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

FORM 10-Q

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

For the quarterly period ended March 31, 2018

OR

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

For the transition period from _____to_____

Commission file number: 001-07964

NOBLE ENERGY, INC.

(Exact name of registrant as specified in its charter)

Delaware	**73-0785597**
(State or other jurisdiction of incorporation or organization)	(I.R.S. employer identification number)
1001 Noble Energy Way	
Houston, Texas	**77070**
(Address of principal executive offices)	(Zip Code)

(281) 872-3100
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 ☒	Accelerated filer ☐	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐	Emerging growth company ☐

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. ☐

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

As of March 31, 2018, there were 484,440,673 shares of the registrant's common stock, par value $0.01 per share, outstanding.

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Item 1. Financial Statements
Noble Energy, Inc.
Consolidated Statements of Operations and Comprehensive Income
(millions, except per share amounts)
(unaudited)

	Three Months Ended March 31,	
	2018	2017
Revenues		
Oil, NGL and Gas Sales	$ 1,173	$ 994
Income from Equity Method Investees and Other	113	42
Total	1,286	1,036
Costs and Expenses		
Production Expense	321	303
Exploration Expense	35	42
Depreciation, Depletion and Amortization	468	528
Asset Impairments	168	—
Gain on Divestitures	(588)	—
General and Administrative	104	99
Other Operating Expense, Net	70	29
Total	578	1,001
Operating Income	708	35
Other (Income) Expense		
Loss (Gain) on Commodity Derivative Instruments	79	(110)
Interest, Net of Amount Capitalized	73	87
Other Non-Operating Expense (Income), Net	13	(1)
Total	165	(24)
Income Before Income Taxes	543	59
Income Tax (Benefit) Expense	(31)	12
Net Income and Comprehensive Income Including Noncontrolling Interests	574	47
Less: Net Income and Comprehensive Income Attributable to Noncontrolling Interests	20	11
Net Income and Comprehensive Income Attributable to Noble Energy	$ 554	$ 36
Net Income Attributable to Noble Energy per Common Share		
Basic	$ 1.14	$ 0.08
Diluted	$ 1.14	$ 0.08
Weighted Average Number of Common Shares Outstanding		
Basic	487	431
Diluted	488	434

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

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

	March 31, 2018	December 31, 2017
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 992	$ 675
Accounts Receivable, Net	707	748
Other Current Assets	895	780
Total Current Assets	2,594	2,203
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method of Accounting)	27,426	29,678
Property, Plant and Equipment, Other	887	879
Total Property, Plant and Equipment, Gross	28,313	30,557
Accumulated Depreciation, Depletion and Amortization	(10,882)	(13,055)
Total Property, Plant and Equipment, Net	17,431	17,502
Other Noncurrent Assets	1,021	461
Goodwill	1,402	1,310
Total Assets	$ 22,448	$ 21,476
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts Payable – Trade	$ 1,423	$ 1,161
Other Current Liabilities	791	578
Total Current Liabilities	2,214	1,739
Long-Term Debt	6,858	6,746
Deferred Income Taxes	976	1,127
Other Noncurrent Liabilities	1,013	1,245
Total Liabilities	11,061	10,857
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; 528 Million and 529 Million Shares Issued, respectively	5	5
Additional Paid in Capital	8,363	8,438
Accumulated Other Comprehensive Loss	(29)	(30)
Treasury Stock, at Cost; 39 Million Shares	(731)	(725)
Retained Earnings	2,754	2,248
Noble Energy Share of Equity	10,362	9,936
Noncontrolling Interests	1,025	683
Total Equity	11,387	10,619
Total Liabilities and Equity	$ 22,448	$ 21,476

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

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

	Three Months Ended March 31,	
	2018	2017
Cash Flows From Operating Activities		
Net Income Including Noncontrolling Interests	$ 574	$ 47
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities		
Depreciation, Depletion and Amortization	468	528
Asset Impairments	168	—
Deferred Income Tax Benefit	(157)	—
Loss (Gain) on Commodity Derivative Instruments	79	(110)
Net Cash (Paid) Received in Settlement of Commodity Derivative Instruments	(28)	3
Gain on Divestitures	(588)	—
Other Adjustments for Noncash Items Included in Income	(2)	20
Changes in Operating Assets and Liabilities		
Decrease in Accounts Receivable	89	59
(Decrease) Increase in Accounts Payable	(33)	45
Increase (Decrease) in Current Income Taxes Payable	14	(23)
Other Current Assets and Liabilities, Net	(18)	(35)
Other Operating Assets and Liabilities, Net	17	2
Net Cash Provided by Operating Activities	583	536
Cash Flows From Investing Activities		
Additions to Property, Plant and Equipment	(787)	(587)
Acquisitions, Net of Cash Acquired	(650)	(346)
Proceeds from Sale of 7.5% Interest in Tamar Field	487	—
Proceeds from Sale of CONE Gathering LLC	308	—
Proceeds from Divestitures	70	40
Net Cash Used in Investing Activities	(572)	(893)
Cash Flows From Financing Activities		
Dividends Paid, Common Stock	(48)	(44)
Purchase and Retirement of Common Stock	(67)	—
Proceeds from Noble Midstream Services Revolving Credit Facility	405	—
Repayment of Noble Midstream Services Revolving Credit Facility	(55)	—
Contributions from Noncontrolling Interest and Other	333	—
Proceeds from Revolving Credit Facility	245	—
Repayment of Revolving Credit Facility	(475)	—
Other	(40)	(22)
Net Cash Provided by (Used in) by Financing Activities	298	(66)
Increase (Decrease) in Cash, Cash Equivalents, and Restricted Cash	309	(423)
Cash, Cash Equivalents, and Restricted Cash at Beginning of Period	713	1,210
Cash, Cash Equivalents, and Restricted Cash at End of Period	$ 1,022	$ 787

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

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, 2017	$ 5	$ 8,438	$ (30)	$ (725)	$ 2,248	$ 683	$ 10,619
Net Income	—	—	—	—	554	20	574
Stock-based Compensation	—	17	—	—	—	—	17
Dividends (10 cents per share)	—	—	—	—	(48)	—	(48)
Purchase and Retirement of Common Stock	—	(67)	—	—	—	—	(67)
Clayton Williams Energy Acquisition	—	(25)	—	—	—	—	(25)
Distributions to Noncontrolling Interest Owners	—	—	—	—	—	(11)	(11)
Contributions from Noncontrolling Interest Owners	—	—	—	—	—	331	331
Other	—	—	1	(6)	—	2	(3)
March 31, 2018	$ 5	$ 8,363	$ (29)	$ (731)	$ 2,754	$ 1,025	$ 11,387
December 31, 2016	$ 5	$ 6,450	$ (31)	$ (692)	$ 3,556	$ 312	$ 9,600
Net Income	—	—	—	—	36	11	47
Stock-based Compensation	—	13	—	—	—	—	13
Dividends (10 cents per share)	—	—	—	—	(44)	—	(44)
Distributions to Noncontrolling Interest Owners	—	—	—	—	—	(6)	(6)
Other	—	9	—	(11)	1	—	(1)
March 31, 2017	$ 5	$ 6,472	$ (31)	$ (703)	$ 3,549	$ 317	$ 9,609

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 (until April 2018); 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 March 31, 2018 and December 31, 2017 and for the three months ended March 31, 2018 and 2017 contain all normally recurring adjustments considered necessary for a fair presentation of our financial position, results of operations, cash flows and equity for such periods. For the periods presented, activity within other comprehensive income or loss was de minimis; therefore, net income is materially consistent with comprehensive income.

In Note 11. Segment Information, we report a new Midstream segment, established second quarter 2017, and present prior period amounts on a comparable basis. The Midstream segment, which includes the consolidated accounts of Noble Midstream Partners LP (Noble Midstream Partners), a publicly traded consolidated subsidiary and limited partnership, US onshore equity method investments and other US onshore midstream assets, was previously reported within the United States reportable segment. Certain other prior-period amounts have been reclassified to conform to the current period presentation.

Operating results for the three months ended March 31, 2018 are not necessarily indicative of the results that may be expected for the year ending December 31, 2018.

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, 2017.

Consolidation Our consolidated financial statements include our accounts, the accounts of subsidiaries which Noble Energy wholly owns, and the accounts of Noble Midstream Partners, which is considered 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.

Investment in Shares of Tamar Petroleum We account for our investment in shares of Tamar Petroleum Ltd. at fair value and record changes in fair value in other non-operating expense (income), net in our consolidated statements of operations. See Note 3. Acquisitions and Divestitures and Note 6. Fair Value Measurements and Disclosures.

Intangible Assets Intangible assets consist of customer contracts and relationships acquired by Noble Midstream Partners in its acquisition of Saddle Butte Rockies Midstream, LLC and affiliates (collectively, Saddle Butte). We recorded the intangible assets at their estimated fair values at the date of acquisition. Amortization is calculated using the straight-line method, which reflects the pattern in which the estimated economic benefit is expected to be received over the estimated useful life of the intangible asset, which is currently over periods of 7 to 13 years. Amortization expense of $5 million is included in depreciation, depletion and amortization expense in our consolidated statements of operations. Intangible assets with finite useful lives are reviewed for impairment when events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. See Note 3. Acquisitions and Divestitures.

Stock Repurchase Program On February 15, 2018, we announced that the Company's Board of Directors had authorized a $750 million share repurchase program which expires December 31, 2020. All purchases will be made from time to time in open market or private transactions, depending on market conditions, and may be discontinued at any time. During first quarter 2018, we repurchased and retired 2.2 million shares of common stock at an average purchase price of $30.21 per share.

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.

ASC 606, Revenue from Contracts with Customers Our revenue is derived from the sale of crude oil, NGL and natural gas production primarily to crude oil refining companies, midstream marketing companies, marketers, industrial companies, electric utility companies, independent power producers and cogeneration facilities, among others. We account for revenue in accordance with ASC 606, *Revenue from Contracts with Customers* (ASC 606), which we adopted on January 1, 2018 using the modified retrospective method. Under ASC 606, performance obligations are the unit of account and generally represent distinct goods or services that are promised to customers. For sales of crude oil, NGLs and natural gas, each unit sold is generally considered a distinct good and the related performance obligation is generally satisfied at a point in time (i.e., at the time control of the commodity is transferred to the customer at the delivery location specified in the contract).

We recognize our sales revenues at a point in time and upon delivery to a customer at the contractually stated price and for the quantity of product delivered. In Israel, because our contracts are long-term arrangements, we recognize revenues for the sale of natural gas over the life of the contract based on the quantity of natural gas delivered.

ASC 606 provides additional clarification related to principal versus agent considerations. Under this guidance, we record revenue on a gross basis if we control a promised good or service before transferring it to a customer. For example, gathering, processing, transportation and fractionation costs incurred before transfer of control to the customer at the tailgate of a plant are accounted for as fulfillment costs and are presented as a component of gathering, transportation and processing expense in our consolidated statements of operations. On the other hand, we record revenue on a net basis if our role is to arrange for another entity to provide the goods or services. For example, costs incurred after control over the product has transferred to the customer, such as at the wellhead or inlet of a plant, are recorded as a reduction of the transaction price received within revenue.

Certain of our contracts for the sale of commodities contain embedded derivatives. We have elected the normal purchases and normal sales scope exception as provided by ASC 815, *Derivatives and Hedging*, and will account for such contracts in accordance with ASC 606.

In the US, we enter into marketing agreements with our non-operating partners to market and sell their share of production to third parties. We have determined that we act as an agent in such arrangements and account for such arrangements on a net basis.

ASC 606 adoption did not have an impact on the opening balance of retained earnings. The adoption resulted in a de minimis increase of $5 million to our first quarter 2018 revenues and expenses, but did not affect operating or net income or operating cash flows. The comparative information for the prior period has not been recast and continues to be reported under the accounting standards in effect for the period. Adoption of the new standard did not impact our financial position and we do not expect that it will do so going forward.

Changes to the presentation of commodity sales revenue and production expense resulted from our assessment of certain contractual arrangements under principal versus agent guidance and assessment of control under ASC 606. In particular, we have determined that the processor is our customer with regard to the sale of natural gas at the wellhead or the sale of NGLs at the tailgate. This is a change from previous conclusions reached under principal versus agent guidance per ASC 605, *Revenue Recognition*, where we previously retained control over our production until the sale to the end customer in the downstream markets. As such, effective January 1, 2018, revenues and expenses are presented on a net basis within revenues in our consolidated statements of operations at the time control over production is transferred to the processor under these arrangements.

Following the control model in ASC 606, we determined that we remain the principal in arrangements with the end customers, such as when we take product in-kind at the tailgate and when we are directly responsible for the transportation and marketing of our production in the downstream markets. In such arrangements, we record NGL and natural gas sales and production expense on a gross basis.

Our commodity sale contracts in the US are index-based and, thus, include variable consideration. In accordance with ASC 606, we allocate variable consideration (market price) to the distinct commodities transferred in the period, but not to the future obligations to deliver production. Such allocation represents the amount of consideration to which we are entitled for deliveries of our commodities to-date and represents the value of product delivered to the customer. Therefore, our revenue is recognized at the time of delivery and is the product of the volume delivered and the index-based price for the period.

