NOBLE ENERGY INC

FORM 10-K
(Annual Report)

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

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2017
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 of incorporation)	(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)
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, $0.01 par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. ☒ Yes ☐ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. ☐ Yes ☒ No

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting, or an emerging growth company. See definitions of "large accelerated filer", "accelerated filer", "smaller reporting company", and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐ Emerging growth company ☐
(Do not check if a smaller reporting 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 Act). ☐ Yes ☒ No

Aggregate market value of Common Stock held by nonaffiliates as of June 30, 2017 : $13.8 billion .

Number of shares of Common Stock outstanding as of December 31, 2017 : 486,902,907 .

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive proxy statement for the 2018 Annual Meeting of Stockholders to be held on April 24, 2018, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2017 , are incorporated by reference into Part III.

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Disclosure Regarding Forward-Looking Statements

This Annual Report on Form 10-K and the documents incorporated by reference in this report contain 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 and development activities;
- our ability to successfully and economically explore for and develop crude oil, natural gas and natural gas liquids (NGLs) 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 tax regulations, and/or terms, such as that involving the protection of the environment or marketing of production, as well as other regulations;
- our ability to make and integrate acquisitions; and
- access to resources.

Forward-looking statements are typically identified by use of terms such as “may,” “will,” “expect,” “believe,” “anticipate,” “estimate,” “intend,” and similar words, although some forward-looking statements may be expressed differently. These forward-looking statements are made based upon management’s 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 and other sections of this report, which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements.

PART I

Items 1. and 2. Business and Properties

In this report, unless otherwise indicated or where the context otherwise requires, information includes that of Noble Energy, Inc. and its subsidiaries (Noble Energy, the Company, we or us). All references to production, sales volumes and reserves quantities are net to our interest unless otherwise indicated. For a summary of commonly used industry terms and abbreviations used in this report, see the Glossary , located at the end of this report.

Noble Energy is an independent crude oil and natural gas exploration and production company with a diversified high-quality portfolio spanning three continents. Founded in 1932, Noble Energy is a Delaware corporation, incorporated in 1969, and has been publicly traded on the New York Stock Exchange (NYSE) since 1980. We have a unique history of growth, evolving from a regional crude oil and natural gas producer to a global exploration and production company included in the Standard & Poor's 500 (S&P 500).

Our purpose, *Energizing the World, Bettering People's Lives ®,* reflects our commitment to find and deliver affordable energy through crude oil, natural gas and NGL exploration and production while living our commitment to contribute to the betterment of people's lives in the communities in which we operate. We strive to build trust through stakeholder engagement, act on our values, provide a safe work environment, respect our environment and care for our employees and the communities where we operate.

Our portfolio of assets is diversified through US and international projects and production mix among crude oil, natural gas, and NGLs. In particular, our business is focused on both US unconventional basins and certain global offshore conventional basins. In US onshore unconventional basins, we have demonstrated competence in applying geological, drilling, completion, and midstream design and operational expertise. In US onshore, we typically apply a major project development concept to an unconventional basin by utilizing an Integrated Development Plan (IDP) approach. In the global offshore, we have had notable exploration and major project successes over the past twelve years, which have led to production from numerous offshore major development projects which have provided long-lived cash flows to our business.

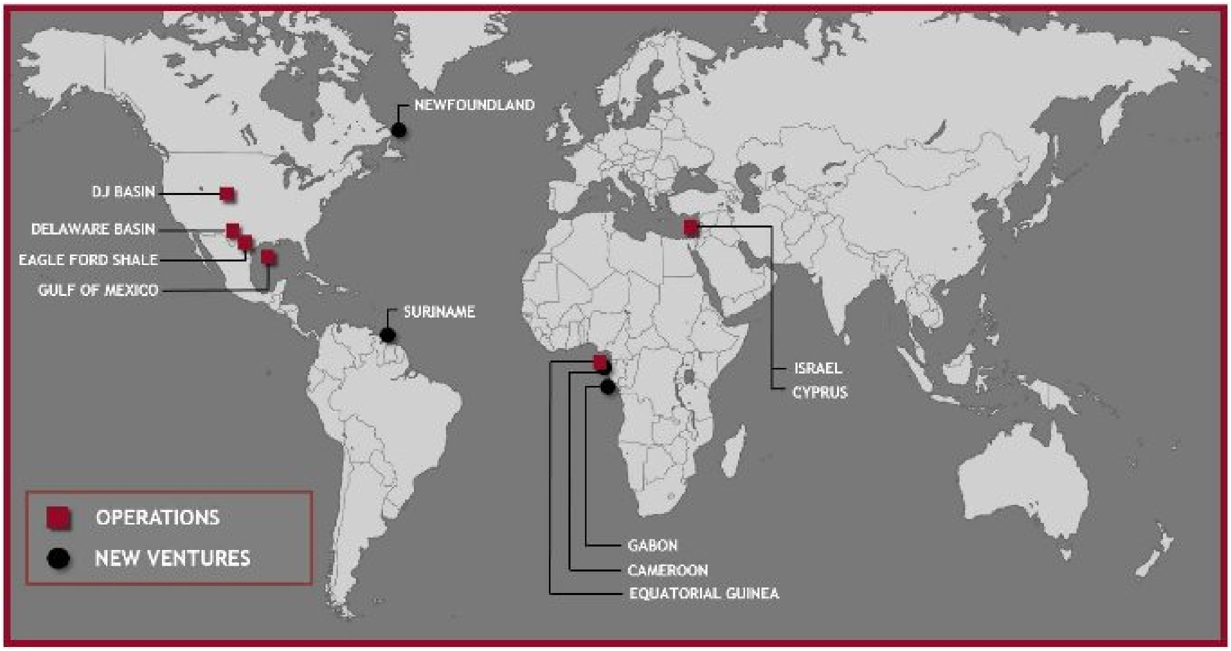
Approximately 70% of our 2018 capital program is allocated to US onshore development, primarily focused on liquids-rich opportunities in the Denver-Julesburg (DJ) Basin, Delaware Basin and Eagle Ford Shale. Eastern Mediterranean capital expenditures, including initial development costs associated with the Leviathan project, represent more than 25% of the total. The remaining portion of our 2018 capital program is designated for exploration for lease acquisition, seismic and other geological analysis in support of future exploration prospects for potential development post 2020, as well as other corporate activities.

In addition, the majority of our assets are held by production, which allows for further investment and financial flexibility. Occasional strategic acquisitions of producing or non-producing properties, combined with the periodic divestment of assets, have allowed us to pursue our objective of a well-positioned and diversified portfolio to maximize strategic value.

Oil and Gas Properties and Activities We search for crude oil and natural gas properties onshore and offshore, and seek to acquire exploration rights and conduct exploration activities in areas of interest. Our activities include geophysical and geological evaluation; analysis of commercial, regulatory and political risks; and exploratory and development drilling leading to production, where appropriate.

Our current portfolio consists primarily of interests in developed and undeveloped crude oil and natural gas leases and concessions. These properties contribute all of our crude oil, natural gas and NGL production, provide continual investment opportunities in proved areas, and offer further exploration opportunities. Our new venture areas provide frontier exploration opportunities, which may result in the establishment of new operational areas in the future. We also own or invest in midstream assets primarily used in the processing and transportation of our US onshore production. See Midstream - Properties and Activities, below.

The map below illustrates the locations of our significant crude oil and natural gas exploration and production activities:



Reportable Segments We manage our operations by geographic region and the nature of the products and services we offer. Our reportable segments include: United States (US onshore and Gulf of Mexico); Eastern Mediterranean (Israel and Cyprus); West Africa (Equatorial Guinea, Cameroon and Gabon); Other International (Newfoundland, Suriname, and other new ventures); and Midstream.

The geographical reportable segments are in the business of crude oil and natural gas exploration, development, production, and acquisition (Oil and Gas Exploration and Production, or E&P). The Midstream reportable segment owns, operates, develops and acquires 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 cost are recorded at the corporate level. See Item 8. Financial Statements and Supplementary Data – Note 14. Segment Information.

Development Activities Our development projects have resulted from both exploration success as well as periodic strategic acquisitions. These projects provide opportunities for growth at attractive financial returns. Each project progresses, as appropriate, through the various development phases including appraisal, engineering and design, development drilling, construction and production. While development projects require significant capital investments, typically over a multi-year period, they are expected to offer sustained cash flows, while on production.

In US onshore, our low production-risk development programs are centered around IDPs and generate efficiencies for upstream and midstream development. IDPs are generally areas of highly contiguous acreage, typically held by production, that accommodate drilling long lateral wells, and other operational synergies. The approach also benefits from the ability to accommodate a flexible capital investment program that can be varied in response to changes in the commodity price environment. We continue to enhance project performance in these areas through technology and operational efficiencies.

Offshore, we engage in long-cycle development projects, such as progressing the first phase of development at the Leviathan natural gas field, offshore Israel, the largest natural gas discovery in our history. Our development activities are discussed in more detail in the sections below.

Divestiture and Acquisition Activities We maintain an ongoing portfolio management program. Accordingly, we may periodically divest assets through asset or equity sales, exchanges or other transactions. During 2017 , we closed several transformative portfolio transactions, demonstrating our continued focus on enhancing profit margins and company returns. We generated cash of $2.1 billion from asset sales, including divestiture of the Marcellus Shale upstream assets, as well as other non-strategic US onshore assets. Periodically, we may also engage in acquisitions of additional crude oil or natural gas properties and related assets through either direct acquisitions of the assets or acquisitions of entities that own the assets. For example, we completed the acquisition (Clayton Williams Energy Acquisition) of Clayton Williams Energy, Inc. (Clayton Williams Energy) in 2017 and the merger (Rosetta Merger) of Rosetta Resources Inc (Rosetta) in 2015. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources , Item 8. Financial Statements and Supplementary Data - Note 3. Clayton Williams Energy Acquisition , and Item 8. Financial Statements and Supplementary Data – Note 4. Acquisitions, Divestitures and Merger .

Exploration Activities We primarily focus on organic growth from exploration and development drilling activities, concentrating on existing basins or plays where we believe we have strategic competitive advantages or in new basins with attractive geological potential and the opportunity for attractive financial returns. These advantages are derived from proprietary seismic data and operational expertise, which we believe will generate superior returns over the oil and gas business cycle. We have had substantial historic exploration success in the Gulf of Mexico, the Levant Basin offshore Eastern Mediterranean and the Douala Basin offshore West Africa, resulting in the successful completion of numerous major development projects. In 2017 , we performed limited exploration activities due to the commodity price environment.

Proved Oil and Gas Reserves Proved reserves at December 31, 2017 were as follows:

	December 31, 2017			
	Proved Reserves			
	Crude Oil and Condensate	NGLs	Natural Gas	Total
Reserves Category	(MMBbls)	(MMBbls)	(Bcf)	(MMBoe) (1)
Proved Developed				
United States	176	119	983	458
Israel	3	—	1,793	302
Equatorial Guinea	29	11	411	108
Total Proved Developed Reserves	208	130	3,187	868
Proved Undeveloped				
United States	243	99	838	482
Israel	6	—	3,655	615
Total Proved Undeveloped Reserves	249	99	4,493	1,097
Total Proved Reserves	457	229	7,680	1,965

(1) Million barrels oil equivalent. Natural gas is converted on the basis of six Mcf of gas per one barrel of crude oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency. Given commodity price disparities, the price for a barrel of crude oil equivalent for US natural gas and NGLs is 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.

Our proved reserves totaled 1,965 MMBoe as of December 31, 2017 as compared with 1,437 MMBoe as of December 31, 2016 . Changes included the following:

- revisions of 135 MMBoe, including positive revisions of 105 MMBoe driven by performance related to the US onshore horizontal drilling programs and offshore Israel associated with the enhanced geologic modeling across the Tamar reservoir, as well as an increase of 30 MMBoe driven by positive price revisions;
- extensions, discoveries and other additions of 736 MMboe, including additions of 551 MMBoe related to the sanction of the first phase of development of the Leviathan natural gas project, as well as extensions of 185 MMBoe related to US onshore horizontal drilling programs due to successful expansion of our extended reach lateral well programs;
- acquisition of 57 MMBoe primarily related to the Clayton Williams Energy Acquisition;

offset by:

- production volumes of 139 MMBoe; and
- divestiture of reserves of 261 MMBoe, primarily due to the Marcellus Shale upstream divestiture and other smaller US onshore divestitures.

Our proved reserves are 48% US and 52% international, and the commodity mix is 35% global liquids (crude oil and NGLs), 50% international natural gas and 15% US natural gas.

See Proved Reserves Disclosures, below, and Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Information (Unaudited) for further discussion of proved reserves.

Oil and Gas Exploration and Production - Properties and Activities

United States

We have been engaged in crude oil, natural gas and NGL exploration and development activities throughout US onshore since 1932 and in the Gulf of Mexico since 1968. US operations accounted for 72% of 2017 total consolidated sales volumes and 48% of total proved reserves at December 31, 2017 . Approximately 45% of the proved reserves in the US is crude oil and condensate, 32% is natural gas and 23% is NGLs.

Sales volumes and proved reserves estimates for our US operating areas were as follows:

	Year Ended December 31, 2017				December 31, 2017			
	Sales Volumes				Proved Reserves			
	Crude Oil & Condensate	NGLs	Natural Gas	Total	Crude Oil & Condensate	NGLs	Natural Gas	Total
	(MBbl/d)	(MBbl/d)	(MMcf/d)	(MBoe/d)	(MMBbls)	(MMBbls)	(Bcf)	(MMBoe)
DJ Basin	59	19	193	110	203	99	1,094	484
Delaware Basin	17	4	24	26	166	38	199	238
Eagle Ford Shale	11	28	186	70	29	79	501	191
Marcellus Shale (1)	1	5	174	34	—	—	—	—
Gulf of Mexico	21	2	21	26	18	2	21	23
Other US Onshore	2	—	9	4	3	—	6	4
Total	111	58	607	270	419	218	1,821	940

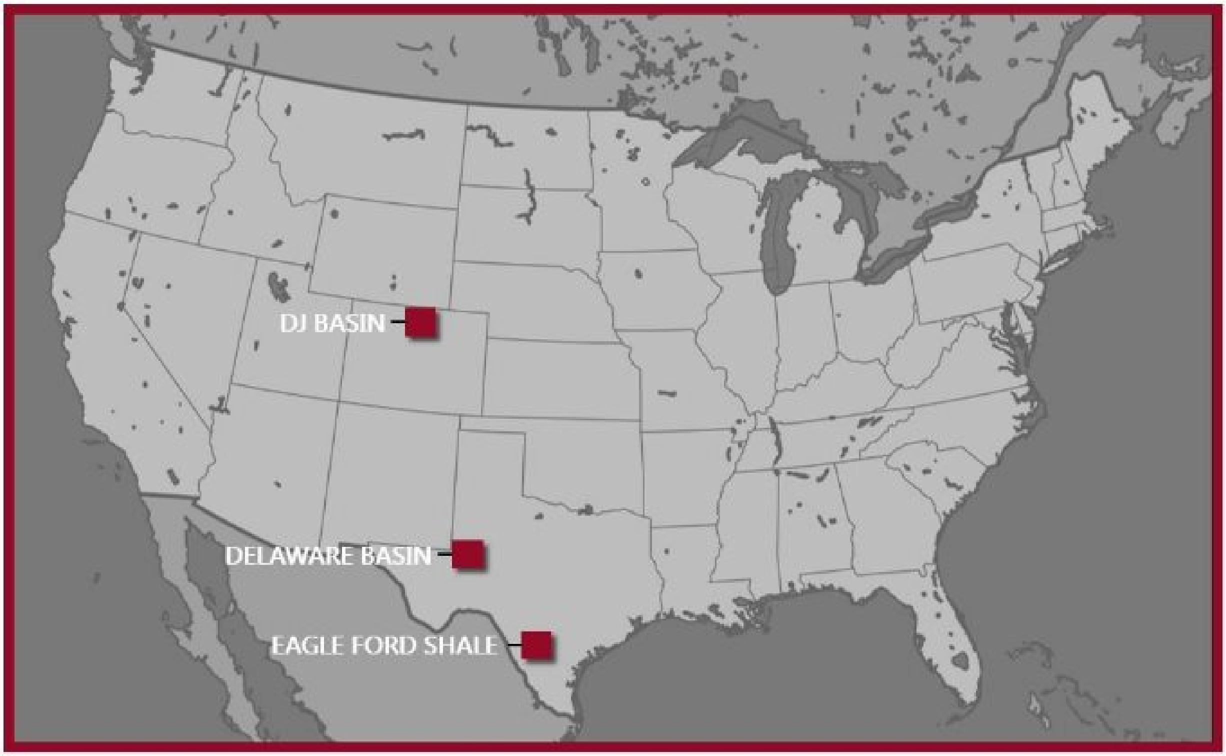
(1) We divested our Marcellus Shale upstream assets in second quarter 2017.

Wells completed in 2017 and productive wells at December 31, 2017 for our US operating areas were as follows:

	Year Ended December 31, 2017	December 31, 2017
	Gross Wells Completed or Participated in	Gross Productive Wells
DJ Basin	138	6,226
Delaware Basin	75	1,898
Eagle Ford Shale	47	344
Gulf of Mexico	—	14
Other US Onshore	12	1
Total	272	8,483

US Onshore

Our US onshore operations are located in proven basins with long-life production profiles. These assets provide low production-risk drilling opportunities in liquids-rich areas that offer predictable and long-term production and cash flow growth at attractive financial returns. Locations of our US onshore operations as of December 31, 2017 are shown on the map below:



DJ Basin In 2017 , we focused our drilling and development activity in the Wells Ranch and East Pony areas that produce a high oil mix. The IDP concept allows us to consolidate processing and handling infrastructure across large areas (typically 30,000 to 80,000 acres). Our IDP approach has provided an opportunity to efficiently and economically support production growth by leveraging infrastructure, such as gas, oil and water, including both fresh and produced water, assets.

2017 Activity Operationally, our focus on drilling longer laterals and obtaining better results from enhanced completions has led to stronger new well performance. Coupled with expansion of midstream infrastructure and execution of synergies as well as prudent management of costs, we are delivering enhanced profit margin returns. During the year, we completed 103 horizontal wells and 101 wells initiated production. We also participated in approximately 35 non-operated development wells during 2017 .

As part of ongoing portfolio management, we entered into an agreement to divest approximately 30,200 net acres, the majority of which were undeveloped, in the Greeley Crescent area of Weld County, Colorado for $608 million. We received proceeds of $568 million at closing and expect to receive the remaining proceeds in mid-2018. As part of the transaction, all of the acreage in the Greeley Crescent Bronco IDP remains subject to dedications to Noble Midstream Partners LP (Noble Midstream Partners) for crude oil gathering, and produced and fresh water services.

