestic midstream infrastructure assets with current focus areas being the DJ and Delaware Basins.

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 June 30, 2017 and December 31, 2016 and for the three and six months ended June 30, 2017 and 2016 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. For the periods presented, activity within other comprehensive income or loss was de minimis; therefore, net income or loss is materially consistent with comprehensive income or loss.

In Note 11. Segment Information, we report a new Midstream segment, established second quarter 2017, and present prior period amounts on a comparable basis. Certain other prior-period amounts have been reclassified to conform to the current period presentation.

Operating results for the three and six months ended June 30, 2017 are not necessarily indicative of the results that may be expected for the year ending December 31, 2017.

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, 2016.

Consolidation Our consolidated financial statements include our accounts, the accounts of subsidiaries which Noble Energy wholly owns, and the accounts of a variable interest entity (VIE) for which Noble Energy is the primary beneficiary. 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.

Consolidated VIE Noble Energy has determined that the partners with equity at risk in Noble Midstream Partners LP (NYSE: NBLX) (Noble Midstream Partners) lack the authority, through voting rights or similar rights, to direct the activities that most significantly impact Noble Midstream Partners' economic performance; therefore, Noble Midstream Partners is considered a VIE. Through Noble Energy's ownership interest in Noble Midstream GP LLC (the General Partner to Noble Midstream Partners), Noble Energy has the authority to direct the activities that most significantly affect economic performance and the obligation to absorb losses or the right to receive benefits that could be potentially significant to Noble Midstream Partners. Therefore, Noble Energy is considered the primary beneficiary and consolidates Noble Midstream Partners.

Goodwill As of June 30, 2017, our consolidated balance sheet includes goodwill of $1.3 billion. This goodwill resulted from the acquisition (Clayton Williams Energy Acquisition) of Clayton Williams Energy, Inc. (Clayton Williams Energy) completed on April 24, 2017, and represents the excess of the consideration paid for Clayton Williams Energy over the net amounts assigned to identifiable assets acquired and liabilities assumed. See Note 3. Clayton Williams Energy Acquisition.

Goodwill is not amortized to earnings but is qualitatively assessed for impairment. We assess goodwill for impairment annually during the third quarter, or more frequently as circumstances require, at the reporting unit level. If, based on our qualitative procedures, it is more likely than not that the fair value of the reporting unit is less than its carrying amount, we perform the two-step goodwill impairment test. The two-step goodwill impairment test is also performed whenever events or changes in circumstances indicate that the carrying value may not be recoverable. It is possible that goodwill could become impaired in the future if commodity prices or other economic factors decline. See Recently Issued Accounting Standards – Intangibles – Goodwill and Other: Simplifying the Test for Goodwill Impairment, below.

If, in the future, we dispose of a reporting unit or a portion of a reporting unit that constitutes a business, we will include goodwill associated with that business in the carrying amount of the business in order to determine the gain or loss on disposal. The amount of goodwill allocated to the carrying amount of a business can significantly impact the amount of gain or loss recognized on the sale of that business. The amount of goodwill to be included in that carrying amount will be based on the relative fair value of the business to be disposed of and the portion of the reporting unit that will be retained.

Exit Costs We recognize the fair value of a liability for an exit cost in the period in which a liability is incurred. Our exit costs for second quarter 2017 relate primarily to estimated costs associated with a retained Marcellus Shale firm transportation contract, for which we accrued an exit liability at June 30, 2017.

The recognition and fair value estimation of a liability requires that management take into account certain estimates and assumptions such as: the determination of whether a cease-use date has occurred (defined as the date the entity ceases using the right conveyed by the contract, for example, the right to use a leased property or to receive future goods or services); the amount, if any, of economic benefit that is expected to be obtained from a contract through partial use or release; and our estimate of costs that will continue to be incurred under the contract. We record the liability at estimated fair value, based on expected future cash outflows required to satisfy the obligation, net of estimated recoveries, and discounted. After initial recording, the liability increases for the passage of time. Exit costs, and associated accretion expense, are included in operating expense in our consolidated statements of operations. See Note 4. Acquisitions and Divestitures and Note 12. Commitments and Contingencies.

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.

Reserves Estimates Estimated quantities of crude oil, natural gas and natural gas liquids (NGL) reserves are the most significant of our estimates. There are numerous uncertainties inherent in estimating quantities of proved crude oil, natural gas and NGL reserves. The accuracy of any reserves estimate is a function of the quality of available engineering and geoscience information and also interpretation of the provided data. As a result, reserves estimates may be different from the quantities of crude oil, natural gas and NGLs that are ultimately recovered.

During second quarter 2017, we recorded the following significant changes in our proved reserves estimates:

- Leviathan Field We recorded proved undeveloped reserves of 551 MMBoe, net, for the Leviathan field, offshore Israel, upon approval and sanction of the first phase of development, and are expecting to initiate natural gas production by the end of 2019.
- Delaware Basin We recorded net proved reserves of approximately 86 MMBoe, of which approximately 17 MMBoe are proved developed reserves and 69 MMBoe are proved undeveloped reserves as of June 30, 2017 related to the Clayton Williams Energy Acquisition.
- Marcellus Shale The Marcellus Shale upstream divestiture resulted in a decrease in net proved reserves of approximately 241 MMBoe as of June 30, 2017, of which approximately 190 MMBoe were proved developed reserves and 51 MMBoe were proved undeveloped reserves.

Recently Issued Accounting Standards

Revenue Recognition 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, revenue recognition would occur upon 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.

The standard is required to be adopted using either the full retrospective approach, with all prior periods presented adjusted, or the modified retrospective approach, with a cumulative adjustment to retained earnings on the opening balance sheet. We are performing an initial review of contracts for each of our revenue streams and developing accounting policies to address the provisions of the ASU. Currently, we do not have any contracts that would require a change from the entitlements method, historically used for certain domestic natural gas sales, to the sales method of accounting. We continue to evaluate the impact of ASU on our accounting policies, internal controls, and consolidated financial statements and related disclosures. While we have not concluded on the application of this standard, we do not expect a material impact, if any. We will adopt the new standard on January 1, 2018, using the modified retrospective approach with a cumulative adjustment to retained earnings as necessary.

Compensation – Stock Compensation (Topic 718): Scope of Modification Accounting In May 2017, the FASB issued Accounting Standards Update No. 2017-09 (ASU 2017-09) Compensation – Stock Compensation (Topic 718). The purpose of this update is to provide clarity as to which modifications of awards require modification accounting under Topic 718, whereas previously issued guidance frequently resulted in varying interpretations and a diversity of practice. An entity should employ modification accounting unless the following are met: (1) the fair value of the award is the same immediately before and after the award is modified; (2) the vesting conditions are the same under both the modified award and the original award; and (3) the classification of the modified award is the same as the original award, either equity or liability. Regardless of whether modification accounting is utilized, award disclosure requirements under Topic 718 remain unchanged. ASU 2017-09 will be effective for annual or any interim periods beginning after December 15, 2017. We do not believe adoption of ASU 2017-09 will have a material impact on our financial statements. We will adopt the new standard on the effective date of January 1, 2018.

Business Combinations: Clarifying the Definition of a Business In January 2017, the FASB issued Accounting Standards Update No. 2017-01 (ASU 2017-01): Business Combinations – Clarifying the Definition of a Business, that assists in determining whether certain transactions should be accounted for as acquisitions or dispositions of assets or businesses. The amendment provides a screen to be applied to the fair value of an acquisition or disposal to evaluate whether the assets in question are simply assets or if they meet the requirements of a business. If the screen is not met, no further evaluation is needed. If the screen is met, certain steps are subsequently taken to make the determination. This ASU is designed to reduce the number of transactions to be accounted for as business transactions, which take more time and cost more to analyze than asset transactions. This ASU is effective for annual and interim periods beginning after December 15, 2017 and is required to be applied prospectively. Our current Clayton Williams Energy Acquisition is not impacted by this guidance and we will apply the new guidance to applicable and qualifying transactions after our adoption on January 1, 2018.

Statement of Cash Flows: Restricted Cash In November 2016, the FASB issued Accounting Standards Update No. 2016-18 (ASU 2016-18): Statement of Cash Flows – Restricted Cash, which requires amounts generally described as restricted cash and restricted cash equivalents be included with cash and cash equivalents when reconciling the total beginning and ending amounts for the periods shown on the statement of cash flows. This ASU will be effective for annual and interim periods beginning after December 15, 2017, with earlier application permitted. We do not believe adoption of ASU 2016-18 will have a material impact on our statement of cash flows and related disclosures. We will adopt the new standard on the effective date of January 1, 2018.

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments In August 2016, the FASB issued Accounting Standards Update No. 2016-15 (ASU 2016-15): Statement of Cash Flows – Classification of Certain Cash Receipts and Cash Payments, to clarify how eight specific cash receipt and cash payment transactions should be presented in the statement of cash flows. ASU 2016-15 will be effective for annual and interim periods beginning after December 15, 2017, with earlier application permitted. We do not believe adoption of ASU 2016-15 will have a material impact on our statement of cash flows and related disclosures as this update pertains to classification of items and is not a change in accounting principle. We will adopt the new standard on the effective date of January 1, 2018.

Leases In February 2016, the Financial Accounting Standards Board (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.

In the normal course of business, we enter into capital and operating lease agreements to support our exploration and development operations and lease assets such as drilling rigs, platforms, storage facilities, field services and well equipment, pipeline capacity, office space and other assets. At this time, we cannot reasonably estimate the financial impact this ASU will have on our financial statements; however, we believe adoption and implementation of this ASU will have a material impact on our balance sheet resulting from an increase in both assets and liabilities relating to our leasing activities. As part of our assessment to date, we have formed an implementation work team, prepared educational and training materials pertinent to this ASU and have begun contract review and documentation. We will adopt the new standard on the effective date of January 1, 2019.

Intangibles – Goodwill and Other: Simplifying the Test for Goodwill Impairment In January 2017, the FASB issued Accounting Standards Update No. 2017-04 (ASU 2017-04): Intangibles – Goodwill and Other – Simplifying the Test for Goodwill Impairment, to simplify how an entity is required to test goodwill for impairment by eliminating Step 2 from the goodwill impairment test. Step 2 measures a goodwill impairment loss by comparing the implied fair value of a reporting unit's goodwill with the carrying amount of that goodwill. Under the new guidance, an entity will perform its annual, or interim, goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount, with an impairment charge being recognized for the amount by which the carrying amount exceeds the reporting unit's fair value. ASU 2017-04 will be effective for annual or any interim goodwill impairment tests in fiscal years beginning after December 15, 2019, with early adoption permitted. We are currently evaluating the provisions of ASU 2017-04 and have not yet determined if we will early adopt.

Financial Instruments: Credit Losses In June 2016, the FASB issued Accounting Standards Update No. 2016-13 (ASU 2016-13): Financial Instruments – Credit Losses, which replaces the incurred loss impairment methodology in current US GAAP with a methodology that reflects expected credit losses. The update is intended to provide financial statement users with more useful information about expected credit losses. The amended guidance is effective for fiscal years beginning after December 15, 2019, with early adoption permitted. We are currently evaluating the effect, if any, that the guidance will have on our consolidated financial statements and related disclosures. We will adopt the new standard on the effective date of January 1, 2020.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions)	2017	2016	2017	2016
Production Expense				
Lease Operating Expense	$124	$119	$263	$281
Production and Ad Valorem Taxes	38	40	83	43
Gathering, Transportation and Processing Expense (1)	121	121	240	232
Total	$283	$280	$586	$556
Loss on Marcellus Shale Upstream Divestiture (2)				
Loss on Sale	$2,270	$—	$2,270	$—
Firm Transportation Commitment (3)	41	—	41	—
Other (4)	11	—	11	—
Total	$2,322	$—	$2,322	$—
Other Operating (Income) Expense, Net				
Marketing Expense (5)	$14	$9	$33	$27
Clayton Williams Energy Acquisition Expenses (6)	90	—	94	—
Gain on Extinguishment of Debt (7)	—	—	—	(80)
Loss on Asset Due to Terminated Contract (8)	—	5	4	47
Other, Net	14	(3)	16	16
Total	$118	$11	$147	$10

(1) Certain of our processing expense was historically presented as a component of other operating expense, net, in our consolidated statements of operations. Beginning in 2017, we have changed our presentation to reflect processing expense as a component of production expense. These costs are now included within gathering, transportation and processing expense. For the three and six months ended June 30, 2017, these costs totaled $2 million and $5 million respectively. For the three and six months ended June 30, 2016, these costs totaled $6 million and $10 million respectively, and have been reclassified from marketing expense to conform to the current presentation.

(2) See Note 4. Acquisitions and Divestitures.

(3) Amount represents expense related to an unutilized firm transportation commitment associated with a Marcellus Shale firm transportation contract. See Note 12. Commitments and Contingencies.

(4) Amount includes costs for legal and advisory services and employee severance charges.

(5) Amounts represent expense for unutilized firm transportation and shortfalls in delivering or transporting minimum volumes under certain commitments.

(6) See Note 3. Clayton Williams Energy Acquisition.

(7) Amount relates to the tendering of senior notes. See Note 6. Debt.

(8) Amounts relate to the termination and final settlement of a rig contract for offshore Falkland Islands as a result of a supplier's non-performance.

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Noble Energy, Inc.
Notes to Consolidated Financial Statements

Balance Sheet Information Other balance sheet information is as follows:

(millions)	June 30, 2017	December 31, 2016
Accounts Receivable, Net		
Commodity Sales	$408	$ 403
Joint Interest Billings	198	106
Proceeds Receivable [1]	—	40
Other	112	86
Allowance for Doubtful Accounts	(19)	(20)
Total	$699	$ 615
Other Current Assets		
Inventories, Materials and Supplies	$65	$ 71
Inventories, Crude Oil	23	18
Assets Held for Sale [2]	191	18
Restricted Cash [3]	—	30
Prepaid Expenses and Other Current Assets	59	23
Total	$338	$ 160
Other Noncurrent Assets		
Equity Method Investments	$286	$ 400
Mutual Fund Investments	67	71
Other Assets, Noncurrent	79	37
Total	$432	$ 508
Other Current Liabilities		
Production and Ad Valorem Taxes	$113	$ 115
Commodity Derivative Liabilities	—	102
Income Taxes Payable	11	53
Asset Retirement Obligations [4]	50	160
Interest Payable	75	76
Current Portion of Capital Lease Obligations	64	63
Other Liabilities, Current [5]	196	173
Total	$509	$ 742
Other Noncurrent Liabilities		
Deferred Compensation Liabilities	$216	$ 218
Asset Retirement Obligations [4]	943	775
Marcellus Shale Firm Transportation Commitment [6]	33	—
Production and Ad Valorem Taxes	32	47
Other Liabilities, Noncurrent	55	63
Total	$1,279	$ 1,103

(1) Balance at December 31, 2016 related to the farm-out of a 35% interest in Block 12 offshore Cyprus; proceeds were received in January 2017. See Note 4. Acquisitions and Divestitures.

(2) Balance at June 30, 2017 primarily includes our equity investment in CONE Gathering, LLC. See Note 4. Acquisitions and Divestitures.

(3) Balance at December 31, 2016 represented amount held in escrow for the purchase of certain Delaware Basin properties. The transaction closed in first quarter 2017. See Note 4. Acquisitions and Divestitures.

(4)

Reclassification from current to noncurrent is driven primarily by a change in expected timing of abandonment activities in the Gulf of Mexico. See Note 9. Asset Retirement Obligations.

(5) Balance at June 30, 2017 includes $8 million associated with the current portion of the Marcellus Shale firm transportation commitment. See Note 12. Commitments and Contingencies.

(6) See Note 12. Commitments and Contingencies.

Note 3. Clayton Williams Energy Acquisition

In January 2017, we announced the Clayton Williams Energy Acquisition, which was approved by Clayton Williams Energy stockholders and closed on April 24, 2017. Acquired assets include 71,000 highly contiguous net acres in the core of the Delaware Basin adjacent to our Reeves County holdings in Texas, and an additional 100,000 net acres in other areas of the Permian and Midland Basins. In total, the acquisition increased our Delaware Basin position to approximately 118,000 net acres.

We recorded net proved reserves of approximately 86 MMBoe, of which approximately 17 MMBoe are proved developed reserves and 69 MMBoe are proved undeveloped reserves, as of June 30, 2017. In addition, upon closing of the acquisition, approximately 64,000 net acres in Reeves County, Texas were dedicated to Noble Midstream Partners for infield crude oil, natural gas and produced water gathering.