The following is a summary of our types of revenue arrangements by commodity and geographic location.

EXPLORATION AND PRODUCTION (E&P) REVENUE ARRANGEMENTS

Crude Oil Sale Arrangements – US We sell crude oil produced in the US under short-term contracts at market-based prices, adjusted for location, quality and transportation charges. Market-based pricing is based on the price index applicable for the location of the sale.

We sell our crude oil production either at the lease location or in downstream markets. Crude oil production at the lease location is sold through netback arrangements, under which we sell crude oil net of transportation costs incurred by the purchaser. We record revenue, net, at the lease location when the customer obtains delivery of the product.

When we move our crude oil production from the lease location to the downstream markets in the US, we incur gathering and transportation costs, which we consider contract fulfillment activities. Such costs are reported as expense within gathering, transportation and processing expense in the consolidated statements of operations. Revenue from the sale of crude oil in downstream markets is recognized upon delivery, as specified in the contract, when control of the product has transferred to the customer.

Crude Oil Buy/Sell Transactions – US We enter into buy/sell arrangements that effect a change in location and/or grade with required repurchase of crude oil at a delivery point. The sale and repurchase of crude oil is settled at the same contractually fixed price (before application of transportation and grade deductions) on a net basis. We account for these transactions on a net basis, in accordance with ASC 845, *Nonmonetary Transactions*. We record the residual transportation fee as transportation expense within gathering, transportation and processing expense in the consolidated statements of operations.

Crude Oil Sale Arrangements – West Africa Our share of crude oil and condensate from the Aseng, Alen and Alba fields is sold at market-based prices to Glencore Energy UK Ltd (Glencore Energy). Crude oil is priced at a Dated Brent FOB net realized price achieved by Glencore Energy and is adjusted by applicable fees, including transportation, insurance, and marketing. We recognize revenue on the sale of crude oil to Glencore Energy at the time crude oil cargo is loaded onto the tanker and control transfers to Glencore Energy. We record revenue at the realized price received from Glencore Energy, net of applicable fees.

Natural Gas and NGLs Sale Arrangements– US Certain of our commodity contracts in the US are for the sale of natural gas to processors at prevailing market prices. We evaluate the contract terms of these arrangements to determine whether the processor is a service provider or a customer on a contract by contract basis. In arrangements where we determine that we sold our product to the processor, we record revenue when the processor takes physical possession of the natural gas and NGLs and in the amount of proceeds expected to be received, net of any fees or deductions charged by the processor.

In other natural gas processing arrangements, we receive natural gas and NGL products "in-kind" after processing at the tailgate of the plant. In these arrangements, we are responsible for the transportation, fractionation and marketing costs of our production. In such cases, we record the sale of natural gas and NGLs and applicable gathering, processing, transportation and fractionation fees on a gross basis at the time the product is delivered to the end customer.

Natural Gas Purchase and Sale Arrangements – US We enter into purchase transactions and separate sale transactions with third parties at prevailing market prices to mitigate unutilized pipeline transportation commitments, primarily related to retained Marcellus Shale firm transportation agreements. Revenues and expenses from the sales and purchases are recorded on a gross basis, as we act as a principal in these transactions by assuming control of the purchased commodity before it is transferred to the customer.

Natural Gas Sale Arrangements – West Africa We sell our share of natural gas production from the Alba field under a long-term contract for $0.25 per MMBtu to a methanol plant, an LPG plant, an LNG plant and a power generation plant. We recognize revenue upon transfer of control to these processors.

Natural Gas Sale Arrangements – Israel Our natural gas sales in Israel are primarily based on long-term contracts with fixed volume commitments over the life of the arrangements. Our performance obligations for the sale of natural gas are satisfied over time using production output to measure progress. The nature of these contracts gives rise to several types of variable consideration, including index-based annual price escalations, commodity-based index pricing, tiered pricing and sales price discounts in periods of volume deficiencies. Additionally, the majority of our sales contracts contain take-or-pay provisions where the customers are required to purchase a contractual minimum over varying time periods. Where the variable consideration is related to market-based pricing or index-based escalations of a fixed base price, we have elected the variable consideration allocation exception pursuant to ASC 606. We record revenue related to the volumes delivered at the contract price at the time of delivery. To date, there have been no impacts of variability in consideration due to tiered pricing, take-or-pay provisions and/or volume deficiency discounts. We believe that any variability due to future sales price adjustments associated with potential volume deficiencies will not have a significant impact on our financial position or results of operations.

Transaction Price Allocated to Remaining Performance Obligations Remaining performance obligations represent the transaction price of firm sales arrangements for which volumes have not been delivered. Pursuant to ASC 606, short and long-term interruptible contracts, and long-term dedicated production agreements, are excluded from the disclosure due to uncertainty associated with estimating future production volumes and future market prices. However, certain of our natural gas sales contracts in Israel have fixed annual sales volumes and fixed base pricing with annual index escalations. The following table includes estimated revenues based upon those certain agreements with fixed minimum take-or-pay sales volumes. Our actual future sales volumes under these agreements may exceed future minimum volume commitments.

(millions)	April - Dec 2018	2019	2020	Total
Natural Gas Revenues [1]	$ 215	$ 137	$ 169	$ 521

[1] The remaining performance obligations are estimated utilizing the contractual base or floor price provision in effect. Our future revenues from the sale of natural gas under these associated contracts will vary from the amounts presented above due to components of variable consideration above the contractual base or floor provision, such as index-based escalations and market price changes.

MIDSTREAM REVENUE ARRANGEMENTS

Our Midstream segment revenues are derived from fixed fee contract arrangements for gathering, transportation and storage services. We have determined that our performance obligations for the provision of such services are satisfied over time using volumes delivered as the measure of progress. ASC 606 adoption did not have an impact on the recognition, measurement and presentation of our midstream revenues and expenses.

Crude Oil Purchase and Sale Arrangements – US As part of the Saddle Butte acquisition in first quarter 2018, we acquired a pipeline and associated third party contracts which include transactions for the purchase and sale of crude oil with varying counterparties. Revenues and expenses from the sales and purchases are recorded on a gross basis as we act as a principal in these transactions by assuming control of the purchased commodity before it is transferred to the customer. The purchases and sales of crude oil are at the prevailing market prices.

Recently Issued Accounting Standards

Leases In February 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2016-02 (ASU 2016-02): *Leases.* The standard 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. ASU 2016-02 also requires disclosures designed to give financial statement users information on the amount, timing, and uncertainty of cash flows arising from leases. In January 2018, the FASB issued Accounting Standards Update No. 2018-01 (ASU 2018-01): *Land Easement Practical Expedient for Transition to Topic 842*, to provide an optional practical expedient to not evaluate existing or expired land easements that were not previously accounted for as leases under Topic 840. 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. We will adopt the new standard on the effective date of January 1, 2019. At this time, we cannot reasonably estimate the impact the standard will have on our consolidated financial statements; however, we believe adoption and implementation will result in: (i) an increase in assets and liabilities, (ii) an increase in depreciation, depletion and amortization expense, (iii) an increase in interest expense, and (iv) additional disclosures. As part of our assessment to date, we have formed an implementation work team and are continuing contract review and documentation.

Accumulated Other Comprehensive Income In February 2018, the FASB issued Accounting Standards Update No. 2018-02 (ASU 2018-02): *Income Statement – Reporting Comprehensive Income,* to allow reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Tax Cuts and Jobs Act. ASU 2018-02 will be effective for annual and interim periods beginning after December 15, 2018, with earlier application permitted. As of March 31, 2018, we have a disproportionate tax effect of approximately $7 million stranded in accumulated other comprehensive income. We are currently evaluating the provisions of this standard.

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 standard, we will perform our 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.

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 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 standard is effective for fiscal years beginning after December 15, 2019, with early adoption permitted. We are currently evaluating the effect, if any, that the standard will have on our consolidated financial statements and related disclosures.

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

	Three Months Ended March 31,	
(millions)	2018	2017
Income From Equity Method Investees and Other		
Income from Equity Method Investees	$ 47	$ 42
Sales of Purchased Oil and Gas [1]	53	—
Midstream Services Revenues – Third Party	13	—
Total	$ 113	$ 42
Production Expense		
Lease Operating Expense	$ 155	$ 139
Production and Ad Valorem Taxes	54	41
Gathering, Transportation and Processing Expense	95	119
Other Royalty Expense	17	4
Total	$ 321	$ 303
Exploration Expense		
Leasehold Impairment and Amortization	$ —	$ 18
Seismic, Geological and Geophysical	11	5
Staff Expense	14	13
Other	10	6
Total	$ 35	$ 42
Other Operating Expense, Net		
Marketing Expense [2]	$ 5	$ 19
Purchased Oil and Gas [1]	57	—
Other, Net	8	10
Total	$ 70	$ 29
Other Non-Operating Expense (Income), Net		
Loss on Investment in Tamar Petroleum Ltd., Net [3]	$ 15	$ —
Other	(2)	(1)
Total	$ 13	$ (1)

(1) As part of the Midstream Saddle Butte acquisition in first quarter 2018, we acquired certain contracts which include the purchase and sale of crude oil with third parties. In addition, in first quarter 2018, as part of our Marcellus Shale upstream firm transportation mitigation efforts, we entered into certain transactions for the purchase of third party natural gas and the subsequent sale of natural gas to other third parties. The cost to purchase natural gas includes transportation expense incurred of $5 million. See Note 11. Segment Information.

(2) Expense relates to unutilized firm transportation and shortfalls in delivering or transporting minimum volumes under certain commitments.

(3) Amount includes a $29 million loss related to the change in fair value, net of $14 million of dividend income related to our investment in Tamar Petroleum Ltd. shares.

Balance Sheet Information Other balance sheet information is as follows:

(millions)	March 31, 2018	December 31, 2017
Accounts Receivable, Net		
Commodity Sales	$ 413	$ 455
Joint Interest Billings	234	207
Other	77	103
Allowance for Doubtful Accounts	(17)	(17)
Total	$ 707	$ 748
Other Current Assets		
Inventories, Materials and Supplies	$ 43	$ 66
Inventories, Crude Oil	17	16
Assets Held for Sale [1]	751	629
Restricted Cash [2]	30	38
Prepaid Expenses and Other Current Assets [3]	54	31
Total	$ 895	$ 780
Other Noncurrent Assets		
Equity Method Investments [4]	$ 378	$ 305
Customer-Related Intangible Assets [5]	334	—
Investment in Tamar Petroleum Ltd. [6]	162	—
Mutual Fund Investments	56	57
Net Deferred Income Tax Asset	25	25
Other Assets, Noncurrent	66	74
Total	$ 1,021	$ 461
Other Current Liabilities		
Production and Ad Valorem Taxes	$ 93	$ 84
Commodity Derivative Liabilities	112	58
Income Taxes Payable	32	18
Asset Retirement Obligations	51	51
Interest Payable	94	67
Current Portion of Capital Lease Obligations	54	61
Liabilities Associated with Assets Held for Sale [1]	231	55
Other Liabilities, Current	124	184
Total	$ 791	$ 578
Other Noncurrent Liabilities		
Deferred Compensation Liabilities	$ 180	$ 197
Asset Retirement Obligations	577	824
Marcellus Shale Firm Transportation Commitment [7]	73	76
Production and Ad Valorem Taxes	86	69
Other Liabilities, Noncurrent	97	79
Total	$ 1,013	$ 1,245

(1) Assets held for sale at March 31, 2018 include our Gulf of Mexico assets and assets in the Greeley Crescent area of the DJ Basin. Assets held for sale at December 31, 2017 include assets in the Greeley Crescent area of the DJ Basin, a 7.5% interest in the Tamar field, offshore Israel, our interest in Southwest Royalties, Inc. acquired in the Clayton Williams Energy Acquisition, and the CONE investments. Liabilities associated with assets held for sale primarily represent asset retirement obligations and other liabilities to be assumed by the purchaser. See Note 3. Acquisitions and Divestitures.

(2) Balance at March 31, 2018 represents amount held in escrow pending closing of the Gulf of Mexico asset sale. Balance at December 31, 2017 represents amount held in escrow pending closing of the Saddle Butte acquisition. See Note 3. Acquisitions and Divestitures.

(3) Balance at March 31, 2018 includes $14 million of accrued dividends receivable on shares of Tamar Petroleum Ltd.
(4) Includes $72 million for our investment in shares of CNX Midstream Partners LP. At December 31, 2017, this investment was included in assets held for sale. See Note 3. Acquisitions and Divestitures and Note 6. Fair Value Measurements and Disclosures.
(5) Amount relates to intangible assets acquired in the Saddle Butte acquisition. See Note 3. Acquisitions and Divestitures.
(6) Amount relates to our investment in shares of Tamar Petroleum Ltd. See Note 3. Acquisitions and Divestitures and Note 6. Fair Value Measurements and Disclosures.
(7) Amounts relate to the long-term portion of retained firm transportation agreements. At March 31, 2018 and December 31, 2017, we recorded $11 million and $14 million, respectively, associated with the current portion of the Marcellus Shale firm transportation commitment. See Note 12. Commitments and Contingencies.