Since 2015, we have been working with the State of Colorado to improve emission control systems as required under a joint consent decree (Consent Decree). Overall compliance with the Consent Decree has resulted in the temporary shut-in and permanent plugging and abandonment of certain wells, the majority of which are vertical, and associated tank batteries. Costs associated with these abandonment activities will be incurred over several years.

We exited 2017 with one drilling rig and intend to increase to two rigs in 2018. Our current 2018 development program contemplates expansion into the Mustang IDP area where we have a large, contiguous acreage position.

Delaware Basin Our Delaware Basin position was significantly transformed in 2017 with the closing of the Clayton Williams Energy Acquisition on April 24, 2017, adding 71,000 highly contiguous net acres in the core of the Delaware Basin adjacent to our Reeves County holdings. We also executed strategic leasing initiatives and entered into a bolt-on acquisition, for $295 million, which closed in January 2017, adding additional production near our producing properties and increasing our contiguous acreage position in the Reeves County area. As of December 31, 2017, we held approximately 117,000 net acres in the Delaware Basin.

2017 Activity In 2017, we successfully integrated the Clayton Williams Energy assets and initiated execution of the Delaware Basin IDP with a focus on long laterals, pad drilling, multi-zone completions and infrastructure development. As demonstrated in the DJ Basin, our IDP approach provides an opportunity to more efficiently and economically develop our acreage.

We successfully transformed our 2017 development program's focus from a single well development approach to an IDP to capture the full resource potential for the Delaware Basin. This was achieved with eight pads that developed multiple zones within the Wolfcamp A formation zone, including two pads that successfully included the shallower 3rd Bone Springs zone. With successful wells in the deeper Wolfcamp zones, as well as expanded understanding of the resource potential and our IDP approach, we are well positioned to efficiently and economically develop our acreage over future years.

We began 2017 with three drilling rigs and exited the year with six drilling rigs. During the year, we completed 45 wells and commenced production on 44 wells, of which 23 were multi-zone pads. We also participated in approximately 30 non-operated development wells during 2017 . In addition, we added two central gathering facilities (CGFs).

For 2018 , we will continue asset development through long laterals, pad drilling, multi-zone development and an infrastructure build-out initiative that will include an additional three CGFs.

Eagle Ford Shale We hold approximately 35,000 net acres located in the highly prolific liquids-rich area of the play, including producing assets in Webb and Dimmit counties. Since acquiring these assets, we have continued to apply IDP learnings and enhancements to optimize development of these assets, including optimizing drilling and completion designs through testing varying clusters per stage, lateral lengths, and proppant quantities to increase investment efficiency. We have also focused on testing co-development of both the Upper and Lower Eagle Ford formation zones utilizing our IDP approach.

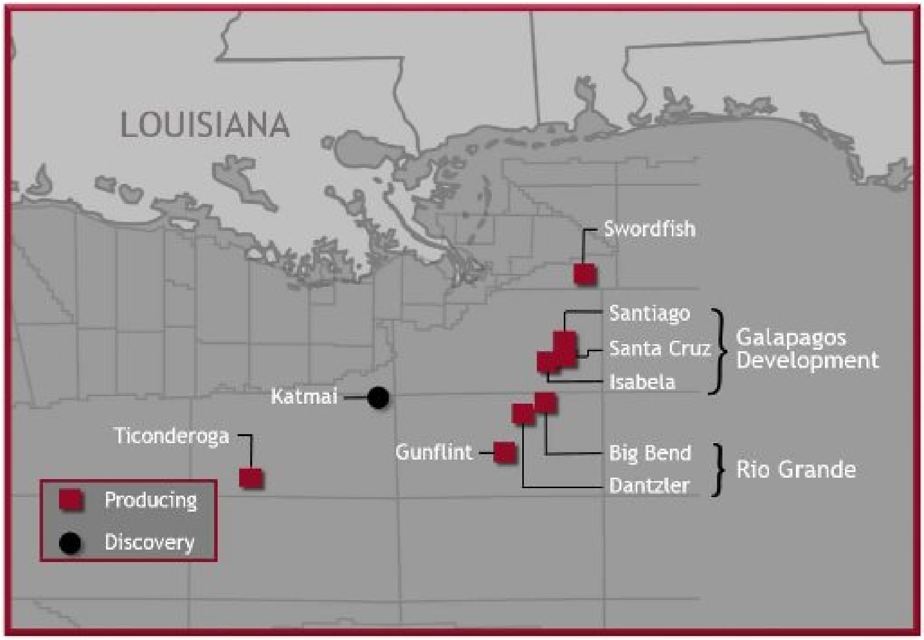
2017 Activity Our 2017 capital program was focused within Webb and Dimmit counties where we operated up to two drilling rigs, completed 47 horizontal wells and commenced production on 49 horizontal wells. All wells drilled during 2017 were on multi-well pads leveraging centralized infrastructure. We also sold certain assets located in Gonzales and DeWitt counties, where we had not engaged in drilling activities since the completion of the merger (Rosetta Merger) with Rosetta Resources Inc. (Rosetta) and received proceeds of $45 million.

We exited 2017 with a two rig drilling program. Our capital program in 2018 focuses on developing the Upper and Lower Eagle Ford formation zones within the Gates Ranch area.

Marcellus Shale On June 28, 2017, we closed the sale of the Marcellus Shale upstream assets, receiving net proceeds of $1.0 billion and recorded a loss on sale of $2.38 billion . The divestment enables us to further focus our organization on our highest-return areas that are expected to deliver production and cash flow growth.

See Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources and Item 8. Financial Statements and Supplementary Data – Note 4. Acquisitions, Divestitures and Merger .

Gulf of Mexico Locations of our operations in the Gulf of Mexico as of December 31, 2017 are shown on the map below:



We have several producing fields and an inventory of identified prospects, which are a combination of both high impact subsalt prospects and smaller tie-back opportunities. These prospects are subject to an ongoing technical maturation process and may or may not emerge as drillable options.

We currently hold leases on approximately 63 deepwater blocks, representing approximately 52,000 net developed acres and approximately 171,000 net undeveloped acres. We are the operator on nearly 80% of our leases.

Subsequent Event On February 15, 2018, we announced the Company signed a definitive agreement to sell its assets in the Gulf of Mexico. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Executive Overview and Item 8. Financial Statements and Supplementary Data – Note 4. Acquisitions, Divestitures and Merger .

2017 Activity Our activity in 2017 primarily focused on optimizing production and progressing our Katmai project. See Offshore Producing Properties and Update to Gulf of Mexico Major Projects, below.

During 2017, we completed our geological evaluation of certain leases and determined that several leases, representing $60 million of undeveloped leasehold cost, should be impaired and expensed.

We have remaining capitalized undeveloped leasehold cost of approximately $44 million related to prospects that have not yet been drilled. Leases representing over 60% of this cost are scheduled to expire over the years 2018 to 2020. In addition, some leases may become impaired if production is not established or should we not take action to extend the terms of the leases. As a result of our exploration activities, capitalized undeveloped leasehold costs could become impaired. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Operating Outlook – Potential for Future Impairments.

Offshore Producing Properties

Gunflint (Mississippi Canyon Block 948; 31% operated working interest) Gunflint is a 2008 crude oil discovery, utilizing a two-well subsea tieback to the Gulfstar 1 spar platform. Production commenced in July 2016 and the development contributed 7 MBoe/d of sales volumes in 2017.

Rio Grande Development including Big Bend (Mississippi Canyon Block 698; 54% operated working interest) and *Dantzler (Mississippi Canyon Block 782; 45% operated working interest)* The Rio Grande crude oil development project consists of a single producing well from Big Bend, a 2012 crude oil discovery, and two producing wells from Dantzler, a 2013 crude oil discovery, flowing to the Thunder Hawk platform for which we assumed operatorship in 2016. The Rio Grande development commenced production in October 2015 and contributed an average of 12 MBoe/d of sales volumes in 2017.

Galapagos Development Project including Isabela (Mississippi Canyon Block 562; 33.33% non-operated working interest), Santa Cruz (Mississippi Canyon Blocks 519/563; 23.25% operated working interest) and *Santiago (Mississippi Canyon Block*

519; 23.25% operated working interest) The Galapagos crude oil development project consists of Isabela, a 2007 discovery, Santa Cruz, a 2009 discovery, and Santiago, a 2011 discovery. The Galapagos development began producing in 2012 and is connected to existing infrastructure through subsea tiebacks. A well stimulation commenced in the fourth quarter of 2017 to enhance recovery. The Galapagos project contributed an average of 4 MBoe/d of sales volumes in 2017.

Swordfish (Viosca Knoll Blocks 917; 961 and 962; 85% operated working interest) Swordfish is a 2001 crude oil discovery and began producing in 2005. The Swordfish project currently includes two producing wells flowing to the Neptune Spar, our 100%-owned floating offshore production platform, and contributed an average of 3 MBoe/d of sales volumes in 2017. We currently plan to begin abandonment activities in 2019.

Ticonderoga (Green Canyon Block 768; 50% non-operated working interest) Ticonderoga is a 2004 crude oil discovery and began producing in 2006. The project currently includes two producing wells, which contributed an average of 1 MBoe/d of sales volumes in 2017. These properties are connected to existing infrastructure through subsea tiebacks.

Update to Gulf of Mexico Major Projects

Katmai (Green Canyon Block 40; 50% operated working interest) During 2014, we announced successful final well results at the Katmai exploratory well. Katmai was drilled to a total depth of 27,900 feet in 2,100 feet of water. Wireline logging data indicated a total of 154 net feet of crude oil pay discovered in multiple reservoirs, including 117 net feet in Middle Miocene and 37 net feet in Lower Miocene reservoirs. In 2016 , we spud our Katmai 2 appraisal well (38% operated working interest), located in Green Canyon Block 39, and encountered high pressure in the untested fault block. In response, we temporarily abandoned the well and are assessing plans to complete appraisal as well as development scenarios for the Katmai project.

Troubadour (Mississippi Canyon Block 699; 60% operated working interest) Troubadour was a 2013 natural gas discovery. In 2017, we determined that the asset was impaired in the current forward outlook for natural gas prices and development scenarios, and charged $63 million to impairment of oil and gas properties and $5 million to undeveloped leasehold impairment expense.

Regulatory Environment Various federal agencies overseeing certain of our activities in the Gulf of Mexico have adopted new regulations and are considering others. See Regulations - US Offshore Regulatory Developments below, and Item 1A. Risk Factors .

International

Our international business focuses on offshore opportunities in a number of countries and diversifies our portfolio. Development projects in the Eastern Mediterranean and West Africa have contributed substantially to our production and cash flow growth over the last decade. Previous exploration successes in these areas have also identified additional multiple major development projects that have the potential to contribute to long-term production and cash flow growth in the future.

During 2017 , we progressed development of offshore Israel assets by completing the Tamar 8 development well and commencing drilling activities for the Leviathan 5 development well. In addition, we advanced our Eastern Mediterranean regional natural gas export opportunities by progressing multiple natural gas sales and purchase agreements (GSPAs). See Eastern Mediterranean (Israel and Cyprus) and West Africa (Equatorial Guinea, Cameroon and Gabon), below.

Operations in Equatorial Guinea, Cameroon, Gabon, Cyprus, and Suriname are conducted in accordance with the terms of Production Sharing Contracts (PSCs). Operations in Israel, Newfoundland (Canada) and other foreign locations are conducted in accordance with concession agreements, permits or licenses. See Item 1A. Risk Factors .

Sales volumes and proved reserves estimates for our international operating areas were as follows:

	Year Ended December 31, 2017				December 31, 2017			
	Sales Volumes				Proved Reserves			
	Crude Oil & Condensate	NGLs	Natural Gas	Total	Crude Oil & Condensate	NGLs	Natural Gas [(1)]	Total
	(MBbl/d)	(MBbl/d)	(MMcf/d)	(MBoe/d)	(MMBbls)	(MMBbls)	(Bcf)	(MMBoe)
International								
Israel	—	—	272	46	9	—	5,448	917
Equatorial Guinea	18	—	239	57	29	11	411	108
Total International	18	—	511	103	38	11	5,859	1,025
Equity Investee	2	6	—	8	—	—	—	—
Total	20	6	511	111	38	11	5,859	1,025
Equity Investee Share of Methanol Sales (MMgal)				163				

(1) Includes 3.3 Tcf proved undeveloped reserves related to initial Leviathan field development offshore Israel.

Wells completed in 2017 and productive wells at December 31, 2017 in our international operating areas were as follows:

	Year Ended December 31, 2017	December 31, 2017
	Gross Wells Completed or Participated in [(1)]	Gross Productive Wells
International		
Israel	1	7
Equatorial Guinea	—	28
Total International	1	35

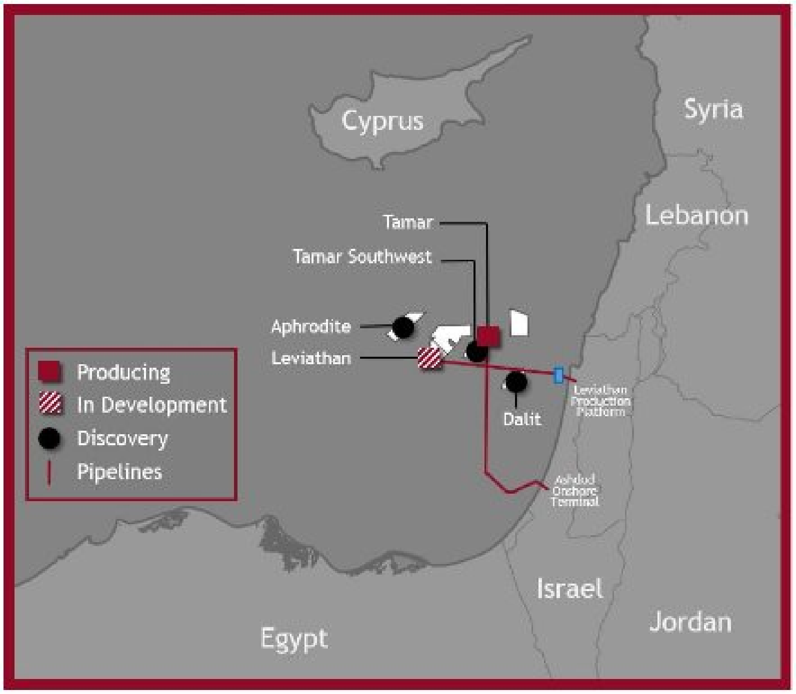
(1) Excludes the Araku-1 exploration well, offshore Suriname.

Eastern Mediterranean (Israel and Cyprus) One of our operating areas is the Eastern Mediterranean, where we have identified the existence of substantial natural gas resources since we obtained our first exploration license offshore Israel in 1998.

Israel, the only producing country in our Eastern Mediterranean area, contributed an average of 272 MMcf/d of natural gas sales volumes in 2017, representing approximately 12% of total consolidated sales volumes, primarily from the Tamar field. With the addition of proved undeveloped reserves associated with Leviathan field development in 2017, Israel represented approximately 47% of total proved reserves at December 31, 2017 . Our leasehold position in the Eastern Mediterranean at December 31, 2017 , included four leases and three licenses operated offshore Israel. Offshore Cyprus, we operate under the terms of a PSC.

At December 31, 2017 , the Eastern Mediterranean position included approximately 78,000 net developed acres and 116,000 net undeveloped acres located between 10 and 90 miles offshore Israel in water depths ranging from 700 feet to 6,500 feet. The license offshore Cyprus covers approximately 33,000 net undeveloped acres adjacent to our Israel acreage.

Locations of our operations in the Eastern Mediterranean as of December 31, 2017 are shown below:



Offshore Israel Noble Energy and our partners have delivered reliable and affordable natural gas to Israeli citizens for over a decade. During this time, we have delivered approximately 2.3 Tcf, gross, of natural gas to Israeli customers, including the Israel Electric Corporation (IEC), the largest supplier of electricity in the country.

We are the first company to construct, operate and produce from a major natural gas development project offshore Israel. Our Mari-B discovery provided the country with its first supply of domestic natural gas in 2004. In 2009, we discovered the Tamar field, another substantial natural gas resource. To maintain and increase natural gas supply to Israel, we developed the Tamar field with a discovery to production cycle time of approximately four years, which is exceptionally fast by global industry standards for an offshore natural gas project of this magnitude and complexity.

In 2010, we discovered the Leviathan field, our largest natural gas discovery to date. The quantity of discovered natural gas resources at Tamar and Leviathan positions Israel to meet domestic needs for decades and to become a significant natural gas exporter. Multiple natural gas customers exist in the region, and Israel's domestic demand is predicted to continue to grow over the next decade, primarily driven by increased use of natural gas over coal to fuel electric power generation. During 2017, growth in power, industrial and residential demand in Israel and first exports to Jordan, coupled with almost 100% asset uptime, enabled us to set a new sales volume record of 956 MMcfe/d, gross, from fields offshore Israel.

In addition to our natural gas discoveries, the Levant Basin is prospective for crude oil discoveries at greater depths. We conducted preliminary exploration activities in 2012 and are analyzing the potential for future exploration.

Domestic Natural Gas Demand As the Israeli economy continues to grow, the demand for natural gas used primarily for electricity generation is also expected to grow. Demand for natural gas in the industrial sector, including refineries, chemical, desalination, cement and other plants, as well as residential uses, is also increasing. These sectors are gaining confidence that a long-term supply of affordable natural gas will be available and are now investing the capital necessary to convert facilities and infrastructure to use natural gas. In addition, government requirements for emissions reductions have also driven incremental demand for natural gas beginning in 2016. We have executed numerous GSPAs with domestic customers. See International Marketing Activities and Delivery and Firm Transportation Commitments , below.

Regional Demand and Exports The Eastern Mediterranean presents an opportunity to match our affordable, abundant supply of natural gas with a substantially undersupplied regional market, including customers in Jordan and Egypt. With the Tamar field online providing reliable production, and the development of the Leviathan field progressing, we are well positioned to supply natural gas to the region for many years.

Israel Natural Gas Projects

Tamar Natural Gas Project (32.5% operated working interest) The Tamar project began production in March 2013 and has peak flow rates of approximately 1.1 Bcf/d, gross, to support seasonal high demand periods. In 2015, we completed the Tamar compression project, which expanded field production capacity by adding compression at the Ashdod onshore terminal (AOT) and in 2017, we completed and commenced production from the Tamar 8 development well. The Tamar 8 well increases supply reliability as domestic demand for natural gas continues to grow.