The acquisition was effected through the issuance of approximately 56 million shares of Noble Energy common stock, with a fair value of approximately $1.9 billion, and cash consideration of $637 million, for total consideration of approximately $2.5 billion, in exchange for all outstanding Clayton Williams Energy shares, including options, restricted stock awards and warrants. The closing price of our stock on the New York Stock Exchange (NYSE) was $34.17 on April 24, 2017. In connection with the transaction, we borrowed $1.3 billion under our Revolving Credit Facility (defined below) to fund the cash portion of the acquisition consideration, redeem outstanding Clayton Williams Energy debt, pay associated make-whole premiums and pay related fees and expenses. See Note 6. Debt.

In connection with the Clayton Williams Energy Acquisition, we have incurred acquisition-related costs of approximately $94 million to date, including $60 million of severance, consulting, investment, advisory, legal and other merger-related fees, and $34 million of noncash share-based compensation expense, all of which were expensed and are included in other operating expense, net in our consolidated statements of operations. In addition, we received approximately 720,000 shares of common stock from Clayton Williams Energy shareholders for the payment of withholding taxes due on the vesting of their restricted shares and options pursuant to the purchase and sale agreement, resulting in a $25 million increase in our treasury stock balance.

Purchase Price Allocation The transaction 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 Clayton Williams Energy to the identifiable assets acquired and the liabilities assumed based on the fair values at the acquisition date, with any excess of the purchase price over the estimated fair value of the identifiable net assets acquired recorded as goodwill. Any value assigned to goodwill is not expected to be deductible for income tax purposes.

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 tax returns that provide the underlying tax basis of Clayton Williams Energy'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 acquisition date, during which time the value of the assets and liabilities, including any goodwill, may be revised as appropriate.

The following table sets forth our preliminary purchase price allocation:

(millions, except per share amounts)	
Fair Value of Common Stock Issued	$1,876
Plus: Cash Consideration Paid to Clayton Williams Energy Stockholders	637
Total Purchase Price	$2,513
Plus Liabilities Assumed by Noble Energy:	
Accounts Payable	68
Other Current Liabilities	38
Long-Term Deferred Tax Liability	522
Long-Term Debt	595
Asset Retirement Obligations	59

Total Purchase Price Plus Liabilities Assumed	$3,795

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The fair value of Clayton Williams Energy's identifiable assets is as follows:

(millions)	
Cash and Cash Equivalents	$21
Other Current Assets	37
Oil and Gas Properties:	
Proved Reserves	724
Undeveloped Leasehold Cost	1,581
Gathering and Processing Assets	49
Asset Retirement Costs	59
Other Property Plant and Equipment	18
Other Noncurrent Assets	17
Implied Goodwill	1,289
Total Asset Value	$3,795

In connection with the acquisition, we assumed, and then subsequently retired, $595 million of Clayton Williams Energy long-term debt. The fair value measurements of long-term debt were estimated based on the early redemption 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 rate. 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 Clayton Williams Energy are included in our consolidated statements of operations beginning on April 24, 2017. We generated revenues of $25 million and a de minimis loss from the Clayton Williams Energy assets during the period April 24, 2017 to June 30, 2017.

Proforma Financial Information The following pro forma condensed combined financial information was derived from the historical financial statements of Noble Energy and Clayton Williams Energy and gives effect to the acquisition as if it had occurred on January 1, 2016. The below information reflects pro forma adjustments based on available information and certain assumptions that we believe are reasonable, including (i) Noble Energy's common stock and equity awards issued to convert Clayton Williams Energy's outstanding shares of common stock and equity awards and conversion of warrants as of the closing date of the acquisition, (ii) depletion of Clayton Williams Energy's fair-valued proved crude oil and natural gas properties, and (iii) the estimated tax impacts of the pro forma adjustments.

Additionally, pro forma earnings for the three and six months ended June 30, 2017 were adjusted to exclude acquisition-related costs of $90 million and $94 million, respectively, incurred by Noble Energy and $26 million, incurred by Clayton Williams Energy in second quarter 2017. The pro forma results of operations do not include any cost savings or other synergies that may result from the Clayton Williams Energy Acquisition or any estimated costs that have been or will be incurred by us to integrate the Clayton Williams Energy 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 Clayton Williams Energy Acquisition taken place on January 1, 2016; furthermore, the financial information is not intended to be a projection of future results.

	Three Months Ended June 30,	Six Months Ended June 30,

(millions, except per share amounts)	2017	2016	2017	2016
Revenues	$1,070	$888	$2,141	$1,641
Net Loss and Comprehensive Loss Attributable to Noble Energy	(1,354)	(316)	(1,324)	(649)
Net Loss Attributable to Noble Energy per Common Share				
Basic and Diluted	$(2.77)	$(0.65)	$(2.71)	$(1.34)

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Note 4. Acquisitions and Divestitures

2017 Asset Transactions

During the first six months of 2017, we engaged in the following asset transactions.

Marcellus Shale Upstream Divestiture On June 28, 2017, we closed the sale of all of our Marcellus Shale upstream assets, which are primarily natural gas properties. The purchase price totaled $1.2 billion, and we received $1.0 billion of net cash proceeds, after consideration of customary adjustments, at closing. The purchase price includes additional contingent consideration of up to $100 million structured as three separate payments of $33.3 million each. The contingent payments are in effect should the average annual price of the Appalachia Dominion, South Point index exceed $3.30 per MMBtu in the individual annual periods from 2018 through 2020. No amounts have been accrued related to the contingent consideration. Proceeds from the transaction were used to repay borrowings resulting from the Clayton Williams Energy Acquisition. See Note 6. Debt.

In second quarter 2017, we recognized a total loss of $2.3 billion, or $1.5 billion after-tax, on this transaction. The aggregate net book value of the properties prior to the sale was approximately $3.4 billion, which included approximately $883 million of undeveloped leasehold cost.

As part of the total loss, we recorded a charge of $41 million, discounted, relating to a retained transportation contract where the pipeline project is currently in service. We no longer have production to satisfy this commitment and do not plan to utilize this capacity in the future. As such, we recorded a charge in accordance with accounting for exit or disposal activities under ASC 420 - Exit or Disposal Cost Obligations. In addition, we have retained other Marcellus Shale firm transportation contracts, relating to pipeline projects which are not yet commercially available to us. These projects are either under construction or have not yet been approved by the Federal Energy Regulatory Commission (FERC). As these projects become commercially available to us, we will assess, based upon the facts and circumstances, the recognition of any potential exit cost liabilities. We expect to incur additional firm transportation, as well as other restructuring or personnel costs, associated with this exit activity in the future. See Note 2. Basis of Presentation and Note 12. Commitments and Contingencies.

For the three and six months ended June 30, 2017, our consolidated statements of operations include a pre-tax loss of $2.3 billion for the respective periods associated with the divested Marcellus Shale upstream assets, driven by the loss on sale. For the three and six months ended June 30, 2016, our consolidated statements of operations include a pre-tax loss of $91 million and $167 million, respectively.

During second quarter 2017, production from the Marcellus Shale upstream assets totaled 393 MMcfe/d. With the closing of the sale, we recorded a decrease in net proved reserves of approximately 241 MMBoe, of which approximately 190 MMBoe were proved developed reserves and 51 MMBoe were proved undeveloped reserves.

Marcellus Shale CONE Gathering Divestiture On May 18, 2017, we announced the signing of a definitive agreement to divest an affiliate that holds the 50% interest in CONE Gathering, LLC (CONE Gathering) and 21.7 million common and subordinated limited partnership units in CONE Midstream Partners LP (NYSE:CNNX) (CONE Midstream), for total cash consideration of $765 million. CONE Gathering owns the general partner of CONE Midstream, and the limited partnership units represent a 33.5% ownership interest in CONE Midstream. CONE Midstream constructs, owns and operates natural gas gathering and other midstream energy assets in support of Marcellus Shale activities.

We expect closing to occur in second half 2017, subject to customary closing conditions and adjustments, and have classified these assets as held for sale at June 30, 2017. The other 50% owner of CONE Gathering is pursuing litigation in response to our sale. At this time, we expect this matter to be resolved prior to closing. Going forward, our midstream efforts are focused on Noble Midstream Partners, supporting our DJ Basin and Delaware Basin growth areas.

Assets Held for Sale At June 30, 2017, assets held for sale included $173 million related to our investment in CONE Gathering and $18 million related to other onshore properties.

Delaware Basin Acquisition In first quarter 2017, we closed a bolt-on acquisition in the Delaware Basin for $301 million, approximately $246 million of which was allocated to undeveloped leasehold cost. The acquisition included seven producing wells, of which four are operated by us.

Noble Midstream Partners

Asset Contribution On June 26, 2017, Noble Midstream Partners acquired an additional 15% limited partner interest in Blanco River DevCo LP (Blanco River DevCo), increasing its ownership to 40% of the Blanco River DevCo LP, and acquired the remaining 20% limited partner interest in Colorado River DevCo LP (Colorado River DevCo) from Noble Energy for $270 million.

Blanco River DevCo holds Noble Midstream Partners' Delaware Basin in-field gathering dedications for crude oil and produced water gathering services on approximately 111,000 net acres, with substantially all of the acreage also dedicated for natural gas gathering. Colorado River DevCo consists of gathering systems across Noble Energy's Wells Ranch and East Pony development areas in the DJ Basin.

The $270 million consideration consisted of $245 million in cash and 562,430 common units representing limited partner interests in Noble Midstream Partners. Noble Midstream Partners funded the cash consideration with approximately $138 million of net proceeds from a concurrent private placement of common units and $90 million of borrowings under the Noble Midstream Services Revolving Credit Facility (defined below) and the remainder from cash on hand.

Advantage Acquisition On April 3, 2017, Noble Midstream Partners and Plains Pipeline, L.P., a wholly owned subsidiary of Plains All American Pipeline, L.P., acquired Advantage Pipeline, L.L.C. (Advantage Pipeline) for $133 million through a newly formed 50/50 joint venture (Advantage Joint Venture). Noble Midstream Partners contributed $66.5 million of cash to the joint venture, funded by available cash on hand and the Noble Midstream Services Revolving Credit Facility. The Advantage Joint Venture is accounted for under the equity method and is included within our Midstream segment.

Noble Midstream Partners serves as the operator of the Advantage Pipeline system, which includes a 70-mile crude oil pipeline in the Delaware Basin from Reeves County, Texas to Crane County, Texas with 150,000 barrels per day of shipping capacity (expandable to over 200,000 barrels per day) and 490,000 barrels of storage capacity.

2016 Asset Transactions

During the first six months of 2016, we engaged in the following asset transactions.

US Onshore Properties We entered into the following transactions for which we:

- closed the divestiture of our Bowdoin property in northern Montana, generating proceeds of $43 million, and recognized a $23 million loss on sale;
- sold certain other US onshore properties, generating net proceeds of $20 million, which were primarily applied to the DJ Basin depletable field, with no recognition of gain or loss;
- entered into a purchase and sale agreement for the divestiture of certain producing and undeveloped interests covering approximately 33,100 net acres in the DJ Basin for $505 million, subject to customary closing adjustments. We received proceeds of $486 million during second quarter 2016, which were primarily applied to the DJ Basin depletable field, with no recognition of gain or loss. We expect to close the sale of the remaining properties, which are classified as held for sale, in the second half of 2017; and
- entered into an acreage exchange agreement receiving approximately 11,700 net acres within our Wells Ranch development area in exchange for approximately 13,500 net acres primarily from our Bronco area, located southwest of Wells Ranch, with no recognition of gain or loss.

Cyprus Project (Offshore Cyprus) In first quarter 2017, we received the remaining $40 million consideration for the farm-out of a 35% interest in Block 12, which includes the Aphrodite natural gas discovery. Proceeds received, including $131 million in first quarter 2016, were applied to the Cyprus project asset with no gain or loss recognized.

Offshore Israel Assets In first quarter 2016, we closed the divestment of our 47% interest in the Alon A and Alon C licenses, which include the Karish and Tanin fields, for a total sales price of $73 million ($67 million for asset consideration and $6 million for cost adjustments). Proceeds were applied to reduce field basis with no recognition of gain or loss.

Note 5. Derivative Instruments and Hedging Activities

Objective and Strategies for Using Derivative Instruments We are exposed to fluctuations in crude oil, natural gas and NGL pricing. 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 June 30, 2017, the following crude oil derivative contracts were outstanding:

Settlement Period	Type of Contract	Index	Bbls Per Day	Swaps	Collars		
				Weighted Average Fixed Price	Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
2H17 [1]	Call Option [2]	NYMEX WTI	3,000	$ —	$ —	$ —	$ 60.12
2H17 [1]	Three-Way Collars	ICE Brent	5,000	—	43.00	50.00	64.00
2017	Three-Way Collars	NYMEX WTI	24,000	—	39.78	47.71	61.20
2017	Two-Way Collars	NYMEX WTI	10,837	—	—	40.80	52.71
2017	Swaps	NYMEX WTI	4,348	50.83	—	—	—
2017	Call Option [2]	NYMEX WTI	3,000	—	—	—	57.00
2017	Three-Way Collars	ICE Brent	2,000	—	43.00	50.00	63.15
2017	Three-Way Collars	Dated Brent	2,000	—	35.00	45.00	66.33
2018	Three-Way Collars	NYMEX WTI	10,000	—	45.25	53.50	69.09
2018	Three-Way Collars	Dated Brent	3,000	—	40.00	50.00	70.41
2018	Swaptions [3]	NYMEX WTI	3,000	56.10	—	—	—

(1) We have entered into contracts for portions of 2017 resulting in the difference in hedged 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) We have entered into certain derivative contracts (swaptions), which give counterparties the right, but not the obligation, to enter into swap agreements with us on the option expiration dates.

Subsequent Event Subsequent to June 30, 2017, we entered into additional ICE Brent crude oil derivative contracts including:

Settlement Period	Type of Contract	Index	Bbls Per Day	Swaps	Collars		
				Weighted Average Fixed Price	Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
2018	Three-Way Collars	ICE Brent	5,000	$ —	$43.00	$ 50.00	$ 59.50
2018	Two-Way Collars	ICE Brent	2,000	—	—	50.00	55.25
2019	Three-Way Collars	ICE Brent	3,000	—	43.00	50.00	64.07

As of June 30, 2017, 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
2017	Three-Way Collars	NYMEX HH	110,000	$ —	$2.58	$ 2.93	$ 3.65
2017	Two-Way Collars	NYMEX HH	70,000	—	—	2.93	3.32
2018	Three-Way Collars	NYMEX HH	120,000	—	2.50	2.88	3.65
2018	Swaptions[1]	NYMEX HH	30,000	3.36	—	—	—

(1) We have entered into certain derivative contracts (swaptions), which give counterparties the right, but not the obligation, to enter into swap agreements with us on the option expiration dates.

In second quarter 2017, we reduced our natural gas hedge portfolio as a result of the Marcellus Shale upstream divestiture and terminated certain natural gas three-way collars covering the remainder of 2017, resulting in a de minimis gain from cash received. In addition, we transfered certain natural gas swaps to the acquirer of the Marcellus Shale upstream assets, resulting in a de minimis loss.

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			
	June 30, 2017		December 31, 2016		June 30, 2017		December 31, 2016	
(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	$ 23	Current Assets	$ —	Current Liabilities	$ —	Current Liabilities	$ 102
	Noncurrent Assets	8	Noncurrent Assets	—	Noncurrent Liabilities	—	Noncurrent Liabilities	14
Total		$ 31		$ —		$ —		$ 116

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions)	2017	2016	2017	2016
Cash (Received) Paid in Settlement of Commodity Derivative Instruments				
Crude Oil	$(11)	$(120)	$(16)	$(276)
Natural Gas	—	(24)	2	(46)
Total Cash Received in Settlement of Commodity Derivative Instruments	(11)	(144)	(14)	(322)
Non-cash Portion of (Gain) Loss on Commodity Derivative Instruments				
Crude Oil	(28)	233	(91)	360
Natural Gas	(18)	62	(62)	69
Total Non-cash Portion of (Gain) Loss on Commodity Derivative Instruments	(46)	295	(153)	429
(Gain) Loss on Commodity Derivative Instruments				

Crude Oil	(39)	113	(107)	84
Natural Gas	(18)	38	(60)	23
Total (Gain) Loss on Commodity Derivative Instruments	$(57)	$151	$(167)	$107

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Note 6. Debt
Debt consists of the following:

	June 30, 2017			December 31, 2016		
(millions, except percentages)	Debt	Interest Rate		Debt	Interest Rate	
Revolving Credit Facility, due August 27, 2020	$ —	—	%	$ —	—	%
Noble Midstream Services Revolving Credit Facility, due September 20, 2021	190	2.32	%	—	—	%
Term Loan Facility, due January 6, 2019	550	2.44	%	550	2.01	%
Leviathan Term Loan Facility, due February 23, 2025	—	—	%	—	—	%
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	%	379	5.625	%
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	%	18	5.875	%
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	%	8	5.875	%
3.90% Senior Notes, due November 15, 2024	650	3.90	%	650	3.90	%
	250	8.00	%	250	8.00	%

8.00% Senior Notes, due April 1, 2027						
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 %
Capital Lease and Other Obligations [1]	307		— %	375		— %
Total	7,236			7,114		
Unamortized Discount	(22	)		(23	)	
Unamortized Premium	15			17		
Unamortized Debt Issuance Costs	(32	)		(34	)	
Total Debt, Net of Unamortized Discount, Premium and Debt Issuance Costs	7,197			7,074		
Less Amounts Due Within One Year						
Capital Lease Obligations	(64	)		(63	)	
Long-Term Debt Due After One Year	$ 7,133			$ 7,011		

[1] The reduction includes $41 million related to certain drilling commitments assumed by the acquirer of the Marcellus Shale upstream assets. See Note 4. Acquisitions and Divestitures and Note 12. Commitments and Contingencies.