Reconciliation of Total Cash We define total cash as cash, cash equivalents and restricted cash. The following table provides a reconciliation of total cash:

	Three Months Ended March 31,	
(millions)	2018	2017
Cash and Cash Equivalents at Beginning of Period	$ 675	$ 1,180
Restricted Cash at Beginning of Period	38	30
Cash, Cash Equivalents, and Restricted Cash at Beginning of Period	$ 713	$ 1,210
Cash and Cash Equivalents at End of Period	$ 992	$ 787
Restricted Cash at End of Period	30	—
Cash, Cash Equivalents, and Restricted Cash at End of Period	$ 1,022	$ 787

Note 3. Acquisitions and Divestitures

2018 Asset Transactions

Divestiture of 7.5% Interest in Tamar Field On March 14, 2018, we closed the sale of a 7.5% working interest in the Tamar field to Tamar Petroleum Ltd. (Tamar Petroleum), a publicly traded entity on the Tel Aviv Stock Exchange (TASE: TMRP). Total consideration included cash and 38.5 million shares of Tamar Petroleum that had a market value of $224 million. The transaction had an effective date of January 1, 2018 and after consideration of closing adjustments and before consideration of taxes, we received $487 million of cash. Our shares of Tamar Petroleum are currently subject to certain temporary lock-up provisions and have no voting rights. Upon subsequent sale of the shares to a third party, the voting rights will be restored and granted to the third party. Due to the lock-up provisions associated with the Tamar Petroleum shares, we have attributed $190 million of fair value to the shares, or 15% lower than the trading value. See Note 6. Fair Value Measurements and Disclosures. In connection with the transaction, we incurred tax expense of $90 million. Total consideration received was applied to the field's basis and resulted in the recognition of a pre-tax gain of $386 million.

The sale is in accordance with the terms of the Israel Natural Gas Framework (Framework) that requires us to reduce our ownership interest in the Tamar field from 32.5% to 25% by year-end 2021. We expect to sell the Tamar Petroleum shares before year-end 2021. Proved reserves related to the 7.5% interest totaled approximately 84 MMBoe as of December 31, 2017.

Divestiture of Southwest Royalties In January 2018, we closed the sale of our interest in Southwest Royalties, Inc. (Southwest Royalties), a subsidiary of Clayton Williams Energy, Inc. (Clayton Williams Energy), which we acquired in the acquisition of Clayton Williams Energy (Clayton Williams Energy Acquisition) in 2017. We received proceeds of $60 million, resulting in no gain or loss recognition on the sale of these assets.

Divestiture of Marcellus Shale CONE Gathering In January 2018, we closed the sale of our 50% interest in CONE Gathering LLC (CONE Gathering) to CNX Resources Corporation. CONE Gathering owns the general partner of CNX Midstream Partners LP (CNX Midstream Partners, NYSE: CNXM). We received proceeds of $308 million in cash and recognized a pre-tax gain of $196 million. We currently hold 21.7 million common units representing a 33.5% limited partner interest in CNX Midstream Partners.

Saddle Butte Acquisition On January 31, 2018, Black Diamond Gathering LLC (Black Diamond), an entity formed by Black Diamond Gathering Holdings LLC, a wholly-owned subsidiary of Noble Midstream Partners, and Greenfield Midstream, LLC (Greenfield), completed the acquisition of Saddle Butte Rockies Midstream, LLC and affiliates (collectively Saddle Butte and subsequently renamed Black Diamond) from Saddle Butte Pipeline II, LLC for total consideration of $681 million, which included $663 million of cash and assumption of $18 million of liabilities. Greenfield funded approximately $343 million of the purchase price, which is reflected as a contribution from noncontrolling interest within our consolidated statement of equity, and Noble Midstream Partners funded the remainder. We consolidate Black Diamond and reflect the third-party ownership within noncontrolling interest within our consolidated statement of equity.

We accounted for the transaction as a business combination using the acquisition method. The total purchase price was allocated to assets acquired and liabilities assumed based on the fair value at the acquisition date. We have recognized goodwill for the amount of the purchase price exceeding the fair value of the assets acquired. Allocated fair value included: $206 million to property, plant and equipment; $340 million to customer-related intangible assets (acquired customer contracts); and $111 million to implied goodwill. The purchase price allocation is preliminary as certain data necessary to complete the purchase allocation is not yet available, such as analysis of the 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.

Other Divestitures During first quarter 2018, we also closed the sale of certain other smaller US onshore properties and received total cash consideration of $10 million, recording a de minimis gain of $6 million.

Subsequent Event – Divestiture of Gulf of Mexico Assets On February 15, 2018, we announced that we had signed a definitive agreement to sell our Gulf of Mexico assets, including all of our interests in producing properties and undeveloped acreage, for cash consideration of $480 million, along with the assumption, by the purchaser, of all abandonment obligations associated with the properties. Proved reserves associated with these properties totaled approximately 23 MMBoe as of December 31, 2017.

In April 2018, we completed the initial closing for certain of the assets. The transaction had an effective date of January 1, 2018 and after consideration of customary closing adjustments, we received $404 million of cash.

A subsequent closing for the remainder of the assets is expected to occur mid-year 2018 with no significant financial statement impact.

In addition, a cumulative contingent payment of up to $100 million is payable to us in the period after the closing of the transaction through the end of 2022, determined quarterly, at a rate of $2 per barrel produced by these assets when the average purchase price for Light Louisiana Sweet (LLS) crude oil exceeds $63 per barrel, and if produced crude oil volumes exceed certain minimum amounts.

As of March 31, 2018, the net book value of the Gulf of Mexico assets was $480 million. In addition, we retained certain transaction related obligations approximating $92 million which will be settled at final close. During first quarter 2018, we recorded impairment expense of $168 million associated with these assets held for sale.

2017 Asset Transactions

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

Clayton Williams Energy Acquisition On April 24, 2017, we completed the Clayton Williams Energy Acquisition. The acquisition was effected through the issuance of 56 million shares of Noble Energy common stock, with a fair value of $1.9 billion, and cash consideration of $637 million, for total consideration of $2.5 billion, in exchange for all of the outstanding Clayton Williams Energy shares, including stock options, restricted stock awards and warrants.

The transaction was accounted for as a business combination using the acquisition method. The following table represents the final allocation of the total purchase price of Clayton Williams Energy to the assets acquired and liabilities assumed, based on the fair value 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.

(millions)		
Fair Value of Common Stock Issued	$	1,851
Plus: Cash Consideration Paid to Clayton Williams Energy Stockholders		637
Total Purchase Price	$	2,488
Plus Liabilities Assumed by Noble Energy:		
Accounts Payable		99
Other Current Liabilities		38
Long-Term Deferred Tax Liability		515
Long-Term Debt		595
Asset Retirement Obligations		63
Total Purchase Price Plus Liabilities Assumed	$	3,798

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

(millions)		
Cash and Cash Equivalents	$	21
Other Current Assets		70
Oil and Gas Properties:		
Proved Reserves		722
Undeveloped Leasehold Costs		1,571
Gathering and Processing Assets		48
Asset Retirement Costs		63
Other Noncurrent Assets		12
Implied Goodwill		1,291
Total Asset Value	$	3,798

In connection with the acquisition, we assumed, and then subsequently retired in second quarter 2017, all of Clayton Williams Energy's long-term debt at a cost of $595 million. 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 were 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 expected future cash flows to a single discounted amount. Significant inputs to the valuation of crude oil and natural gas properties included estimates of: (i) proved, possible and probable reserves; (ii) production rates and related development timing; (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 were the most sensitive.

Based upon the final purchase price allocation, we recognized $1.3 billion of goodwill, all of which is assigned to the Texas reporting unit.

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, 2017. The information below 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.

The pro forma results of operations do not include any cost savings or other synergies that we expect to realize 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, 2017; furthermore, the financial information is not intended to be a projection of future results.

	Three Months Ended March 31,	
(millions, except per share amounts)	2018 [1]	2017
Revenues	$ 1,286	$ 933
Net Income and Comprehensive Income Attributable to Noble Energy	554	51
Net Income Attributable to Noble Energy per Common Share		
Basic	$ 1.14	$ 0.10
Diluted	$ 1.14	$ 0.10

[1] No pro forma adjustments were made for the period as Clayton Williams Energy operations are included in our historical results.

Note 4. 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 6. Fair Value Measurements and Disclosures for a discussion of methods and assumptions used to estimate the fair values of our derivative instruments.

Unsettled Commodity Derivative Instruments As of March 31, 2018, the following crude oil derivative contracts were outstanding:

				Swaps		Collars		
Settlement Period	Type of Contract	Index	Bbls Per Day	Weighted Average Differential	Weighted Average Fixed Price	Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
2018	Three-Way Collars	NYMEX WTI	10,000	$ —	$ —	$ 45.50	$ 52.50	$ 69.09
2018	Swaps	NYMEX WTI	58,000	—	59.74	—	—	—
2018	Two-Way Collars	NYMEX WTI	18,000	—	—	—	50.42	58.82
2018	Three-Way Collars	Dated Brent	3,000	—	—	40.00	50.00	70.41
2018	Swaps	ICE Brent	2,000	—	59.00	—	—	—
2018	Two-Way Collars	ICE Brent	2,000	—	—	—	50.00	55.25
2018	Three-Way Collars	ICE Brent	5,000	—	—	43.00	50.00	59.50
2018	Basis Swaps	[1]	12,000	(0.60)	—	—	—	—
2019	Swaps	NYMEX WTI	31,000	—	57.77	—	—	—
2019	Swaps	ICE Brent	5,000	—	57.00	—	—	—
2019	Three-Way Collars	ICE Brent	3,000	—	—	43.00	50.00	64.07
2019	Basis Swaps	[1]	12,000	(1.01)	—	—	—	—
2020	Swaption[2]	NYMEX WTI	5,000	—	61.79	—	—	—

[1] We have entered into crude oil basis swap contracts in order to fix the differential between pricing in Midland, Texas, and Cushing, Oklahoma. The weighted average differential represents the amount of reduction to Cushing, Oklahoma prices for the notional volumes covered by the basis swap contracts.

[2] 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.

As of March 31, 2018, 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
2018	Three-Way Collars	NYMEX HH	120,000	$ —	$ 2.50	$ 2.88	$ 3.65

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

Fair Value of Derivative Instruments

	Asset Derivative Instruments				Liability Derivative Instruments			
	March 31, 2018		December 31, 2017		March 31, 2018		December 31, 2017	
(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	$ 8	Current Assets	$ 2	Current Liabilities	$ 112	Current Liabilities	$ 58
	Noncurrent Assets	2	Noncurrent Assets	—	Noncurrent Liabilities	20	Noncurrent Liabilities	15
Total		$ 10		$ 2		$ 132		$ 73

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

	Three Months Ended March 31,	
(millions)	2018	2017
Cash Paid (Received) in Settlement of Commodity Derivative Instruments		
Crude Oil	$ 30	$ (5)
Natural Gas	(2)	2
Total Cash Paid (Received) in Settlement of Commodity Derivative Instruments	28	(3)
Non-cash Portion of Loss (Gain) on Commodity Derivative Instruments		
Crude Oil	50	(63)
Natural Gas	1	(44)
Total Non-cash Portion of Loss (Gain) on Commodity Derivative Instruments	51	(107)
Loss (Gain) on Commodity Derivative Instruments		
Crude Oil	80	(68)
Natural Gas	(1)	(42)
Total Loss (Gain) on Commodity Derivative Instruments	$ 79	$ (110)

Note 5. Debt

Debt consists of the following:

	March 31, 2018		December 31, 2017	
(millions, except percentages)	Debt	Interest Rate	Debt	Interest Rate
Revolving Credit Facility, due March 9, 2023	$ —	—%	$ 230	2.27%
Noble Midstream Services Revolving Credit Facility, due March 9, 2023	435	2.78%	85	2.49%
Leviathan Term Loan Facility, due February 23, 2025	—	—%	—	—%
Senior Notes, due May 1, 2021 (1)	379	5.63%	379	5.63%
Senior Notes, due December 15, 2021	1,000	4.15%	1,000	4.15%
Senior Notes, due October 15, 2023	100	7.25%	100	7.25%
Senior Notes, due November 15, 2024	650	3.90%	650	3.90%
Senior Notes, due April 1, 2027	250	8.00%	250	8.00%
Senior Notes, due January 15, 2028	600	3.85%	600	3.85%
Senior Notes, due March 1, 2041	850	6.00%	850	6.00%
Senior Notes, due November 15, 2043	1,000	5.25%	1,000	5.25%
Senior Notes, due November 15, 2044	850	5.05%	850	5.05%
Senior Notes, due August 15, 2047	500	4.95%	500	4.95%
Other Senior Notes and Debentures (2)	92	7.13%	92	7.13%
Capital Lease Obligations	257	—%	273	—%
Total	6,963		6,859	
Unamortized Discount	(24)		(24)	
Unamortized Premium	11		12	
Unamortized Debt Issuance Costs	(38)		(40)	
Total Debt, Net of Unamortized Discount, Premium and Debt Issuance Costs	6,912		6,807	
Less Amounts Due Within One Year				
Capital Lease Obligations	(54)		(61)	
Long-Term Debt Due After One Year	$ 6,858		$ 6,746	

(1) In April 2018, we issued an early call for $379 million of senior notes, with expected redemption in May 2018.