In 2017, we installed subsea equipment to allow for future tie-back of our 2013 Tamar Southwest discovery into the Tamar platform and other existing infrastructure. We continue to work with the Government of Israel to obtain regulatory approval of the development plan, which would help reinforce the reliability for the Tamar project and support increased customer demand.

We are also assessing the possibility for expansion of the Tamar project. The project would expand field deliverability from the current capacity level of approximately 1.2 Bcf/d to up to approximately 2.1 Bcf/d, a quantity that would allow for additional regional export. Expansion would include a third flow line component and additional producing wells. Timing of project sanction is dependent upon progress relating to domestic and regional marketing efforts of these resources as well as regulatory approvals from respective governments.

The Israel Natural Gas Framework (Framework) provides for reduction in our ownership interest in the Tamar and Dalit fields from 36% to 25% by year-end 2021. In 2016, we divested 3.5% of our interest in these respective fields, partially fulfilling this commitment required by the Framework. Further, on January 29, 2018, we signed a definitive agreement to divest a 7.5% working interest in these respective fields to Tamar Petroleum Ltd (TASE: TMRP). See Item 8. Financial Statements and Supplementary Data – Note. 4. Acquisitions, Divestitures and Merger .

Leviathan Natural Gas Project (39.66% operated working interest) In early 2017, we announced project sanction of the Leviathan natural gas project and recorded initial proved reserves of 3.3 Tcf (551 MMBoe) associated with the first phase of development. The first phase of development of the Leviathan field provides 1.2 Bcf/d of production capacity and consists of four wells, a subsea production system and a shallow-water processing platform, with a connection to an onshore valve station and the Israel Natural Gas Lines (INGL) pipeline network. We expect our share of development costs to total approximately $1.5 billion and to be funded from our share of cash flows from the Tamar asset and expected proceeds to be received from the sell-down of our ownership interest in Tamar as noted above. In addition, we have the ability to borrow under the Leviathan Term Loan Facility (defined below). As we progress the first phase of development, we have included volume capacity expansion optionality on the Leviathan platform to allow for cost effective expansion to meet growing regional natural gas demand.

During 2017, we commenced drilling and continued detailed design and engineering activities and fabrication of onshore facilities, topsides, jacket and subsea equipment. We will continue drilling activities and commence well completions in 2018 as we progress the project towards first gas sales by the end of 2019. As of December 31, 2017 , the project remained within budget and on schedule at approximately 35% complete, with all critical path equipment and major contracts secured.

The marketing and development of natural gas from this asset is intended to serve both domestic demand and regional export. We are actively engaged in natural gas marketing activities and have progressed multiple GSPAs totaling up to approximately 525 MMcf/d, gross (approximately 208 MMcf/d, net) of natural gas from the Leviathan field.

Our largest Leviathan GSPA, with the National Electric Power Company Ltd. (NEPCO) of Jordan, provides for sales of natural gas intended for consumption in power production facilities over a 15-year period. Sales to NEPCO are anticipated to commence at field startup. We continue to market natural gas from the Leviathan field toward realizing full utilization of the 1.2 Bcf/d of production capacity. See Israel Natural Gas Framework and Regulatory Environment, below.

Alon D License In August 2017, the Petroleum Commissioner of Israel granted us a 32-month extension of the Alon D license *(47.059% operated working interest)* to drill an exploration well. We are performing geologic and environmental studies necessary to progress the prospect to an investment decision.

Other Discoveries Offshore Israel Our development plan for the Dalit field *(32.5% operated working interest)* , a 2009 natural gas discovery, was approved by the Government of Israel. Development includes a tieback to the Tamar platform. We are also analyzing 3D seismic data to evaluate the additional potential of the area, including the possible existence of hydrocarbons at deeper intervals.

Asset Impairments No impairment expense was recorded during 2017. During 2016, we recorded impairment expense of $88 million related to certain Leviathan field development concepts which were not selected. During 2015, we recorded impairment expense of $36 million , primarily due to an increase in field abandonment costs. See Item 8. Financial Statements and Supplementary Data – Note 5. Asset Impairments .

Israel Natural Gas Framework and Regulatory Environment We are subject to certain fiscal, antitrust and other regulatory challenges in Israel. These challenges have been addressed with the enactment of the Framework by the Government of Israel.

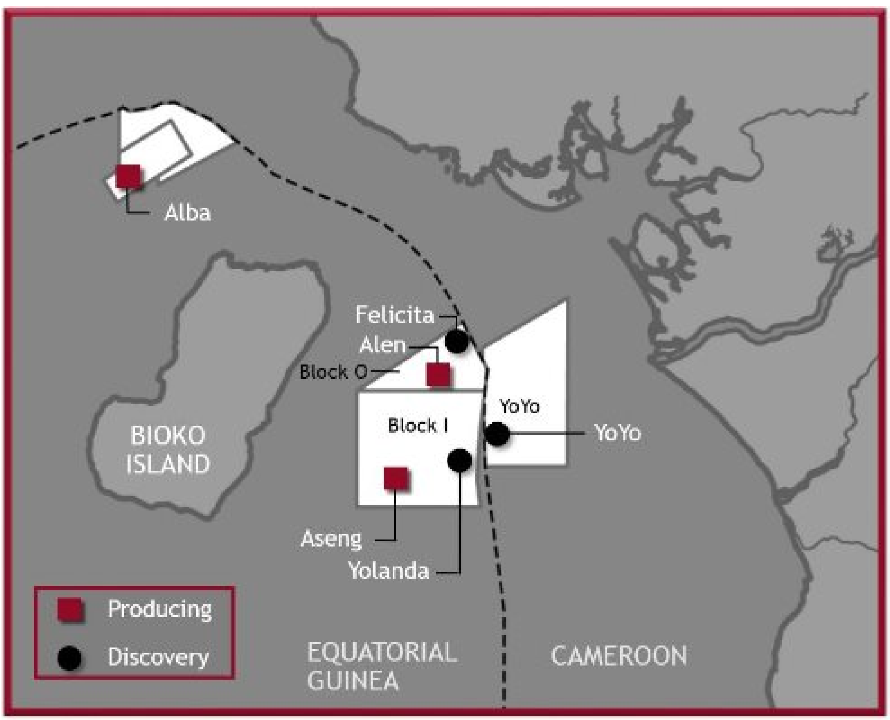
See Regulations – Israel Regulatory Environment and Item 1A. Risk Factors – *Our Eastern Mediterranean discoveries bear certain geopolitical, regulatory, financial and technical challenges that could adversely impact our ability to monetize these natural gas assets.*

Cyprus Natural Gas Project (Offshore Cyprus) During fourth quarter 2015, we entered into a farm-out agreement with a partner for a 35% interest in Block 12, which includes the Aphrodite natural gas discovery, for $171 million. We received initial proceeds of $131 million related to the farm-out agreement in 2016 and received the remaining consideration, subject to post-close adjustments, in January 2017. We continue to operate with a 35% interest. As part of the farm-out process, we negotiated a waiver of our remaining exploration well obligation.

In September 2017, we submitted an updated development plan to the Government of Cyprus. We continue to work with the Government of Cyprus to obtain approval of the development plan and the issuance of an Exploitation License for the Aphrodite field. Receiving an Exploitation License, in conjunction with securing markets for Aphrodite natural gas, will allow us and our partners to perform the necessary FEED studies and progress the project to final investment decision. In preparation for FEED, we and our partners are currently performing preliminary engineering and design (pre-FEED) for the potential development of the Aphrodite field that, as currently planned, would deliver natural gas to regional customers. During 2017, we progressed capital project cost improvements and continued regional natural gas marketing efforts.

West Africa (Equatorial Guinea, Cameroon and Gabon) West Africa is one of our operating areas and includes the Alba field, Block O and Block I offshore Equatorial Guinea, the YoYo PSC, offshore Cameroon, and one block offshore Gabon. In West Africa, our interests can be burdened by overriding royalty interests and/or other government interests. As such, our working interests may differ from our revenue interests. Equatorial Guinea is currently our only producing country in our West Africa segment and, excluding the impact of equity investees, Equatorial Guinea contributed an average of 57 MBoe/d of sales volumes in 2017 and represented approximately 15% of total consolidated sales volumes. At December 31, 2017 , Equatorial Guinea represented approximately 5% of total proved reserves. We held approximately 118,000 net developed acres and 30,000 net undeveloped acres in Equatorial Guinea, 168,000 net undeveloped acres in Cameroon, and 403,000 net undeveloped acres in Gabon at December 31, 2017 .

Locations of our upstream operations in Equatorial Guinea and Cameroon, as of December 31, 2017 are shown on the map below:



Aseng Field Aseng is an oil field on Block I *(40% operated working interest, 38% revenue interest)* , offshore Equatorial Guinea, which began producing in 2011. The development includes five horizontal producing wells flowing to the Aseng floating production, storage and offloading vessel (FPSO) where the crude oil is stored until sold, and natural gas and water are reinjected into the reservoir to maintain pressure and maximize crude oil recoveries. During 2017 , the Aseng field produced approximately 7 MBoe/d, net.

The Aseng FPSO is designed to act as a crude oil production hub, as well as a liquids storage and offloading facility, with capabilities to support future subsea oil field developments in the area. It also has the ability to process and store condensate from natural gas condensate fields in the area, the first of which is Alen. Since it first came online, the Aseng field has maintained reliable performance, averaging over 99% production uptime and, as of December 31, 2017, has produced 89 MMBbls of cumulative gross crude oil production.

Alen Field Alen is a natural gas and condensate field primarily on Block O *(51% operated working interest, 45% revenue interest)* , offshore Equatorial Guinea, which includes three production wells and three natural gas injection wells connected to a production platform that utilizes the Aseng FPSO for storage and offloading. Alen has been producing since 2013 and produced approximately 4 MBoe/d, net, during 2017 . As of December 31, 2017, Alen has produced over 33 MMBbls of cumulative gross condensate production.

The Alen platform is expected to be utilized in our natural gas monetization efforts. See West Africa Natural Gas Monetization, below.

In October 2017, we executed a unitization agreement on the Alen field with our partners and the Government of Equatorial Guinea. The agreement was between Block O and Block I interest owners. We expect the impact on our allocated future sales volumes to be de minimis.

Alba Field Alba is a natural gas and condensate field located offshore Equatorial Guinea *(33% non-operated working interest, 32% revenue interest)* , which has been producing since 1991. Operations include the Alba field and related production and condensate storage facilities, a liquefied petroleum gas (LPG) processing plant where additional condensate is extracted along with LPGs, and a methanol plant capable of producing up to 3,100 gross metric tons per day of methanol. The LPG processing plant and the methanol plant are located on Bioko Island, Equatorial Guinea. During 2017 , Alba field sales volumes totaled 54 MBoe/d, net, reflecting 46 MBoe/d attributable to total sales volumes and 8 MBoe/d attributable to an equity investee.

In April 2017, we executed a unitization agreement on the Alba field with our partner and the Government of Equatorial Guinea. The agreement was between Alba Block and Block D interest owners. As a result of the unitization, our revenue interest going forward changed from 34% to 32%, and our non-operated working interest changed from 35% to 33%. As anticipated, our 2017 sales volumes from the Alba field were lower as a result of the unitization, and the impact on our proved reserves was de minimis. We expect the impact on our allocated future sales volumes to be de minimis.

We sell our share of primary condensate produced in the Alba field under short-term contracts at market-based prices. We sell our share of natural gas production from the Alba field to the LPG plant, the methanol plant and an unaffiliated liquefied natural gas (LNG) plant. The LPG plant is owned by Alba Plant LLC (Alba Plant), in which we have a 28% interest. The methanol plant is owned by Atlantic Methanol Production Company, LLC (AMPCO), in which we have a 45% interest. AMPCO purchases natural gas from the Alba field under a contract that runs through 2026 and subsequently markets the produced methanol primarily to customers in the US and Europe. Alba Plant sells its LPG products and secondary condensate at our marine terminal at prevailing market prices.

We account for both Alba Plant and AMPCO as equity method investments and present our share of income as a component of revenues. We consider these equity method investments essential components of our business as well as necessary and integral elements of our value chain in support of ongoing operations in our West Africa operating area. Our Alba asset teams are fully engaged in operational and financial decisions and exert significant influence in the monetization of the Alba field and Alba Plant. We hold a voting position on AMPCO's leadership team through AMPCO's management committee, and our asset teams influence decisions regarding capital investments, budgets, turnarounds, maintenance and other project matters.

West Africa Natural Gas Monetization We continue our efforts to monetize the significant natural gas resources represented by our discoveries offshore West Africa, including our 2007 Yolanda discovery (Block I), the YoYo discovery, offshore Cameroon, as well as natural gas from our Aseng and Alen fields.

As part of our monetization efforts, a natural gas development team has been working with local governments to evaluate natural gas monetization concepts. After analyzing existing infrastructure, including the Alen platform and other facilities, we believe these assets can be efficiently modified and retrofitted to allow for future commercialization of natural gas. Leveraging existing assets for the development of natural gas minimizes future capital expenditures while providing advantageous financial returns.

Cameroon We have an interest in approximately 168,000 undeveloped acres offshore Cameroon in our YoYo PSC *(100% operated working interest)* . The YoYo-1 exploratory well was drilled in 2007, discovering natural gas and condensate. We are working with the government of Cameroon to evaluate natural gas development options, which will provide a more robust framework directly related to oil and gas operational activities. In June 2017, we converted our mining concession license for the YoYo block into a PSC.

Offshore Gabon We are the operator of Block Doukou Dak *(60% working interest)* , an undeveloped, deepwater area, covering approximately 671,000 gross acres. Our exploration commitment includes an obligation for 3D seismic, which was acquired and processed throughout 2016 and the first half of 2017. We received the final product mid-year 2017 and are currently evaluating the seismic data results.

See also Item 8. Financial Statements and Supplementary Data – Note 6. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs .

Other International

Other international operations include the following:

Offshore Newfoundland (Canada) In November 2016, we acquired a non-operated 25% working interest in exploration parcels (blocks) 3, 4 and 8, and a non-operated 40% working interest in exploration parcel (block) 10. BP Canada Energy Group ULC is the operator of the blocks. We have acquired 3D seismic data which will allow us to assess the economic viability of this exploration prospect.

Offshore Suriname We hold a non-operated 20% working interest in Block 54 offshore Suriname in the Atlantic Ocean. In October 2017, our partner spud the Araku-1exploration well and subsequently plugged and abandoned the well. As a result, we recorded dry hole expense of $7 million and are currently analyzing the well results to update modeling of the basin and review further prospectivity. See Note 5. Asset Impairments .

Offshore Falkland Islands In 2016, following completion of our geological assessment, we exited all licenses, excluding the PL-001 which contains the Rhea prospect. The exit resulted in a $25 million undeveloped leasehold impairment expense. As of December 31, 2017, there is no remaining net book value associated with the assets.

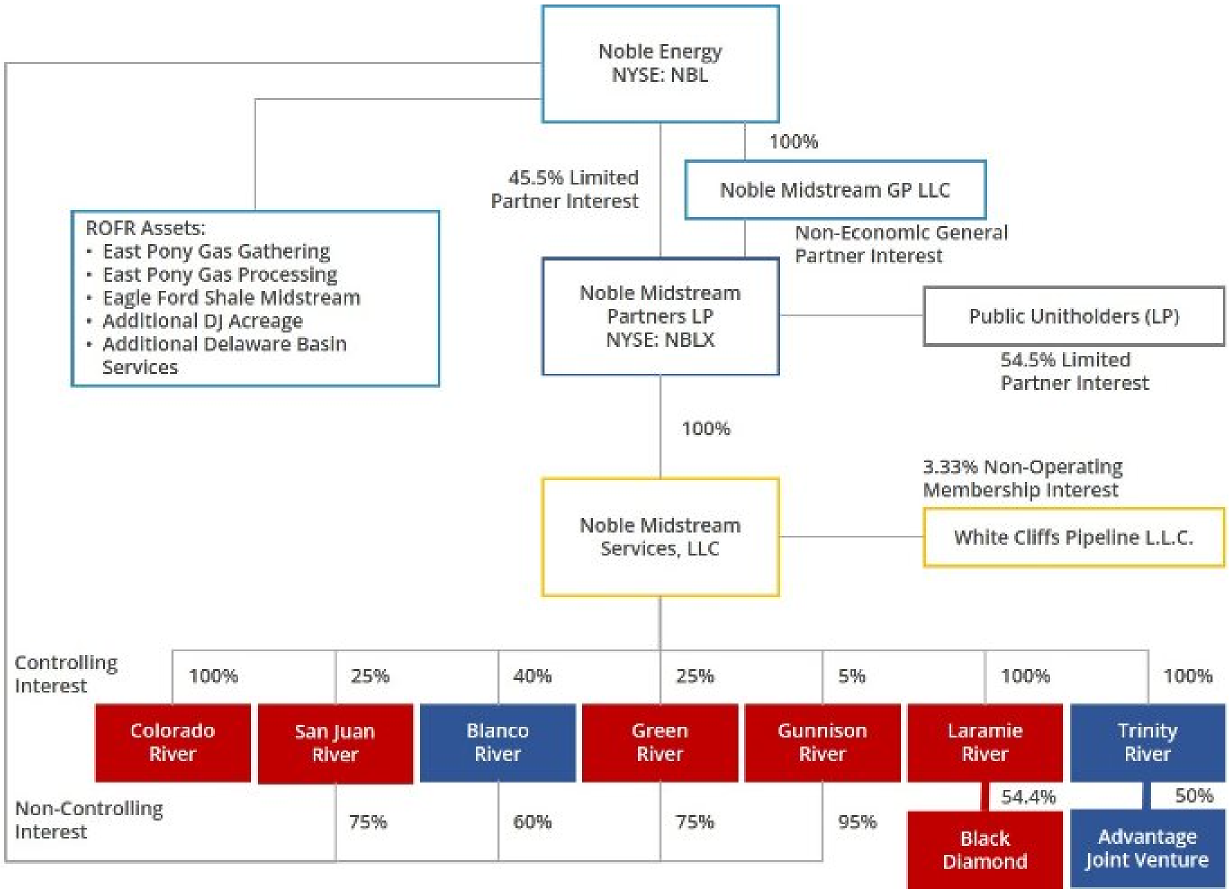
North Sea The non-operated MacCulloch field is currently undergoing decommissioning activities. Due to its size and location, field abandonment is a multi-year process, requiring several phases. Therefore, our share of estimated field abandonment costs, recorded as an asset retirement obligation, may change over time. For example, during 2017, the operator of the MacCulloch field notified working interest owners that the scope and magnitude of decommissioning activities has been revised downward, resulting in lower projected field abandonment costs. As such, we recorded a revision of $42 million in 2017 that decreased our estimated asset retirement obligation for the remediation project. The discounted obligation totaled 44 million at December 31, 2017. We will continue to monitor the status and costs of the project and will adjust our estimate accordingly.