Revolving Credit Facility Our Credit Agreement, as amended, provides for a $4 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.

On April 24, 2017, we borrowed $1.3 billion to fund the cash portion of the Clayton Williams Energy Acquisition consideration, redeem assumed Clayton Williams Energy long-term debt, pay associated make-whole premiums, pay related fees and expenses associated with the transaction and to fund other general corporate expenditures. We repaid all outstanding borrowings during second quarter 2017 with proceeds received from the Marcellus Shale upstream divestiture, cash on hand, and cash generated by the Noble Midstream Partners private placement of limited partner units and Noble Midstream Services borrowings. The outstanding borrowing was subject to a floating interest rate which was 2.02% on April 24, 2017.

Noble Midstream Services Revolving Credit Facility In 2016, Noble Midstream Services, LLC, a subsidiary of Noble Midstream Partners, entered into a credit agreement for a $350 million revolving credit facility (Noble Midstream Services Revolving Credit Facility) which is available to fund working capital and to finance acquisitions and other capital expenditures of Noble Midstream Partners.

Borrowings by Noble Midstream Partners under the Noble Midstream Services Revolving Credit Facility bear interest at a rate equal to an applicable margin plus, at Noble Midstream Partners' option, either (a) in the case of base rate borrowings, a rate equal to the highest of (1) the prime rate, (2) the greater of the federal funds rate or the overnight bank funding rate, plus 0.5% and (3) the LIBOR for an interest period of one month plus 1.00%; or (b) in the case of LIBOR borrowings, the offered rate per annum for deposits of dollars for the applicable interest period.

As of June 30, 2017, $190 million was outstanding under the Noble Midstream Services Revolving Credit Facility which was used to partially fund acquisitions. See Note 4. Acquisitions and Divestitures.

Leviathan Term Loan Agreement On February 24, 2017, Noble Energy Mediterranean Ltd. (NEML), a wholly owned subsidiary of Noble Energy, entered into a facility agreement (Leviathan Term Loan Facility) which provides for a limited recourse secured term loan facility with an aggregate principal borrowing amount of up to $1.0 billion, of which $625 million is initially committed. Any amounts borrowed under the Leviathan Term Loan Facility will be available to fund a portion of our share of costs for the initial phase of development of the Leviathan field offshore Israel.

Any amounts borrowed will be subject to repayment on a quarterly basis following production startup for the first phase of development which is targeted for the end of 2019. Repayment will be in accordance with an amortization schedule set forth in the facility agreement, with a final balloon payment of no more than 35% of the loans outstanding. The Leviathan Term Loan Facility matures on February 23, 2025 and we can prepay borrowings at any time, in whole or in part, without penalty. The Leviathan Term Loan Facility contains customary representations and warranties, affirmative and negative covenants, events of default and also includes a prepayment mechanism that reduces the final balloon amount if cash flows exceed certain defined coverage ratios.

Any amounts borrowed will accrue interest at LIBOR, plus a margin of 3.50% per annum prior to production startup, 3.25% during the period following production startup until the last two years of maturity, and 3.75% during the last two years until the maturity date. We are also required to pay a commitment fee equal to 1.00% per annum on the unused and available commitments under the Leviathan Term Loan Facility until the beginning of the repayment period.

The Leviathan Term Loan Facility is secured by a first priority security interest in substantially all of NEML's interests in the Leviathan field and its marketing subsidiary, and in assets related to the initial phase of the project. All of NEML’s revenues from the first phase of Leviathan development will be deposited in collateral accounts and we will be required to maintain a debt service reserve account for the benefit of the lenders under the Leviathan Term Loan Facility. Once servicing accounts are replenished and debt service made, all remaining cash will be available to us and our subsidiaries.

Term Loan Agreement and Completed Tender Offers In 2016, we entered into a term loan agreement (Term Loan Facility) which provides for a three-year term loan facility for a principal amount of $1.4 billion. The Term Loan Facility accrues 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) LIBOR plus 1.0%, plus a margin that ranges from 10 basis points to 75 basis points depending upon our credit rating, or (b) LIBOR plus a margin that ranges from 100 basis points to 175 basis points depending upon our credit rating.

Borrowings under the Term Loan Facility were used solely to fund tender offers for approximately $1.38 billion of notes assumed in our merger with Rosetta Resources Inc. in 2015. As a result, we recognized a gain of $80 million in first quarter 2016 which is reflected in other operating (income) expense, net in our consolidated statements of operations. In fourth quarter 2016, we prepaid $850 million of long-term debt outstanding under the Term Loan Facility from cash on hand. As of June 30, 2017, $550 million was outstanding under the facility.

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.

Stock-Based Compensation Liability A portion of the value of the liability associated with our phantom unit plan is dependent upon the fair value of Noble Energy common stock as of the end of each reporting period.

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

	Fair Value Measurements Using				
(millions)	Quoted Prices in Active Markets (Level 1) (1)	Significant Other Observable Inputs (Level 2) (2)	Significant Unobservable Inputs (Level 3) (3)	Adjustment (4)	Fair Value Measurement
June 30, 2017					
Financial Assets					
Mutual Fund Investments	$ 67	$ —	$ —	$ —	$ 67
Commodity Derivative Instruments	—	34	—	(3)	31
Financial Liabilities					
Commodity Derivative Instruments	—	(3)	—	3	—
Portion of Deferred Compensation Liability Measured at Fair Value	(86)	—	—	—	(86)
Stock Based Compensation Liability Measured at Fair Value	(12)	—	—	—	(12)
December 31, 2016					
Financial Assets					
Mutual Fund Investments	$ 71	$ —	$ —	$ —	$ 71
Commodity Derivative Instruments	—	5		(5)	—
Financial Liabilities					
Commodity Derivative Instruments	—	(121)	—	5	(116)
Portion of Deferred Compensation Liability Measured at Fair Value	(88)	—	—	—	(88)
Stock Based Compensation Liability Measured at Fair Value	(9)	—	—	—	(9)

(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 such as inventory, oil and gas properties and assets held for sale are measured at fair value on a nonrecurring basis in our consolidated balance sheets. For the six months ended June 30, 2017 and 2016, we had no adjustments in fair value related to these items. Other items measured at fair value on a nonrecurring basis are discussed below.

Marcellus Shale Firm Transportation Liability As of June 30, 2017, we recorded a $41 million liability representing the discounted present value of our remaining obligation under a firm transportation contract. See Note 12. Commitments and Contingencies.

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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 and the Noble Midstream Services Revolving Credit Facility are variable-rate, non-public debt. The fair value is estimated based on significant other observable inputs. As such, we consider the fair value of these facilities to be a Level 2 measurement on the fair value hierarchy. See Note 6. Debt.
Fair value information regarding our debt is as follows:

	June 30, 2017		December 31, 2016	
(millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt, Net [1]	$6,890	$7,373	$6,699	$7,112

[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 Costs
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)	Six Months Ended June 30, 2017		
Capitalized Exploratory Well Costs, December 31, 2016	$	768	
Additions to Capitalized Exploratory Well Costs Pending Determination of Proved Reserves	6		
Reclassified to Proved Oil and Gas Properties Based on Determination of Proved Reserves [1]	(203		)
Capitalized Exploratory Well Costs, June 30, 2017	$	571	

[1] Amount relates to the approval and sanction of the first phase of development of the Leviathan field, offshore Israel. During second quarter 2017, we recorded Leviathan field proved undeveloped reserves of 551 MMBoe, net.

The following table provides an aging of capitalized exploratory well costs based on the date that drilling commenced:

(millions)	June 30, 2017	December 31, 2016
Exploratory Well Costs Capitalized for a Period of One Year or Less	$ 19	$ 69
Exploratory Well Costs Capitalized for a Period Greater Than One Year Since Commencement of Drilling [1]	552	699
Balance at June 30, 2017	$ 571	$ 768

[1] The decrease from December 31, 2016 is attributable to the reclassification of the Leviathan field to development work in process, partially offset by the capitalization of interest during the period on remaining exploratory wells.

Undeveloped Leasehold Costs

We reclassify undeveloped leasehold costs to proved property costs when proved reserves, including proved undeveloped reserves, become attributable to the property as a result of our exploration and development activities.

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As of June 30, 2017, we had remaining undeveloped leasehold costs, to which proved reserves had not been attributed, of $3.1 billion, primarily related to properties acquired of $1.6 billion in the Clayton Williams Energy Acquisition, and $1.2 billion and $185 million attributable to Delaware Basin and Eagle Ford Shale assets, respectively, acquired in the Rosetta Resources Inc. acquisition. Undeveloped leasehold costs were derived from allocated fair values as a result of business combinations or other purchases of unproved properties and, in that the properties are primarily held by production, they are subject to impairment testing utilizing a future cash flows analysis.

The remaining undeveloped leasehold costs as of June 30, 2017 included $86 million related to Gulf of Mexico unproved properties and $52 million related to international unproved properties. These costs are evaluated as part of our periodic impairment review. If, based upon a change in exploration plans, availability of capital and suitable rig and drilling equipment, resource potential, comparative economics, changing regulations and/or other factors, an impairment is indicated, we will record impairment expense related to the respective leases.

During the first six months of 2017, we completed a geological evaluation of certain Gulf of Mexico leases and determined that $18 million of undeveloped leasehold cost should be written-off.

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:

	Six Months Ended June 30,	
(millions)	2017	2016
Asset Retirement Obligations, Beginning Balance	$935	$989
Liabilities Incurred	82	3
Liabilities Settled	(32)	(38)
Revision of Estimate	(15)	4
Accretion Expense [1]	23	25
Asset Retirement Obligations, Ending Balance	$993	$983

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

For the Six Months Ended June 30, 2017 Liabilities incurred include $59 million related to the Clayton Williams Energy Acquisition and $23 million primarily for other US onshore wells and facilities placed into service. Liabilities settled primarily related to US onshore property abandonments, as well as $12 million related to properties sold in the Marcellus Shale upstream divestiture. Revisions of estimates related to decreases in cost and timing estimates of $30 million for US onshore and Gulf of Mexico, partially offset by an increase of $15 million for West Africa.

For the Six Months Ended June 30, 2016 Liabilities incurred were due to new wells and facilities for onshore US. Liabilities settled primarily related to onshore US property abandonments.

Note 10. Income Taxes

The income tax provision (benefit) consists of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions)	2017	2016	2017	2016
Current [1]	$37	$45	$49	$65
Deferred	(873)	(228)	(873)	(414)
Total Income Tax Benefit	$(836)	$(183)	$(824)	$(349)
Effective Tax Rate	35.8 %	36.7 %	36.2 %	36.7 %

[1] Current income taxes are attributable to our operations in Israel and Equatorial Guinea.

Effective Tax Rate (ETR) At the end of each interim period, we apply a forecasted annualized effective tax rate (ETR) to current year earnings or loss before tax, which can result in significant interim ETR fluctuations. Our ETR for the three and six months ended June 30, 2017 varied as compared with the three and six months ended June 30, 2016 primarily due to a larger discrete tax benefit in the prior year driven by a tax rate change in a foreign jurisdiction. In addition, the significant increase in the deferred tax benefit for the three and six months ended June 30, 2017 is primarily due to the loss recorded for the Marcellus Shale upstream divestiture.

In our major tax jurisdictions, the earliest years remaining open to examination are as follows: US – 2013, Israel – 2015 and Equatorial Guinea – 2011.

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Note 11. Segment Information
During second quarter 2017, as a result of the strategic changes in our US onshore portfolio, we established our Midstream business as a new reportable segment. The Midstream segment, which includes the consolidated accounts of Noble Midstream Partners, additional US onshore midstream assets and US onshore equity method investments, was previously reported within the United States reportable segment. As a result, as of June 30, 2017, we now have five reportable segments, United States (US onshore and Gulf of Mexico); Eastern Mediterranean (Israel and Cyprus); West Africa (Equatorial Guinea, Cameroon and Gabon); Other International (Falkland Islands, Suriname, Canada and New Ventures); and Midstream.
The geographical reportable segments are in the business of crude oil and natural gas exploration, development, production, and acquisition (Oil and Gas Exploration and Production). The Midstream reportable segment owns, operates, develops and acquires domestic midstream infrastructure assets with current focus areas being the DJ and Delaware Basins.
Prior period amounts are presented on a comparable basis.

(In millions)	Consolidated	Oil and Gas Exploration and Production				Midstream		
		United States	Eastern Mediter-ranean	West Africa	Other Int'l	United States	Intersegment Eliminations and Other	Corporate
Three Months Ended June 30, 2017								
Crude Oil, NGL and Natural Gas Revenues from Third Parties	$ 1,017	$ 780	$ 133	$ 104	$ —	$ —	$ —	$ —
Income from Equity Method Investees and Other	42	—	—	25	—	17	—	—
Intersegment Revenues	—	—	—	—	—	69	(69)	—
Total Revenues	1,059	780	133	129	—	86	(69)	—
DD&A	503	427	19	39	1	5	—	12
Loss on Marcellus Shale Upstream Divestiture	2,322	2,322	—	—	—	—	—	—
Gain on Commodity Derivative Instruments	(57)	(51)	—	(6)	—	—	—	—
(Loss) Income Before Income Taxes [1]	(2,334)	(2,319)	106	72	(4)	58	(13)	(234)
Three Months Ended June 30, 2016								
Crude Oil, NGL and Natural Gas Revenues from Third Parties	$ 823	$ 576	$ 131	$ 116	$ —	$ —	$ —	$ —
Income from Equity Method Investees and Other	24	—	—	9	—	15	—	—
Intersegment Revenues	—	—	—	—	—	43	(43)	
Total Revenues	847	576	131	125	—	58	(43)	—
DD&A	622	539	19	49	1	5	—	9
Loss on Divestitures	23	23	—	—	—	—	—	—
Loss on Commodity Derivative Instruments	151	129	—	22	—	—	—	—
(Loss) Income Before Income Taxes	(498)	(409)	71	18	(8)	39	—	(209)

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(In millions)	Consolidated	Oil and Gas Exploration and Production: United States	Oil and Gas Exploration and Production: Eastern Mediter-ranean	Oil and Gas Exploration and Production: West Africa	Oil and Gas Exploration and Production: Other Int'l	Midstream: United States	Intersegment Eliminations and Other	Corporate
Six Months Ended June 30, 2017								
Crude Oil, NGL and Natural Gas Revenues from Third Parties	$ 2,011	$ 1,550	$ 265	$ 196	$ —	$ —	$ —	$ —
Income from Equity Method Investees and Other	84	—	—	52	—	32	—	—
Intersegment Revenues	—	—	—	—	—	127	(127)	—
Total Revenues	2,095	1,550	265	248	—	159	(127)	—
DD&A	1,031	886	37	74	2	10	—	22
Loss on Marcellus Shale Upstream Divestiture	2,322	2,322	—	—	—	—	—	—
Gain on Commodity Derivative Instruments	(167)	(154)	—	(13)	—	—	—	—
(Loss) Income Before Income Taxes [1]	(2,275)	(2,251)	207	138	(11)	107	(35)	(430)
Six Months Ended June 30, 2016								
Crude Oil, NGL and Natural Gas Revenues from Third Parties	$ 1,528	$ 1,065	$ 257	$ 206	$ —	$ —	$ —	$ —
Income from Equity Method Investees and Other	43	—	—	12	—	31	—	—
Intersegment Revenues	—	—	—	—	—	85	(85)	—
Total Revenues	1,571	1,065	257	218	—	116	(85)	—
DD&A	1,239	1,064	39	104	3	9	—	20
Loss on Divestitures	23	23	—	—	—	—	—	—
Loss on Commodity Derivative Instruments	107	92	—	15	—	—	—	—
(Loss) Income Before Income Taxes	(951)	(743)	155	27	(70)	80	—	(400)
June 30, 2017								
Goodwill	$ 1,289	$ 1,289	$ —	$ —	$ —	$ —	$ —	$ —
Total Assets	21,574	16,143	2,594	1,437	83	1,106	(131)	342
December 31, 2016								
Total Assets	21,011	16,079	2,233	1,479	89	851	(19)	299

[1] The intersegment eliminations related to (loss) income before income taxes are the result of midstream expenditures. These costs are presented as property, plant and equipment within the upstream business on an unconsolidated basis, in accordance with the successful efforts method of accounting, and are eliminated upon consolidation.