(2) Includes $8 million of Senior Notes due June 1, 2024 and $84 million of Senior Debentures due August 1, 2097. The weighted average interest rate for these instruments is 7.13%.

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 and (iii) includes sub-facilities for short-term loans and letters of credit up to an aggregate amount of $500 million under each sub-facility.

During first quarter 2018, we repaid all amounts outstanding under the Revolving Credit Facility. In addition, we extended the maturity date of the Revolving Credit Facility from August 2020 to March 2023.

Noble Midstream Services Revolving Credit Facility Noble Midstream Services, LLC, a subsidiary of Noble Midstream Partners, maintains a 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.

In first quarter 2018, the facility capacity was increased from $350 million to $800 million and the maturity date was extended from September 2021 to March 2023.

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 March 31, 2018, $435 million was outstanding under the Noble Midstream Services Revolving Credit Facility, with the increase since December 31, 2017 primarily used to fund the Saddle Butte acquisition. See Note 3. 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, $625 million of which 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. As of March 31, 2018, there were no borrowings under the Leviathan Term Loan Facility.

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

Annual Debt Maturities Our nearest annual maturity of outstanding debt, excluding capital lease payments and outstanding balances under the revolving credit facilities, is $1.4 billion of senior notes, $1.0 billion of which mature in 2021 and $0.4 billion of which is scheduled to be redeemed in May 2018. The Revolving Credit Facility and Noble Midstream Services Revolving Credit Facility both mature in March 2023. No other balances are due within the next five years.

Note 6. Fair Value Measurements and Disclosures

Assets and Liabilities Measured at Fair Value on a Recurring Basis

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

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

Mutual Fund Investments Our mutual fund investments 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, enhanced swaps and basis 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 4. Derivative Instruments and Hedging Activities.

Investment in Tamar Petroleum Ltd Our investment in shares of Tamar Petroleum was acquired on March 14, 2018. The fair value of these shares is determined at the end of each quarter based on the trading price of Tamar Petroleum shares on the Tel Aviv Stock Exchange and is reduced by a 15% discount. The discount rate is based on analysis of historical discounts realized in private placements of public common stock, which we believe represents a reasonable estimate of the impact of the temporary lock-up provisions applicable to the shares we own. See Note 2. Basis of Presentation and Note 3. Acquisitions and Divestitures.

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
March 31, 2018					
Financial Assets					
Mutual Fund Investments	$ 56	$ —	$ —	$ —	$ 56
Commodity Derivative Instruments	—	29	—	(19)	10
Investment in Tamar Petroleum Ltd.	—	162	—	—	162
Financial Liabilities					
Commodity Derivative Instruments	—	(151)	—	19	(132)
Portion of Deferred Compensation Liability Measured at Fair Value	(70)	—	—	—	(70)
December 31, 2017					
Financial Assets					
Mutual Fund Investments	$ 57	$ —	$ —	$ —	$ 57
Commodity Derivative Instruments	—	7	—	(5)	2
Financial Liabilities					
Commodity Derivative Instruments	—	(78)	—	5	(73)
Portion of Deferred Compensation Liability Measured at Fair Value	(71)	—	—	—	(71)
Stock Based Compensation Liability Measured at Fair Value	(10)	—	—	—	(10)

(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 oil and gas properties, goodwill and other intangibles, are not required to be measured at fair value on a recurring basis. However, these assets are assessed for impairment, and a resulting asset impairment would require the asset be recorded at fair value.

Asset Impairments During first quarter 2018, upon classification of the Gulf of Mexico properties as assets held for sale, we recognized an impairment of $168 million. See Note 3. Acquisitions and Divestitures. For first quarter 2017, we had no adjustments in fair value related to oil and gas properties.

Additional Fair Value Disclosures

Investment in CNX Midstream Partners Our investment in CNX Midstream Partners, which is included in our Midstream reportable segment, is accounted for using the equity method. The fair value of the investment is based on the published market price of the units for the date indicated below.

	March 31, 2018		December 31, 2017	
(millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Investment in CNX Midstream Partners (21,692,198 Units)	$ 72	$ 399	$ 70	$ 364

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 Revolving Credit Facility, the Noble Midstream Services Revolving Credit Facility and the Leviathan Term Loan 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 5. Debt.

Fair value information regarding our debt is as follows:

	March 31, 2018		December 31, 2017	
(millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt [1]	$ 6,706	$ 7,096	$ 6,586	$ 7,142

[1] Excludes unamortized discount, premium, debt issuance costs and capital lease obligations.

Note 7. 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)	Three Months Ended March 31, 2018
Capitalized Exploratory Well Costs, Beginning of Period	$ 520
Additions to Capitalized Exploratory Well Costs Pending Determination of Proved Reserves	3
Reclassified to Assets Held for Sale [1]	(159)
Reclassified to Proved Oil and Gas Properties Based on Determination of Proved Reserves	(1)
Capitalized Exploratory Well Costs, End of Period	$ 363

[1] Represents costs related to Gulf of Mexico assets.

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

(millions)	March 31, 2018	December 31, 2017
Exploratory Well Costs Capitalized for a Period of One Year or Less	$ 3	$ 10
Exploratory Well Costs Capitalized for a Period Greater Than One Year Since Commencement of Drilling	360	510
Balance at End of Period	$ 363	$ 520

Undeveloped Leasehold Costs We reclassify undeveloped leasehold costs to proved property costs when, as a result of exploration and development activities, probable and possible resources are reclassified to proved reserves, including proved undeveloped reserves. On the other hand, if, based upon a change in exploration plans, timing and extent of development activities, availability of capital and suitable rig and drilling equipment, resource potential, comparative economics, changing regulations and/or other factors, an impairment is indicated, we record impairment expense related to the respective leases or licenses.

As of March 31, 2018, we had remaining undeveloped leasehold costs, to which proved reserves had not been attributed, of $2.7 billion, including $1.6 billion related to Delaware Basin assets acquired in the Clayton Williams Energy Acquisition in 2017, and $1.0 billion and $129 million attributable to Delaware Basin and Eagle Ford Shale assets, respectively, acquired in the Rosetta Resources Inc. acquisition in 2015. Undeveloped leasehold costs were derived from allocated fair values as a result of business combinations or other purchases of unproved properties and are subject to impairment testing.

The remaining balance of undeveloped leasehold costs as of March 31, 2018 included $53 million related to international unproved properties. These costs pertain to acquired leases or licenses that are subject to expiration over the next several years unless production is established on units containing the acreage. These costs are evaluated as part of our periodic impairment review.

In first quarter 2018, we transferred $135 million and $20 million of undeveloped leasehold costs to proved properties associated with Delaware Basin and Eagle Ford Shale assets, respectively, acquired in the Rosetta Resources Inc. acquisition. This transfer resulted from additions of proved reserves through development activities. In addition, capitalized costs of $43 million associated with Gulf of Mexico leases and licenses were transferred to assets held for sale during the quarter. See Note 3. Acquisitions and Divestitures.

Note 8. Asset Retirement Obligations

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

	Three Months Ended March 31,	
(millions)	2018	2017
Asset Retirement Obligations, Beginning Balance	$ 875	$ 935
Liabilities Incurred	2	1
Liabilities Settled	(20)	(9)
Revisions of Estimates	(11)	(7)
Reclassification to Liabilities Associated with Assets Held for Sale	(227)	—
Accretion Expense [1]	9	12
Asset Retirement Obligations, Ending Balance	$ 628	$ 932

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

For the Three Months Ended March 31, 2018 In 2018, we transferred $227 million of ARO liabilities related to Gulf of Mexico properties to liabilities associated with assets held for sale. Liabilities settled include $20 million related to abandonment of US onshore properties, primarily in the DJ Basin. Revisions of estimates relate to decreases in cost and timing estimates of $11 million associated with the North Sea abandonment project.

For the Three Months Ended March 31, 2017 Liabilities incurred were due to new wells and facilities placed into service for US onshore. Liabilities settled primarily related to US onshore property abandonments. Revisions of estimates related to changes in Gulf of Mexico cost estimates.

Note 9. Income Taxes

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

	Three Months Ended March 31,	
(millions, except percentages)	2018	2017
Current	$ 126	$ 12
Deferred	(157)	—
Total Income Tax (Benefit) Expense	$ (31)	$ 12
Effective Tax Rate	(5.7)%	20.3%

Recent Changes in US Tax Law On December 22, 2017, the US Congress enacted the Tax Cuts and Jobs Act (Tax Reform Legislation), which made significant changes to US federal income tax law, including a reduction in the federal corporate tax rate to 21%, effective January 1, 2018. In accordance with US GAAP, we recognized the effect of the rate change on deferred tax assets and liabilities as of December 31, 2017.

On April 2, 2018, the US Department of the Treasury and the Internal Revenue Service released Notice 2018-26, signaling intent to issue regulations related to the transition tax (toll tax) on a one-time “deemed repatriation” of accumulated foreign earnings for the year ended December 31, 2017. Notice 2018-26 clarifies that an Internal Revenue Code Section 965(n) election is available with respect to both current year operating losses and net operating losses from a prior year. As a result, during first quarter 2018, we released the valuation allowance recorded against foreign tax credits that will be utilized against the $268 million toll tax liability we had recorded as of December 31, 2017, resulting in a $252 million tax benefit, and reduced our estimated toll tax liability to $16 million to be paid in installments over eight years. We also recorded a corresponding expense of $107 million for the tax rate change adjustment on the previously utilized net operating losses. The impact on first quarter 2018 total tax expense, related to this additional guidance, was a net $145 million discrete tax benefit.

The ultimate impact of the Tax Reform Legislation may differ from our estimates due to changes in interpretations and assumptions made by us, as well as additional regulatory guidance that may be issued. In particular, our estimate of the impact of the toll tax is a provisional amount, based on current legal interpretations. This amount may be adjusted further in future periods, as an adjustment to income tax expense or benefit, in the period in which the final amounts are determined.

Effective Tax Rate (ETR) At the end of each interim period, we apply a forecasted annualized effective tax rate (ETR) to current period earnings or loss before tax, which can result in significant interim ETR fluctuations. Our ETR for the three months ended March 31, 2018 varied as compared with the three months ended March 31, 2017 primarily due to a deferred tax benefit of $145 million recorded discretely in the current year as discussed above. In addition, the increase in the current income tax expense for the three months ended March 31, 2018 is primarily due to foreign taxes on a gain associated with the first quarter 2018 divestiture of a 7.5% interest in the Tamar field, offshore Israel.

In our major tax jurisdictions, the earliest years remaining open to examination are as follows: US – 2014, Israel – 2015 and Equatorial Guinea – 2012.

Note 10. Income Per Share Attributable to Noble Energy

Noble Energy's basic income per share of common stock is computed by dividing net income attributable to Noble Energy by the weighted average number of shares of Noble Energy common stock outstanding during each period. The following table summarizes the calculation of basic and diluted income per share:

	Three Months Ended March 31,	
(millions, except per share amounts)	2018	2017
Net Income and Comprehensive Income Attributable to Noble Energy	$ 554	$ 36
Weighted Average Number of Shares Outstanding, Basic	487	431
Incremental Shares from Assumed Conversion of Dilutive Stock Options, Restricted Stock, and Shares of Common Stock in Rabbi Trust	1	3
Weighted Average Number of Shares Outstanding, Diluted	488	434
Income Per Share, Basic	$ 1.14	$ 0.08
Income Per Share, Diluted	1.14	0.08
Number of Antidilutive Stock Options, Shares of Restricted Stock, and Shares of Common Stock in Rabbi Trust Excluded from Calculation Above	16	14

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, US onshore equity method investments and other US onshore midstream assets, was previously reported within the United States reportable segment. As a result, as of June 30, 2017, we have the following 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 acquisition and exploration, development, and production (Oil and Gas Exploration and Production). The Midstream reportable segment owns, acquires, operates, and develops domestic midstream infrastructure assets, with current focus areas being the DJ and Delaware Basins. Expenses related to debt, headquarters depreciation and corporate general and administrative expenses are recorded at the corporate level. Prior period amounts are presented on a comparable basis.