Midstream – Properties and Activities

We continue to develop our Midstream business, which includes gathering, treating, and transportation assets as well as water-related infrastructure, including fresh water delivery and produced water disposal assets, that support our upstream operations. Our Midstream assets are strategically located with our exploration and production activities in the DJ and Delaware Basins. These assets also provide services to third party customers.

Our Midstream operations include those of Noble Midstream Partners, a publicly traded consolidated subsidiary and limited partnership that owns, operates, develops, and acquires a wide range of domestic midstream infrastructure assets. Noble Midstream Partners is a fee-based, growth-oriented Delaware master limited partnership formed in December 2014 organized in a development company structure. At December 31, 2017, our ownership interest in Noble Midstream Partners consisted of a 45.5% limited partner interest, the entire non-economic general partner interest, and all of the incentive distribution rights.
On September 20, 2016, Noble Midstream Partners completed its initial public offering of common units, which provided access to capital markets to support funding of our US onshore midstream investment program.

The following diagram depicts our organizational structure as of December 31, 2017. Development companies identified in red and blue indicate the location of the assets as either in the DJ Basin or Delaware Basin, respectively.



Advantage Joint Venture In April 2017, Noble Midstream Partners, along with its partner, Plains Pipeline, L.P., formed the Advantage joint venture (Advantage Joint Venture) and subsequently completed the acquisition of Advantage Pipeline L.L.C. (Advantage Pipeline). Noble Midstream Partners serves as the operator of the Advantage Pipeline System, which includes a 70-mile crude oil pipeline (Advantage Delaware Basin Pipeline) in the Delaware Basin from Reeves County, Texas to Crane County, Texas with 150 MBbls per day of capacity (expandable to over 200 MBbls per day) and 490 MBbls of storage capacity. Noble Midstream Partners owns a 50% interest in the joint venture.

Asset Contribution On June 26, 2017, Noble Midstream Partners acquired an additional 15% limited partner interest in Blanco River DevCo LP (Blanco River DevCo), increasing its ownership to 40% of Blanco River DevCo, and acquired the remaining 20% limited partner interest in Colorado River DevCo LP (Colorado River DevCo) from Noble Energy. Blanco River DevCo holds Noble Midstream Partners' Delaware Basin in-field gathering dedications for crude oil and produced water gathering services on approximately 111,000 net acres, with substantially all of the acreage also dedicated for natural gas gathering. Colorado River DevCo consists of gathering systems across Noble Energy's Wells Ranch and East Pony development areas in the DJ Basin.

Black Diamond Gathering and Acquisition of Saddle Butte Pipeline In December 2017, Noble Midstream Partners and Greenfield Midstream, LLC (Greenfield Midstream) formed an entity, Black Diamond Gathering LLC (Black Diamond Gathering), to acquire Saddle Butte Rockies Midstream, LLC and affiliates (Saddle Butte). 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. Saddle Butte has approximately 141,000, net dedicated acres from six customers under fixed fee arrangements.

The transaction closed on January 31, 2018, with Noble Midstream Partners funding $319.9 million of the total cash consideration of $638.5 million. Noble Midstream Partners received a 54.4% equity ownership and Greenfield Midstream will own the remaining 45.6% of Black Diamond Gathering. Noble Midstream Partners will operate the Saddle Butte system.

Marcellus Shale CONE Gathering Divestiture In late 2017 , we announced the signing of a definitive agreement to divest our 50% interest in CONE Gathering, LLC (CONE Gathering). CONE Gathering owns the general partner of CONE Midstream Partners LP (CONE Midstream). As of December 31, 2017, the net book value of the assets held by Noble Energy was approximately $181 million. In January 2018, we closed the sale of CONE Gathering, receiving cash proceeds of $308 million. We now hold 21.7 million common units representing limited partner interests in CNX Midstream Partners LP (NYSE: CNXM). As of December 31, 2017, the net book value of the limited partner interests was approximately $70 million.

See Item 8. Financial Statements and Supplementary Data – Note 4. Acquisitions, Divestitures and Merger and Item 8. Financial Statements and Supplementary Data – Note 7. Equity Method Investments .

Major Construction Projects Our activity in 2017 primarily focused on construction and development of midstream infrastructure assets, including:

- completion of a produced water expansion project servicing the Wells Ranch IDP area;
- completion of crude oil and produced water gathering systems servicing the Greeley Crescent IDP area;
- completion of the connection from the CGF in the Delaware Basin to the Advantage Pipeline, which began allowing crude oil to flow from the completed facility to the Advantage Pipeline in third quarter 2017;
- completion of the construction of two CGFs in the Delaware Basin; and
- continued construction activities on expansion of our freshwater system servicing the Mustang IDP area and the commencement of construction of the backbone gathering infrastructure build-out, which is expected to be completed in early 2018.

In 2018, we expect to continue our midstream investment to focus on the DJ and Delaware Basins to meet the needs of our upstream operations.

Third Party Sales During 2017, we began providing crude oil and produced water gathering and fresh water delivery services to an unaffiliated third party in the Greeley Crescent IDP area of the DJ Basin.

Proved Reserves Disclosures

Internal Controls Over Reserves Estimates Our policies and processes regarding internal controls over the recording of reserves estimates require reserves to be in compliance with the Securities and Exchange Commission (SEC) definitions and guidance and prepared in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Our internal controls over reserves estimates also include the following:

- the Audit Committee of our Board of Directors reviews significant reserves changes on an annual basis;
- fields that meet a minimum reserve quantity threshold, newly sanctioned development projects, and certain fields selected on a rotational basis, which combined represent over 80% of our proved reserves, are audited by Netherland, Sewell & Associates, Inc. (NSAI), a third-party petroleum consulting firm, on an annual basis; and
- NSAI is engaged by, and has direct access to, the Audit Committee. See Third-Party Reserves Audit, below.

Responsibility for compliance in reserves estimation is delegated to our Corporate Reservoir Engineering group. Qualified petroleum engineers in our Houston and Denver offices prepare all reserves estimates for our different geographical regions. These reserves estimates are reviewed and approved by regional management and senior engineering staff with final approval by the Senior Vice President – Corporate Development and certain other members of senior management.

Our Senior Vice President – Corporate Development oversees our corporate business development, strategic planning, and reserves departments. He is the technical person primarily responsible for overseeing the preparation of our reserves estimates and the third-party audit of our reserves estimates. He has Bachelor of Science and Master of Science degrees in Petroleum Engineering and over 37 years of industry experience with positions of increasing responsibility in engineering, evaluations, and business unit management at the Company. The Senior Vice President – Corporate Development reports directly to our Chief Executive Officer.

Technologies Used in Reserves Estimation The SEC's reserves rules allow the use of techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

We used a combination of production and pressure performance, wireline wellbore measurements, simulation studies, offset analogies, seismic data and interpretation, wireline formation tests, geophysical logs and core data to calculate our reserves estimates, including the material additions to the 2017 reserves estimates.

Based on reasonable certainty of reservoir continuity in US onshore formations where we operate, we may record proved reserves associated with wells more than one offset location away from an existing proved producing well. All of our wells drilled that were more than one offset away from a proved producing well at the time of drilling were determined to be economically producible.

Third-Party Reserves Audit In each of the years 2017 , 2016 , and 2015 , we retained NSAI to perform audits of proved reserves. The reserves audit for 2017 included a detailed review of six of our major US onshore and international fields, which covered approximately 92% of US proved reserves and 99% of international proved reserves (95% of total proved reserves). The reserves audit for 2016 included a detailed review of nine of our major US onshore and international fields, which covered approximately 88% of US proved reserves and 99.9% of international proved reserves (92% of total proved reserves). The reserves audit for 2015 included a detailed review of nine of our major fields and covered approximately 91% of total proved reserves.

In connection with the 2017 reserves audit, NSAI prepared its own estimates of our proved reserves. In order to prepare its estimates of proved reserves, NSAI examined our estimates with respect to reserves quantities, future production rates, future net revenue, and the present value of such future net revenue. NSAI also examined our estimates with respect to reserves categorization, using the definitions for proved reserves set forth in Rule 4-10(a) of Regulation S-X and subsequent SEC staff interpretations and guidance.

In the conduct of the reserves audit, NSAI did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, crude oil and natural gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the fields and sales of production. However, if in the course of the examination something came to the attention of NSAI which brought into question the validity or sufficiency of any such information or data, NSAI did not rely on such information or data until it had satisfactorily resolved its questions relating thereto or had independently verified such information or data.

NSAI determined that our estimates of reserves have been prepared in accordance with the definitions and regulations of the SEC, including the criteria of "reasonable certainty," as it pertains to expectations about the recoverability of reserves in future years, under existing economic and operating conditions, consistent with the definition in Rule 4-10(a)(24) of Regulation S-X. NSAI issued an unqualified audit opinion on our proved reserves at December 31, 2017 , based upon their evaluation. NSAI concluded that our estimates of proved reserves were, in the aggregate, reasonable and have been prepared in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. NSAI's report is attached as Exhibit 99.1 to this Annual Report on Form 10-K.

When compared on a field-by-field basis, some of our estimates are greater and some are less than the estimates of NSAI. Given the inherent uncertainties and judgments that go into estimating proved reserves, differences between internal and external estimates are to be expected. For proved reserves at December 31, 2017 , on a quantity basis, the NSAI field estimates ranged from 18 MMBoe or 8% below to 9 MMBoe or 2% above as compared with our estimates on a field-by-field basis. Differences between our estimates and those of NSAI are reviewed for accuracy but are not further analyzed unless the aggregate variance is greater than 10%. Reserves differences at December 31, 2017 were, in the aggregate, approximately 17 MMBoe, or less than 1%.

Proved Reserves

We have historically added reserves through our exploration program, development activities, and acquisition of producing properties. Changes in proved reserves were as follows:

	Year Ended December 31,		
	2017	2016	2015
(MMBoe)			
Proved Reserves Beginning of Year	1,437	1,421	1,404
Revisions of Previous Estimates	135	64	(216)
Extensions, Discoveries and Other Additions	736	179	100
Purchase of Minerals in Place	57	4	269
Sale of Minerals in Place	(261)	(77)	(6)
Production	(139)	(154)	(130)
Proved Reserves End of Year	1,965	1,437	1,421

Revisions Revisions of previous estimates represent changes in previous reserves estimates, either upward (positive) or downward (negative), resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors, such as commodity prices, operating costs, development costs or abandonment costs. Revisions primarily included the following:

- positive price revisions of 30 MMBoe globally, as well as positive performance revisions of 49 MMBoe for the Tamar field, offshore Israel, 30 MMBoe for the Delaware Basin and 22 MMBoe for the Eagle Ford Shale, partially offset by abandonment cost increases for US onshore in 2017 ;

- positive revisions of 43 MMBoe for the DJ Basin, 42 MMBoe for the Marcellus Shale, 11 MMBoe for the Delaware Basin, and 10 MMBoe for the Alba field, offshore Equatorial Guinea, due to increased performance and/or lower development or operating costs; partially offset by negative revisions of 53 MMBoe due to lower commodity prices in 2016 ; and
- negative price revisions of 307 MMBoe, partially offset by positive performance revisions of 81 MMBoe for the Marcellus Shale and 17 MMBoe for the Delaware Basin in 2015 .

Extensions, Discoveries and Other Additions These are additions to proved reserves that result from (1) extension of the proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to discovery and (2) discovery of new fields with proved reserves or of new reservoirs of proved reserves in old fields. Extensions, discoveries and other additions primarily included the following:

- increases primarily relate to 99 MMBoe in the DJ Basin and 77 MMBoe in the Delaware Basin as a result of enhanced completion techniques in our horizontal drilling programs and an increase of 551 MMBoe due to the sanction of the first phase of development at the Leviathan natural gas field in 2017 ;
- increases of 83 MMBoe in the DJ Basin, 42 MMBoe in the Marcellus Shale, 33 MMBoe in the Delaware Basin and 21 MMBoe in the Eagle Ford Shale, all associated with our horizontal drilling programs in 2016 ; and
- increases of 86 MMBoe in the DJ Basin and 14 MMBoe in the Marcellus Shale associated with our horizontal drilling programs in 2015 .

Approximately 70% of our 2018 capital program is allocated to US onshore, primarily the DJ Basin, Delaware Basin and Eagle Ford Shale, and more than 25% is allocated to offshore Israel. In turn, we expect that future reserves additions will primarily come from our development projects in the US onshore and offshore Israel. Potential new discoveries resulting from our exploration programs in our operational areas as well as global new ventures programs could also lead to future reserve additions. In addition, we may also purchase proved properties in strategic acquisitions. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Acquisition, Capital Expenditures and Other Exploration Expenditures .

Purchase of Minerals in Place We occasionally enhance our asset portfolio with strategic acquisitions of producing properties. Purchases primarily included the following:

- an increase of 57 MMBoe in the Delaware Basin primarily as a result of the Clayton Williams Energy Acquisition in 2017; and
- the acquisition of additional acreage, primarily in the Eagle Ford Shale and Delaware Basin in Texas in 2015 in connection with the Rosetta Merger.

Sale of Minerals in Place We maintain an ongoing portfolio management program through which we may periodically divest assets. Sales primarily included the following:

- a reduction of 241 MMBoe related to the Marcellus Shale upstream divestiture, as well as 20 MMBoe associated with divestment of non-strategic US onshore assets in 2017;
- a reduction of 36 MMBoe in Israel driven by our 3.5% sale of Tamar working interest, as well as a 29 MMBoe divestment in the Marcellus Shale in 2016; and
- the sale of non-strategic US onshore assets in 2015.

See Items 1. and 2. Business and Properties and Item 8. Financial Statements and Supplementary Data – Note 4. Acquisitions, Divestitures and Merger .

Production See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations - E&P - Revenues and Critical Accounting Policies and Estimates – Reserves and Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Information (Unaudited) .

Proved Undeveloped Reserves (PUDs) As of December 31, 2017 , our PUDs totaled 249 MMBbls of crude oil and condensate, 4.5 Tcf of natural gas, and 99 MMBbls of NGLs for a total of 1,097 MMBoe, or 56% of proved reserves. Changes in PUDs that occurred during the year are summarized below:

	United States	Israel	Total
(MMBoe)			
Proved Undeveloped Reserves Beginning of Year	422	64	486
Revisions of Previous Estimates	26	—	26
Extensions, Discoveries and Other Additions	174	551	725
Purchase of Minerals in Place	36	—	36
Sale of Minerals in Place	(54)	—	(54)
Conversion to Proved Developed	(122)	—	(122)
Proved Undeveloped Reserves End of Year	482	615	1,097

Revisions of previous estimates include the transfer of PUDs to unproved reserve categories as a result of changes in development plans and/or the impact of changes in commodity prices, and the addition of new PUDs arising from current development plans. Positive revisions of 26 MMBoe in the US for 2017 included 7 MMBoe related to positive price revisions and 19 MMBoe related to enhancements of our horizontal drilling programs.

Extensions, discoveries and other additions include the addition of proved reserves through additional drilling or the discovery of new reservoirs in proven fields. During 2017 , we recorded the following additions as a result of successful expansion of our long lateral well programs in US onshore and recording of reserves for Leviathan:

- 94 MMBoe in the DJ Basin;
- 74 MMBoe in the Delaware Basin;
- 6 MMBoe in the Eagle Ford Shale; and
- 551 MMBoe in the Leviathan field.

Conversion to proved developed reserves included the following transfers:

- 34 MMBoe in the DJ Basin;
- 17 MMBoe in the Delaware Basin;
- 60 MMBoe in the Eagle Ford Shale; and
- 11 MMBoe in the Marcellus Shale, prior to divestiture.

US PUDs Locations In 2017 , we converted 122 MMBoe of our US PUDs, or 29% of our US PUDs beginning balance, to developed status. Based on our current inventory of identified horizontal well locations and our anticipated rate of drilling and completion activity, we expect our US PUDs recorded as of December 31, 2017 to be converted to proved developed reserves within five years of initial disclosure.

As of December 31, 2017 , our US PUDs included:

- 263 MMBoe in the DJ Basin;
- 181 MMBoe in the Delaware Basin; and
- 38 MMBoe in the Eagle Ford Shale.

Our PUDs are expected to be recovered from new wells on undrilled acreage or from existing wells where additional capital expenditures are required for completion, such as drilled but uncompleted (DUC) wells. As of December 31, 2017 , we had approximately 32 MMBoe of PUDs associated with DUC well locations related to our US onshore operations, approximately 75% of which are in the DJ Basin and the remainder are in the Delaware Basin and Eagle Ford Shale.

International PUDs Locations As of December 31, 2017 , our international PUDs included 615 MMBoe in Israel, of which 551 MMBoe relate to the Leviathan field, which is currently in the first phase of development. The Tamar field contains 35 MMBoe, and the Tamar Southwest field, which is awaiting government approval of the development plan, contains 29 MMBoe. Our Tamar Southwest PUDs of 29 MMBoe, or less than 5% of our international PUDs, are expected to remain undeveloped for five years or longer since initial disclosure in 2013. We have been working with the government of Israel for the approval of the development plan and have continued capital investment within this field, including laying subsea equipment in 2017 for future tie-in of field production into existing Tamar infrastructure. Other than the Tamar Southwest PUDs, we expect all of our international PUDs, including those associated with the initial phase of development at the Leviathan field, to be converted to proved developed reserves within five years of initial disclosure.

Development Costs Costs incurred to convert PUDs to proved developed reserves were approximately $1.2 billion in 2017 , $656 million in 2016 , and $1.5 billion in 2015 . Costs incurred in 2017 primarily related to the DJ Basin, Delaware Basin and Eagle Ford Shale development projects, as well as certain costs incurred for the development of the Tamar 8 well. In addition, we incurred approximately $416 million in 2017 to advance the development of the Leviathan PUDs which are expected to be converted to proved developed reserves in 2019.

Estimated future development costs relating to the development of all PUDs are projected to be approximately $1.7 billion in 2018 , $1.9 billion in 2019 , and $1.4 billion in 2020 . Estimated future development costs include capital spending on development projects and PUDs related to development projects will be reclassified to proved developed reserves when production commences.

Drilling Plans Our long range development plans will result in the conversion of all PUDs to developed reserves within five years of their initial disclosure, with the exception of the previously mentioned Tamar Southwest PUDs. PUDs associated with the Tamar Southwest field are expected to be converted to proved developed reserves prior to the end of 2020 as contemplated in our long range development plans, subject to local government approval. Initial production from all PUDs is expected to begin during the years 2018 to 2022 .