Note 12. Commitments and Contingencies

Legal Proceedings We are involved in various legal proceedings in the ordinary course of business. These proceedings are subject to the uncertainties inherent in any litigation. We are defending ourselves vigorously in all such matters and we believe that the ultimate disposition of such proceedings will not have a material adverse effect on our financial position, results of operations or cash flows.

Marcellus Shale Firm Transportation Contracts In connection with the Marcellus Shale upstream divestiture, we reduced our firm transportation commitment through transfer of certain contracts to the acquirer.

We retained certain other firm transportation contracts representing a total financial commitment of approximately $1.6 billion, undiscounted, primarily with remaining contract terms of 15 years. Of this amount, $616 million, undiscounted, relates to pipeline projects which are currently under construction and targeted to be placed in service fourth quarter 2017. The remaining commitments relate to pipeline projects that are targeted to be placed in service late 2018 but have not yet been approved by the FERC.
We are currently engaged in actions to reduce the financial commitments associated with these contracts. However, we cannot guarantee these efforts will be successful and we may recognize substantial future liabilities, at fair value, for the net amount of the estimated remaining commitments under these contracts. These financial commitments are included in the table below consistent with expected future cash payments associated with the underlying agreements. See Note 4. Acquisitions and Divestitures.
Non-Cancelable Leases and Other Commitments We hold leases and other commitments for drilling rigs, buildings, equipment and other property and have entered into numerous long-term contracts for gathering, processing and transportation services. Minimum commitments have been updated to give effect to the Clayton Williams Energy Acquisition, the Marcellus Shale upstream divestiture, as well as commitments related to Leviathan development activities, and consist of the following as of June 30, 2017:

(millions)	Drilling, Equipment, and Purchase Obligations	Transportation and Gathering Obligations[1]	Operating Lease Obligations	Capital Lease Obligations[2]	Total
July - December 2017	$ 306	$ 116	$ 24	$ 39	$485
2018	341	247	47	74	709
2019	146	276	35	45	502
2020	22	250	33	42	347
2021	4	213	34	29	280
2022 and Thereafter	33	1,496	198	145	1,872
Total	$ 852	$ 2,598	$ 371	$ 374	$4,195

(1) Includes $1.6 billion of future cash payments related to retained Marcellus Shale firm transportation contracts. See discussion above.
(2) Annual lease payments, net to our interest, exclude regular maintenance and operating costs. See Note 6. Debt.

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 and 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 also being expended in accordance with schedules established in the Consent Decree. During 2015 and 2016, we spent approximately $54.7 million to undertake injunctive relief at certain tank systems following the outcome of adequacy of design evaluations and certain operation and maintenance activities to handle potential peak instantaneous vapor flow rates. Future costs associated with injunctive relief are not yet precisely quantifiable as we are continually evaluating various approaches to meet the ongoing obligations of the Consent Decree.
Overall compliance with the Consent Decree has resulted in the temporary shut-in and permanent plugging and abandonment of certain wells and associated tank batteries. Consent Decree compliance could result in additional temporary shut-ins and 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 that may be extended depending on certain situations. The Consent Decree contains additional obligations for

ongoing inspection and monitoring beyond that which is required under existing Colorado regulations.
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 Water Quality Control Division Matter In January 2017, we received a Notice of Violation/Cease and Desist Order (NOV/CDO) advising us of alleged violations of the Colorado Water Quality Control Act (Act) and its implementing regulations as it relates to our Colorado Discharge Permit System General Permit for construction activities associated with oil and gas exploration and /or production within our Wells Ranch Drilling and Production field located in Weld County, Colorado (Permit). The NOV/CDO further orders us to cease and desist from all violations of the Act, the regulations and the Permit and to undertake certain corrective actions. Given the uncertainty associated with administrative actions of this nature, we are unable to predict the ultimate outcome of this action at this time but believe that the resolution of this action will not have a material adverse effect on our financial position, results of operations or cash flows.
Colorado Air Compliance Order on Consent In April 2017, we received a proposed Compliance Order on Consent (COC) from the Colorado Department of Public Health and Environment’s Air Pollution Control Division (APCD) to resolve allegations of noncompliance associated with compliance testing of certain engines subject to various General Permit 02 conditions and/or individual permit conditions. In May 2017, we reached a final resolution with the APCD and executed the COC, which requires payment of a civil penalty of $24,710 and an expenditure of no less than $98,840 on an approved SEP(s). This resolution is not believed to have a material adverse effect on our financial position, results of operations or cash flows.

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

Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) is intended to provide a narrative about our business from the perspective of 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 – E&P;
- Results of Operations – Midstream;
- Liquidity and Capital Resources; and
- Critical Accounting Policies and Estimates, Update.

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

EXECUTIVE OVERVIEW

The following discussion highlights significant operating and financial results for second quarter 2017. This discussion should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2016, which includes disclosures regarding our critical accounting policies as part of “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

Current Upstream Environment

Crude Oil Prices During second quarter 2017, crude oil prices softened as US shale producers brought production online faster than the market expected. Further, evidence of effectiveness of the OPEC-led production cuts has not yet been reflected in global inventories due in part to the increase in US onshore production. As a result, near-term crude oil continues to be oversupplied globally.

For the remainder of 2017, inventory and production levels, particularly US onshore supply growth and the effectiveness of OPEC curtailment actions as well as OPEC production from countries not bound to OPEC curtailments, such as Libya and Nigeria, are likely to be the primary determinants of near-term crude oil prices with the risk that continued strong production trends cause crude oil prices to remain persistently low. Future OPEC decisions regarding extension of production curtailments, changes in crude oil storage levels and US shale oil production trends, are likely to continue to have significant impacts on crude oil prices.

Natural Gas Prices The US domestic natural gas market also remains oversupplied as domestic production has continued to grow due to drilling efficiencies, completion of drilled but uncompleted well inventory and de-bottlenecking of transportation infrastructure. As with crude oil, there has been little offsetting demand growth. As a result, during the first six months of 2017, natural gas prices remained range bound. We expect this situation to continue for the remainder of 2017, with natural gas prices near current or recent trading levels.

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Price Trend Chart The chart below shows the historical trend in benchmark prices for West Texas Intermediate (WTI) crude oil, Brent crude oil and U.S. Henry Hub natural gas.

Development and Operating Costs Third party oilfield service and supply costs are also subject to supply and demand dynamics. During the first six months of 2017, increases in US onshore drilling and completion activity resulted in higher demand for oilfield services. As a result, the costs of drilling, equipping and operating wells and infrastructure have begun to experience some inflation, which, along with the commodity price softness noted above, results in continued pressures on industry operating margins. Conversely, the industry has reduced capital-intensive offshore exploration and drilling activities in response to the commodity price environment. As a result, demand for and costs associated with offshore services have declined and in the near-term, will likely not be subject to cost inflation.

Recent Achievements

Despite the current commodity price and cost environment, Noble Energy had a very successful second quarter 2017, achieving several strategic, operational and financial goals. Strategically, we closed several transformative portfolio transactions demonstrating our continued focus on enhancing margins and project returns. Operationally, we continued to enhance US onshore drilling and completions and advanced our Eastern Mediterranean regional natural gas developments. Financially, we continued to maintain our strong balance sheet and liquidity position.

Clayton Williams Energy Acquisition On April 24, 2017, we completed the acquisition (Clayton Williams Energy Acquisition) of Clayton Williams Energy, Inc. (Clayton Williams Energy) for $2.5 billion of stock and cash consideration. In connection with the acquisition, we assumed, and then subsequently retired, $595 million of Clayton Williams Energy long-term debt. The transaction adds highly contiguous acreage in the core of the Delaware Basin and materially expands our Delaware position to approximately 118,000 net acres. The integration of the Clayton Williams Energy assets into our portfolio expands our opportunities in the core, high crude-oil content area of the Delaware Basin, significantly increasing our US onshore growth outlook. See Item 1. Financial Statements – Note 3. Clayton Williams Energy Acquisition.

Marcellus Shale Upstream Divestiture On June 28, 2017, we closed the sale of the Marcellus Shale upstream assets, receiving net proceeds of $1.0 billion. The divestment enables us to further focus our organization on our highest-return areas that are expected to deliver US onshore volume and cash flow growth. In addition, we have signed a definitive agreement to divest our Marcellus Shale midstream business for $765 million. See Item 1. Financial Statements – Note 4. Acquisitions and Divestitures and Note 12. Commitments and Contingencies.

Midstream Growth Along with our upstream portfolio actions, we continued to grow our Midstream business and completed our first drop-down transaction of midstream assets to Noble Midstream Partners L.P (NBLX) for total consideration of $270 million.

Operational Accomplishments Operationally, we delivered quarterly sales volumes of 408 MBoe/d, an increase of 7% from first quarter 2017, established a record for second quarter gross sales volumes of 962 MMcfe/d in Israel and continued to progress the Leviathan development project within budget towards first natural gas production by the end of 2019. See Project Updates, below, and Result of Operations.

Financial Flexibility, Liquidity and Balance Sheet Strength We continue to undertake proactive and strategic actions to maintain liquidity and a strong balance sheet. An example of this is using proceeds received from the Marcellus Shale upstream

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divestiture and NBLX drop-down transaction to offset the cash impact of the Clayton Williams Energy Acquisition. Proceeds received from these transactions were used to retire $1.3 billion borrowed under our Revolving Credit Facility to pay for the cash consideration of the Clayton Williams Energy Acquisition and associated costs, as well as the retirement of all $595 million of assumed Clayton Williams Energy debt. We strive to maintain a robust liquidity position and ended second quarter 2017 with approximately $4.5 billion of liquidity, which includes cash on hand and unused borrowing capacity. See Liquidity and Capital Resources.

Positioned for the Future

We believe the following guiding principles will contribute to the sustainability and success of our business throughout the commodity price cycle, including extended periods of lower prices:

- Execution of a disciplined capital allocation process by:
  - designing a flexible investment program aligned with the current commodity price environment; and
  - maintaining a strong balance sheet and liquidity position.
- Enhancing capital efficiencies through:
  - utilizing our technical competencies and applying historical learnings from unconventional US shale plays to reduce US onshore finding and development costs; and
  - driving Delaware Basin economics through development cycle efficiencies.
- Leveraging the benefits of our well-positioned and diversified portfolio including:
  - exercising investment optionality and flexibility afforded by our assets held by production; and
  - continuing portfolio optimization actions to maximize strategic value.
- Capitalizing on a currently low-cost offshore environment with execution of high-quality long-cycle development projects, such as:
  - sanctioning and commencing the first phase of Leviathan field development.

In summary, as we progress through the remainder of 2017, we believe we are positioned for sustainability, operational efficiency, and long-term success throughout the oil and gas business cycle. We remain committed to maintaining capital discipline and financial strength and will continuously evaluate commodity prices along with well productivity and efficiency gains as we optimize our activity levels in alignment with commodity price conditions. To this end, our 2017 capital investment program is responsive to positive or negative commodity price conditions that may develop. Excluding acquisition and Noble Midstream Partners capital, we expect our 2017 capital spending program to be in the upper end of our investment range of $2.3 to $2.6 billion, or approximately 50% higher than 2016. See Operating Outlook – 2017 Capital Investment Program, below.

Although the industry has begun to recover from the recent downturn, if commodity prices decline or operating costs begin to rise, we could experience material negative impacts on our revenues, profitability, cash flows, liquidity and proved reserves, and in response, we may consider reductions in our capital program or dividends, asset sales or cost structure. Our production and our stock price could decline as a result of these potential developments.

Recently Issued Accounting Standards

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

OPERATING OUTLOOK

2017 Production Our expected crude oil, natural gas and NGL production for the remainder of 2017 may be impacted by several factors including:

- commodity prices which, if subject to further decline, could result in certain 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;
- with increased drilling activity, US onshore cost inflation pressure may result in certain current production becoming less profitable or uneconomic;
- Israeli industrial and residential demand for electricity, which is largely impacted by weather conditions and conversion of the Israeli electricity portfolio from coal to natural gas;
-

- timing of the divestiture of a portion of our working interest in the Tamar field, in accordance with the Israel Natural Gas Framework (Framework), which will lower our sales volumes;
- timing of crude oil and condensate liftings impacting sales volumes in West Africa as well as the unitization of the Alba field;
- integration and timing of producing wells acquired as a result of the Clayton Williams Energy Acquisition;
- divestment of Marcellus Shale upstream assets;

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- additional purchases of producing properties or divestments of operating assets;
- natural field decline in the US onshore, Gulf of Mexico and offshore Equatorial Guinea;
- potential weather-related volume curtailments due to hurricanes in the Gulf of Mexico and Gulf Coast areas, or winter storms and flooding impacting US onshore operations;
- reliability of support equipment and facilities, pipeline disruptions, and/or potential pipeline and processing facility capacity constraints which may cause restrictions or interruptions in production and/or midstream processing;
- timing and completion of midstream expansion projects by Noble Midstream Partners in areas that provide services to our assets;
- malfunctions and/or mechanical failures at terminals or other US onshore delivery points;
- impact of enhanced completion efforts for US onshore assets;
- possible abandonment of low-margin US onshore wells;
- shut-in of US producing properties if storage capacity becomes unavailable; and
- drilling and/or completion permit delays due to future regulatory changes.

2017 Capital Investment Program Given the current commodity price environment, we have designed a flexible capital investment program as part of our comprehensive effort to maintain strong liquidity and manage the Company's balance sheet. Excluding acquisition capital and Noble Midstream Partners, we expect our 2017 capital investment program to be in the upper end of our range of $2.3 to $2.6 billion, of which $1.3 billion has been incurred during the six months ended June 30, 2017. More than 75% of the total capital investment program is allocated to US onshore development primarily in liquids-rich opportunities in the DJ Basin, Delaware Basin, and Eagle Ford Shale. The remaining 25% capital investment program will be predominately allocated to the Eastern Mediterranean, including initial development costs associated with the Leviathan project.
See Liquidity and Capital Resources – Financing Activities, below.
Potential for Future Dry Hole Cost, Lease Abandonment Expense or Property Impairments
Exploration Activities Our exploration program seeks to provide growth through long-term and/or large-scale exploration opportunities. We continue to seek exploration opportunities in various geographical areas, such as our entry into Newfoundland, Canada. In other areas of the world, we have capitalized a significant amount of exploratory drilling costs. In the event we conclude that an exploratory well did not encounter hydrocarbons or that a discovery or prospect is not economically or operationally viable, the associated capitalized exploratory well costs would be charged to expense. See Item 1. Financial Statements - Note 8. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs and Results of Operations – Oil and Gas Exploration Expense, below.
We may also impair and/or relinquish certain undeveloped leases prior to expiration, based upon geological evaluation or other factors. For example, during the first six months of 2017, we impaired $18 million of cost related to Gulf of Mexico undeveloped leases. We have numerous leases for Gulf of Mexico prospects that have not yet been drilled. A significant portion of these leases are scheduled to expire over the years 2018 to 2020 and some leases may become impaired if production is not established, no action is taken to extend the terms of the leases, or the leases become uneconomic due to low commodity prices or other factors.
As of June 30, 2017, we have capitalized costs related to exploratory wells of $571 million. In addition, we have undeveloped leasehold costs, to which proved reserves had not been attributed, of $3.1 billion. Of this amount, $1.6 billion is attributable to properties acquired in the Clayton Williams Energy Acquisition, and $1.2 billion and $185 million are attributable to Delaware Basin and Eagle Ford Shale assets, respectively, acquired in the Rosetta Resources Inc. acquisition. These costs were derived from allocated fair values as a result of business combinations or other purchases of unproved properties and, in that the properties are primarily held by production, they are subject to impairment testing utilizing a future cash flows analysis.
The remaining undeveloped leasehold costs as of June 30, 2017 included $86 million related to Gulf of Mexico unproved properties and $52 million related to international unproved properties. These costs are evaluated as part of our periodic impairment review. If, based upon a change in exploration plans, availability of capital and suitable rig and drilling equipment, resource potential, comparative economics, changing regulations and/or other factors, an impairment is indicated, we will record impairment expense related to the respective leases. As a result of our

exploration activities, future exploration expense, including undeveloped leasehold impairment expense, could be significant. See Results of Operations - Oil and Gas Exploration Expense, below.