		Oil and Gas Exploration and Production				Midstream		
(millions)	Consolidated	United States	Eastern Mediter-ranean	West Africa	Other Int'l	United States	Intersegment Eliminations and Other [1]	Corporate
Three Months Ended March 31, 2018								
Crude Oil Sales	$ 773	$ 682	$ 2	$ 89	$ —	$ —	$ —	$ —
NGL Sales	146	146	—	—	—	—	—	—
Natural Gas Sales	254	120	129	5	—	—	—	—
Total Crude Oil, NGL and Natural Gas Sales	1,173	948	131	94	—	—	—	—
Income from Equity Method Investees and Other	60	—	—	35	—	25	—	—
Intersegment Revenues	—	—	—	—	—	81	(81)	—
Sales of Purchased Oil and Gas	53	31	—	—	—	22	—	—
Total Revenues	1,286	979	131	129	—	128	(81)	—
Lease Operating Expense	155	126	7	22	—	—	—	—
Production and Ad Valorem Taxes	54	53	—	—	—	1	—	—
Gathering, Transportation and Processing Expense	95	128	—	—	—	20	(53)	—
Other Royalty Expense	17	17	—	—	—	—	—	—
Total Production Expense	321	324	7	22	—	21	(53)	—
DD&A	468	404	13	26	—	17	(3)	11
Asset Impairments	168	168	—	—	—	—	—	—
Gain on Divestitures	(588)	(6)	(386)	—	—	(196)	— —	—
Purchased Oil and Gas	57	36	—	—	—	21	—	—
Loss on Commodity Derivative Instruments	79	64	—	15	—	—	—	—
Income (Loss) Before Income Taxes	543	(43)	473	64	(9)	247	(15)	(174)
Three Months Ended March 31, 2017								
Crude Oil Sales	$ 527	$ 439	$ 1	$ 87	$ —	$ —	$ —	$ —
NGL Sales	105	105	—	—	—	—	—	—
Natural Gas Sales	362	226	130	6	—	—	—	—
Total Crude Oil, NGL and Natural Gas Sales	994	770	131	93	—	—	—	—
Income from Equity Method Investees and Other	42	—	—	28	—	14	—	—
Intersegment Revenues	—	—	—	—	—	58	(58)	—
Total Revenues	1,036	770	131	121	—	72	(58)	—

Lease Operating Expense	139	108	8	23	—	—	—	—
Production and Ad Valorem Taxes	41	40	—	—	—	1	—	—
Gathering, Transportation and Processing Expense	119	142	—	—	—	15	(38)	—
Other Royalty Expense	4	4	—	—	—	—	—	—
Total Production Expense	303	294	8	23	—	16	(38)	—
DD&A	528	459	19	34	1	5	—	10
Gain on Commodity Derivative Instruments	(110)	(102)	—	(8)	—	—	—	—
Income (Loss) Before Income Taxes	59	62	101	66	(21)	49	(22)	(176)
March 31, 2018								
Goodwill [2]	$ 1,402	$ 1,291	$ —	$ —	$ —	$ 111	$ —	$ —
Total Assets	22,448	15,622	3,263	1,306	85	2,141	(217)	248
December 31, 2017								
Goodwill [2]	1,310	1,310	—	—	—	—	—	—
Total Assets	21,476	15,767	2,846	1,308	114	1,357	(163)	247

[1] The intersegment eliminations related to income (loss) 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.
[2] Goodwill in the United States reportable segment is associated with our Texas reporting unit. Goodwill in the Midstream segment is associated with the Saddle Butte acquisition.

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 2017 Marcellus Shale upstream divestiture, we retained certain firm transportation obligations to flow Marcellus Shale natural gas production to various markets inside and outside of the Marcellus Basin. Our financial commitment for these agreements, which have remaining terms of two to 16 years, is approximately $1.4 billion, undiscounted. The agreements for firm transportation primarily relate to services on certain pipelines which were placed into service in late 2017/early 2018 or for services on new pipeline projects to be constructed by, and connecting to, existing and new interstate pipeline systems, with estimated in-service dates in late 2018.

We are currently engaged in actions to commercialize and address these remaining commitments, which provide for the transportation of approximately 450,000 MMBtu/d of natural gas. Actions include the permanent assignment of capacity, negotiation of capacity release, utilization of capacity through purchase of third party natural gas, and other potential arrangements. We expect these actions, some of which may require pipeline and/or FERC approval, to ultimately reduce our 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.

We cannot guarantee our commercialization 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. As of March 31, 2018, our exit cost accrual, relating to certain transportation arrangements, totals $84 million, discounted. For first quarter 2018, we incurred expense of $2 million related to unutilized commitments related to these contracts.

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 US District Court for the District of Colorado 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 $5.0 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. Since 2015, we have incurred approximately $82 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 Oil and Gas Conservation Commission Administrative Order on Consent In November 2017, we received a proposed Administrative Order on Consent (AOC) from the Colorado Oil and Gas conservation Commission (COGCC) to resolve allegations of noncompliance associated with site preparation and stabilization at an oil and gas location in Weld County, Colorado. The AOC, which provides for an opportunity to further discuss the offer of settlement, has not yet been executed. 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.

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;
- Results of Operations - Corporate; and
- Liquidity and Capital Resources.

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

EXECUTIVE OVERVIEW

The following discussion highlights significant operating and financial results for first quarter 2018. This discussion should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2017, which includes disclosures regarding our critical accounting policies as part of "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Recent Achievements

Since 2015, we have strategically repositioned our portfolio to focus future efforts primarily in US onshore plays, including the DJ and Delaware Basins and Eagle Ford Shale, and on our international offshore assets in the Eastern Mediterranean and West Africa. The focus of our capital programs in these areas is expected to positively impact our future cash flows and margins. Going forward, we are concentrating our exploration capabilities on higher-impact opportunities that can drive substantial long-term value creation.

During first quarter 2018, we continued to enhance and increase our US onshore drilling and completions activities and advanced our Eastern Mediterranean regional natural gas developments. Financially, we strengthened our strong balance sheet and liquidity position.

Recent achievements include the following:

Gulf of Mexico Asset Sale On February 15, 2018, we announced that we had signed a definitive agreement to sell our Gulf of Mexico assets, including our interests in six producing fields and all undeveloped leases. In April 2018, we completed the initial closing for certain of the assets, and received cash consideration of $404 million, net of customary price adjustments. We expect the final closing for the remainder of the assets to occur in mid-2018. We recognized impairment expense of $168 million during first quarter 2018 related to our estimate of the excess of the net book value of the assets over the expected proceeds. See Item 1. Financial Statements – Note 3. Acquisitions and Divestitures.

Divestiture of 7.5% Interest in Tamar Field On March 14, 2018, we closed the sale of a 7.5% working interest in the Tamar field, offshore Israel, to Tamar Petroleum Ltd. (Tamar Petroleum) for cash proceeds of approximately $487 million, after consideration of price adjustments and before consideration of taxes, and 38.5 million shares of Tamar Petroleum, and we recognized a pre-tax gain of $386 million. This sale follows an initial divestment of 3.5% of our working interest in the Tamar field in mid-2016. Cash proceeds from the transaction will be utilized to support the capital investment in our Leviathan development. See Item 1. Financial Statements – Note 3. Acquisitions and Divestitures.

GSPAs for Israeli Export On February 19, 2018, we executed two independent gas sale and purchase agreements (GSPAs) for the sale of natural gas from the Leviathan and Tamar fields to Dolphinus Holdings Limited to supply natural gas in Egypt. Sales volumes under the GSPA associated with the Leviathan field are anticipated to begin at a firm rate of approximately 350 MMcf/d, gross, (approximately 121 MMcf/d, net) at the startup of the Leviathan project, currently anticipated at the end of 2019. For the Tamar agreement, sales volumes are anticipated to begin at an interruptible rate of up to 350 MMcf/d, gross, (approximately 77 MMcf/d, net) dependent upon gas availability beyond existing customer obligations in Israel and Jordan. The GSPA includes an option to convert the Tamar interruptible quantity to a firm-basis with a take or pay commitment. Both contracts are for a 10-year term and have pricing terms indexed to Brent crude oil, similar to other export contracts in the region. The GSPAs are subject to satisfaction of conditions precedent, including regulatory approvals and licenses, and finalizing natural gas transportation agreements.

Share Repurchase Program On February 15, 2018, we announced that our Board of Directors had authorized a share repurchase program of $750 million to enhance and accelerate value return to our shareholders. During first quarter 2018, we purchased and retired 2.2 million shares of common stock for total consideration of $67 million.

CONE Gathering Sale In January 2018, we closed the sale of our 50% interest in CONE Gathering, LLC (CONE Gathering), which owns the general partner of CONE Midstream Partners LP (CONE Midstream), receiving cash proceeds of approximately $308 million and recognizing a gain of $196 million. See Item 1. Financial Statements – Note 3. Acquisitions and Divestitures.

Saddle Butte Pipeline Acquisition On January 31, 2018, Noble Midstream Partners, through its affiliate, Black Diamond Gathering LLC, closed the acquisition of Saddle Butte Rockies Midstream LLC and affiliates (collectively Saddle Butte and subsequently renamed Black Diamond) for $681 million. The acquisition includes a large-scale integrated crude oil gathering system in the DJ Basin, consisting of approximately 160 miles of pipeline in operation and 300 MBbls per day of delivery capacity. See Item 1. Financial Statements – Note 3. Acquisitions and Divestitures.

Sales Volumes We delivered quarterly sales volumes of 370 MBoe/d with approximately 56% of our production mix attributable to crude oil and NGLs. Reported volumes reflect the impact of adoption of ASC 606, *Revenue from Contracts with Customers* (ASC 606). See Exploration and Production (E&P) – Results of Operations.

Financial Flexibility, Liquidity and Balance Sheet Strength As we progress through the remainder of 2018, 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 2018 capital investment program is responsive to positive or negative commodity price conditions that may develop. See Operating Outlook – 2018 Capital Investment Program.

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.

First Quarter Changes in Tax Estimates

The US Department of the Treasury and the Internal Revenue Service recently signaled their intent to issue regulations related to the transition tax (toll tax) on a one-time "deemed repatriation" of accumulated foreign earnings. Our tax benefit for first quarter 2018 reflects a net $145 million discrete tax benefit recorded in response to this new guidance. See Item 1. Financial Statements – Note 9. Income Taxes.

Adoption of ASC 606

As of January 1, 2018, we adopted ASC 606*,* using the modified retrospective method. ASC 606 adoption did not have an impact on the opening balance of retained earnings, and, for the current period, resulted in a de minimis increase of $5 million to both revenues and expenses, but did not affect operating or net income or operating cash flows. Comparative information for the prior period has not been recast and continues to be reported under the accounting standards in effect for that period. Adoption of the new standard did not impact our financial position and we do not expect that it will going forward. See Exploration and Production (E&P) – Results of Operations.

Recently Issued Accounting Standards

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

OPERATING OUTLOOK

2018 Production Our expected crude oil, natural gas and NGL sales for the remainder of 2018 may be impacted by several factors including:

- commodity prices which, if subject to a significant decline, could result in certain existing 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;
- increased drilling activity in the basins in which we operate, which may cause US onshore cost inflation pressure and 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 crude oil and condensate liftings impacting sales volumes in West Africa;

- natural field decline in the US onshore and offshore Equatorial Guinea;
- additional purchases of producing properties or divestments of operating assets;
- potential weather-related volume curtailments due to winter storms and flooding impacting US onshore operations;
- availability or reliability of supplier services, including access to support equipment and facilities, potential processing facility capacity constraints, and/or occurrence of pipeline disruptions, which may cause delays, restrictions or interruptions in production and/or midstream processing;
- access to transportation and takeaway pipelines for increasing US onshore production volumes, such as in the Delaware Basin, which may cause infield bottlenecks and/or widening of location-basis differentials;
- malfunctions and/or mechanical failures at terminals or other US onshore delivery points;
- impact of enhanced completion efforts for US onshore assets;
- potential growth from participation in future, or decline from existing, non-operated wells;
- abandonment of low-margin US onshore wells;
- shut-in of US producing properties if storage capacity becomes unavailable; and
- potential drilling and/or completion permit delays due to future regulatory changes.

2018 Capital Investment Program Our 2018 capital investment program is designed to deliver near and long-term value and is flexible in the current commodity price environment. Excluding capital funded by Noble Midstream Partners, our preliminary 2018 program accommodates an investment level of approximately $2.7 to $2.9 billion, with approximately 95% being allocated to US onshore development, associated midstream infrastructure and the Eastern Mediterranean. The remaining portion of our 2018 capital program is designated for other activities, including exploration for lease acquisition, seismic and other geological analysis in support of future exploration prospects, as well as other corporate activities.

We will evaluate the level of capital spending throughout the year based on the following factors, among others, and their effect on project financial returns:

- commodity prices, including price realizations on specific crude oil, natural gas and NGL production;
- operating and development costs;
- production, drilling and delivery commitments, or other contractual obligations;
- drilling results;
- property acquisitions and divestitures;
- exploration activity;
- cash flows from operations, including cash flows from potential midstream drop-down transactions;
- indebtedness levels;
- availability of financing or other sources of funding;
- impact of new laws and regulations on our business practices, including potential legislative or regulatory changes regarding the use of hydraulic fracturing; and
- potential changes in the fiscal regimes of the US and other countries in which we operate.

See Liquidity and Capital Resources – Financing Activities.