In accordance with US GAAP, we disclose a standardized measure of discounted future net cash flows related to our proved reserves. In order to standardize the measure, all companies are required to use a 10% discount rate and SEC pricing rules. This prescribed calculation can result in some PUDs having negative present worth, meaning while these PUDs have positive cash flows, the rate of return is lower than 10%. As of December 31, 2017 , we had no PUDs with a negative present worth when discounted at 10%.

We consider the economic development of reserves based on our estimates of future pricing, future investments, production and other economic factors that are excluded from the SEC reserves requirements and are committed to developing PUDs within five years of initial disclosure. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Operating Outlook – 2018 Capital Investment Program .

For more information see the following:

- Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies and Estimates – Reserves for further discussion of our reserves estimation process; and
- Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Information (Unaudited) for additional information regarding estimates of crude oil, NGL and natural gas reserves, including estimates of proved, proved developed, and proved undeveloped reserves, the standardized measure of discounted future net cash flows, and the changes in the standardized measure of discounted future net cash flows.

Sales Volumes, Price and Cost Data Sales volumes, price and cost data are as follows:

	Sales Volumes			Average Sales Price			Production Cost (1)
	Crude Oil & Condensate MBbl	NGLs MBbl	Natural Gas MMcf	Crude Oil & Condensate Per Bbl	NGLs Per Bbl	Natural Gas Per Mcf	Per BOE
Year Ended December 31, 2017 (2)							
United States							
DJ Basin	21,564	6,911	70,660	$ 50.20	$ 25.22	$ 2.96	$ 4.46
Marcellus Shale	233	1,654	63,443	36.91	23.81	3.15	1.05
Other US	18,757	12,521	87,364	48.01	22.34	2.99	6.48
Total US	40,554	21,086	221,467	49.11	23.40	3.02	4.81
Israel							
Tamar Field	130	—	96,894	46.95	—	5.37	2.02
Other Israel	—	—	2,346	—	—	3.56	N/M
Total Israel	130	—	99,240	46.95	—	5.32	2.01
Equatorial Guinea (3)	6,460	—	87,269	53.68	—	0.27	4.30
Total Consolidated Operations	47,144	21,086	407,976	49.73	23.40	3.01	$ 4.31
Equity Investee (4)	662	2,162	—	55.13	38.48	—	N/M
Total	47,806	23,248	407,976	$ 49.84	$ 24.81	$ 3.01	N/M
Year Ended December 31, 2016 (2)							
United States							
DJ Basin	20,342	7,651	82,431	$ 40.85	$ 14.66	$ 2.80	$ 3.99
Marcellus Shale	431	3,094	177,872	28.25	16.34	1.68	0.90
Other US	15,572	9,087	62,017	38.26	14.65	2.42	6.65
Total US	36,345	19,832	322,320	39.59	14.92	2.11	3.74
Israel							
Tamar Field	140	—	102,280	36.67	—	5.22	2.58
Other Israel	—	—	528	—	—	3.20	N/M
Total Israel	140	—	102,808	36.67	—	5.21	2.60
Equatorial Guinea (3)	9,415	—	85,987	43.54	—	0.27	4.40
Total Consolidated Operations	45,900	19,832	511,115	40.39	14.92	2.42	$ 3.72
Equity Investee (4)	629	1,993	—	45.44	26.30	—	N/M
Total	46,529	21,825	511,115	$ 40.46	$ 15.96	$ 2.42	N/M
Year Ended December 31, 2015 (2)							
United States							
DJ Basin	20,909	6,910	85,369	$ 44.37	$ 14.21	$ 2.53	$ 5.75
Marcellus Shale	673	3,480	143,465	22.39	14.04	1.75	1.38
Other US	7,680	3,705	29,806	42.83	13.25	2.56	7.15
Total US	29,262	14,095	258,640	43.46	13.91	2.10	4.46
Israel							
Tamar Field	121	—	91,884	46.91	—	5.34	3.12
Other Israel	—	—	136	—	—	3.01	N/M
Total Israel	121	—	92,020	46.91	—	5.34	3.15
Equatorial Guinea (3)	11,416	—	82,729	48.85	—	0.27	5.22
United Kingdom	88	—	49	55.52	—	6.32	N/M
Total Consolidated Operations	40,887	14,095	433,438	45.00	13.91	2.44	$ 4.54
Equity Investee (4)	554	1,850	—	48.85	28.40	—	N/M
Total	41,441	15,945	433,438	$ 45.05	$ 15.59	$ 2.44	N/M

N/M Amount is not meaningful.

(1) Average production cost includes crude oil and natural gas operating costs and workover and repair expense and excludes production and ad valorem taxes and transportation expense.

(2) For each respective year, reserves associated with the Delaware Basin or the Eagle Ford Shale did not comprise 15% or more of total reserves on a BOE basis.
(3) Natural gas from the Alba field is under contract for $0.25 per MMBtu to a methanol plant, an LPG plant, an LNG plant and a power generation plant. The methanol and LPG plants are owned by affiliated entities accounted for under the equity method.
(4) Volumes represent sales of condensate and LPG from the LPG plant in Equatorial Guinea.

Revenues from sales of crude oil, NGLs and natural gas have accounted for 90% or more of consolidated revenues for each of the last three fiscal years.

At December 31, 2017 , our operated properties accounted for substantially all of our total production. Being the operator of a property improves our ability to directly influence production levels and the timing of projects, while also enhancing our control over operating expenses and capital expenditures.

Productive Wells The number of productive crude oil and natural gas wells in which we held an interest at December 31, 2017 was as follows:

	Crude Oil Wells		Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	3,565	2,682	4,918	4,382	8,483	7,064
Israel	—	—	7	2	7	2
Equatorial Guinea	5	2	23	8	28	10
Total	3,570	2,684	4,948	4,392	8,518	7,076

Productive wells are producing wells and wells mechanically capable of production. A gross well is a well in which a working interest is owned. The number of gross wells is the total number of wells in which a working interest is owned. The number of net wells is the sum of the fractional working interests owned in gross wells expressed as whole numbers and fractions thereof. Wells with multiple completions are counted as one well in the table above.

Developed and Undeveloped Acreage Developed and undeveloped acreage (including both leases and concessions) in which we held an interest at December 31, 2017 was as follows:

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
(thousands of acres)				
United States				
Onshore	754	504	564	358
Gulf of Mexico	93	52	247	171
Total United States	847	556	811	529
International				
Israel	185	78	284	116
Equatorial Guinea (1)	284	118	81	30
Suriname	—	—	2,095	419
Newfoundland, Canada	—	—	2,331	681
Gabon	—	—	671	403
Cyprus	—	—	95	33
Cameroon	—	—	168	168
Other International	2	—	284	211
Total International	471	196	6,009	2,061
Total	1,318	752	6,820	2,590

(1) Undeveloped acreage includes an exploration lease totaling approximately 55,000 gross (19,000 net) acres which had expired in 2016. The lease was subsequently negotiated with the government of Equatorial Guinea in 2017 and was extended.

Developed acreage is comprised of leased acres that are within an area spaced by or assignable to a productive well. Undeveloped acreage is comprised of leased acres with defined remaining terms and not within an area spaced by or assignable to a productive well. A gross acre is any leased acre in which a working interest is owned. A net acre is comprised of the total of the owned working interest(s) in a gross acre expressed in a fractional format.

The above table includes certain undeveloped acreage that is set to expire if production is not established or we take no other action to extend the terms of the leases, licenses, or concessions within a specified period of time. Approximately 0.9 million (including 0.4 million in Suriname and 0.4 million in Gabon), 0.3 million , and 0.1 million net acres will expire in 2018 , 2019 , and 2020 , respectively.

Drilling Activity The results of crude oil and natural gas wells drilled and completed for each of the last three years were as follows:

	Net Exploratory Wells			Net Development Wells			
	Productive	Dry	Total	Productive	Dry	Total	Total
Year Ended December 31, 2017							
United States	—	—	—	185.3	—	185.3	185.3
Israel	—	—	—	0.3	—	0.3	0.3
Suriname	—	0.2	0.2	—	—	—	0.2
Total	—	0.2	0.2	185.6	—	185.6	185.8
Year Ended December 31, 2016							
United States	0.4	0.5	0.9	156.7	—	156.7	157.6
Total	0.4	0.5	0.9	156.7	—	156.7	157.6
Year Ended December 31, 2015							
United States	1.5	4.0	5.5	212.5	—	212.5	218.0
Equatorial Guinea	—	—	—	0.3	—	0.3	0.3
Cameroon	—	0.5	0.5	—	—	—	0.5
Other International	—	0.4	0.4	—	—	—	0.4
Total	1.5	4.9	6.4	212.8	—	212.8	219.2

In addition to the wells drilled and completed in 2017 included in the table above, wells that were in the process of drilling or completing at December 31, 2017 were as follows:

	Exploratory [1]		Development [2]		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	1	0.5	114	105.0	115	105.5
Israel	1	0.3	5	2.0	6	2.3
Equatorial Guinea	2	0.9	—	—	2	0.9
Cameroon	1	1.0	—	—	1	1.0
Cyprus	1	0.4	—	—	1	0.4
Total	6	3.1	119	107.0	125	110.1

(1) Includes exploratory wells drilled and suspended awaiting a sanctioned development plan or being evaluated to assess the economic viability of the well.
(2) Includes wells pending completion activities. Israel development wells include the Leviathan 3, 4, 5 and 7 development wells and the Tamar Southwest well.

See Item 8. Financial Statements and Supplementary Data – Note 6. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs for additional information on suspended exploratory wells.

Domestic Marketing Activities Crude oil, natural gas, condensate and NGLs produced in the US onshore and Gulf of Mexico are sold under short-term and long-term contracts at market-based prices adjusted for location and quality. Onshore production of crude oil and condensate is distributed through pipelines and by trucks and rail cars to gatherers, transportation companies and refineries. Gulf of Mexico production is distributed through pipelines.

With the advent of US onshore shale gas, demand has increased for access to takeaway pipelines for ballooning production volumes. For example, in the Permian Basin, midstream suppliers are working to construct new gathering, transportation and processing facilities or to repurpose existing infrastructure in an effort to proactively outpace anticipated production growth as well as expected future LNG demand from export facilities on the Gulf Coast.

International Marketing Activities Our share of crude oil and condensate from the Aseng and Alen fields is sold at market-based prices to Glencore Energy UK Ltd (Glencore Energy). Our share of crude oil and condensate from the Alba field is sold to Glencore Energy under a short-term sales contract, subject to renewal. These products are transported by tanker.

Natural gas from the Alba field is sold for $0.25 per MMBtu to a methanol plant, an LPG plant, an unaffiliated LNG plant and a power generation plant. The sales contract with the methanol plant runs through 2026, and the sales contract with the LNG plant runs through 2023. The methanol and LPG plants are owned by affiliated entities accounted for under the equity method.

In Israel, we sell natural gas from the Tamar field, and have agreements with multiple customers to sell natural gas under long-term contracts, with initial terms ranging from 15 to 17 years. See Delivery and Firm Transportation Commitments, below.

Delivery and Firm Transportation Commitments

Domestic Contracts We have entered into various long-term gath ering, processing and transportation contracts for some of our US onshore production, with remaining terms of one to 11 years. We use long-term contracts such as these to provide production flow assurance and ensure access to markets for our products at the best possible price and at the lowest possible logistics cost .

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

For 2017 , 2016 , and 2015 , we incurred expense of approximately $47 million , $58 million , and $33 million , respectively, related to volume deficiencies and/or unutilized commitments primarily in our US onshore operations. These amounts are recorded as marketing expense in our consolidated statements of operations.

We expect to continue to incur expense related to deficiency and/or unutilized commitments in the near-term. Should commodity prices decline or if we are unable to continue to develop our properties as planned, or certain wells become uneconomic and are shut-in, we could incur additional shortfalls in delivering or transporting the minimum volumes and we could be required to make payments in the event that these commitments are not otherwise offset. We continually seek to optimize under-utilized assets through capacity release and third-party arrangements, as well as, for example, through the shifting of transportation of production from rail cars to pipelines when we receive a higher netback price. We may continue to experience these shortfalls both in the near and long-term.

Our financial commitments under these contracts are included in our contractual obligations disclosures. In addition, we have retained certain other firm transportation agreements after the completing the Marcellus Shale upstream divestiture. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Contractual Obligations .

Israel Natural Gas Sales and Purchase Agreements We currently sell natural gas from our Tamar field, offshore Israel, to the IEC and numerous other Israeli purchasers, including independent power producers, cogeneration facilities and industrial companies. Most contracts provide for the sale of natural gas over an initial term of 15 to 17 years. Some of the contracts provide f or an increase or reduction in total quantities, and some contracts are interruptible during certain contract periods. Sales prices may be based on an initial base price subject to price indexation over the life of the contract and have a contractual floor. The IEC contract provides for price reopeners in certain years with limits on the increase/decrease from the contractual price.

Under the contracts, we and our partners have a financial exposure in the event we cannot fully deliver the contract quantities. This exposure is capped by contract and will be reflected as a reduction in sales price to the purchaser for periods in which we are delivering partial contract quantities, or as a direct payment to the customer under certain circumstances and with a cap. The cap is subject to force majeure considerations. We believe that any such sales price adjustments or direct payments would not have a material impact on our earnings or cash flows.

As of December 31, 2017 , a total of approxima tely 5.4 Tcf, gross (1.7 Tcf, net), of natural gas remained to be delivered under our Tamar contracts. As of December 31, 2017 , we have recor ded 2.0 Tcf, net, of proved na tural gas reserves, including proved developed reser ves of 1.8 Tcf, net, and PUD r eserve s of 212 Bcf, net, for the Tamar field. Based on current production levels and future development plans, our available quantities of prove d reserves are more than sufficient to meet near-term delivery commitments associated with Tamar sale agreements without further capital investment.

We are also actively engaged in domestic and regional marketing activities for future sales of the natural gas reserves recorded for the Leviathan field . See Eastern Mediterranean (Israel and Cyprus), above.

Significant Purchasers BP North American Funding (BP) and Shell Trading (US) (Shell) were the largest single purchasers of our 2017 production. Sales to BP accounted for 10% of 2017 total crude oil, natural gas and NGL sales, or 15% of 2017 crude oil sales. Sales to Shell accounted for 13% of our 2017 total crude oil, natural gas and NGL sales, or 22% of crude oil sales. Both BP and Shell purchased crude oil and condensate domestically from our US onshore operations and Gulf of Mexico operations.

No other single purchaser accounted for 10% or more of crude oil, natural gas and NGL sales in 2017 . We maintain credit insurance associated with specific purchasers and believe that the loss of any one purchaser would not have a material effect on our financial position or results of operations since there are numerous potential purchasers of our production.

Hedging Activities Commodity prices continue to be volatile and are affected by a variety of factors beyond our control. We use derivative instruments to reduce the impact of commodity price uncertainty and increase cash flow predictability relating to the marketing of our crude oil and natural gas. As a result of hedging, a portion of near-term cash flow volatility is reduced.

We exercise strong management of our hedging program with strong oversight by our Board of Directors. For additional information, see Item 1A. Risk Factors , Item 7A. Quantitative and Qualitative Disclosures About Market Risk , and Item 8. Financial Statements and Supplementary Data – Note 8. Derivative Instruments and Hedging Activities .

Regulations

Exploration for, and production and marketing of, crude oil, natural gas and NGLs are extensively regulated at the federal, state, and local levels in the US, and internationally. Crude oil, natural gas and NGL development and production activities are subject to various laws and regulations (and orders of regulatory bodies pursuant thereto) governing a wide variety of matters, including, among others, allowable rates of production, transportation, prevention of waste and pollution, and protection of the environment. Laws affecting the crude oil and natural gas industry are under constant review for amendment or expansion over time and frequently impose more stringent requirements on crude oil and natural gas companies.

Our ability to economically produce and sell crude oil, natural gas and NGLs is affected by a number of legal and regulatory factors, including federal, state and local laws and regulations in the US and laws and regulations of foreign nations. Many of these governmental bodies have issued rules, regulations and orders that require extensive efforts to ensure compliance, that impose incremental costs to comply, and that carry substantial penalties for failure to comply. These laws, regulations and orders may restrict the rate of crude oil, natural gas and NGL production below the rate that would otherwise exist in the absence of such laws, regulations and orders. The regulatory requirements on the crude oil and natural gas industry often result in incremental costs of doing business and consequently affect our profitability. See Item 1A. Risk Factors – *We are subject to increasing governmental regulations and environmental requirements that may cause us to incur substantial incremental costs.*

Internationally, our operations are subject to legal and regulatory oversight by energy-related ministries or other agencies of our host countries, each having certain relevant energy or hydrocarbons laws. Examples include:

- the Ministry of Mines and Hydrocarbons, which, under such laws as the hydrocarbons law enacted in 2006 by the government of Equatorial Guinea, regulates our exploration, development and production activities offshore Equatorial Guinea;
- the Ministry of Energy, which regulates our exploration and development activities offshore Israel and the Israeli electricity market into which we sell our natural gas production;
- the Israeli Antitrust Commission, which reviews Israel's domestic natural gas sales and ownership in offshore blocks and leases; and
- the Ministry of Energy, Commerce, Industry and Tourism, which regulates our exploration and development activities offshore Cyprus.

Examples of US federal agencies with regulatory authority over our exploration for, and production and sale of, crude oil, natural gas and NGLs include:

- the Bureau of Land Management (BLM), the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE), which under laws such as the Federal Land Policy and Management Act, Endangered Species Act, National Environmental Policy Act and Outer Continental Shelf Lands Act, have certain authority over our operations on federal lands and waters, particularly in the Rocky Mountains and Gulf of Mexico;
- the Office of Natural Resources Revenue, which under the Federal Oil and Gas Royalty Management Act of 1982, has certain authority over our payment of royalties, rentals, bonuses, fines, penalties, assessments, and other revenue;
- the US Environmental Protection Agency (EPA) and the Occupational Safety and Health Administration (OSHA), which under laws such as the Comprehensive Environmental Response, Compensation and Liability Act, the Resource Conservation and Recovery Act, the Oil Pollution Act of 1990, the Clean Air Act, the Clean Water Act, the Safe Drinking Water Act, and the Occupational Safety and Health Act have certain authority over environmental, health and safety matters affecting our operations;
- the US Fish and Wildlife Service (FWS) and US National Marine Fisheries Service, which under the Endangered Species Act have authority over activities that may result in the take of any endangered or threatened species or its habitat;
- the US Army Corps of Engineers, which under the Clean Water Act has authority to regulate the construction of structures involving the fill of certain waters and wetlands subject to federal jurisdiction, including well pads, pipelines and roads;
- the Federal Energy Regulatory Commission (FERC), which under laws such as the Energy Policy Act of 2005 has certain authority over the marketing and transportation of crude oil, natural gas and NGLs we produce onshore and from the Gulf of Mexico; and

- the Department of Transportation, which has certain authority over the transportation of products, equipment and personnel necessary to our US onshore and Gulf of Mexico operations.