Proved and Unproved Properties During the first six months of 2017, no impairments were incurred related to proved properties. 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, 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 also be difficult to estimate costs of rigs and services in periods of fluctuating demand. In addition, we do not operate certain assets and we therefore work with respective operators to receive updated estimates of abandonment activities and costs. For example, as of June 30, 2017, we had an asset retirement obligation of $88 million related to a North Sea remediation project. As the operator moves beyond the initial decommissioning phase, we will continue to monitor the status and costs of the project and will adjust our estimate accordingly. See Item 1. Financial Statements - Note 9. Asset Retirement Obligations.

Divestments We actively manage our asset portfolio to ensure our assets are well-positioned on the industry cost of supply curve and offer growth at financially attractive rates of return. Therefore, we may periodically divest certain assets, such as the Marcellus Shale upstream assets, to reposition our portfolio. Proceeds from asset sales are redeployed in our capital investment program, used to pay down debt, strengthen our balance sheet and/or support returns to shareholders through dividends or other mechanisms.

When properties meet the criteria for reclassification as assets held for sale, they are valued at the lower of net book value or anticipated sales proceeds less transaction related costs to sell. Impairment expense would be recorded for any excess of net book value over anticipated sales proceeds less transaction related costs to sell.

We strive to obtain the most advantageous price for any asset divestment; however, various factors, such as current and future commodity prices, reserves, production profiles, operating costs, capital investment requirements and potential future liabilities, as well as legal and regulatory requirements, can make it difficult to predict an asset's selling price and whether a transaction will result in a gain or loss. Inability to achieve a desired sales price, or underestimation of amounts of retained liabilities or indemnification obligations, can result in a possible loss on the sale, which could be material. See Item 1. Financial Statements - Note 4. Acquisitions and Divestitures.

We continue to review our portfolio to ensure alignment with the aforementioned strategic objectives. Further, the State of Israel requires that 7.5% of our working interest in the Tamar field offshore Israel be divested by December 2021, reducing our working interest from 32.5% to 25%. Additional potential divestments may be considered, even though no commitments have been made by our management and our Board of Directors.

Regulatory Update

US Regulatory Developments In early 2017, President Trump issued two executive orders directing the US Environmental Protection Agency (EPA) and other executive agencies to review their rules and policies that unduly burden domestic energy development. Specifically, on February 28, 2017, President Trump signed an executive order directing the EPA and the US Army Corps of Engineers (Corps) to review the Clean Water Rule and to initiate rulemaking to rescind or revise it, as appropriate under the stated policies of protecting navigable waters from pollution while promoting economic growth, reducing uncertainty, and showing due regard for Congress and the states. On March 28, 2017, President Trump signed an executive order directing the EPA and other executive agencies to review all regulations, orders, guidance documents and policies and take actions to suspend, revise or rescind them, as appropriate and consistent with the law, to the extent that they unduly burden the development of domestic energy resources beyond the degree necessary to protect the public interest.

Pursuant to the first executive order, on June 27, 2017, the EPA and the Corps announced a proposed rule to rescind the Clean Water Rule and to re-codify the regulations that existed before the Clean Water Rule. Consistent with the second executive order, on June 5, 2017, the EPA published notice that it would reconsider certain requirements of a May 2016 rule, which set standards for emissions of methane and volatile organic compounds from new and modified oil and gas production sources, and that it would stay for 90 days those requirements pending reconsideration. On June 16, 2017, the EPA published a proposed rule to extend the stay for two years. On July 3, 2017, the D.C. Circuit Court of Appeals vacated the 90-day stay, but noted that this decision did not limit the EPA’s authority to reconsider its regulations and proceed with the June 16, 2017 proposed rulemaking. The EPA and the Bureau of Land Management have also announced that they are reconsidering, or plan to reconsider, additional regulations that impact the oil and

gas industry. However, it remains unclear how and to what extent this broad review could impact environmental regulations at the federal level.
Voluntary Withdrawal from International Climate Change Accord In December 2015, the United States signed the Paris Agreement on climate change and pledged to take efforts to reduce greenhouse gas (GHG) emissions and to conserve and enhance sinks and reservoirs of GHGs. The Paris Agreement entered into force in November 2016. However, on June 1, 2017, President Trump announced that the United States would withdraw from the Paris Agreement and begin negotiations to either re-enter or negotiate an entirely new agreement with more favorable terms for the United States. While President Trump

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expressed a clear intent to cease implementing the Paris Agreement, it is not clear how the Administration plans to accomplish this goal, whether a new agreement can be negotiated, or what terms would be included in such an agreement. Furthermore, in response to the announcement, many state and local leaders stated their intent to intensify efforts to uphold the commitments set forth in the international accord. It is not possible at this time to predict the timing or effect of international treaties or regulations on our operations or to predict with certainty the future costs that we may incur in order to comply with such treaties or regulations.

Impact of Dodd-Frank Act Section 1504 In June 2016, the Securities and Exchange Commission (SEC) adopted resource extraction issuer payment disclosure rules under Section 1504 of the Dodd-Frank Act that would have required resource extraction companies, such as us, to publicly file with the SEC beginning in 2019 information about the type and total amount of payments made to a foreign government, including subnational governments (such as states and/or counties), or the U.S. federal government for each project related to the commercial development of crude oil, natural gas or minerals, and the type and total amount of payments made to each government (such rules, the Resource Extraction Issuer Payment Rules).

However, on February 14, 2017, President Trump signed a joint resolution passed by the United States Congress under the Congressional Review Act and eliminated the Resource Extraction Issuer Payment Rules. It should be noted that Section 1504 of the Dodd-Frank Act has not been repealed and that the SEC will now have until February 2018 to issue replacement rules to implement Section 1504 of the Dodd-Frank Act, and that under the Congressional Review Act a rule may not be issued in “substantially the same form” as the disapproved rule unless it is specifically authorized by a subsequent law. We cannot predict whether the SEC will issue replacement rules or, if it does so, whether such replacement rules will again be eliminated pursuant to the Congressional Review Act.

We will continue to monitor proposed and new regulations and legislation in all of our operating jurisdictions to assess the potential impact on our company. We continue to engage 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.

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EXPLORATION AND PRODUCTION (E&P)
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 reached. Second quarter 2017 activities included the following:
DJ Basin (US Onshore) Our activities during second quarter 2017 were focused primarily in Wells Ranch and East Pony where we operated an average of two drilling rigs, drilled 29 wells and commenced production on 33 wells. We continue to optimize value in these oil-rich areas through our horizontal development program, which has led to an increasing mix of crude oil sales volumes and a record crude oil mix of 53% in the DJ Basin during second quarter 2017. We expect total horizontal production and, specifically, production from Wells Ranch and East Pony, to continue to grow for the remainder of 2017, while we anticipate certain of our legacy horizontal wells, as well as the majority of our vertical wells, to experience production declines as we enhance our focus on horizontal development in the oil-rich areas of the basin.
Delaware Basin (US Onshore) On April 24, 2017, we completed the Clayton Williams Energy Acquisition and increased our portfolio holdings in the Delaware Basin. During second quarter 2017, we operated an average of four and a half drilling rigs (including one on the recently acquired Clayton Williams Energy properties), drilled 13 horizontal wells (of which four were on Clayton Williams Energy leases) and commenced production from six wells, all of which were from our existing Delaware Basin assets. Our integration and assumption of operations of the Clayton Williams Energy assets has been successful and we are currently applying learnings from our legacy Delaware Basin assets to optimize our development plan.
Eagle Ford Shale (US Onshore) During second quarter 2017, we focused our activity in Webb and Dimmit Counties where we operated an average of one and a half drilling rigs, drilled 11 horizontal wells and commenced production on 21 wells. We continue to execute a strong development plan which led to record quarterly sales volumes of 69 MBoe/d during second quarter 2017. For the remainder of 2017, we anticipate sales volumes to continue to grow in this liquids-rich play.
Gulf of Mexico (US Offshore) Our offshore assets continue to provide high-margin oil production, and during second quarter 2017, average daily sales volumes were 27 MBoe/d, net, which includes substantial uptime performance at both the Neptune Spar and Thunder Hawk Production Facility. During second quarter 2017, we received approval from the United States Coast Guard for a life extension related to the Neptune Spar, our floating offshore production platform which services our Swordfish asset. The approval is the first life extension in the Gulf of Mexico granted for a floating production system in our industry.
Leviathan Natural Gas Project (Offshore Israel) The first phase of development of the Leviathan field provides 1.2 Bcf/d of production capacity and consists of four wells, a subsea production system and a shallow-water processing platform, with a connection to an onshore valve station. We expect our share of development costs to total approximately $1.5 billion and be funded from our share of cash flows from the Tamar asset as well as borrowings under the Leviathan Term Loan Facility (defined below).
During second quarter 2017, we drilled the L5 development well. Detailed design and engineering, as well as equipment and pipeline manufacturing activities, are currently underway. We expect to continue drilling activities and commence well completion in 2018 and are targeting first production by the end of 2019.
At June 30, 2017, we recorded Leviathan proved undeveloped reserves of 551 MMBoe, net.
Tamar Natural Gas Project (Offshore Israel) In April 2017, we commenced production from the Tamar 8 well and results from the well are currently being integrated into our geologic modeling for application across the reservoir. Growth in power and industrial demand in Israel, resulting from the increased use of natural gas over coal to fuel power generation, and coupled with almost 100% uptime, enabled us to set a new second quarter record for average daily gross sales volumes of 962 MMcfe/d during second quarter 2017. We continue to market a portion of our working interest in Tamar, in accordance with the Framework, which provides for reduction in our ownership interest to 25% by year-end 2021.

Alba Field Unitization (Offshore West Africa) In April 2017, we executed a unitization agreement on the Alba field with our partner and the Government of Equatorial Guinea. The agreement was between Alba Block and Block D partners. As a result of the unitization, our revenue interest going forward changes from 34% to 32% and our non-operated working interest changed from 35% to 33%. We anticipate third quarter 2017 sales volumes from the Alba field to be lower as a result of the unitization; however, we expect the impact on our proved reserves and allocated future sales volumes to be de minimis.

Unsanctioned Development Projects

Tamar Expansion Project (Offshore Israel) We are engaged in the planning phase for the Tamar expansion project. The project would expand field deliverability from the current level of approximately 1.2 Bcf/d to approximately 2.1 Bcf/d, a quantity that

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would allow for additional regional export. Expansion would include a third flow line component and additional producing wells. Timing of project sanction is dependent upon progress relating to marketing efforts of these resources.

Cyprus Natural Gas Project (Offshore Cyprus) We continue to work with the Government of Cyprus on a plan of development for the Aphrodite field that, as currently planned, would deliver natural gas to potential regional customers. In addition, we are focused on natural gas marketing efforts and execution of natural gas sales and purchase agreements which, once secured, will progress the project to a final investment decision.

West Africa Natural Gas Monetization We continue our efforts to monetize our significant natural gas discoveries offshore West Africa. A natural gas development team has been working with local governments to evaluate natural gas monetization concepts. After analyzing existing infrastructure, including the Alen platform and other facilities, we believe these assets can be efficiently modified and retrofitted to allow for future commercialization of natural gas. Leveraging existing assets for the development of natural gas minimizes future capital expenditures while providing advantageous financial returns.

Given the monetization plan, to develop the Alen resources through existing infrastructure, we changed the units-of-production depletion rate, based on risked resources, during first quarter 2017. As a result, we proportionally allocated the existing book value associated with the existing infrastructure assets to the natural gas resources that will be developed in the future, resulting in approximately $153 million of net asset value being reclassified as development costs not subject to depletion in first quarter 2017. See Item 1. Financial Statements – Note 8. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs, Operating Outlook – Potential for Future Dry Hole Cost, Lease Abandonment Expense or Property Impairments, below, and Results of Operations - Operating Costs and Expenses, below.

Exploration Program Update

Our 2017 exploration budget has been substantially reduced compared to prior years due to the current commodity price environment. In 2017, we anticipate engaging in seismic acquisition and processing and participating in drilling an exploratory well offshore Suriname in which we own a 20% non-operating working interest.

Through our drilling activities, we do not always encounter hydrocarbons. 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 will 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 Costs and Operating Outlook – Potential for Future Dry Hole Cost, Lease Abandonment Expense or Property Impairments, below.

Results of Operations

Highlights for our E&P business were as follows:

Second Quarter 2017 Significant E&P Operating Highlights Included:

- total average daily sales volumes of 408 MBoe/d, net;
- record average daily sales volumes for US onshore crude oil of 88 MBbl/d;
- average daily sales volumes of 275 MMcfe/d, net, in Israel, and record second quarter average daily gross sales volumes of 962 MMcfe/d;
- closed the Clayton Williams Energy Acquisition for $2.5 billion of stock and cash consideration, adding highly contiguous acreage in the core of the Delaware Basin and proved reserves of 86 MMBoe, of which 69 MMBoe are proved undeveloped;
- closed the sale of all of the Marcellus Shale upstream assets on June 28, 2017, representing approximately 241 MMBoe of proved natural gas reserves, and received cash of $1.0 billion;
- recorded Leviathan field proved undeveloped reserves of 551 MMBoe, net; and
- sold midstream assets to Noble Midstream Partners for $270 million consideration.

Second Quarter 2017 E&P Financial Results Included:

- loss on Marcellus Shale upstream divestiture of $2.3 billion;
- pre-tax loss of $2.1 billion, as compared with pre-tax loss of $328 million for second quarter 2016; and
- capital expenditures of $613 million, excluding acquisitions, as compared with $257 million for second quarter 2016.

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Following is a summarized statement of operations for our E&P business:

(millions)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Oil, NGL and Gas Sales from Third Parties	$1,017	$823	$2,011	$1,528
Income from Equity Method Investees	25	9	52	12
Total Revenues	1,042	832	2,063	1,540
Production Expense	310	308	627	610
Exploration Expense	30	89	72	252
Depreciation, Depletion and Amortization	486	608	999	1,210
Loss on Marcellus Shale Upstream Divestiture [1]	2,322	—	2,322	—
(Gain) Loss on Commodity Derivative Instruments	(57)	151	(167)	107
Clayton Williams Energy Acquisition Expenses [2]	90	—	94	—
Loss Before Income Taxes	(2,145)	(328)	(1,917)	(631)

[1] See Note 4. Acquisitions and Divestitures.

[2] See Note 3. Clayton Williams Energy Acquisition.

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Oil, NGL and Gas Sales

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

	Sales Volumes				Average Realized Sales Prices		
	Crude Oil & Condensate (MBbl/d)	NGLs (MBbl/d)	Natural Gas (MMcf/d)	Total (MBoe/d) (1)	Crude Oil & Condensate (Per Bbl)	NGLs (Per Bbl)	Natural Gas (Per Mcf)
Three Months Ended June 30, 2017							
United States	110	63	736	296	$45.78	$18.79	$ 3.20
Israel	—	—	272	46	—	—	5.34
Equatorial Guinea (2)	22	—	231	60	49.53	—	0.27
Total Consolidated Operations	132	63	1,239	402	46.40	18.79	3.13
Equity Investees (3)	2	4	—	6	50.93	34.46	—
Total	134	67	1,239	408	$46.49	$19.84	$ 3.13
Three Months Ended June 30, 2016							
United States	96	59	924	309	$40.64	$14.10	$ 1.75
Israel	—	—	276	46	—	—	5.15
Equatorial Guinea (2)	27	—	233	66	44.55	—	0.27
Total Consolidated Operations	123	59	1,433	421	41.51	14.10	2.16
Equity Investees (3)	1	5	—	6	49.94	27.64	—
Total	124	64	1,433	427	$41.61	$15.07	$ 2.16
Six Months Ended June 30, 2017							
United States	105	56	733	283	$47.31	$21.04	$ 3.32
Israel	—	—	272	46	—	—	5.33
Equatorial Guinea (2)	20	—	237	59	51.28	—	0.27
Total Consolidated Operations	125	56	1,242	388	47.95	21.04	3.18
Equity Investees (3)	2	5	—	7	51.71	35.38	—
Total	127	61	1,242	395	$48.01	$22.29	$ 3.18
Six Months Ended June 30, 2016							
United States	99	56	917	308	$35.22	$12.73	$ 1.82
Israel	—	—	271	45	—	—	5.17
Equatorial Guinea (2)	27	—	214	63	39.53	—	0.27
Total Consolidated Operations	126	56	1,402	416	36.14	12.73	2.23
Equity Investees (3)	1	4	—	6	42.34	25.02	—
Total	127	60	1,402	422	$36.20	$13.63	$ 2.23

(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 between reporting periods.