Impact of Recent Changes in US Tax Law On December 22, 2017, the US Congress enacted the Tax Cuts and Jobs Act (Tax Reform Legislation), making significant changes to US federal income tax law beginning in 2018. While we believe that certain aspects of the new law will positively impact our future after-tax earnings, primarily due to the lower federal statutory tax rate, the ultimate impact of the Tax Reform Legislation may differ from our estimates due to changes in interpretations and assumptions made by us as well as additional regulatory guidance that may be issued. See Item 1. Financial Statements – Note 9. Income Taxes.

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. First quarter 2018 activities included the following:

DJ Basin (US Onshore) Our activities during first quarter 2018 were focused primarily in the Wells Ranch and East Pony Integrated Development Plan (IDP) areas. During the quarter, we operated an average of one drilling rig, completed 18 wells and commenced production on 31 wells. Average sales volumes during first quarter 2018 were 120 MBoe/d, including 9 MBoe/d due to ASC 606 adoption. In late first quarter 2018, we expanded completion activities into the Mustang IDP area, where we have a large contiguous acreage position. Our development plan in this area includes applying multiple techniques from our other successful US onshore plays, including utilizing row development concepts, enhanced completion designs, capital efficient facility designs, and other techniques to optimize project returns.

Delaware Basin (US Onshore) During first quarter 2018, we operated an average of six drilling rigs, completed 18 wells and commenced production on 13 wells, with the majority of our activity focused on long laterals and multi-well pads targeting multiple zones within the basin. We averaged 45 MBoe/d of sales volumes during first quarter 2018, with 69% of our production mix attributable to crude oil. In late March 2018, we commissioned our third central gathering facility in the Delaware Basin, the first facility in our southern acreage. We expect to commence operations at two additional central gathering facilities by the end of the second quarter 2018.

Eagle Ford Shale (US Onshore) Our activity in South Texas, specifically in Webb and Dimmit Counties, during first quarter 2018 primarily focused on well completion activities for five previously drilled wells within the Upper and Lower Eagle Ford formation zones along with continuing drilling activities within the northern area of Gates Ranch. We continue to execute our development plan and averaged sales volumes of 81 MBoe/d during first quarter 2018.

Tamar Natural Gas Project (Offshore Israel) In first quarter 2018, sales volumes averaged 263 MMcfe/d, net, and on a gross basis, sales volumes reached a cumulative milestone delivering 1.5 Tcf of natural gas to-date. On March 14, 2018, we closed the sale of a 7.5% working interest in the Tamar field to Tamar Petroleum for cash proceeds of approximately $487 million, after consideration of price adjustments and before consideration of taxes, and 38.5 million shares of Tamar Petroleum. The sale, which is effective as of January 1, 2018, is in accordance with the terms of the Israel Natural Gas Framework (Framework) that requires us to reduce our ownership interest in the Tamar field from 32.5% to 25% by year-end 2021. See Item 1. Financial Statements – Note 3. Acquisitions and Divestitures and Note 6. Fair Value Measurements and Disclosures.

Leviathan Natural Gas Project (Offshore Israel) 2018 represents the peak year for the initial phase of Leviathan development. During first quarter 2018, we progressed construction of the production platform, installed critical infield flowlines and progressed gathering lines. The project remains on budget and on schedule, with approximately 45% complete. First gas sales are anticipated by the end of 2019.

Unsanctioned Development Projects

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 capital cost improvements, as well as 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 and progress negotiations. 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 attractive financial returns.

Exploration Program Update

We continue to seek and evaluate significant onshore and/or offshore opportunities for future exploration. 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 7. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs.

Results of Operations

Highlights for our E&P business were as follows:

First Quarter 2018 Significant E&P Operating Highlights Included:

- total average daily sales volumes of 370 MBoe/d;
- average daily sales volumes for US onshore crude oil of 103 MBbl/d; and
- average daily sales volumes of 263 MMcfe/d, net, in Israel, and a first quarter record for average daily gross sales volumes of 959 MMcfe/d, primarily from the Tamar field.

First Quarter 2018 E&P Financial Results Included:

- $386 million pre-tax gain on sale of a 7.5% interest in the Tamar field;
- $168 million impairment expense related to Gulf of Mexico assets held for sale;
- pre-tax income of $485 million, as compared with pre-tax income of $208 million for first quarter 2017; and
- capital expenditures of $667 million, excluding acquisitions, as compared with $598 million for first quarter 2017.

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

	Three Months Ended March 31,	
(millions)	2018	2017
Oil, NGL and Gas Sales to Third Parties [1]	$ 1,173	$ 994
Sales of Purchased Gas [2]	31	—
Income from Equity Method Investees	35	28
Total Revenues	1,239	1,022
Production Expense [1]	353	325
Exploration Expense	35	42
Depreciation, Depletion and Amortization	443	513
Purchases of Gas [2]	36	—
Gain on Divestitures [3]	(392)	—
Asset Impairments [3]	168	—
Loss (Gain) on Commodity Derivative Instruments	79	(110)
Income Before Income Taxes	485	208

(1) On January 1, 2018, we adopted ASC 606. As a result of adoption, we changed the presentation of certain US midstream processing arrangements as related to net and gross presentation of revenues and expenses. This presentation change resulted in an increase of $5 million to our NGL revenues with a corresponding increase of $5 million to production expense. See Item 1. Financial Statements – Note 2. Basis of Presentation.

(2) In first quarter 2018, as part of our Marcellus Shale firm transportation mitigation efforts, we entered into certain transactions for the purchase of third party natural gas and the subsequent sale of natural gas to other third parties.

(3) See Item 1. Financial Statements - Note 3. Acquisitions and Divestitures.

Oil, NGL and Gas Sales

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

	Sales Volumes [1]				Average Realized Sales Prices [1]		
	Crude Oil & Condensate (MBbl/d)	NGLs (MBbl/d)	Natural Gas (MMcf/d)	Total (MBoe/d) [2]	Crude Oil & Condensate (Per Bbl)	NGLs (Per Bbl)	Natural Gas (Per Mcf)
Three Months Ended March 31, 2018							
United States [3]	122	64	504	270	$ 61.95	$ 25.53	$ 2.63
Eastern Mediterranean	—	—	261	44	—	—	5.48
West Africa [4]	15	—	206	49	68.14	—	0.27
Total Consolidated Operations	137	64	971	363	62.60	25.53	2.90
Equity Investees [5]	2	5	—	7	66.08	39.90	—
Total	139	69	971	370	$ 62.64	$ 26.62	$ 2.90
Three Months Ended March 31, 2017							
United States	99	49	730	270	$ 49.03	$ 23.97	$ 3.44
Eastern Mediterranean	—	—	271	46	—	—	5.32
West Africa [4]	18	—	244	58	53.42	—	0.27
Total Consolidated Operations	117	49	1,245	374	49.70	23.97	3.23
Equity Investees [5]	2	6	—	8	52.59	36.04	—
Total	119	55	1,245	382	$ 49.73	$ 25.34	$ 3.23

(1) On January 1, 2018, we adopted ASC 606. As a result of adoption, we changed the presentation of certain US midstream processing arrangements as related to net and gross presentation of revenues and expenses. This presentation change resulted in an increase of $5 million to our NGL revenues with a corresponding increase of $5 million to production expense. Furthermore, we recorded additional NGL and natural gas sales volumes of 4 MBbl/d and 31 MMcf/d, respectively, due to ASC 606 adoption. The resulting impact reduced our average realized NGL and natural gas sales prices by $0.87/Bbl and $0.10/Mcf, respectively. See Item 1. Financial Statements – Note 2. Basis of Presentation.

(2) 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 prices 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.

(3) Includes 24 MBoe/d related to the Gulf of Mexico assets, which were sold in April 2018.

(4) 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.

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

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

	Sales Revenues			
(millions)	Crude Oil & Condensate	NGLs	Natural Gas	Total
Three Months Ended March 31, 2017	$ 527	$ 105	$ 362	$ 994
Changes due to				
Increase (Decrease) in Sales Volumes	94	15	(84)	25
Increase (Decrease) in Sales Prices	152	21	(24)	149
Impact of ASC 606 Adoption	—	5	—	5
Three Months Ended March 31, 2018	$ 773	$ 146	$ 254	$ 1,173

Crude Oil and Condensate Sales Revenues Revenues from crude oil and condensate sales increased first quarter 2018 as compared with 2017 due to the following:

- 26% increase in average realized prices due to the partial rebalancing of global supply and demand factors; and
- higher US onshore sales volumes of 28 MBbl/d, primarily driven by an increase in development activity in the DJ Basin and Delaware Basin. Delaware Basin sales volumes more than doubled compared to first quarter 2017 due to increased development activities and sales volumes from the acquired Clayton Williams Energy assets in second quarter 2017;

partially offset by:

- lower sales volumes of 5 MBbl/d in the Gulf of Mexico due to natural field decline; and
- lower sales volumes of 4 MBbl/d offshore West Africa due to timing of liftings.

NGL Sales Revenues Revenues from NGL sales increased first quarter 2018 as compared with 2017 due to the following:

- higher US onshore sales volumes of 11 MBbl/d (exclusive of 4 MBbl/d from adoption of ASC 606), primarily attributable to development activities in the southern area of Gates Ranch in the Eagle Ford Shale;
- 10% increase in average realized prices due to the partial rebalancing of domestic supply and demand factors; and
- $5 million increase associated with the adoption of ASC 606;

partially offset by:

- lower sales volumes of 10 MBbl/d due to the divestiture of the Marcellus Shale upstream assets in second quarter 2017.

Natural Gas Sales Revenues Revenues from natural gas sales decreased first quarter 2018 as compared with 2017 due to the following:

- lower sales volumes of 370 MMcf/d due to the divestiture of the Marcellus Shale upstream assets in second quarter 2017; and
- lower sales volumes of 38 MMcf/d from the Alba field, offshore Equatorial Guinea, due to natural field decline;
- 7% decrease in average realized prices due to the impact of differentials for US onshore sales volumes;

partially offset by:

- higher US onshore sales volumes of 124 MMcf/d (exclusive of 31 MMcf/d from adoption of ASC 606), primarily attributable to development activities in the southern area of Gates Ranch in the Eagle Ford Shale.

Sales of Purchased Gas, Net Beginning in first quarter 2018, we entered into purchase transactions and separate sale transactions with third parties at prevailing market prices to mitigate unutilized pipeline transportation commitments, primarily related to retained Marcellus Shale natural gas firm transportation agreements. Revenues and expenses from the sales and purchases are recorded on a gross basis, as we act as a principal in these transactions by assuming control of the purchased commodity before it is transferred to the customer. Transportation costs incurred related to utilization of the retained Marcellus Shale firm transportation agreements are recorded within purchases of gas in our consolidated statements of operations. For first quarter 2018, the net effect of third party purchases and sales of natural gas was a loss of $5 million.

Income from Equity Method Investees 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 three months of 2018 as compared with 2017. The increase includes a $3 million increase from Atlantic Methanol Production Company, LLC (AMPCO), our methanol investee, and a $4 million increase from Alba Plant, our LPG investee, both primarily driven by rising commodity prices.

Production Expense Components of production expense from our upstream operations were as follows:

(millions, except unit rate)		Total per BOE (1) (2)		Total		United States (2)		Eastern Mediter- ranean		West Africa
Three Months Ended March 31, 2018										
Lease Operating Expense (3)	$	4.75	$	155	$	126	$	7	$	22
Production and Ad Valorem Taxes		1.62		53		53		—		—
Gathering, Transportation and Processing (4)		3.92		128		128		—		—
Other Royalty Expense		N/M		17		17		—		—
Total Production Expense	$	10.29	$	353	$	324	$	7	$	22
Total Production Expense per BOE			$	10.29	$	13.31	$	1.79	$	5.01
Three Months Ended March 31, 2017										
Lease Operating Expense (3)	$	4.13	$	139	$	108	$	8	$	23
Production and Ad Valorem Taxes		1.19		40		40		—		—
Gathering, Transportation and Processing (4)		4.22		142		142		—		—
Other Royalty Expense		N/M		4		4		—		—
Total Production Expense	$	9.54	$	325	$	294	$	8	$	23
Total Production Expense per BOE			$	9.54	$	12.11	$	1.95	$	4.36

N/M - Amount is not meaningful.

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

(2) United States E&P production expense includes charges from our midstream operations that are eliminated on a consolidated basis. See Item 1. Financial Statements – Note 11. Segment Information.

(3) Lease operating expense includes oil and gas operating costs (labor, fuel, repairs, replacements, saltwater disposal and other related lifting costs) and workover expense.

(4) Upon adoption of ASC 606 on January 1, 2018, we changed the presentation for certain of our gathering, transportation and processing expenses in accordance with the control model under the new standard. As such, we reflected an increase of $5 million to gathering, transportation and processing expense related to US operations for first quarter 2018. On a per BOE basis, the presentation change resulted in a decrease of $0.25/Boe for US production expense and $0.12/Boe for total production expense. No other geographical locations were affected by the presentation change. Comparative information for the prior period has not been recast and continues to be reported under ASC 605, *Revenue Recognition*, the accounting standard in effect for the prior period.