Other US federal agencies with certain authority over our business include the Internal Revenue Service (IRS) and the SEC. In addition, we are governed by the rules and regulations of the NYSE, upon which shares of our common stock are traded.

Among the laws affecting our operations are the following:

Environmental Matters We take into account the cost of complying with environmental regulations in planning, designing, drilling, operating, and abandoning wells. In most instances, the regulatory requirements relate to the handling and disposal of drilling and production wastes, water and air pollution control procedures, facility siting and construction, prevention of and responses to leaks and spills, and the remediation of petroleum-product contamination. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically or seismically sensitive areas, and other protected areas, require action to prevent or remediate pollution from current or former operations, such as plugging abandoned wells or closing pits, result in the suspension or revocation of necessary permits, licenses and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from our operations.

Under state and federal laws, we could be required to remove or remediate previously disposed wastes, including wastes disposed of or released by us, or by prior owners or operators, in accordance with current laws, to suspend or cease operations in contaminated areas, or to perform remedial well plugging operations or cleanups. The EPA and various state agencies have limited the disposal options for hazardous and non-hazardous wastes and may continue to do so. The owner and operator of a site, and persons that treated, disposed of, or arranged for the disposal of hazardous substances found at a site, may be liable, without regard to fault or the legality of the original conduct, for the release of a hazardous substance into the environment. The EPA, state environmental agencies and, in some cases, third parties are authorized to take actions in response to threats to human health or the environment and to seek to recover from responsible classes of persons the costs of such action. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

Furthermore, certain wastes generated by our crude oil and natural gas operations that are currently exempt from the definition of hazardous waste may in the future be subject to considerably more rigorous and costly operating and disposal requirements. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and natural gas exploration, development and production wastes as “hazardous wastes.” Also, in December 2016, the EPA agreed in a consent decree to review its regulation of oil and gas waste. It has until March 2019 to determine whether any revisions are necessary.

Under federal and state occupational safety and health laws, we must develop and maintain information about hazardous materials used, released, or produced in our operations. Certain portions of this information must be provided to employees, state and local governmental authorities, and local citizens. We are also subject to the requirements and reporting set forth in federal workplace standards.

Moreover, certain state or local laws or regulations and common law may impose liabilities in addition to, or restrictions more stringent than, those described herein.

We have made and will continue to make expenditures necessary to comply with environmental requirements. We do not believe that compliance with such requirements will have a material adverse effect on our capital expenditures, earnings or competitive position. Although such requirements do have a substantial impact on the crude oil and natural gas industry, they do not appear to affect us to any greater or lesser extent than other companies in the industry.

The following is a summary of the more significant US environmental developments and requirements that may affect our operations.

Various state and federal statutes such as the Endangered Species Act (ESA) prohibit certain actions that adversely affect endangered or threatened species and their habitat, wetlands, migratory birds, marine mammals, or natural resources. Where the taking or harm of such species occurs or may occur, or where damages to wetlands or natural resources may occur, the government or private parties may act to prevent crude oil and natural gas exploration activities. In particular, a federal or state agency could order a complete halt to drilling activities in certain locations or during certain seasons when such activities could result in a serious adverse effect upon a protected species. The presence of a protected species in areas where we operate could adversely affect future production from those areas and government agencies frequently add to the lists of protected species. For example, listing of the Lesser Prairie Chicken likewise could impact our operations in the Delaware Basin. The Lesser Prairie Chicken was removed from the ESA list of endangered species in July 2016 after a federal court invalidated the FWS’s listing of the bird as threatened because the FWS failed to give proper consideration to voluntary conservation measures; however, the FWS announced in November 2016 an ongoing new status review of the Lesser Prairie Chicken to determine whether listing is still warranted.

The Federal Water Pollution Control Act of 1972, as amended, also known as the "Clean Water Act" or "CWA," the Safe Drinking Water Act, the Oil Pollution Act and analogous state laws and regulations promulgated thereunder impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other gas and oil wastes, into navigable waters. Provisions of the CWA require authorization from the US Army Corps of Engineers, or the "Corps", prior to the placement of dredge or fill material into jurisdictional waters. Spill prevention, control and countermeasure plan requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak.

On June 29, 2015, the EPA and Corps jointly published the final rule defining the scope of the EPA's and Corps' jurisdiction, known as the "Clean Water Rule." The Clean Water Rule has been challenged in multiple federal courts; however, at this time, we cannot predict the outcome of this litigation. Subsequently, the EPA and the Corps proposed a rulemaking in June 2017 to repeal the June 2015 rule, and also announced their intent to issue a new rule defining the Clean Water Act's jurisdiction. Both agencies also published a proposed rule in November 2017 delaying implementation of the Clean Water Rule for two years. As a result, future implementation of the June 2015 rule is uncertain at this time. To the extent the rule expands the scope of the CWA's jurisdiction, we could face increased costs and delays with respect to spill prevention, storm water management, and wetlands permitting. We are continuing to monitor the regulatory updates and to evaluate the impact of the new rule on our operations.

Also, on June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants. The EPA is also conducting a study of private wastewater treatment facilities (also known as centralized waste treatment, or CWT, facilities) accepting oil and natural gas extraction wastewater. The EPA is collecting data and information related to the extent to which CWT facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of CWT facilities, and the environmental impacts of discharges from CWT facilities. In addition, the EPA previously announced its plans to develop a Notice of Proposed Rulemaking by June 2018, which would describe a proposed mechanism - regulatory, voluntary, or a combination of both - to collect data on hydraulic fracturing chemical substances and mixtures.

The federal Clean Air Act, as amended, and comparable state laws and regulations, regulate emissions of various air pollutants through the issuance of permits and the imposition of other requirements. The EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. New facilities may be required to obtain permits before work can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. These laws and regulations may increase the costs of compliance for some facilities we own or operate, and federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations.

There also have been a series of recent air regulations and proposals that affect, or that may affect, our operations. In 2012, for example, the EPA issued New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants to control air emissions associated with crude oil, natural gas and NGL production, including natural gas wells that are hydraulically fractured. In addition to addressing emissions from storage tanks and other equipment, those regulations required technologies and processes that, while reducing emissions, enable companies to collect additional natural gas that can be sold. Specifically, as of January 2015, owners and operators of natural gas wells must use emissions reduction technology called "green completions," technologies that were already widely deployed at wells. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. In response, the EPA has issued, and will likely continue to issue, revised rules responsive to some of the requests for reconsideration. In particular, on May 12, 2016, the EPA amended its regulations to impose new standards for methane and volatile organic compounds emissions for certain new, modified, and reconstructed equipment, processes, and activities across the oil and natural gas sector. However, in a March 28, 2017 executive order, the EPA was directed to review the 2016 regulations and, if appropriate, to initiate a rulemaking to rescind or revise them consistent with the stated policy of promoting clean and safe development of the nation's energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production. On June 16, 2017, the EPA published a proposed rule to stay for two years certain requirements of the 2016 regulations, including fugitive emission requirements. These standards, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or mandate the use of specific equipment or technologies to control emissions. To date, these rules have had minimal impact on our business since the reduction of greenhouse gas (GHG) emissions already was one of our priorities and we had been working to improve our methods to reduce GHGs through operational and business practices. For example, we have undertaken emission reduction projects such as our US Vapor Recovery Unit (VRU) program, where we have installed VRUs to capture natural gas that would otherwise be flared on a substantial number of our tank batteries.

Also, on May 12, 2016, the EPA issued a final rule regarding the criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting processes and requirements, which could increase our compliance costs and may require facility siting and design changes.

As another prong of the previous US Administration's methane strategy, on November 15, 2016, the BLM finalized a rule to reduce the flaring, venting and leaking of methane from oil and gas operations on federal and Indian lands. The rule requires operators to use currently available technologies and equipment to reduce flaring, periodically inspect their operations for leaks, and replace outdated equipment that vents large quantities of gas into the air. The rule also clarifies when operators owe the government royalties for flared gas. State and industry groups have challenged this rule in federal court, asserting that the BLM lacks authority to prescribe air quality regulations. On March 28, 2017, the BLM was directed by executive order to review the above rule and, if appropriate, to initiate a rulemaking to rescind or revise it. Accordingly, on December 8, 2017, the BLM published a final rule to suspend or delay certain requirements of the 2016 methane rule until January 17, 2019. Further legal challenges are expected. At this time, it is uncertain when, or if, the rules will be implemented, and what impact they would have on our operations. It also bears noting that substantially all of our US onshore properties are subject to EPA's requirements for reporting annual GHG emissions. Information in such reports could form the basis of further GHG regulations.

In another air development, the EPA announced in October 2015 that it was lowering the primary national ambient air quality standard for ozone from 75 parts per billion to 70 parts per billion. Implementation will take place over several years; however, areas that cannot meet the new standard eventually will need to impose additional requirements on sources of VOCs and other ozone precursors which could increase the cost of siting and operating our facilities.

Apart from these federal matters, most of the states where we operate have separate authority to regulate operational and environmental matters.

Colorado In February 2013, the Colorado Oil and Gas Conservation Commission (COGCC) approved setback rules for crude oil and natural gas wells and production facilities located in close proximity to occupied buildings. Previously, the COGCC had allowed setback distances of 150 feet in rural areas and 350 feet in high density urban areas. These have been increased to a uniform 500 feet statewide setback from occupied buildings and 1,000 feet from high occupancy building units. The setback rules also require operators to utilize increased mitigation measures to limit potential drilling impacts to surface owners and the owners of occupied building units. In addition, the rules require advance notice to surface owners, the owners of occupied buildings and local governments prior to the filing of an Application for Permit to Drill or Oil and Gas Location Assessment as well as outreach and communication efforts by an operator.

The COGCC also has implemented rules making Colorado the first state to require sampling of groundwater for hydrocarbons and other indicator compounds both before and after drilling. Those statewide rules require sampling of up to four water wells within a half mile radius of a new crude oil and natural gas well before drilling, between six and 12 months after completion, and between five and six years after completion. For the Greater Wattenberg Area, the COGCC requires operators to sample only one water well per quarter governmental section before drilling and between six to 12 months after completion. Further, the COGCC has adopted rules increasing the maximum penalty for violations of its requirements.

The state environmental agency, the Colorado Department of Public Health and Environment, likewise has adopted measures to regulate air emissions, water protection, and waste handling and disposal relating to our crude oil and natural gas exploration and production. For air, the Colorado Department of Public Health and Environment has extended the EPA's emissions standards for crude oil and natural gas operations to directly control methane. The final rules, which cover the life cycle of oil and gas development, production, and maintenance, reflect a collaborative effort by the Environmental Defense Fund, Noble Energy and other oil and gas operators.

Some of the counties and municipalities where we operate in Colorado have adopted their own regulations or ordinances that impose additional restrictions on our crude oil and natural gas exploration and production. To date these have not significantly impacted our operations. However, a few localities in Colorado have tried to prohibit certain exploration and production activities, particularly use of hydraulic fracturing within their boundaries. In May 2016, the Colorado Supreme Court found that the local laws intended to increase regulatory requirements on oil and gas development were preempted by existing state law and were therefore invalid. See Hydraulic Fracturing, below.

In April 2015, we entered into a joint consent decree (Consent Decree) with the EPA, 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 oil and natural gas operations within the Non-Attainment Area of the DJ Basin. The Consent Decree was entered by the US District Court of Colorado on June 2, 2015 and requires us to perform certain activities. All fines required under the Consent Decree were paid in 2015; however, the required injunctive relief remains ongoing. Based on currently available information, we have concluded that the remaining obligations will not have a material adverse effect on our financial position, results of operations or cash flows. See Item 1A. Risk Factors – *Our operations require us to comply with a number of US and international laws* *and regulations, violations of which could result in substantial fines or sanctions and/or impair our ability to do business* and Item 8. Financial Statements and Supplementary Data – Note 17. Commitments and Contingencies .

Texas Texas has regulations governing conservation matters, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum rates of production from oil and gas wells, the regulation of spacing, and requirements for plugging and abandonment of wells.

In February 2012, the Texas Railroad Commission (RRC) implemented a hydraulic fracturing disclosure rule, requiring Texas oil and gas operators to disclose on the FracFocus website, chemical ingredients and water volumes used in hydraulic fracturing treatments.

In May 2013, the RRC issued an updated “well integrity rule” that addresses requirements for drilling, casing and cementing wells. The rule also includes new testing and reporting requirements, including clarifying that cementing reports must be submitted after well completion or after cessation of drilling, whichever is earlier.

In October 2014, the RRC adopted new permit rules for injection wells to address seismic activity concerns within the state. Among other things, the rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells, and allow the RRC to modify, suspend, or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. The RRC has used this authority to deny permits for waste disposal wells.

US Offshore Regulatory Developments Our operations on federal oil and natural gas leases in the Gulf of Mexico are subject to regulation by BSEE and BOEM. These leases contain relatively standardized terms and require compliance with detailed BSEE and BOEM regulations and orders issued pursuant to various federal laws, including the Outer Continental Shelf Lands Act (OCSLA). These laws and regulations are subject to change, and many new requirements, including those related to safety, permitting and performance, were imposed by BSEE and BOEM subsequent to the April 2010 Deepwater Horizon incident.

In April 2016, the BSEE issued a final rule entitled “Oil and Gas and Sulfur Operations in the Outer Continental Shelf - Blowout Preventer Systems and Well Control,” which updates standards for blowout prevention systems and other well controls for offshore oil and gas activities conducted in US federal waters, including the Gulf of Mexico. The final rule, which went into effect on July 28, 2016, increases the costs associated with well design, drilling and completion operations, as well as ongoing monitoring costs for our wells in the Gulf of Mexico. More recently, pursuant to executive orders dated March 28, 2017, and April 28, 2017, the BSEE initiated a review of whether the final rule is consistent with the stated policy of encouraging energy exploration and production, while ensuring that any such activity is safe and environmentally responsible. On October 24, 2017, the BSEE announced - in a report published by the Department of Interior - that it is considering several revisions to the rule and that it is in the process of determining the most effective way to engage stakeholders in the process.

Also, in April 2016, the BOEM published a proposed air quality rule that would significantly broaden the obligations of operators and lessees in the Outer Continental Shelf, including the Gulf of Mexico, to assess, report and, when appropriate, control emissions. Among other items, the proposed rule would expand the types of emissions that must be measured, change the boundary for evaluating air emissions, and increase the scope of sources that must be addressed. If adopted as proposed, the new rule would likely increase the cost associated with our activities in the Gulf of Mexico. Pursuant to the Executive Orders, the BOEM is reviewing the proposed air quality rule. On October 24, 2017, the Department of Interior announced that it is currently reviewing recommendations on how to proceed, including promulgating final rules for certain necessary provisions and issuing a new proposed rule that may withdraw certain provisions and seek additional input on others.

Additionally, in order to cover the various decommissioning obligations of lessees on the OCS, the BOEM generally requires that lessees post some form of acceptable financial assurances that such obligations will be met, such as surety bonds. The BOEM recently updated its regulations and program oversight to establish more robust risk management, financial assurance and loss prevention requirements for oil and gas operations in the Outer Continental Shelf, including the Gulf of Mexico. On July 14, 2016, the BOEM issued an updated Notice to Lessees and Operators (NTL) providing details on revised procedures the agency will be using to determine a lessee’s or operator's ability to carry out decommissioning obligations for activities in the Outer Continental Shelf, including the Gulf of Mexico. This revised policy institutes new criteria by which the BOEM will evaluate the financial strength and reliability of lessees and operators active in the Outer Continental Shelf. If the BOEM determines under the revised policy that a lessee or operator does not have the financial ability to meet its decommissioning and other obligations, that lessee or operator will be required to post additional financial security as assurance. The revised policy originally became effective September 12, 2016; however, the BOEM extended the implementation timeline for six months in certain circumstances. Pursuant to the Executive Orders, the BOEM is reviewing the NTL to determine whether modifications are necessary to ensure operator compliance with lease terms while minimizing unnecessary regulatory burdens. On June 22, 2017, the BOEM announced that, pending its review of the NTL, the implementation timeline would be indefinitely extended, subject to certain exceptions. We estimated the impact of the new financial criteria on our operations in the Gulf of Mexico and do not believe that the revised policy will have a material impact on our operations in the Gulf of Mexico, or on our financial position or cash flows.

The National Oceanic and Atmospheric Administration (NOAA) is proposing to expand the boundaries of the Flower Garden Banks National Marine Sanctuary in the Gulf of Mexico. NOAA released its draft environmental impact statement (DEIS) on the proposed expansion in June 2016, in which it proposed five alternatives for expanding existing sanctuary regulations to new geographic areas. Two of these alternatives for sanctuary expansion have the potential to impact certain of our leases which could increase drilling, operating and decommissioning costs. The comment period for the expansion alternatives outlined in the DEIS expired on August 19, 2016 and the issuance of NOAA's report recommending alternatives is expected in early 2018. We are currently evaluating the expansion alternatives and assessing any potential impact on our operations in the Gulf of Mexico.

Climate Change In recent years, the EPA has finalized a series of greenhouse (GHG) gas monitoring, reporting and emissions control rules for the oil and natural gas industry, and the US Congress has, from time to time, considered adopting legislation to reduce emissions. In addition, almost one-half of the states have already taken measures to reduce emissions of greenhouse gases primarily through the development of greenhouse gas emission inventories and/or regional greenhouse gas cap-and-trade programs.

At the international level, in December 2015, the United States signed the Paris Agreement on climate change and pledged to take efforts to reduce GHG emissions and to conserve and enhance sinks and reservoirs of GHGs. The Paris Agreement entered into force in November 2016. However, in August 2017, the United States notified the United Nations that it would be withdrawing from the Paris Agreement and begin negotiations to either re-enter or negotiate an entirely new agreement with more favorable terms for the United States. While the Administration expressed a clear intent to cease implementing the Paris Agreement, it is not clear how it plans to accomplish this goal, whether a new agreement can be negotiated, or what terms would be included in such an agreement. Furthermore, in response to the announcement, many state and local leaders stated their intent to intensify efforts to uphold the commitments set forth in the international accord.