(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.

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

	Sales Revenues			
(millions)	Crude Oil & Condensate	NGLs	Natural Gas	Total
Three Months Ended June 30, 2016	$465	$76	$ 282	$823
Changes due to				
Increase (Decrease) in Sales Volumes	33	4	(28)	9
Increase in Sales Prices	59	28	98	185
Three Months Ended June 30, 2017	$557	$108	$ 352	$1,017
Six Months Ended June 30, 2016	$829	$130	$ 569	$1,528
Changes due to				
Decrease in Sales Volumes	(5)	(1)	(56)	(62)
Increase in Sales Prices	260	84	201	545
Six Months Ended June 30, 2017	$1,084	$213	$ 714	$2,011

Crude Oil and Condensate Sales Revenues Crude oil prices continue to be volatile. During second quarter 2017, our sales volumes grew significantly.

Revenues from crude oil and condensate sales increased for second quarter 2017 as compared with 2016 due to the following:

- higher average realized prices, as compared with 2016, due to partial price recovery;
- higher sales volumes of 5 MBbl/d, net, in the DJ Basin primarily attributable to well locations being developed in the oil-rich part of the basin and enhanced well design and completion techniques;
- higher sales volumes of 10 MBbl/d, net, in the Delaware Basin primarily attributable to increased development and enhanced well design and completion techniques, as well as sales volumes contributed by recently acquired Clayton Williams Energy assets which contributed 5 MBbl/d, net, of the basin's total crude oil sales volumes; and
- production from the Gunflint development, Gulf of Mexico, which began producing in July 2016 and contributed 6 MBbl/d, net, during the current quarter;

partially offset by:

- lower sales volumes in the Eagle Ford Shale primarily attributable to commodity mix from recently completed wells; and
- lower sales volumes due to natural field decline at Aseng and Alen, offshore Equatorial Guinea.

Revenues from crude oil and condensate sales increased for the six months ended June 30, 2017 as compared with 2016 due to the following:

- higher average realized prices due to the partial rebalancing of global supply and demand factors and steady price recovery, primarily during first quarter 2017;
- higher sales volumes of 1 MBbl/d, net, in the DJ Basin primarily attributable to well locations being developed in the oil-rich part of the basin and enhanced well design and completion techniques;
- higher sales volumes of 7 MBbl/d, net, in the Delaware Basin primarily attributable to increased development and enhanced well design and completion techniques, as well as sales volumes contributed by recently acquired Clayton Williams Energy assets which contributed 3 MBbl/d, net, of the basin's total crude oil sales volumes; and
- production from the Gunflint development, Gulf of Mexico, which began producing in July 2016 and contributed 5 MBbl/d, net;

partially offset by:

- lower sales volumes in the Eagle Ford Shale primarily attributable to commodity mix from recently completed wells; and
- lower sales volumes due to natural field decline at Aseng and Alen, offshore Equatorial Guinea.

NGL Sales Revenues Revenues from NGL sales increased for second quarter 2017 as compared with 2016 due to the following:

- higher average realized prices due to the partial rebalancing of domestic supply and demand factors;
- higher sales volumes of 3 MBbl/d, net, in the Delaware Basin during the quarter primarily attributable to increased development and enhanced well design and completion techniques as well as sales volumes contributed by recently acquired Clayton Williams Energy assets, which contributed 1 MBbl/d, net, of the basin's NGL sales volumes; and
- higher sales volumes in the Eagle Ford Shale primarily attributable to commodity mix from recently completed wells;

partially offset by:

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- lower sales volumes in the DJ Basin primarily attributable to increased focus on the oil-rich well locations of the basin.

Revenues from NGL sales increased for the six months ended June 30, 2017 as compared with 2016 due to the following:

- higher average realized prices due to the partial rebalancing of domestic supply and demand factors and steady price recovery, primarily during first quarter 2017; and
- higher sales volumes of 2 MBbl/d, net, in the Delaware Basin primarily attributable to increased development and enhanced well design and completion techniques;

partially offset by:

- lower sales volumes in the DJ Basin primarily attributable to increased focus on the oil-rich well locations of the basin.

Natural Gas Sales Revenues Natural gas prices have traded within a narrow range thus far in 2017. Revenues from natural gas sales increased for second quarter and the first six months of 2017 as compared with 2016 due to the following:

- higher average realized US prices due to the partial rebalancing of domestic supply and demand factors and significant price recovery as compared with 2017;
- higher sales volumes in the Delaware Basin primarily attributable to increased development and enhanced well design and completion techniques as well as sales volumes contributed by recently acquired Clayton Williams Energy assets;
- higher sales volumes in the Eagle Ford Shale primarily attributable to commodity mix from recently completed wells; and
- production from the Gunflint development, Gulf of Mexico, which began producing in July 2016;

partially offset by:

- lower sales volumes in the Marcellus Shale primarily due to natural well decline;
- lower sales volumes in the DJ Basin primarily attributable to increased focus on the oil-rich well locations of the basin; and
- lower sales volumes of 29 MMcf/d, net, during the second quarter and first six months of 2017 as a result of the sale of 3.5% working interest in the Tamar field in December 2016.

Income from Equity Method Investees We have interests in equity method investees that operate midstream assets servicing our West Africa production. 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 during the first six months of 2017 as compared with 2016. The increase includes a $24 million increase from Atlantic Methanol Production Company, LLC (AMPCO), our methanol investee, and a $16 million increase from Alba Plant, our LPG investee, both primarily driven by rising commodity prices and a 1 MBbl/d increase in sales volumes at Alba Plant.

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Production Expense   Components of production expense were as follows:

(millions, except unit rate)	Total per BOE (1)	Total	United States	Eastern Mediter-ranean	West Africa	Other Int'l
Three Months Ended June 30, 2017						
Lease Operating Expense (2)	$3.54	$129	$105	$ 6	$ 18	$ —
Production and Ad Valorem Taxes	1.07	39	39	—	—	—
Gathering, Transportation and Processing (3)	3.89	142	142	—	—	—
Total Production Expense	$8.50	$310	$286	$ 6	$ 18	$ —
Total Production Expense per BOE		$8.50	$10.64	$ 1.46	$ 3.28	$ —
Three Months Ended June 30, 2016						
Lease Operating Expense (2)	$3.45	$132	$101	$ 7	$ 24	$ —
Production and Ad Valorem Taxes	1.02	39	39	—	—	—
Gathering, Transportation and Processing (3)	3.58	137	137	—	—	—
Total Production Expense	$8.05	$308	$277	$ 7	$ 24	$ —
Total Production Expense per BOE		$8.05	$9.86	$ 1.66	$ 3.99	$ —
Six Months Ended June 30, 2017						
Lease Operating Expense (2)	$3.78	$265	$211	$ 14	$ 40	$ —
Production and Ad Valorem Taxes	1.17	82	82	—	—	—
Gathering, Transportation and Processing (3)	3.99	280	280	—	—	—
Total Production Expense	$8.94	$627	$573	$ 14	$ 40	$ —
Total Production Expense per BOE		$8.94	$11.20	$ 1.71	$ 3.72	$ —
Six Months Ended June 30, 2016						
Lease Operating Expense (2)	$3.98	$302	$232	$ 17	$ 53	$ —
Production and Ad Valorem Taxes	0.53	40	40	—	—	—
Gathering, Transportation and Processing (3)	3.54	268	268	—	—	—
Total Production Expense	$8.06	$610	$540	$ 17	$ 53	$ —
Total Production Expense per BOE		$8.06	$9.65	$ 2.05	$ 4.63	$ —

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 processing expense was historically presented as a component of other operating expense, net, in our consolidated statements of operations. Beginning in 2017, we have changed our presentation to reflect processing expense as a component of production expense. These costs are now included within gathering, transportation and processing expense. For the three and six months ended June 30, 2017, these costs totaled $2 million and $5 million respectively. For the three and six months ended June 30, 2016, these costs totaled $6 million and $10 million respectively, and have been reclassified from marketing expense to conform to the current presentation.

For second quarter 2017, total production expense remained flat as compared with 2016. Changes included the following:

- an increase in lease operating expense due to higher production in the Delaware Basin; and
- an increase in gathering, transportation and processing expense due to higher production in the Delaware Basin, the shifting of crude oil volumes onto a new export pipeline and contractual increases of pipeline fees in the DJ Basin, and the startup of our Gunflint development, Gulf of Mexico, which began producing in July 2016;

partially offset by:

- a decrease in lease operating expense due to the timing of workover projects in the DJ Basin and offshore West Africa; and
-

a decrease in gathering, transportation and processing expense due to lower production in the DJ Basin and Marcellus Shale.

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For the first six months of 2017, total production expense increased as compared with 2016 due to the following:

- an increase in lease operating expense due to higher production in the Delaware Basin;
- an increase in production and ad valorem taxes due to higher commodity prices; and
- an increase in gathering, transportation and processing expense due to the factors noted above;

partially offset by:

- a decrease in lease operating expense due to the timing of workover projects in the DJ Basin and offshore West Africa;
- a decrease in production and ad valorem taxes due to a $28 million US onshore severance tax refund recorded in first quarter 2016 versus a $7 million US onshore severance tax charge recorded in first quarter 2017; and
- a decrease in gathering, transportation and processing expense due to lower production in the DJ Basin and Marcellus Shale.

Production expense on a per BOE basis increased due lower sales volumes and increases in production and ad valorem taxes as discussed above. Transportation expense per BOE is also higher in the first six months of 2017 as compared to 2016 due to the shifting of crude oil volumes onto a new export pipeline and contractual increases of pipeline fees in the DJ Basin.

Exploration Expense Our 2017 exploration budget has been substantially reduced compared to prior years due to the current commodity price environment. Exploration expense for second quarter and the first six months of 2017 included Gulf of Mexico leasehold impairment expense of $18 million.

Exploration expense for second quarter and the first six months of 2016 included dry hole cost of $114 million primarily related to the Silvergate exploratory well, Gulf of Mexico, and the Dolphin 1 natural gas discovery, offshore Israel.

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

(millions, except unit rate)	Total	United States	Eastern Mediter-ranean	West Africa	Other Int'l
Three Months Ended June 30, 2017					
DD&A Expense (millions) [1]	$486	$427	$ 19	$39	$ 1
Unit Rate per BOE [2]	$13.32	$15.89	$ 4.62	$7.11	$ —
Three Months Ended June 30, 2016					
DD&A Expense (millions) [1]	$608	$539	$ 19	$49	$ 1
Unit Rate per BOE [2]	$15.88	$19.19	$ 4.55	$8.15	$ —
Six Months Ended June 30, 2017					
DD&A Expense (millions) [1]	$999	$886	$ 37	$74	$ 2
Unit Rate per BOE [2]	$14.25	$17.32	$ 4.52	$6.88	$ —
Six Months Ended June 30, 2016					
DD&A Expense (millions) [1]	$1,210	$1,064	$ 39	$104	$ 3
Unit Rate per BOE [2]	$16.00	$19.01	$ 4.75	$9.09	$ —

[1] For DD&A expense by geographical area, see Item 1. Financial Statements – Note 11. Segment Information.
[2] Consolidated unit rates exclude sales volumes and expenses attributable to equity method investees.

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Total DD&A expense for second quarter and the first six months of 2017 decreased as compared with 2016 due to the following:

- lower sales volumes in the DJ Basin and the impact of certain property divestitures in second quarter 2016;
- timing of the Marcellus Shale upstream divestiture which reduced DD&A expense by approximately $63 million as a result of being classified as held for sale during April 2017;
- sale of a 3.5% working interest in the Tamar field, offshore Israel, in December 2016 which reduced DD&A expense by approximately $2 million and $4 million, in second quarter and first six months of 2017, respectively;
- a reduction in depletable costs of $153 million due to the reallocation of common asset costs from Alen, offshore Equatorial Guinea, to the West Africa natural gas monetization development project, which reduced DD&A expense by $16 million in the first six months of 2017; and
- lower sales volumes in Gulf of Mexico due to natural field decline and reduction in the depletable costs due to negative revisions in estimates of asset retirement costs;

partially offset by:

- increased sales volumes in the Delaware Basin due to higher levels of development activity as well as sales volumes contributed by recently acquired Clayton Williams Energy assets, which contributed 8 MBb/d, net of the basin's total sales volumes;
- an increase in sales volumes from the Gunflint development, Gulf of Mexico, which commenced production in July 2016; and
- higher sales volumes from the Tamar field, offshore Israel, due to higher domestic demand.

The decrease in the unit rate per BOE for the second quarter and the first six months of 2017 as compared with 2016, was due to the reduction of higher-cost production volumes from divested Marcellus Shale properties, an increase in lower-cost production volumes from the Tamar field, decreased production from the DJ Basin and the reduction in Alen net book value, partially offset by decreases in proved reserves at year-end 2016 due to downward price revisions in the US and Equatorial Guinea.

(Gain) Loss on Commodity Derivative Instruments (Gain) loss on commodity derivative instruments includes (i) cash settlements (received) or paid relating to our crude oil and natural gas commodity derivative contracts; and (ii) non-cash (increases) or decreases in the fair values of our crude oil and natural gas commodity derivative contracts.

For the first six months of 2017, gain on commodity derivative instruments included:

- net cash settlement receipts of $14 million; and
- non-cash increases in the fair value of our derivative instruments of $153 million primarily driven by changes in the forward commodity price curves for both crude oil and natural gas.

For the first six months of 2016, loss on commodity derivative instruments included:

- net cash settlement receipts of $322 million; and
- non-cash decreases in the fair value of our derivative instruments of $429 million primarily driven by changes in the forward commodity price curves for both crude oil and natural gas.

See Item 1. Financial Statements – Note 5. Derivative Instruments and Hedging Activities and Note 7. Fair Value Measurements and Disclosures.

MIDSTREAM

The Midstream segment owns, operates, develops and acquires domestic midstream infrastructure assets with current focus areas being the DJ and Delaware Basins.

Noble Midstream Partners – Major Midstream Project Updates

Third-Party Sales During second quarter 2017, we initiated sales of fresh water delivery services to a third party producer located in the Greeley Crescent IDP area of the DJ Basin.

Acreage Dedications The majority of the Delaware Basin acreage acquired in the Clayton Williams Energy Acquisition has been dedicated to the Midstream segment for infield crude oil, natural gas and produced water gathering. Additionally, infield natural gas gathering has been added to the existing crude oil and produced water dedication on Noble Energy's original 47,000, net, Delaware Basin acres.

Major Midstream Construction Projects During second quarter 2017, we progressed the construction and development of multiple major projects including:

- completion of a produced water expansion project servicing the Wells Ranch IDP area of the DJ Basin;

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- continued construction on crude oil and produced water gathering systems servicing the Greeley Crescent IDP area of the DJ Basin, which are expected to be operational in third quarter 2017;
- completion of our first central gathering facility (CGF) and crude oil, natural gas and produced water gathering infrastructure located in the Delaware Basin of Texas, which became operational in July 2017; and
- continued construction activities on the expansion of a freshwater system servicing the Mustang IDP area of the DJ Basin.

Advantage Pipeline Acquisition In April 2017, Noble Midstream Partners, along with its partner, Plains, completed the acquisition of Advantage Pipeline for $133 million through a newly formed 50/50 joint venture. Noble Midstream Partners contributed $66.5 million of cash, funded by available cash on hand and the Noble Midstream Services Revolving Credit Facility. Noble Midstream Partners serves as the operator of the Advantage Pipeline system, which includes a 70-mile crude oil pipeline in the Delaware Basin from Reeves County, Texas to Crane County, Texas with 150,000 barrels per day of shipping capacity (expandable to over 200,000 barrels per day) and 490,000 barrels of storage capacity.