For first quarter 2018, total production expense increased as compared with 2017 due to the following:

- an increase in US lease operating expense primarily due to increased development activities in the Delaware Basin;
- an increase in US production and ad valorem taxes due to higher commodity prices;
- an increase in US gathering, transportation and processing expense primarily attributable to development activities in the southern area of Gates Ranch in the Eagle Ford Shale which led to increased sales volumes; and
- an increase in US other royalty expense due to increased commodity market prices;

partially offset by:

- a decrease in US lease operating expense in the Gulf of Mexico due to lower production caused by natural field decline; and
- decreases in US lease operating and gathering, transportation and processing expenses due to the divestiture of the Marcellus Shale upstream assets in second quarter 2017.

Production expense on a per BOE basis increased for the three months ended March 31, 2018 as compared with 2017 primarily due to the decrease in total sales volumes driven by the divestiture of the Marcellus Shale upstream assets in second quarter 2017, coupled with an increase in certain production expenses noted above. Specifically, the divestiture of the Marcellus Shale upstream assets removed lower-cost, natural gas-focused sales volumes from our portfolio, while an increase in volumes from the Delaware Basin and Eagle Ford Shale contributed higher-cost, crude oil-focused sales volumes, thereby increasing our average production expense per BOE.

Exploration Expense Exploration expense for the first three months of 2018 totaled $35 million, including $13 million of lease rental expense primarily in the Delaware Basin and $22 million of staff expense and other.

Exploration expense for the first three months of 2017 totaled $42 million, including $18 million of undeveloped leasehold impairment expense related to the impairment of leases in deepwater Gulf of Mexico and $24 million of staff expense and other.

Depreciation, Depletion and Amortization DD&A expense for our upstream operations was as follows:

(millions, except unit rate)	Total	United States	Eastern Mediter- ranean	West Africa	Other Int'l
Three Months Ended March 31, 2018					
DD&A Expense	$ 443	$ 404	$ 13	$ 26	$ —
Unit Rate per BOE [1]	$ 13.57	$ 16.60	$ 3.32	$ 5.92	N/M
Three Months Ended March 31, 2017					
DD&A Expense	$ 513	$ 459	$ 19	$ 34	$ 1
Unit Rate per BOE [1]	$ 15.24	$ 18.90	$ 4.63	$ 6.44	N/M

N/M - Amount is not meaningful.

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

Total DD&A expense for first quarter 2018 decreased as compared with 2017 due to the following:

- year-end reserve additions, primarily in US onshore due to enhanced well design and completion techniques in our horizontal drilling program and globally due to positive price revisions;
- Marcellus Shale upstream divestiture in second quarter 2017, which reduced DD&A expense by $73 million;
- lower sales volumes in Gulf of Mexico due to natural field decline and classification of the assets as held for sale in first quarter 2018, which reduced DD&A expense by $47 million; and
- reclassification of a 7.5% working interest in the Tamar field, offshore Israel, as asset held for sale, resulting in the cessation of DD&A expense and a decrease of approximately $5 million;

partially offset by:

- higher sales volumes in the Delaware Basin, which more than doubled, due to increased development activities subsequent to the Clayton Williams Energy Acquisition in second quarter 2017;
- increased development activities in the southern area of Gates Ranch in the Eagle Ford Shale; and
- higher sales volumes from the Tamar field, offshore Israel, due to higher domestic demand.

The unit rate per BOE for first quarter 2018, as compared with 2017, decreased due to the divestiture of natural gas-focused sales volumes from Marcellus Shale upstream assets in 2017, the cessation of DD&A on Gulf of Mexico assets and the 7.5% Tamar interest, which were assets held for sale, and the reduction in Equatorial Guinea production due to timing of liftings and natural field decline. These decreases were offset by the commencement of sales volumes from new US onshore crude oil-focused wells.

Other Operating Expense, Net See Item 1. Financial Statements – Note 2. Basis of Presentation and Item 1. Financial Statements – Note 11. Segment Information for discussion of other operating expense items for first quarter 2018 as compared with 2017.

Loss (Gain) on Commodity Derivative Instruments Loss (Gain) 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 three months of 2018, loss on commodity derivative instruments included:

- net cash settlement payments of $28 million; and
- non-cash increases in the liability fair value of our derivative instruments of $51 million driven by changes in the forward commodity price curves for both crude oil and natural gas.

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

- net cash settlement receipts of $3 million; and
- non-cash decreases in the liability fair value of our derivative instruments of $107 million driven by changes in the forward commodity price curves for both crude oil and natural gas.

See Item 1. Financial Statements – Note 4. Derivative Instruments and Hedging Activities and Note 6. 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.

Results of Operations

Highlights for our Midstream segment were as follows:

First Quarter 2018 Significant Midstream Operating Highlights Included:

- completion of the Saddle Butte acquisition;
- completion of the Coronado central gathering facility (CGF) construction and continued construction on two additional CGFs in the Delaware Basin;
- commencement of compression services in the Delaware Basin and purchase of additional mainline pumps for expansion of the Advantage pipeline; and
- continued construction of freshwater delivery infrastructure in the Mustang IDP area, which is expected to become operational mid-year 2018, and initiation of procurement and construction on the oil, gas and produced water gathering systems.

First Quarter 2018 Midstream Financial Results Included:

- gain of $196 million on the sale of CONE Gathering;
- pre-tax income of $247 million compared with pre-tax income of $49 million for first quarter 2017; and
- capital expenditures, excluding acquisitions, of $253 million.

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

	Three Months Ended March 31,	
(millions)	2018	2017
Midstream Services Revenues – Third Party	$ 13	$ —
Sales of Purchased Oil	22	—
Income from Equity Method Investees	12	14
Intersegment Revenues	81	58
Total Revenues	128	72
Operating Costs and Expenses	39	18
Depreciation and Amortization	17	5
Gain on Divestiture	(196)	—
Purchased Oil	21	—
Total (Income) Expense	(119)	23
Income Before Income Taxes	$ 247	$ 49

The amount of revenue generated by the midstream business depends primarily on the volumes of crude oil, natural gas and water for which services are provided to the E&P business and third party customers. These volumes are primarily affected 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 months ended March 31, 2018 increased from 2017 primarily due to an increase in crude oil and produced water gathering services revenue and fresh water delivery revenue due to the commencement of services in the Greeley Crescent IDP area and Delaware Basin subsequent to first quarter 2017. In addition, fresh water delivery revenue increased due to the timing of well completion activity in the Mustang IDP area and sales of purchased crude oil which commenced in first quarter 2018.

Crude Oil Purchase and Sale As part of the Saddle Butte acquisition in first quarter 2018, we acquired a pipeline and associated third party contracts which include transactions for the purchase and sale of crude oil with varying counterparties. Revenues and expenses from the sales and purchases are recorded on a gross basis as we act as a principal in these transactions by assuming control of the purchased commodity before it is transferred to the customer. The purchases and sales of crude oil are at the prevailing market prices. For first quarter 2018, the net effect of third party purchases and sales of crude oil was de minimis.

Total operating expenses for the three months ended March 31, 2018 increased from 2017 primarily due to an increase in gathering systems and facilities operating expense associated with the the Billy Miner CGF and Jesse James CGF, which commenced operations in the second half of 2017, along with the Saddle Butte acquisition in first quarter 2018.

Depreciation and amortization expense for the three months ended March 31, 2018 increased from 2017 due to assets placed in service subsequent to first quarter 2017, including expense related to assets acquired in the Saddle Butte acquisition during first quarter 2018.

Gain on divestiture relates to the sale of our interest in CONE Gathering. See Item 1. Financial Statements – Note 3. Acquisitions and Divestitures.

Results of Operations – Corporate and Other

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

	Three Months Ended March 31,	
(millions, except unit rate)	2018	2017
G&A Expense	$ 104	$ 99
Unit Rate per BOE [1]	$ 3.18	$ 2.94

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

G&A expense for first quarter 2018 increased as compared with 2017 primarily due to increased employee costs and third party fees driven by acquisition activities. The increase in the unit rate per BOE for the first three months of 2018 as compared with 2017 was due primarily to the increase in total G&A expense combined with the decrease in total sales volumes.

Other Operating Expense, Net See Item 1. Financial Statements – Note 2. Basis of Presentation and Item 1. Financial Statements – Note 11. Segment Information for discussion of other operating expense items for first quarter 2018 as compared with 2017.

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

	Three Months Ended March 31,	
(millions, except unit rate)	2018	2017
Interest Expense, Gross	$ 90	$ 99
Capitalized Interest	(17)	(12)
Interest Expense, Net	$ 73	$ 87
Unit Rate per BOE [1]	$ 2.24	$ 2.58

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

Interest expense, gross, for first quarter 2018 decreased as compared with 2017 primarily due to a decrease in the overall debt balance. Specifically, we repaid $550 million on our Term Loan Facility due January 6, 2019, which was partially offset by an increase of $435 million in our Noble Midstream Services Revolving Credit Facility. In addition, subsequent to first quarter 2017, we refinanced our 8.25% Senior Notes, resulting in a lower interest rate. See Item 1. Financial Statements - Note 5. Debt.

Capitalized interest for first quarter 2018 increased as compared with 2017 primarily due to higher work in progress amounts related to the Leviathan development. See Item 1. Financial Statements - Note 7. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs.

The unit rate of interest expense, net, per BOE for first quarter 2018 decreased as compared with 2017 primarily due to the changes noted above, partially offset by the decrease in total sales volumes.

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 a sustained period of low prices. Specifically, we strive to retain the ability to fund long cycle, multi-year, capital intensive development projects throughout a range of scenarios, while also funding a continuing exploration program and maintaining capacity to capitalize on financially attractive merger and acquisition opportunities. We endeavor to maintain a strong balance sheet and an investment grade debt rating in service of these objectives.

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 $4.0 billion unsecured revolving credit facility (Revolving Credit Facility) and proceeds from divestitures of properties. We occasionally access the capital markets to ensure adequate liquidity exists in the form of unutilized capacity under our Revolving Credit Facility or to refinance scheduled debt maturities. We also evaluate potential strategic farm-out arrangements of our working interests for reimbursement of our capital spending. We periodically consider repatriations of foreign cash to increase our financial flexibility and fund our capital investment program. See Operating Outlook – Impact of Recent Changes in US Tax Law.

Our portfolio transformation strategy, primarily executed during 2017, has continued into 2018 with the sale of our Gulf of Mexico assets. Including proceeds from the recent Gulf of Mexico asset sale, our divestitures have generated cash proceeds of approximately $3.3 billion during 2017-2018. Proceeds were used to improve our capital structure and strengthen our liquidity profile. In addition, our Board of Directors authorized a $750 million share repurchase program in first quarter 2018 to enhance and accelerate value return to our shareholders. Through March 31, 2018, we have repurchased an initial $67 million in common shares. Our Board of Directors also announced in April 2018 a 10% increase in the quarterly cash dividend from prior quarter, further reflecting our commitment to deliver returns to our shareholders.

Going forward, we will strive to fund our capital program through organic cash flows and, when needed, utilize borrowings under our Revolving Credit Facility.

During first quarter 2018, we repaid all amounts outstanding under the Revolving Credit Facility and extended its maturity date by two and a half years to March 2023. We also amended Noble Midstream Partners' credit agreement to increase the capacity from $350 million to $800 million and extend the maturity date of the Noble Midstream Services LLC revolving credit facility (Noble Midstream Services Revolving Credit Facility) by one and a half years to March 2023. In April 2018, we issued an early call for $379 million of legacy Rosetta Resources Inc. senior notes, with expected redemption in May 2018.

In addition, during the first three months of 2018, we received $120 million in payments from foreign operations on an outstanding note payable, leaving a balance of approximately $282 million that can be repaid without additional US tax impact.

As of March 31, 2018, our outstanding debt (excluding capital lease obligations) totaled $6.7 billion. We may periodically seek to access the capital markets to refinance a portion of our outstanding indebtedness.

We may from time to time seek to retire or purchase our outstanding senior notes through cash purchases in open market purchases, privately negotiated transactions or otherwise. Such repurchases, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be significant.

Available Liquidity

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

(millions, except percentages)	March 31, 2018	December 31, 2017
Total Cash [(1)]	$ 1,022	$ 713
Amount Available to be Borrowed Under Revolving Credit Facility [(2)]	4,000	3,770
Total Liquidity	$ 5,022	$ 4,483
Total Debt [(3)]	$ 6,963	$ 6,859
Noble Energy Share of Equity	10,362	9,936
Ratio of Debt-to-Book Capital [(4)]	40%	41%

(1) As of March 31, 2018, total cash included cash and cash equivalents of $25 million related to Noble Midstream Partners and $30 million restricted cash related to the Gulf of Mexico asset sale, which closed in April 2018. As of December 31, 2017, total cash included $18 million cash of Noble Midstream Partners and $37.5 million restricted cash related to the Saddle Butte acquisition that closed in first quarter of 2018.