The current state of development of the ongoing international climate initiatives and any related domestic actions make it difficult to assess the timing or effect on our operations or to predict with certainty the future costs that we may incur in order to comply with future international treaties, legislation or new regulations. However, future restrictions on emissions of GHGs, or related measures to encourage use of renewable energy, could have a significant impact on our future operations and reduce demand for our products. See also Items 1. and 2. Business and Properties - Regulations and Item 1A. Risk Factors .

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

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

Israel Regulatory Environment

Natural Gas Policy and Antitrust Authority The Framework, as adopted by the Government of Israel, provides clarity on numerous matters concerning resource development, including certain fiscal, antitrust and other regulatory matters. The Framework provides for the reduction of our ownership interest in the Tamar and Dalit fields to 25% by year-end 2021, while enabling the marketing of Leviathan natural gas to Israeli customers. See Item 8. Financial Statements and Supplementary Data – Note 4. Acquisitions, Divestiture and Merger.

Israeli Tax Law Effective December 21, 2016, the Israeli government decreased the corporate income tax rate from 25% to 24% for 2017 and announced a further rate decrease from 24% to 23% effective January 2018. The change decreased the deferred tax expense for 2017 by $12 million . Furthermore, our Israeli operations are subject to the Natural Resources Profits Taxation Law, 2011, which imposes a separate additional tax on profits from oil and gas activities (Profits Tax). See Item 8. Financial Statements and Supplementary Data – Note 11. Income Taxes .

Hydraulic Fracturing

Hydraulic fracturing techniques have been used for decades on the majority of all new onshore crude oil and natural gas wells drilled domestically. The process involves the injection of water, sand and chemical additives under pressure into targeted subsurface formations to stimulate oil and gas production. We strive to adopt best practices and industry standards and comply with all regulatory requirements regarding well construction and operation. For example, the qualified service companies we use to perform hydraulic fracturing, as well as our personnel, monitor rate and pressure to assure that the services are performed as planned. Our well construction practices include installation of multiple layers of protective steel casing surrounded by cement that are specifically designed and installed to protect freshwater aquifers by preventing the migration of fracturing fluids into those aquifers. To help reduce our operational demand for freshwater and need for disposal, we are currently developing technology and infrastructure to expand our water recycling capacity in the DJ and Delaware Basins. We believe that these processes help ensure hydraulic fracturing is safe and does not and will not pose a risk to water supplies, the environment or public health.

Although hydraulic fracturing is regulated primarily at the state level, legislation has been proposed in recent sessions of Congress to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of "underground injection," to require federal permitting and regulatory control of hydraulic fracturing, and to require disclosure of the chemical constituents of the fluids used in the fracturing process. Furthermore, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the Underground Injection Control program, specifically as "Class II" Underground Injection Control wells under the Safe Drinking Water Act. In addition, the EPA previously announced its plans to develop a Notice of Proposed Rulemaking by June 2018, which would describe a proposed mechanism - regulatory, voluntary, or a combination of both - to collect data on hydraulic fracturing chemical substances and mixtures.

In addition, on March 26, 2015, the Bureau of Land Management (BLM) published a final rule governing hydraulic fracturing on federal and Indian lands. The rule requires public disclosure of chemicals used in hydraulic fracturing, implementation of a casing and cementing program, management of recovered fluids, and submission to the BLM of detailed information about the proposed operation, including wellbore geology, the location of faults and fractures, and the depths of all usable water. On June 21, 2016, the United States District Court for Wyoming set aside the rule, holding that the BLM lacked Congressional authority to promulgate the rule. The BLM has appealed the decision to the Tenth Circuit Court of Appeals. On March 28, 2017, an executive order was signed, directing the BLM to review the rule and, if appropriate, to initiate a rulemaking to rescind or revise it. Accordingly, on December 29, 2017, the BLM published a final rule to rescind the 2015 hydraulic fracturing rule. Further legal challenges are expected. At this time, it is uncertain when, or if, the rules will be implemented, and what impact they would have on our operations.

Furthermore, governments and agencies at all levels from federal to municipal are studying the potential environmental impacts of hydraulic fracturing and evaluating the need for further requirements. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing, and could ultimately make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business.

In June 2012, OSHA and the National Institute of Occupational Safety and Health (NIOSH) issued a joint hazard alert for workers who use silica (sand) in hydraulic fracturing activities. The following year saw the agency formally propose to lower the permissible exposure limit for airborne silica. In 2016, OSHA finalized a lower exposure limit for silica along with stricter silica work practices. For hydraulic fracturing, the new obligations start to take effect in 2018. OSHA also has prepared guidance identifying additional workplace hazards resulting from hydraulic fracturing and ways to reduce exposure to those hazards.

To date, hydraulic fracturing has been regulated primarily at the state level, and all of the states where our US onshore operations are located (including Colorado and Texas) have developed such requirements. See Regulations - Colorado and Texas , above. Also, state and federal regulatory agencies recently have focused on a possible connection between the operation of injection wells used for oil and gas waste disposal and seismic activity, which some have termed "induced seismicity." In a few instances, operators of injection wells in the vicinity of seismic events have been ordered to reduce injection volumes or suspend operations. Some state regulatory agencies have modified their regulations to account for induced seismicity with regard to the operation of injection wells used for oil and gas waste disposal. Increased regulation and attention given to induced seismicity in the states where we operate could lead to greater opposition, including litigation, to oil and gas activities utilizing injection wells for waste disposal.

Several states, including Colorado and Texas, have adopted regulations requiring disclosure of certain information regarding the components and chemicals used in the hydraulic-fracturing process. These state regulations allow disclosure through the public registry FracFocus.org, which is operated jointly by the Interstate Oil & Gas Compact Commission and the Ground Water Protection Council. Disclosure through the FracFocus web site includes ways to protect proprietary information and we are currently providing disclosure information on FracFocus.org for all US onshore areas in which we operate.

Additional Information See:

- Items 1. and 2. Business and Properties – Regulations ;
- Item 1A. Risk Factors ; and
- Risk and Insurance Program .

Risk and Insurance Program

As protection against financial loss resulting from many, but not all operating hazards, we maintain insurance coverage, including certain physical damage, business interruption (loss of production income), employer's liability, third party liability, worker's compensation insurance and certain insurance related to cyber security. We maintain insurance at levels that we believe are appropriate and consistent with industry practice and we regularly review our potential risks of loss and the cost and availability of insurance and the company's ability to sustain uninsured losses, and revise our insurance program accordingly.

Availability of insurance coverage, subject to customary deductibles and recovery limits, for certain perils such as war or political risk is often excluded or limited within property policies. In Israel and Equatorial Guinea, we insure against acts of war and terrorism in addition to providing insurance coverage for normal operating hazards facing our business. Additionally, as being part of critical national infrastructure, the Israel offshore and onshore assets are included in a special property coverage afforded under the Israeli government's Property Tax and Compensation Fund Law; however, the amount of financial recovery through the fund is not guaranteed.

We have a risk assessment program that analyzes safety and environmental hazards, including cyber threats, and establishes procedures, work practices, training programs and equipment requirements, including monitoring and maintenance rules, for continuous improvement. We also use third party consultants to help us identify and quantify our risk exposures at major facilities. We have a robust prevention program and continue to manage our risks and operations such that we believe the likelihood of a significant event is remote. However, if an event occurs that is not covered by insurance, not fully protected by insured limits or our non-operating partners are not fully insured, it could have a material adverse impact on our financial condition, results of operations and cash flows. See Item 1A. Risk Factors .

Undeveloped Oil and Gas Leases

Oil and gas exploration is a lengthy process of obtaining data, evaluating, and de-risking prospects, and it takes time to develop resources in a responsible manner. The period of time from lease acquisition to discovery can take many years of ongoing effort.

We begin by leasing acreage (or deepwater lease blocks) from individuals, other operators or the host government. It may take years for us to assemble sufficient acreage to cover the areal extent of a prospect that we wish to explore.

Once the acreage position is assembled, we obtain seismic data either through purchase of available data or by contracting for seismic services. Our exploration staff then begin a lengthy process of analyzing the seismic and other data in order to identify a potential optimal location for drilling an initial exploratory well. Once we decide to drill an exploratory well, we must obtain permits and contract a drilling rig with the specifications for the depth and well pressures which we expect to drill.

If there is a discovery, we may need to obtain additional data and/or drill appraisal wells in order to estimate the extent of the reservoir and the volume of resources that could potentially be recovered. Appraisal or development drilling requires additional time to contract for an appropriate drilling rig, and obtain pipe, other equipment, and supplies.

Competition

The crude oil and natural gas industry is highly competitive. We encounter competition from other crude oil and natural gas companies in all areas of operations, including the acquisition of seismic data and lease rights on crude oil and natural gas properties and for the labor and equipment required for exploration and development of those properties. Our competitors include major integrated crude oil and natural gas companies, state-controlled national oil companies, independent crude oil and natural gas companies, service companies engaging in exploration and production activities, drilling partnership programs, private equity, and individuals. Many of our competitors are large, well-established companies. Such companies may be able to pay more for seismic information and lease rights on crude oil and natural gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. See Item 1A. Risk Factors .

Employees

As of December 31, 2017 , we had 2,277 full-time employees.

Offices

Our principal corporate office is located at 1001 Noble Energy Way, Houston, Texas, 77070. We maintain additional regional exploration and/or production offices primarily in Denver, Colorado; Greeley, Colorado; Pecos, Texas; Dilley, Texas; and in Israel, Cyprus, and Equatorial Guinea.

Title to Properties

We believe that our title to the various interests set forth above is satisfactory and consistent with generally accepted industry standards, subject to exceptions that would not materially detract from the value of the interests or materially interfere with their use in our operations. Individual properties may be subject to burdens such as royalty, overriding royalty and other outstanding interests customary in the industry. In addition, interests may be subject to obligations or duties under applicable laws or burdens such as production payments, net profits interest, liens incident to operating agreements and for current taxes, development obligations under crude oil and natural gas leases or capital commitments under PSCs or exploration licenses. We have also dedicated certain of our US onshore acreage to Noble Midstream Partners for the provision of midstream services to us.

Furthermore, while the majority of our assets are held by production, certain of our 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 and failure to meet these obligations may result in the loss of a lease.

Title Defects Subsequent to a lease or fee interest acquisition transaction, the buyer usually has a period of time in which to examine the leases for title defects. Adjustments for title defects are generally made within the terms of the sales agreement, which may provide for arbitration between the buyer and seller.

Conflicts with Surface Rights Mineral rights are property rights that include the right to use land surface that is reasonably necessary to access minerals beneath. Lawsuits regarding conflicts between surface rights and mineral rights are currently pending in several states. In several cases, owners of surface rights are suing various companies to prevent companies from using their land surface to drill horizontal wells to explore for or produce hydrocarbons from neighboring mineral tracts. If a plaintiff were to prevail in such a case, it could become more difficult and expensive for a company to place multi-acre well pads and/or limit the length of horizontal wells drilled from a pad.

Available Information

Our website address is *www.nblenergy.com.* Available on this website under “Investors – Financial Information – SEC Filings,” free of charge, are our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements, Forms 3, 4 and 5 filed on behalf of directors and executive officers and amendments to those reports as soon as reasonably practicable after such materials are electronically filed with or furnished to the SEC. Alternatively, you may access these reports at the SEC’s website at *www.sec.gov* .

Also posted on our website under “Our Story – Transparency – Corporate Governance - Committee Charters”, and available in print upon request made by any stockholder to the Investor Relations Department, are charters for our Audit Committee, Compensation, Benefits and Stock Option Committee, Corporate Governance and Nominating Committee, and Environment, Health and Safety Committee. Copies of the Code of Conduct and the Code of Ethics for Chief Executive and Senior Financial Officers (the Codes) are also posted on our website under the “Other Governance Documents” section. Within the time period required by the SEC and the NYSE, as applicable, we will post on our website any modifications to the Codes and any waivers applicable to senior officers as defined in the applicable Code, as required by the Sarbanes-Oxley Act of 2002.

Item 1A. Risk Factors

Described below are certain risks that we believe are applicable to our business and the oil and gas industry in which we operate. There may be additional risks that are not presently material or known. You should carefully consider each of the following risks and all other information set forth in this Annual Report on Form 10-K.

If any of the events described below occur, our business, financial condition, results of operations, cash flows, liquidity or access to the capital markets could be materially adversely affected. In addition, the current global economic and political environment intensifies many of these risks.

The oil and gas industry is cyclical and an extended period of suppressed commodity prices could have material adverse effects on our operations, our liquidity, and the price of our common stock.

Our ability to operate profitably, maintain adequate liquidity, grow our cash flow and pay dividends on our common stock depend upon the prices we receive for our crude oil, natural gas, and NGL production. Commodity prices are cyclical and subject to supply and demand dynamics. For the past three years, following the significant decline that began in late 2014, crude oil prices, in particular, have been trading in a much lower range. While we have witnessed a certain degree of commodity price improvement, we expect that economic, geopolitical, and supply and demand forces will remain volatile. As a result we may continue to operate in a soft market, with sustained lower commodity prices, subject to further decline if the excess of supply over demand increases.

If commodity prices continue to trade at low or lower levels for an extended period, one or more of the following could occur:

- significant reductions of our revenues, profit margins, operating income and cash flows;
- reduction in the amount of crude oil, natural gas and NGLs that we can produce economically, leading to shut-in or early abandonment of producing wells and increased capital requirements for abandonment operations;
- certain properties in our portfolio becoming economically unviable;
- impairments of proved or unproved properties or other long-lived assets;
- loss of undeveloped acreage if our production is shut-in or we are unable to make scheduled delay rental payments;
- use of cash flow to satisfy minimum obligations under throughput agreements if production is suspended;
- reduction, or suspension, of our 2018 or future capital investment programs, resulting in a reduced ability to develop our reserves;
- delay, postponement or cancellation of some of our exploration or development projects;
- inability to meet exploration commitments, leading to loss of leases or exploration rights;
- divestments of properties to generate funds to meet cash flow or liquidity requirements;
- limitations on our financial condition, liquidity, including access to sources of capital, such as debt and equity, and/or ability to finance planned capital expenditures and operations;
- failure of our partners to fund their share of development costs or obtain financing could result in delay or cancellation of future projects, thus limiting our growth and future cash flows;
- inability to meet scheduled interest and/or debt payments or payments due under operating or capital leases;
- a series of credit rating downgrades or other negative rating actions which could increase our cost of financing and may increase our requirements to post collateral as financial assurance of performance under certain other contracts which, in turn, could have a negative impact on our liquidity;
- changes in corporate structure that could lead to loss of key personnel and interrupt our business activities; and
- reduction or suspension of dividends on our common stock.

In addition, lower commodity prices, including declines in commodity forward price curves, may result in the following:

- declines in our stock price;
- additional counterparty credit risk exposure on commodity hedges and joint venture receivables; and
- a reduction in the carrying value of goodwill.

Our hedging arrangements in place will not fully mitigate the effects of commodity price volatility.

Furthermore, certain crude oil demand estimates suggest a hypothetical point in the future when global oil demand reaches its peak demand level. The International Energy Agency's 450 Scenario sets out an energy pathway consistent with the goal of limiting the global increase in temperature to 2°C by limiting concentration of greenhouse gases in the atmosphere to around 450 parts per million of CO_2. Under this scenario, global oil demand peaks by 2020, and the subsequent decline in demand accelerates year-on-year, so that by the late 2020s global demand is falling by over one million barrels per day every year. This decline in demand, if it occurs, would negatively impact commodity prices as well as our ability to explore for and develop our crude oil and natural gas resources.

Markets and prices for crude oil, natural gas and NGLs depend on factors beyond our control, factors including, among others:

- global demand for crude oil, natural gas and NGLs as impacted by economic factors that affect gross domestic product growth rates of countries around the world;
- global supply for crude oil, natural gas and NGLs as impacted by OPEC and non-OPEC countries (e.g. US, Russia, Canada);
- technology advances that increase crude oil, natural gas and NGL production, thereby increasing supply;
- new technologies that promote fuel efficiency and reduce energy consumption;
- developments in the global LNG market, including exports from the US;
- geopolitical conditions and events, including generational leadership or regime changes, changes in government energy policies, including imposed price controls and/or product subsidies, or instability/armed conflict in hydrocarbon-producing regions;
- fluctuations in US dollar exchange rates, the currency in which the world's crude oil trade is generally denominated;
- the price and availability of alternative fuels, including coal, solar, wind, nuclear energy and biofuels, as well as the availability of battery storage;
- the long-term impact on the crude oil market of the use of natural gas and electricity as an alternative fuel for road transportation or the use of natural gas as fuel for electricity generation impacting the demand for electricity;
- fuel efficiency regulations, such as the Corporate Average Fuel Economy (CAFE) standards, and its impacts on demand for crude oil as a transportation fuel;

- the availability of pipeline capacity/infrastructure as well as refining capacity;
- the level and effect of trading in commodity futures markets, including by commodity price speculators and others;
- the effectiveness of worldwide conservation measures;
- weather conditions;
- access to government-owned and other lands for exploration and production activities; and
- domestic and foreign governmental regulations and taxes.

Sector cost inflation could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

Our industry is cyclical and third party oilfield materials, service and supply costs are also subject to supply and demand dynamics. During periods of decreasing levels of industry exploration and production, the demand for, and cost of, drilling rigs and oilfield services decreases. Conversely, during periods of increasing levels of industry activity, the demand for, and cost of, drilling rigs and oilfield services increases.

During 2017, increases in US onshore drilling and completion activity resulted in higher demand for oilfield services. As a result, the costs of drilling, equipping and operating wells and infrastructure began to experience some inflation. If this trend continues, and if the commodity price recovery is robust, we expect industry exploration and production activities to continue to increase, resulting in even higher demand for oilfield services and supplies, which could result in significant sector price inflation. In addition, the costs of such items could increase and their availability may become limited, particularly in basins of relatively higher activity. Potential scarcity of competent service personnel may impact our ability to execute our exploration and development plans in a timely and profitable manner.

In addition, regulatory changes, such as those related to hydraulic fracturing or water disposal, may also result in reduced availability and/or higher costs for rigs and services. As a result, drilling rigs and oilfield services may not be available at rates that provide a satisfactory return on our investment.

Our international operations may be adversely affected by economic and geopolitical developments.