Results of Operations

Highlights for our Midstream segment were as follows:

Second Quarter 2017 Significant Midstream Operating Highlights Included:

- signed a definitive agreement to divest an affiliate that holds the 50% interest in CONE Gathering, LLC (CONE Gathering) for $765 million;
- acquisition by Noble Midstream Partners of additional midstream assets from Noble Energy for $270 million consideration, including $245 million in cash and 562,430 of common units, funded with $138 million net proceeds from a concurrent private placement of common units, $90 million of borrowings and the remainder from cash on hand;
- acquisition of Advantage Pipeline L.L.C. (Advantage Pipeline) for $66.5 million, net, through a newly formed 50/50 joint venture between Noble Midstream Partners and Plains Pipeline, L.P. (Plains), a wholly owned subsidiary of Plains All American Pipeline, L.P.;
- commencement of fresh water delivery services to an unaffiliated third party in the Greeley Crescent integrated development plan (IDP) area of the DJ Basin; and
- record throughput volumes resulting from increased upstream development activities in the Wells Ranch and East Pony IDP areas of the DJ Basin.

Second Quarter 2017 Midstream Financial Results Included:

- pre-tax income of $58 million, as compared with pre-tax income of $39 million for second quarter 2016; and
- capital expenditures, excluding acquisitions, of $88 million compared with de minimis capital expenditures for second quarter 2016.

Following is a summarized statement of operations for our Midstream segment:

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions)	2017	2016	2017	2016
Midstream Services Revenues - Third Party	$ 4	$ —	$ 4	$ —
Income from Equity Method Investees [1]	13	15	28	31
Intersegment Revenues	69	43	127	85
Total Revenues	86	58	159	116
Operating Costs and Expenses	23	14	42	27
Depreciation, Depletion and Amortization	5	5	10	9
Income Before Income Taxes	58	39	107	80

[1] Includes earnings from equity method investment in the Advantage Joint Venture.

The amount of revenue generated by the midstream business primarily depends on the volumes of crude oil, natural gas and water for which services are provided to the E&P business. These volumes are affected primarily by the level of drilling and completion activity in the areas of upstream operations and by changes in the supply of, and demand for, crude oil, natural gas and NGLs in the markets served directly or indirectly by our midstream assets.
Total revenues for the three and six months ended June 30, 2017 increased from 2016 due to the following:

- an increase of $23 million and $41 million, respectively, driven by drilling and completion activity in the Wells Ranch and East Pony IDP areas of the DJ Basin which resulted in increased services related to fresh water delivery, water logistics, and additional crude oil and natural gas gathering services; and
- an increase of $4 million due to the commencement of fresh water deliveries to a third party in the Greeley Crescent IDP area of the DJ Basin;

partially offset by

- a decrease in income from Cone Gathering LLC and Cone Midstream Partners LP.

Total operating expenses for the three and six months ended June 30, 2017 increased from 2016 primarily due to higher drilling and completion activity in the Wells Ranch and East Pony IDP areas of the DJ Basin which resulted in increased fresh water volumes required and additional water logistic services for produced water.

Results of Operations – Corporate and Other

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
G&A Expense (millions)	$103	$107	$202	$198
Unit Rate per BOE (1)	$2.82	$2.79	$2.88	$2.62

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

G&A expense for second quarter and the first six months of 2017 remained flat as compared with 2016. The increase in the unit rate per BOE for the first six months of 2017 as compared with 2016 was due primarily to the decrease in total sales volumes.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions, except unit rate)	2017	2016	2017	2016
Interest Expense, Gross	$107	$102	$206	$209
Capitalized Interest	(11)	(24)	(23)	(52)
Interest Expense, Net	$96	$78	$183	$157
Unit Rate per BOE (1)	$2.63	$2.04	$2.61	$2.07

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

Interest expense, gross, for second quarter and the first six months of 2017 remained relatively flat as compared with 2016 as our debt structure has not changed significantly. See Item 1. Financial Statements - Note 6. Debt.

The decrease in capitalized interest for second quarter and the first six months of 2017 as compared with 2016 is primarily due to lower work in progress amounts related to major long-term projects including Gunflint, Gulf of Mexico, and the Alba B3 compression project, offshore Equatorial Guinea, which were both completed in July 2016. We also impaired certain of our discoveries offshore Equatorial Guinea after an additional review of 3D seismic data was completed in fourth quarter 2016, resulting in a lower capitalized exploratory well cost balance. See Item 1. Financial Statements - Note 8. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs.

The increase in the unit rate of interest expense, net, per BOE was due to the changes noted above, combined with the decrease in total sales volumes.

Income Taxes See Item 1. Financial Statements – Note 10. Income Taxes for a discussion of the change in our effective tax rate for second quarter and the first six months of 2017 as compared with 2016.

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 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 periodically capitalize on financially attractive merger and acquisition opportunities, such as the recent Clayton Williams Energy Acquisition. We endeavor to maintain a strong balance sheet and investment grade debt rating in service of these objectives.

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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 property divestitures. 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. We also evaluate potential strategic farm-out arrangements of our working interests for reimbursement of our capital spending. Although we engaged in significant development and portfolio activities during second quarter 2017, including the Clayton Williams Energy Acquisition and the Marcellus Shale upstream divestiture, we ended the quarter with no amounts outstanding under our Revolving Credit Facility or additional fixed-rate debt. We also maintained a debt-to-book capital ratio of 43%.

Additionally, we reduced our natural gas hedge portfolio as a result of the Marcellus Shale upstream divestiture. In this regard, we terminated, restructured or transferred to the acquirer of the Marcellus Shale upstream assets certain natural gas hedge arrangements. The impact to our consolidated financial statements was de minimis for the three and six months ended June 30, 2017.

During second quarter 2017, Noble Midstream Partners purchased additional midstream assets from Noble Energy for $270 million and expanded its business through entry into a joint venture. Funding for these transactions included a $138 million private placement of common units and $90 million of net borrowings under the Noble Midstream Services Revolving Credit Facility.

Also, during the first six months of 2017, we received $175 million in payments from foreign operations on an outstanding note payable, leaving a balance of approximately $551 million that can be repaid without additional US tax impact.

As of June 30, 2017, our outstanding debt (excluding capital lease obligations) totaled $6.9 billion. While we have no near-term debt maturities, we may periodically seek to access the capital markets to refinance a portion of our outstanding indebtedness.

Available Liquidity

Information regarding cash and debt balances is shown in the table below:

	June 30,	December 31,
(millions, except percentages)	2017	2016
Total Cash [1]	$540	$1,209
Amount Available to be Borrowed Under Revolving Credit Facility [2]	4,000	4,000
Total Liquidity	$4,540	$5,209
Total Debt [3]	$7,236	$7,114
Noble Energy Share of Equity	9,635	9,288
Ratio of Debt-to-Book Capital [4]	43 %	43 %

(1) As of June 30, 2017, total cash included cash and cash equivalents of $20 million related to Noble Midstream Partners. As of December 31, 2016, total cash included cash and cash equivalents of $57 million related to Noble Midstream Partners and restricted cash of $30 million related to a Delaware Basin property acquisition that closed in January 2017.

(2) Excludes $160 million and $625 million available to be borrowed under the Noble Midstream Services Revolving Credit Facility and Leviathan Term Loan Facility, respectively, which are not available to Noble Energy for general corporate purposes. See discussion below.

(3) Total debt includes capital lease obligations and excludes unamortized debt discount/premium. See Item 1. Financial Statements – Note 6. Debt.

(4) 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 Noble Energy's share of equity.

Cash and Cash Equivalents We had approximately $540 million in cash and cash equivalents at June 30, 2017, primarily denominated in US dollars and invested in money market funds and short-term deposits with major financial institutions. Approximately $462 million of this cash is attributable to our foreign subsidiaries. We have recorded a related deferred tax liability on undistributed foreign earnings of $332 million for the future additional US tax liability for the US and foreign tax rate differences, net of estimated foreign tax credits. Our cash and cash equivalents at June 30, 2017 included $20 million relating to Noble Midstream Partners.

Revolving Credit Facility Noble Energy's Revolving Credit Facility matures on August 27, 2020, and the commitment is $4 billion through the maturity date. On April 24, 2017, we borrowed $1.3 billion to fund activities in connection with the Clayton Williams Energy Acquisition, including the cash portion of the acquisition consideration, redeem outstanding debt, pay associated make-whole premiums and pay related fees and expenses. We repaid all outstanding borrowings during second quarter 2017 with proceeds received from the Marcellus Shale upstream divestiture, cash on hand, and cash proceeds received from the Noble Midstream Partners asset contribution. Subsequent to second quarter 2017, we borrowed and had outstanding

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$165 million as of July 31, 2017 under our Revolving Credit Facility which was utilized for general corporate purposes. See Item 1. Financial Statements - Note 3. Clayton Williams Energy Acquisition and Note 4. Acquisitions and Divestitures.

Noble Midstream Services Revolving Credit Facility Noble Midstream Services Revolving Credit Facility matures on September 20, 2021, and the commitment is $350 million through the maturity date. During second quarter 2017, we drew amounts to fund acquisition activity, resulting in an outstanding balance of $190 million at June 30, 2017.

Leviathan Term Loan Facility On February 24, 2017, we entered into a facility agreement (Leviathan Term Loan Facility) providing for a limited recourse secured term loan facility with an aggregate principal borrowing amount of up to $1.0 billion, of which $625 million is initially committed. Any loans borrowed under the Leviathan Term Loan Facility will be available to fund a portion of our share of costs for the initial phase of development of the Leviathan field, offshore Israel. To support the Leviathan development program and to bring first production online by the end of 2019, we may borrow amounts under this facility in the near-term. As of June 30, 2017, no amounts were drawn under this facility.

Interest Rate Risk Certain of our borrowings subject us to interest rate risk. See Item 1. Financial Statements – Note 6. Debt and Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Contractual Obligations

See Item 1. Financial Statements – Note 12. Commitments and Contingencies for an updated tabular presentation of non-cancelable leases and other commitments as of June 30, 2017.

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 and/or penalty payments.

Leviathan Development Obligations The development of our Leviathan field requires substantial infrastructure and capital. We have executed major equipment and installation contracts in support of our development activities in the field. As of June 30, 2017, we had entered into approximately $644 million, net, of contracts to support the development of this field and bring first production online by the end of 2019.

Continuous Development Obligations Although the majority of our assets are held by production, certain of our US onshore assets are held through continuous development obligations. As such, we plan our activities and budget accordingly to ensure that we meet any such obligations that are in line with our strategic plans. Therefore, we are contractually obligated to fund a level of development activity in these areas.

Marcellus Shale Firm Transportation Agreements In connection with the Marcellus Shale upstream divestiture, we reduced our firm transportation financial commitments through transfer of several contracts to the acquirer.

We retained certain other firm transportation contracts representing a total financial commitment of approximately $1.6 billion, undiscounted, primarily with remaining contract terms of 15 years.

One of the retained contracts, related to Texas Eastern pipeline, will be fully utilized through an agreement with the acquirer, whereby the acquirer will deliver quantities of natural gas to us and receive a netback sales price that reflects the value received by us at the sales point, less our effective fixed transportation fees and other expenses, plus a margin. This contract represents an undiscounted financial commitment of approximately $124 million, before offset by the netback agreement, thus reducing the remaining overall commitment noted above.

Two of the retained contracts relate to the Leach & Rayne Xpress projects, which are currently under construction and targeted to be placed in service fourth quarter 2017. These contracts represent an undiscounted financial commitment of $616 million.

Two additional retained contracts relate to the WB Xpress and NEXUS projects. Although scheduled to be placed in service fourth quarter 2018, these projects have not yet been approved by the Federal Energy Regulatory Commission (FERC), and construction has not begun. These contracts represent an undiscounted financial commitment of $869 million.

We are currently engaged in actions to commercialize and address these remaining four commitments, which provide for the transportation of approximately 500,000 MMBtu/day of natural gas. Actions include negotiation of capacity release, utilization of capacity through purchase of third party natural gas, and other potential arrangements. In addition, we have a “call” or right to purchase natural gas, priced at a regional index, from the acquirer of the Marcellus Shale upstream assets. This call extends through July 1, 2022 and may be exercised on quantities of the acquirer's production between 431,100 MMBtu/d and 832,645 MMBtu/d.

We expect these actions, some of which may require pipeline and/or FERC approval, to ultimately reduce the financial commitment associated with these contracts. At the date each pipeline is placed in service and our commitment begins, we will evaluate our position. If we determine that we will not utilize a portion, or all, of the contracted pipeline capacity, we will accrue a liability, at fair value, for the net amount of the estimated remaining financial commitment and include the related expense in operating expense in our consolidated statements of operations.

In accordance with US GAAP, we recognize the fair value of a liability for an exit cost in the period in which a liability is incurred. As a result, as of June 30, 2017, we accrued non-cash exit costs of $41 million, discounted, relating to our transportation contract with the Gateway pipeline project. Gateway is currently in service; however, we no longer have production to satisfy this commitment and do not plan to utilize this capacity in the future. As such, we recorded a charge to expense which is included in loss on Marcellus Shale upstream divestiture in our consolidated statements of operations.

See Item 1. Financial Statements – Note 12. Commitments and Contingencies.

Other Delivery and Firm Transportation Agreements We have entered into various long-term gathering, processing and transportation contracts for some of our US onshore and offshore production, primarily in the DJ Basin and South Texas, with remaining terms of one to 11 years. We use long-term contracts such as these to provide production flow assurance and ensure access to markets for our products at the best possible price and at the lowest possible logistics cost. See Item 1. Financial Statements – Note 12. Commitments and Contingencies.

Certain of these contracts require us to make payments for any shortfalls in delivering or transporting minimum volumes under the commitments. As properties are undergoing development activities, we may experience temporary shortfalls until production volumes increase to meet or exceed the minimum volume commitments.

For the first six months of 2017 and 2016, we incurred expense of approximately $33 million and $27 million, respectively, related to volume deficiencies and/or unutilized commitments primarily in our US onshore operations. These amounts are recorded as marketing expense in our consolidated statements of operations. We expect to continue to incur expense related to deficiency and/or unutilized commitments in the near-term. Should commodity prices 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. We continually seek to optimize under-utilized assets through capacity release and third-party arrangements, as well as, for example, through the shifting of transportation of production from rail cars to pipelines when we receive a higher netback price. We may continue to experience these shortfalls both in the near and long-term.

Credit Rating Events   We do not have any triggering events on our consolidated 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

Summary cash flow information is as follows:

	Six Months Ended June 30,	
(millions)	2017	2016
Total Cash Provided By (Used in)		
Operating Activities	$877	$440
Investing Activities	(1,091)	(51)
Financing Activities	(426)	(117)
(Decrease) Increase in Cash and Cash Equivalents	$(640)	$272

Operating Activities   Net cash provided by operating activities for the first six months of 2017 increased as compared with 2016. Increases in average realized commodity prices were partially offset by decreases in sales volumes. Working capital changes resulted in a $99 million operating cash flow decrease for the first six months of 2017, as compared with a $381 million operating cash flow decrease for the first six months of 2016. The changes in working capital were primarily due to an increase in accounts payable driven by increased operational activity partially offset by an increase in accounts receivable resulting from higher revenues.

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 occurred in prior periods.

Capital spending for property, plant and equipment increased by $403 million during the first six months of 2017 as compared with the first six months of 2016, primarily due to increased US onshore development activity in response to current

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commodity prices. In addition, we used $637 million of cash to fund a portion of the consideration paid in the Clayton Williams Energy Acquisition, and we acquired Delaware Basin assets for $301 million. We received net cash proceeds of $1.0 billion from the Marcellus Shale upstream divestiture, and other investing activities provided a net $33 million of cash. During the first six months of 2016, we received net proceeds of $767 million from asset sales.
Financing Activities Our financing activities include the issuance or repurchase of Noble Energy common stock and Noble Midstream Partners common units, payment of cash dividends to shareholders and distributions to noncontrolling interest owners, borrowings and repayments of borrowings. During the first six months of 2017, we borrowed and repaid $1.3 billion under our Revolving Credit Facility and borrowed a net $190 million under the Noble Midstream Services Revolving Credit Facility. We also repaid $595 million of assumed Clayton Williams Energy debt. We used cash of $92 million to pay dividends on our common stock and $12 million to pay distributions to noncontrolling interest owners.
In comparison, during the first six 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 ($86 million), fund the purchase of certain of our outstanding senior notes ($1.38 billion), and make principal payments related to capital lease obligations ($27 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 June 30,		Six Months Ended June 30,	
(millions)	2017	2016	2017	2016
Acquisition, Capital and Exploration Expenditures				
Unproved Property Acquisition [1]	$1,581	$—	$1,826	$—
Proved Property Acquisition [2]	782	—	840	—
Exploration	7	58	17	156
Development	598	189	1,182	436
Midstream [3]	152	5	245	20
Corporate and Other	10	10	15	20
Total	$3,130	$262	$4,125	$632
Investment in Equity Method Investee [4]	$67	$—	$67	$6

[1] Unproved property acquisition cost for the first six months of 2017 includes $1.6 billion related to the Clayton Williams Energy Acquisition and $246 million related to the Delaware Basin asset acquisition.
[2] Proved property acquisition cost for the first six months of 2017 includes $724 million of proved properties and $59 million of asset retirement obligations acquired in the Clayton Williams Energy Acquisition and $58 million related to the Delaware Basin asset acquisition.
[3] Midstream expenditures for the first six months of 2017 include $67 million related to the Clayton Williams Energy Acquisition.
[4] Investment in equity method investee for the first six months of 2017 represents our contribution to the Advantage Joint Venture, in which Noble Midstream Partners owns a 50% interest.
Development costs increased during the first six months of 2017 as compared with 2016 as we have increased our US onshore activity in response to the current commodity price environment and focus on development of liquids-rich assets in the DJ Basin, Delaware Basin, and Eagle Ford Shale. See Operating Outlook – 2017 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 June 30, 2017, we had no amount outstanding under the Revolving Credit Facility, leaving $4.0 billion available for

use. On April 24, 2017, we drew $1.3 billion under our Revolving Credit Facility to fund activities in connection with the Clayton Williams Energy Acquisition, including the cash portion of the acquisition consideration, redeem outstanding debt, pay associated make-whole premiums and pay related fees and expenses. We repaid all outstanding borrowings in late June 2017 with proceeds received from the Marcellus Shale upstream divestiture, cash on hand, and cash proceeds received from the Noble Midstream Partners asset contribution.