(2) Excludes amounts 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 5. 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 $992 million in cash and cash equivalents at March 31, 2018, primarily denominated in US dollars and invested in money market funds and short-term deposits with major financial institutions. Approximately $831 million of this cash is attributable to our foreign subsidiaries.

Revolving Credit Facilities Noble Energy's Revolving Credit Facility of $4.0 billion matures in 2023. The Noble Midstream Services Revolving Credit Facility of $800 million also matures in 2023. These facilities are used to fund capital investment programs and acquisitions and may periodically provide amounts for working capital purposes. At March 31, 2018, no amounts were outstanding under the Revolving Credit Facility and $435 million was outstanding under the Noble Midstream Services Revolving Credit Facility, leaving $4.0 billion and $365 million in remaining availability under the respective credit facilities. See Item 1. Financial Statements – Note 6. Debt.

Leviathan Term Loan Facility The Leviathan Term Loan Facility 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. 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 March 31, 2018, 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 5. Debt and Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Contractual Obligations

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 initial development of our Leviathan field requires substantial infrastructure and capital, and we have executed major equipment and installation contracts in support of our development activities. As of March 31, 2018, we had entered into approximately $378 million, net, of contracts to support development 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, such as our Eagle Ford Shale and Delaware Basin properties, are held through continuous development obligations. Therefore, we are contractually obligated to fund a level of development activity in these areas which could be substantial. Failure to meet these obligations may result in the loss of a lease.

Marcellus Shale Firm Transportation Agreements We have remaining financial commitments of approximately $1.4 billion, undiscounted, associated with Marcellus Shale firm transportation contracts. We have engaged in actions to commercialize and address a substantial portion of these remaining commitments, which provide for the transportation of approximately 450,000 MMBtu/d of natural gas. Actions include the permanent assignment of capacity, 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 our 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 continue to reduce our financial commitment associated with these contracts. For pipelines currently under construction and targeted for in-service late 2018, we will evaluate our position at the date each pipeline is placed in service and our commitment begins. 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. These contracts represent approximately $870 million, undiscounted, of the total commitment noted above. See Item 1. Financial Statements – Note 12. Commitments and Contingencies.

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:

(millions)	Three Months Ended March 31, 2018	2017
Total Cash Provided By (Used in)		
Operating Activities	$ 583	$ 536
Investing Activities	(572)	(893)
Financing Activities	298	(66)
Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	$ 309	$ (423)

Operating Activities Cash provided by operating activities increased for the first three months of 2018 compared with 2017 by approximately $47 million. The increase is primarily due to higher realized crude oil prices and an increase in crude oil production in the DJ and Delaware basins. These increases were partially offset by lower realized natural gas prices and a decrease in natural gas production attributable to our exit from the Marcellus Shale in second quarter 2017.

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.

Total additions to property, plant and equipment increased during the first quarter of 2018 as compared with 2017 primarily due to increases in spending related to development costs in the Delaware Basin, construction of midstream infrastructure and Leviathan development costs, partially offset by decreases in development costs primarily in the Marcellus Shale and Eagle Ford Shale. See Operating Outlook – 2018 Capital Investment Program, above.

During the first three months of 2018, we completed certain portfolio activities including the Saddle Butte acquisition for $650 million, net, which included $206 million related to Midstream expenditures. Also during the quarter, we received net proceeds of $865 million from asset sales (not including the Gulf of Mexico asset sale that closed in April 2018). In comparison, during the first three months of 2017, we acquired Delaware Basin assets and other onshore US assets for $346 million and received net proceeds of $40 million from asset sales.

Financing Activities Our financing activities, in general, include the issuance and repurchase of Noble Energy common stock and Noble Midstream Partners common units, payment of cash dividends to Noble Energy shareholders and cash distributions to Noble Midstream Partners noncontrolling interest owners, and debt transactions.

Our primary financing activities during the first three months of 2018 included a $230 million, net, Revolving Credit Facility payment and $350 million, net, Noble Midstream Services Revolving Credit Facility borrowings used primarily to fund an acquisition. In addition, we made common stock repurchases totaling $67 million pursuant to our stock repurchase program, paid $48 million of cash dividends to Noble Energy shareholders and $11 million of cash distributions to Noble Midstream Partners noncontrolling interest owners, and made $16 million of capital lease principal payments.

Also, during the first three months of 2018, we purchased 219,171 shares of treasury stock, with a value of $7 million, related to stock received by us from employees for the payment of withholding taxes due on shares of restricted stock issued under our stock-based compensation plans.

In comparison, during the first three months of 2017, we paid $44 million of cash dividends and made $16 million of capital lease principal payments. We also received $9 million cash proceeds from the exercise of stock options and purchased 260,146 shares of treasury stock from employees with a value of $10 million for the payment of withholding taxes.

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

Dividends On April 23, 2018, our Board of Directors declared a quarterly cash dividend of 11 cents per common share, which will be paid on May 21, 2018 to shareholders of record on May 7, 2018. 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.

Capital Expenditure Activities The following presents our capital expenditures (on an accrual basis) for the three months ended March 31, 2018 and 2017:

	Three Months Ended March 31,			
(millions)	2018		2017	
Acquisition, Capital and Exploration Expenditures				
Unproved Property Acquisition [1]	$	—	$	246
Proved Property Acquisition [1]		—		58
Exploration		15		10
Development		641		587
Midstream [2]		459		93
Corporate and Other		11		5
Total	$	1,126	$	999

[1] 2017 acquisition costs relate to the Delaware Basin acquisition.
[2] Midstream expenditures for the three months ended March 31, 2018 includes $206 million related to the Saddle Butte acquisition.

Total capital expenditures increased by $127 million during the first three months of 2018 as compared with the first three months of 2017, primarily due to an increase of $180 million in development capital spending related to drilling, facilities and well completion costs incurred in the Delaware Basin, as a result of our focus on developing the acreage. Furthermore, development costs increased by $48 million related to the initial Leviathan project development. The increase in development costs was partially offset by a decrease of $174 million in costs incurred in the Marcellus Shale, DJ Basin, and Eagle Ford Shale. In addition, midstream capital spending increased due to the acquisition of Saddle Butte and the construction of gathering systems in the DJ and Delaware Basins.

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 - E&P, 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 March 31, 2018, 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 liability position with a fair value of $122 million. Based on the March 31, 2018 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 increase the fair value of our net commodity derivative liability by approximately $58 million. Our derivative instruments are executed under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net cash settled at the time of election. See Item 1. Financial Statements – Note 4. Derivative Instruments and Hedging Activities.

Interest Rate Risk

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

At March 31, 2018, we had approximately $6.7 billion (excluding capital lease obligations) of long-term debt outstanding, net of unamortized discount, premium and debt issuance costs. Of this amount, $6.2 billion was fixed-rate debt, net of unamortized discount, premium and debt issuance costs, with a weighted average interest rate of 5.04%. Although near term changes in interest rates may affect the fair value of our fixed-rate debt, they do not expose us to interest rate risk or cash flow loss.

However, we are exposed to interest rate risk related to our interest-bearing cash and cash equivalents balances. As of March 31, 2018, our cash and cash equivalents totaled $992 million, approximately 75% of which was invested in money market funds and short-term investments with major financial institutions.

In addition, borrowings under the Revolving Credit Facility, Noble Midstream Services Revolving Credit Facility and Leviathan Term Loan Facility are subject to variable interest rates which expose us to the risk of earnings or cash flow loss due to potential increases in market interest rates. A change in the interest rate applicable to our variable-rate debt could expose us to additional interest cost. While we currently have no interest rate derivative instruments as of March 31, 2018, 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 or the amounts currently outstanding under the Noble Revolving Credit Facility, Noble Midstream Services Revolving Credit Facility or Leviathan Term Loan 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, for example certain local working capital items, are denominated in a foreign currency and remeasured into US dollars. 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. Furthermore, our investment in Tamar Petroleum is denominated and settled in New Israeli Shekels.

Net transaction gains and losses were de minimis for the three months ended March 31, 2018.

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;
- 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, 2017 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, 2017 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, 2017.

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, 2017.

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 [(2)]		Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
						(millions)
1/1/2018 - 1/31/2018	87	$	30.19	—		
2/1/2018 - 2/28/2018	544,005		30.84	334,700		
3/1/2018 - 3/31/2018	1,907,479		30.15	1,897,700		
Total	2,451,571	$	30.30	2,232,400	$	683

(1) Includes stock repurchases of 219,171 during the period relating 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. In addition, 745,202 of common shares were retired in the period relating to the Clayton Williams Energy Acquisition.

(2) On February 15, 2018, we announced that the Company's Board of Directors had authorized a $750 million share repurchase program, which expires December 31, 2020. During first quarter 2018, we repurchased and retired 2.2 million shares of common stock at an average purchase price of $30.21 per share.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Item 6. 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).
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 30, 2018) (filed as Exhibit 3.1 to the Registrant's Current Report on Form 8-K (Date of Report: January 30, 2018) filed on February 1, 2018 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).
10.1*	Form of Restricted Stock Award (3-year time-vested officers) under the Noble Energy, Inc. 2017 Long-Term Incentive Plan (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Report: January 29, 2018) filed February 1, 2018 and incorporated herein by reference).
10.2*	Form of Restricted Stock Award (3-year cliff vested) under the Noble Energy, Inc. 2017 Long-Term Incentive Plan (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K (Date of Report: January 29, 2018) filed February 1, 2018 and incorporated herein by reference).
10.3*	Noble Energy, Inc. Change of Control Severance Plan for Executives, as amended and restated, effective January 30, 2018 (filed as Exhibit 10.39 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2017 and incorporated herein by reference).
10.4	Third Amendment, dated March 9, 2018, by and among Noble Energy, Inc., NBL International Finance B.V., JPMorgan Chase Bank, N.A., as administrative agent, Citibank N.A., as syndication agent, and Bank of America, N.A., The Bank of Tokyo-Mitsubishi UFJ, Ltd., Mizuho Bank, Ltd. and DNB Bank ASA, New York Branch as documentation agents, and the other commercial lending institutions party thereto (filed as Exhibit 10.1 of the Registrant's Current Report on Form 8-K (Date of Report: March 9, 2018) filed on March 12, 2018 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	Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH	XBRL Schema Document
101.CAL	XBRL Calculation Linkbase Document
101.LAB	XBRL Label Linkbase Document
101.PRE	XBRL Presentation Linkbase Document
101.DEF	XBRL Definition Linkbase Document

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

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

Signatures

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

NOBLE ENERGY, INC.
(Registrant)

Date May 1, 2018

/s/ Kenneth M. Fisher

Kenneth M. Fisher
Executive Vice President, Chief Financial Officer

EXHIBIT 12.1

Noble Energy, Inc.

Calculation of Ratio of Earnings to Fixed Charges

	Three Months Ended March 31,	Year Ended December 31,				
	2018	2017	2016	2015	2014	2013
(millions, except ratio amounts)						
Income (Loss) From Continuing Operations Before Income Tax, Non-controlling Interests and Income From Equity Investees	$ 476	$ (2,436)	$ (1,887)	$ (2,309)	$ 1,540	$ 1,138
Add (Deduct)						
Fixed Charges	97	426	440	435	349	296
Capitalized Interest	(17)	(49)	(84)	(144)	(116)	(121)
Distributed Income From Equity Investees	41	139	83	77	226	204
Earnings (Loss) as Defined	$ 597	$ (1,920)	$ (1,448)	$ (1,941)	$ 1,999	$ 1,517
Net Interest Expense	73	354	328	263	210	158
Capitalized Interest	17	49	84	144	116	121
Interest Portion of Rental Expense	7	23	28	28	23	17
Fixed Charges as Defined	$ 97	$ 426	$ 440	$ 435	$ 349	$ 296
Ratio of Earnings to Fixed Charges	6.2	—	—	—	5.7	5.1
Amount by Which Earnings Were Insufficient to Cover Fixed Charges	$ —	$ 2,346	$ 1,888	$ 2,376	$ —	$ —

Exhibit 31.1

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

I, David L. Stover, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: May 1, 2018

/s/ David L. Stover

David L. Stover
Chief Executive Officer

Exhibit 31.2

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

I, Kenneth M. Fisher, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Noble Energy, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

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

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

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

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

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

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

Date: May 1, 2018

/s/ Kenneth M. Fisher

Kenneth M. Fisher
Chief Financial Officer

Exhibit 32.1

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

In connection with the accompanying Quarterly Report of Noble Energy, Inc. (the “Company”) on Form 10-Q for the period ended March 31, 2018 (the “Report”), I, David L. Stover, Chief Executive Officer of the Company, hereby certify that to my knowledge:

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

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

Date:	May 1, 2018	*/s/ David L. Stover*
		David L. Stover
		Chief Executive Officer

Exhibit 32.2

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

In connection with the accompanying Quarterly Report of Noble Energy, Inc. (the “Company”) on Form 10-Q for the period ended March 31, 2018 (the “Report”), I, Kenneth M. Fisher, Chief Financial Officer of the Company, hereby certify that to my knowledge:

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

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

Date:	May 1, 2018	*/s/ Kenneth M. Fisher*
		Kenneth M. Fisher
		Chief Financial Officer