We may rely on our Revolving Credit Facility to help fund our capital investment program, and may periodically borrow amounts for working capital purposes. See Item 1. Financial Statements – Note 6. Debt.

Our outstanding fixed-rate debt (excluding capital lease obligations) totaled approximately $6.2 billion at June 30, 2017. The weighted average interest rate on fixed-rate debt was 5.69%, with maturities ranging from March 2019 to August 2097.

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Dividends We paid total cash dividends of 20 cents per share of common stock during the first six months of 2017, consistent with 20 cents per share during the first six months of 2016.

On July 25, 2017, our Board of Directors declared a quarterly cash dividend of 10 cents per common share, which will be paid on August 21, 2017 to shareholders of record on August 7, 2017. 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.

Distributions to Noncontrolling Interest Owners During the first six months of 2017, distributions paid to noncontrolling interest owners totaled $12 million.

Exercise of Stock Options We received cash proceeds of $9 million from the exercise of stock options during the first six months of 2017 and $7 million during the first six months of 2016.

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 986,394 shares with a value of $35 million, including 719,849 shares with a value of $25 million related to vesting of Clayton Williams Energy restricted stock and options in connection with the Clayton Williams Energy Acquisition, during the first six months of 2017. We received 232,870 shares with a value of $8 million during the first six months of 2016.

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CRITICAL ACCOUNTING POLICIES AND ESTIMATES, UPDATE

The following discussion updates the policies and estimates disclosed in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies and Estimates of our Annual Report on Form 10-K for the year ended December 31, 2016.

Goodwill

As of June 30, 2017, our consolidated balance sheet included goodwill of $1.3 billion, which resulted from the excess of the purchase price over amounts assigned to assets acquired and liabilities assumed in the Clayton Williams Energy Acquisition in second quarter 2017. The goodwill was assigned to the Texas reporting unit.

Annual Goodwill Test Goodwill is not amortized to earnings but is assessed, at least annually, for impairment at the reporting unit level. Our policy is to conduct a qualitative goodwill impairment assessment by examining relevant events and circumstances which could have a negative impact on our goodwill such as: macroeconomic conditions; industry and market conditions, including commodity prices; cost factors; overall financial performance; segment dispositions and acquisitions; and other relevant entity-specific events.

If, after assessing the totality of events or circumstances described above, we determine that it is more likely than not that the fair value of our US onshore reporting unit is less than its carrying amount, the two-step goodwill test is performed. The two-step goodwill impairment test is also performed whenever events or changes in circumstances indicate that the carrying value may not be recoverable. If, after performing the two-step goodwill test, it is determined that the carrying value of goodwill is impaired, the amount of goodwill is reduced and a corresponding charge is made to earnings in the period in which the goodwill is determined to be impaired.

The two-step impairment test is used to identify potential goodwill impairment and measure the amount of a goodwill impairment loss to be recognized. The first step of the goodwill impairment test, used to identify potential impairment, compares the fair value of a reporting unit with its carrying amount, including goodwill. If the fair value of the reporting unit exceeds its carrying amount, goodwill is not considered to be impaired, and the second step of the test is not required. If necessary, the second step of the impairment test, used to measure the amount of impairment loss, compares the implied fair value of reporting unit goodwill with the carrying amount of that goodwill. If the carrying amount of reporting unit goodwill exceeds the implied fair value of that goodwill, an impairment loss is recognized in an amount equal to the excess.

The first step of the impairment test requires management to make estimates regarding the fair value of the reporting unit to which goodwill has been assigned. If it is necessary to determine the fair value of the US onshore reporting unit, we use a combination of the income approach and the market approach.

Under the income approach, the fair value of the US onshore reporting unit is estimated based on the present value of expected future cash flows. The income approach is dependent on a number of factors including estimates of forecasted revenue and operating costs and proved reserves, as well as the success of future exploration for and development of unproved reserves, discount rates and other variables. Negative revisions of estimated reserves quantities, increases in future cost estimates, divestiture of a significant component of the reporting unit, or sustained decreases in crude oil or natural gas prices could lead to a reduction in expected future cash flows and possibly an impairment of all or a portion of goodwill in future periods.

Key assumptions used in the discounted cash flow model described above include estimated quantities of crude oil, natural gas and NGL reserves, including both proved reserves and risk-adjusted unproved reserves; estimates of market prices considering forward commodity price curves as of the measurement date; and estimates of operating, administrative and capital costs adjusted for inflation. We discount the resulting future cash flows using a peer company based weighted average cost of capital.

Under the market approach, we estimate the value of the US onshore reporting unit by comparison to similar businesses whose securities are actively traded in the public market. This requires management to make certain judgments about the selection of comparable companies and/or comparable recent company and asset transactions and transaction premiums. We use a peer company multiple method for the market approach. Market multiples represent market estimates of fair value based on selected financial metrics. We use earnings before interest, taxes, DD&A and exploration expense (also known as EBITDAX) as our financial metric as we believe it more accurately compares companies using successful efforts and full cost accounting methods, both of which are in our peer group.

Although we base the fair value estimate of the US onshore reporting unit on assumptions we believe to be reasonable, those assumptions are inherently unpredictable and uncertain and actual results could differ from the estimate. In the event of a prolonged industry downturn, commodity prices may stay depressed or decline further, thereby causing the fair value of the US onshore reporting unit to decline, which could result in an impairment of goodwill.

Disposals If, in the future, we dispose of a reporting unit or a portion of a reporting unit that constitutes a business, we will include goodwill associated with that business in the carrying amount of the business in order to determine the gain or loss on disposal. The amount of goodwill allocated to the carrying amount of a business can significantly impact the amount of gain or

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loss recognized on the sale of that business. The amount of goodwill to be included in that carrying amount will be based on the relative fair value of the business to be disposed of and the portion of the reporting unit that will be retained. We did not allocate any goodwill to the carrying amount of the Marcellus Shale upstream assets that were sold on June 28, 2017. See Item 1. Financial Statements - Note 3. Clayton Williams Energy Acquisition.

Exit Costs

During second quarter 2017, in connection with our Marcellus Shale upstream divestiture, we accrued a liability of $41 million, discounted, for exit costs related to our commitment under a retained firm transportation contract, and charged the amount to loss on Marcellus Shale upstream divestiture in our consolidated statements of operations.

We have retained additional Marcellus Shale firm transportation contracts, relating to pipeline projects which are not yet commercially available to us. These projects are either under construction or have not yet been approved by the FERC. We did not accrue any exit cost liabilities related to these contracts as of June 30, 2017. See Item 1. Financial Statements – Note 12. Commitments and Contingencies.

We account for exit costs in accordance with ASC 420 – Exit or Disposal Cost Obligations, which requires that a liability for a cost associated with an exit or disposal activity be recognized at fair value in the period in which the liability is incurred. Further, a liability for costs that will continue to be incurred under a contract for its remaining term without economic benefit to the entity shall be recognized at the "cease-use date", which is defined as the date the entity ceases using the right conveyed by the contract, for example, the right to use a leased property or to receive future goods or services.

As these projects become commercially available to us, our management must make significant judgments and estimates regarding the timing and amount of recognition of any additional exit cost liabilities, taking into consideration our commercialization activities and/or the potential occurrence of a cease-use date.

Any additional exit cost liability will be initially recorded at fair value, and, in periods subsequent to initial measurement, changes to the liability, including changes resulting from revisions to either the timing or the amount of estimated cash flows over the future contract period, will be recognized as an adjustment to the liability in the period of the change. Therefore, initial recognition of a liability, as well as subsequent increases or decreases in exit cost liability estimates, could have a significant impact on our consolidated net income (loss).

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

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. See Results of Operations - Revenues, above.

Derivative Instruments Held for Non-Trading Purposes Due to the volatility of crude oil and natural gas prices, we continue to use derivative instruments as a means of managing our exposure to price changes.

At June 30, 2017, 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 $31 million. Based on the June 30, 2017 published commodity futures price curves for the underlying commodities, a hypothetical price increase of 10% per Bbl for crude oil and 10% per MMBtu for natural gas would decrease the fair value of our net commodity derivative asset by approximately $43 million, effectively changing our net asset position to a net liability of $12 million. Our derivative instruments are executed under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net cash settled at the time of election. See Item 1. Financial Statements – Note 5. Derivative Instruments and Hedging Activities.

Marcellus Shale Firm Transportation Contracts We retained certain other firm transportation contracts after the closing of the Marcellus Shale upstream divestiture. These contracts generally relate to pipelines which are currently under construction and not available for use, or pipelines for which construction has not yet begun and which are not currently approved by the FERC. Our volume commitments under these contracts total approximately 500,000 MMBtu/d.

Access to these contracts may be operationally or financially beneficial to other natural gas operators in the region. We are currently assessing various options to commercialize and address the remaining commitments, including the negotiation of capacity release, utilization of capacity through the purchase of third party natural gas and other potential arrangements. In addition, we have a “call” or right to purchase natural gas priced at a regional index from the acquirer of the Marcellus Shale upstream assets through July 1, 2022 when the acquirer's production exceeds 431,100 MMBtu/d but is less than 832,645 MMBtu/d. However, we do not have information regarding the acquirer's future development plans; therefore, there is uncertainty regarding when or if any volumes may become available. We expect these actions, some of which may require pipeline and/or FERC approval, to ultimately reduce the financial commitment associated with these contracts. Changes in natural gas prices, in and out of basin supply and demand, the industry's ability to export substantial natural gas volumes to areas outside of the Marcellus Shale, as well as changes in basis differentials, could impact our commercialization options. We have no control over these market factors and therefore may not realize any benefits from our commercialization efforts. As a result, and when or if required, we may recognize substantial future liabilities, at fair value, for the net amount of the estimated remaining commitments under these contracts and charges to other operating expense in future periods. See Item 1. Financial Statements – Note 12. Commitments and Contingencies.

Interest Rate Risk

Changes in interest rates affect the amount of interest we pay on certain of our borrowings and the amount of interest we earn on our short-term investments.

At June 30, 2017, we had approximately $6.9 billion (excluding capital lease obligations) of long-term debt, net, outstanding. Of this amount, $6.2 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 June 30, 2017, our cash and cash equivalents totaled $540 million, approximately 46% of which was invested in money market funds and short-term investments with major financial institutions.

In addition, borrowings under the Term Loan Facility and Noble Midstream Services Revolving Credit 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 June 30, 2017, 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, Term Loan Facility or the amount currently outstanding under the Noble Midstream Services Revolving Credit Facility 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 the three and six months ended June 30, 2017 and 2016.

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 future results of operations;
- our liquidity and ability to finance our exploration, development and acquisitions activities;
- our ability to satisfy contractual commitments, including utilization or commercialization of firm transportation commitments in the Marcellus Shale;
- our ability to make and integrate acquisitions;
- our ability to successfully and economically explore for and develop crude oil, natural gas and NGL resources;

- anticipated trends in our business;
- market conditions in the oil and gas industry;

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- the impact of governmental fiscal regulation, including federal, state, local, and foreign host regulations, and/or terms, such as those involving the protection of the environment or marketing of production, as well as other regulations; and
- access to resources.

Any such projections or statements reflect Noble Energy's views (as of the date such projects were published or such statements were made) about future events and financial performance. No assurances can be given that such events or performance will occur as projected, and actual results may differ materially from those projected. Important factors that could cause the actual results to differ materially from those projected include, without limitation, the volatility in commodity prices for crude oil and natural gas, the presence or recoverability of estimated reserves, the ability to replace reserves, environmental risks, drilling and operating risks, exploration and development risks, competition, government regulation or other action, the ability of management to execute its plans to meet its goals and other risks inherent in Noble Energy's business that are detailed in its Securities and Exchange Commission filings.

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, 2016 and in this quarterly report on Form 10-Q, 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, 2016 is available on our website at www.nblenergy.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. These forms can also be obtained from the SEC by calling 1-800-SEC-0330. Alternatively, you may access these reports at the SEC's website at www.sec.gov.

Part II. Other Information

Item 1. Legal Proceedings

See discussion of legal proceedings in Part I. Financial Information, Item 1. Financial Statements - Note 12. 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, 2016.

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, 2016.

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)
4/1/2017 - 4/30/2017 (2)	721,724	$ 34.19	—	—
5/1/2017 - 5/31/2017	2,714	31.02	—	—
6/1/2017 - 6/30/2017	1,810	29.41	—	—
Total	726,248	$ 34.19	—	—

(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.

(2) Includes 719,849 shares related to the payment of withholding taxes due by Clayton Williams Energy shareholders upon vesting of restricted stock and options in connection with the Clayton Williams Energy Acquisition.

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Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Item 6. Exhibits

The information required by this 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.

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Signatures

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	NOBLE ENERGY, INC. (Registrant)
Date August 3, 2017	/s/ Kenneth M. Fisher Kenneth M. Fisher Executive Vice President, Chief Financial Officer

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Index to Exhibits

Exhibit Number	Exhibit**
2.1	Agreement and Plan of Merger, dated as of January 13, 2017, by and among Noble Energy, Inc., Wild West Merger Sub Inc., NBL Permian LLC, and Clayton Williams Energy, Inc. (filed as Exhibit 2.1 to the Registrant's Current Report on Form 8-K (Date of Report: January 13, 2017) filed on January 17, 2017 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).
2.3	Exchange Agreement, executed October 29, 2016, by and between CNX Gas Company LLC and Noble Energy, Inc. (filed as Exhibit 2.3 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2016 and incorporated herein by reference).
2.4	Purchase and Sale Agreement among Noble Energy, Inc. and HG Energy II Appalachia, LLC dated May 1, 2017 (filed as Exhibit 2.1 to the Registrant's Current Report on Form 8-K (Date of Report: May 1, 2017) filed on May 5, 2017 and incorporated herein by reference).
2.5	Purchase Agreement by and among Wheeling Creek Midstream, LLC, Noble Energy US Holdings, LLC and Noble Energy, Inc. dated May 17, 2017 (filed as Exhibit 2.1 to the Registrant's Current Report on Form 8-K (Date of Report: May 17, 2017) filed on May 23, 2017 and incorporated herein by reference).
3.1	Restated Certificate of Incorporation of Noble Energy Inc., (filed as Exhibit 3.3 to the Registrant's Current Report on Form 8-K (Date of Report: July 26, 2016) filed on July 28, 2016 and incorporated herein by reference).
3.2	By-Laws of Noble Energy, Inc. (as amended through January 24, 2017) (filed as Exhibit 3.1 to the Registrant's Current Report on Form 8-K (Date of Report: January 23, 2017) filed on January 27, 2017 and incorporated herein by reference).
3.3	Certificate of Elimination of the Series A Junior Participating Preferred Stock of Noble Energy, Inc. (filed as Exhibit 3.1 to the Registrant's Current Report on Form 8-K (Date of Report: July 26, 2016) filed on July 28, 2016 and incorporated herein by reference).
3.4	Certificate of Elimination of the Series B Mandatorily Convertible Preferred Stock of Noble Energy, Inc. (filed as Exhibit 3.2 to the Registrant's Current Report on Form 8-K (Date of Report: July 26, 2016) filed on July 28, 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

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101.PRE	XBRL Presentation Linkbase Document
101.DEF	XBRL Definition Linkbase Document

** 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.