We have significant international operations, with approximately 27% of our 2017 total consolidated sales volumes and approximately 52% of our total proved reserves as of December 31, 2017 attributable to our international operations in Israel and Equatorial Guinea. We also conduct exploration activities in other international areas. Our operations may be adversely affected by political and economic developments, including the following:

- renegotiation, modification or nullification of existing contracts, such as may occur pursuant to future regulations enacted as a result of changes in Israel's antitrust, export and natural gas development policies, or the hydrocarbons law enacted in 2006 by the government of Equatorial Guinea, which can result in an increase in the amount of revenues that the host government receives from production (government take) or otherwise decrease project profitability;
- loss of revenue, property and equipment as a result of actions taken by host nations, such as expropriation or nationalization of assets or termination of contracts;
- disruptions caused by territorial or boundary disputes in certain international regions;
- changes in drilling or safety regulations;
- laws and policies of the US and foreign jurisdictions affecting trade, foreign investment, taxation and business conduct;
- potential for Israel natural gas production and regional exports to be interrupted by political conditions and events, and regional instability or armed conflict in the region;
- difficulties enforcing our rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations;
- US and international monetary policies impacting foreign exchange or repatriation restrictions in countries in which we conduct business;
- war, piracy, acts of terrorism or civil unrest; and
- other hazards arising out of foreign governmental sovereignty over areas in which we conduct operations.

Such political and economic developments could have a negative impact on our results of operations and cash flows and reduce the fair values of our properties, resulting in impairment charges.

Our operations may be adversely affected by changes in the fiscal regimes and related government policies and regulations in the countries in which we operate.

Fiscal regimes impact oil and gas companies through laws and regulations governing resource access along with government participation in oil and gas projects, royalties and taxes. We operate in the US and other countries whose fiscal regimes may change over time. Changes in fiscal regimes result in an increase or decrease in the amount of government financial take from developments, and a corresponding decrease or increase in the revenues of an oil and gas company operating in that particular country. For example, a significant portion of our production comes from Israel and Equatorial Guinea; therefore, changes in or uncertainties related to the fiscal regimes of these countries could have a significant impact on our operations and financial performance. Further, we cannot predict how government agencies or courts will interpret existing regulations and tax laws or the effect such interpretations could have on our business.

Many governments globally are seeking additional revenue sources, including, potentially, increases in government financial take from oil and gas projects. In developing nations, governments may seek additional revenues to support infrastructure and economic development and for social spending. In many nations of the Organisation for Economic Cooperation and Development (OECD), governments continue to incur significant budget deficits and growing national debt levels, as well as pressure from financial markets to address structural spending imbalances.

The OECD Base Erosion and Profit Sharing (BEPS) initiative aims to standardize and modernize global tax policy and disclosure of financial and operational data with tax authorities. The BEPS's recommendations are being widely adopted by the majority of the foreign jurisdictions in which we operate and many of these jurisdictions are party to the Multilateral Convention to Implement Tax Treaty Related Measures to Prevent Base Erosion and Profit Shifting. Progress on the implementation of BEPS measures and development of tax authority interpretation could result in changes to tax policies, including transfer pricing policies. To the extent such changes significantly increase the overall tax imposed on currently producing projects, these projects could become less economic, or wholly uneconomic, thereby reducing the amount of proved reserves we record and cash flows we receive, and possibly resulting in asset impairment charges.

Changes in fiscal regimes have long-term impacts on our business strategy, and fiscal uncertainty makes it difficult to formulate and execute capital investment programs. The implementation of new, or the modification of existing, laws or regulations increasing the tax costs on our business could disrupt our business plans and negatively impact our operations and our stock price in the following ways, among others:

- restrict resource access or investment in lease holdings;
- limit or cancel exploration and/or development activities, which could have a long-term negative impact on the quantities of proved reserves we record and inhibit future production growth;
- have a negative impact on the ability of us and/or our partners to obtain financing;
- reduce the profitability of our projects, resulting in decreases in net income and cash flows with the potential to make future investments uneconomical;
- result in currently producing projects becoming uneconomic, to the extent fiscal changes are retroactive, thereby reducing the amount of proved reserves we record and cash flows we receive, and possibly resulting in asset impairment charges;
- require that valuation allowances be established against deferred tax assets, with offsetting increases in income tax expense, resulting in decreases in net income and cash flow; and/or
- restrict our ability to compete with imported volumes of crude oil or natural gas.

Tax laws and regulations may change over time, and could adversely affect our business and financial condition.

On December 22, 2017, the US Congress enacted the Tax Cuts and Jobs Act (Tax Reform Legislation). The Tax Reform Legislation, among other things, (i) permanently reduces the US corporate income tax rate to 21% beginning in 2018, (ii) repeals the corporate alternative minimum tax (AMT) allowing for corresponding refunds of prior period AMT credits, (iii) provides for a five year period of 100% bonus depreciation followed by a phase-down of the bonus depreciation percentage, (iv) imposes a new limitation on the utilization of net operating losses generated in taxable years beginning after December 31, 2017, and (v) provides for more general changes to the taxation of corporations, including changes to the deductibility of interest expense, the adoption of a modified territorial tax system, assessing a repatriation tax or “toll-charge” on undistributed earnings and profits of US-owned foreign corporations, and introducing certain anti-base erosion provisions. The Tax Reform Legislation is complex and far-reaching and could eliminate or postpone certain tax deductions that currently are available with respect to oil and gas development, or increase costs. 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, and our business and financial condition could be adversely affected.

In addition, from time to time, legislation has been proposed that, if enacted into law, would make significant changes to US federal and state income tax laws, including (i) the elimination of the immediate deduction for intangible drilling and development costs, (ii) the repeal of the percentage depletion allowance for oil and natural gas properties; and (iii) an extension of the amortization period for certain geological and geophysical expenditures. While these specific changes are not included in the Tax Reform Legislation, no accurate prediction can be made as to whether any such legislative changes will be proposed or enacted in the future, or the timing of any such action. The elimination of such US federal tax deductions, as well as any other changes to or the imposition of new federal, state, local or non-US taxes (including the imposition of, or increases in production, severance or similar taxes) could adversely affect our business and financial condition.

We are subject to increasing governmental regulations and environmental requirements that may cause us to incur substantial incremental costs.

Our industry is subject to complex laws and regulations adopted or promulgated by international, federal, state and local authorities relating to the exploration for, and the development, production and marketing of, crude oil, natural gas and NGLs. As the various government and/or regulatory bodies issue or rescind various regulations, our operations are subject to significant volatility in response to the issuance, interpretation and application of these regulations.

Changes in price controls, taxes and environmental laws relating to our industry have the ability to substantially affect crude oil, natural gas and NGL production, operations and economics. Environmental laws, in particular, can change frequently, often become stricter and at times may force us to incur additional costs as changes are implemented.

We cannot always predict with certainty how agencies or courts will interpret existing laws and regulations or the effect these interpretations may have on our business or financial condition.

Additionally, the unintentional discharge of natural gas, crude oil, or other pollutants into the air, soil or water may give rise to liabilities on our part to government agencies and/or third parties, and may require us to incur costs to achieve remediation objectives and/or requirements.

In April 2015, for example, we entered into a Consent Decree with the US EPA, US Department of Justice and State of Colorado to improve emission control systems at a number of our condensate storage tanks in the DJ Basin. The Consent Decree required us to pay a civil penalty and to perform certain injunctive relief activities, mitigation projects, and supplemental environmental projects. We continue to incur costs associated with these activities. In addition, compliance with the Consent Decree could result in the temporary shut in or permanent plugging and abandonment of certain wells and associated tank batteries within the Non-Attainment Area of the DJ Basin.

Noncompliance with existing or future legislation or regulations could potentially result in an increased risk of civil or criminal fines or sanctions. For example, fines or sanctions associated with a well incident or spill could well exceed the actual cost of containment and cleanup.

Further expansion of environmental, safety and performance regulations or an increase in liability for drilling or production activities, including punitive fines, may have one or more of the following impacts on our business:

- increase the costs of drilling exploratory and development wells;
- cause delays in, or preclude, the development of our projects resulting in longer development cycle times;
- result in additional operating and capital costs;
- divert our cash flows from capital investments in order to maintain liquidity;
- increase or remove liability caps for claims of damages from oil spills;
- increase our share of civil or criminal fines or sanctions for actual or alleged violations if a well incident were to occur; and
- limit our ability to obtain additional insurance coverage, at a level that balances the cost of insurance and our desired rates of return, to protect against any increase in liability.

Any of the above operating or financial factors may result in a reduction of our cash flows, profitability, and the fair value of our properties or reduce our financial flexibility. Because we strive to achieve certain levels of return on our projects, an increase in our financial responsibility could result in certain of our planned projects becoming uneconomic. See [Items 1. and 2. Business and Properties – Regulations](#) .

We face various risks associated with global populism and general political uncertainty.

Following the 2008/2009 global financial crisis, the world has experienced lower economic growth versus the levels attained in previous decades. This has resulted in economic stagnation for certain citizens and, as a result, there are concerns around jobs, economic well-being and wealth distribution. Globally, certain individuals and organizations are attempting to focus the public's attention on income and wealth distribution and implement income and wealth redistribution policies.

In addition, if efforts to challenge and change individual and/or corporate taxation are successful, they could result in increased taxation on individuals and/or corporations, as well as, potentially, increased regulation on companies and financial institutions. These measures would further burden companies and individuals with additional tax costs.

Recent events have intensified these risks. In the US, the growing trends toward populism and political polarization, has resulted in uncertainty regarding potential changes in regulations, fiscal policy, social programs, domestic and foreign relations and international trade policies. Global uncertainty and/or reductions in global trade activities could contribute to slower economic growth which could negatively impact business and commerce.

Potential changes in relationships among the US, China and Russia, or among China, Russia and other countries, can have significant impacts on the balance of power, as well as on global trade, with further impacts on both global and local economies. In addition, changes in the relationships between the US and its neighbors, such as Mexico, can have significant, potentially negative, impacts on commerce. In Europe, the populist movement has resulted in the Brexit vote and increasing populist demands and rises in nationalism could have a negative impact on economic policy and consequently pose a potential threat to the unity of the European Union.

Our ability to respond to these developments or comply with any resulting new legal or regulatory requirements, including those involving economic and trade sanctions, as well as any potential increased tax expense, could reduce our ability to negotiate the sale of our products, increase our costs of doing business, reduce our financial flexibility and otherwise have a material adverse effect on our business, financial condition and results of our operations.

We face various risks associated with the trend toward increased anti-oil and gas development activity.

In recent years, we have seen significant growth in opposition to oil and gas development both in the US and globally.

Companies in our industry can be the target of opposition to hydrocarbon development from stakeholder groups, including national, state and local governments, regulatory agencies, non-government organizations and public citizens. This opposition is focused on attempting to limit or stop hydrocarbon development. Examples of such opposition include: efforts to reduce access to public and private lands; delaying or canceling permits for drilling or pipeline construction; limiting or banning industry techniques such as hydraulic fracturing, and/or adding restrictions on or the use of water and associated disposal; imposition of set-backs on oil and gas sites; delaying or denying air-quality permits; advocating for increased regulations, punitive taxation, or citizen ballot initiatives or moratoriums on industry activity; and the use of social media channels to cause reputational harm. We have experienced these efforts in Colorado in the past and it is likely they will continue into the future. Recent efforts by the US Administration to modify federal oil and gas related regulations could intensify the risk of anti-development efforts from grass roots opposition.

Our need to incur costs associated with responding to these anti-development efforts, including legal challenges, or complying with any new legal or regulatory requirements resulting from these efforts, could have a material adverse effect on our business, financial condition and results of operations.

Restricted land access could reduce our ability to explore for and develop crude oil, natural gas and NGL reserves.

Our ability to adequately explore for and develop crude oil, natural gas and NGL resources is affected by a number of factors related to access to land. Examples of factors which reduce our access to land include, among others:

- new municipal, state or federal land use regulations, which may restrict drilling locations or certain activities such as hydraulic fracturing;
- local and municipal government control of land or zoning requirements, which can conflict with state law and deprive land owners of property development rights;
- landowner, community and/or governmental opposition to infrastructure development;
- regulation of federal and Indian land by the BLM;
- anti-development activities, which can reduce our access to leases through legal challenges or lawsuits, disruption of drilling, or damage to equipment;
- the presence of threatened or endangered species or of their habitat;
- disputes regarding leases; and
- disputes with landowners, royalty owners, or other operators over such matters as title transfer, joint interest billing arrangements, revenue distribution, or production or cost sharing arrangements.

Loss of access to land for which we own mineral rights could result in a reduction in our proved reserves and a negative impact on our results of operations and cash flows. Reduced ability to obtain new leases could constrain our future growth and opportunity set by limiting the expansion of our upstream portfolio. In addition, loss of rights granted under surface use agreements, rights-of-way, surface leases or other easement rights, could disrupt or prohibit our ability to construct or operate midstream assets and could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

A change in international and/or US federal and state climate policy could have a significant impact on our operations and profitability.

Domestic and international response to climate and related energy issues are matters of public policy consideration. We are currently in a period of increasing uncertainty as to these matters, and, at this time, it is difficult to anticipate how the current US Administration, or other entities, may act on exiting or new laws and regulations. As compared with certain large multi-national, integrated energy companies, we do not conduct fundamental research regarding the scientific inquiry of climate change. However, we will continue to closely monitor all relevant developments in this regard. Changes in international, federal or state laws and regulations regarding climate policy could have a significant negative impact on our ability to explore for and develop crude oil and natural gas resources or reduce demand for our products.

In recent years, international, federal, state and local governments have taken steps to reduce emissions of greenhouse gases. The EPA has finalized a series of greenhouse gas monitoring, reporting and emissions control rules for the oil and natural gas industry, and the US Congress has, from time to time, considered adopting legislation to reduce emissions. Almost one-half of states in the US have taken measures to reduce emissions of greenhouse gases primarily through the development of greenhouse gas emission inventories and/or regional greenhouse gas cap-and-trade programs. For a description of existing and proposed greenhouse gas rules and regulations, see Items 1. and 2. Business and Properties - Regulations .

In addition, claims have been made against certain energy companies alleging that greenhouse gas emissions from oil and natural gas operations constitute a public nuisance under federal and/or state common law. As a result, private individuals or other entities may make claims against us for alleged personal injury, property damage, or other potential liabilities. While our business is not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could impact our operations and could have an adverse impact on our financial condition.

Moreover, there has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornadoes and snow or ice storms, as well as rising sea levels. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially hotter or colder than their historical averages. Extreme weather conditions can interfere with our production and increase our costs and damage resulting from extreme weather may not be fully insured.

Our Eastern Mediterranean discoveries bear certain geopolitical, regulatory, financial and technical challenges that could adversely impact our ability to monetize these natural gas assets.

We have entered into and are currently negotiating various long-term GSPAs for our Eastern Mediterranean natural gas assets. Some of these agreements would require the export of natural gas from either Israel or Cyprus to other countries in the region, such as Egypt and Jordan. These agreements are subject to a variety of risks, including geopolitical, regulatory, financial and other uncertainties. War, political violence, civil unrest or lack of intergovernmental cooperation could affect both our and our counterparties' abilities to cooperate and to perform under these agreements, and could potentially lead to a breach or termination of such agreements. In addition, economic conditions or financial duress of our counterparties could jeopardize their ability to fulfill their payment obligations under these contracts. Furthermore, if material disruptions occur, including events or circumstances constituting force majeure under contract provisions, such that they inhibit us or our counterparties from performing under these GSPAs, or our counterparties are unable to pay us for a sustained period of time, we could incur significant financial losses. While the State of Israel continues to maintain its ability to generate electricity via coal-fired power plants, as they transition from coal-fired power plants to natural gas-fired power plants, they become more dependent on us and our partners for their source of natural gas supply. Any material disruption in our ability to deliver natural gas to the State of Israel could have a material impact on our expected profitability, financial performance and reputation.

We are subject to certain regulatory provisions under the Framework, as adopted by the Government of Israel, including a requirement to reduce our ownership in the Tamar and Dalit fields to 25% by the end of 2021. We recently signed a definitive agreement to divest a 7.5% working interest in each of the fields to Tamar Petroleum Ltd., closing of the transaction is subject to satisfactory conclusion of certain conditions, including Tamar Petroleum's debt financing. Upon closing, we will receive consideration of both cash and Tamar Petroleum Ltd. shares, approximating 70% and 30%, respectively, of the transaction value, which will fluctuate based on market conditions. In accordance with the Framework, we must divest Tamar Petroleum Ltd. shares received by the end of 2021. In addition, changes in Israel's fiscal and/or regulatory regimes or energy policies occurring as a result of government policy on natural gas development and/or exports could delay or reduce the profitability of our Tamar and/or Leviathan development projects, and/or render future exploration and development projects uneconomic.

Development of our Eastern Mediterranean natural gas assets requires substantial investment and will take several years to complete. Our partners must be able to fund their share of investment costs through the development cycle, through cash flow from operations, external credit facilities, or other sources, including financing arrangements. If our project partners' cash flows or ability to maintain adequate financing are negatively impacted through similar risks factors described herein, the development of a project could be delayed and the timing and receipt of planned cash flows and expected profitability could be negatively impacted.

Due to the scale of our Leviathan (Israel) and Aphrodite (Cyprus) discoveries, realization of their full economic value depends on our ability to execute successful phased, development scenarios, the failure or delay of which could reduce our future growth and have negative effects on our future operating results. Offshore projects of this magnitude entail significant technical complexities including subsea tiebacks to a FPSO or production platform, pressure maintenance systems, gas re-injection systems, onshore receiving terminals, or other specialized infrastructure. In addition, we depend on third-party technology and service providers and other supply chain participants for these complex projects. Delays and differences between estimated and actual timing of critical events related to these projects could have a material adverse effect on our results of operations.

Concentration of capital in, and production and cash flows from, certain operations may increase our exposure to risks enumerated herein.

A significant portion of our production and revenues is highly concentrated and is generated from a limited number of conventional deepwater wells. These wells, located in the Gulf of Mexico, offshore Israel and offshore Equatorial Guinea, contributed approximately 33% of our 2017 total consolidated revenues and 34% of our 2017 total consolidated sales volumes. In addition, with the recording of reserves associated with the initial development of the Leviathan field, we now have a major concentration of reserves offshore Israel, with approximately 47% of our year-end 2017 proved reserves attributable to this area. These fields are also capital and resource-intensive.

Although we carry contingent business interruption for these producing assets, as well as other insurance, the insurance may be insufficient to cover all of risks including, a disruption to downstream operations impacting the processing, marketing and distribution of our production, such as from an accident, natural disaster, government intervention or other event, would have a significant impact on our production profile, cash flows, profitability, and overall business plan.

We also have significant concentrations of capital and production in unconventional basins including the DJ Basin, Delaware Basin and Eagle Ford Shale, and we expect to invest approximately 65%, of our total capital investment program to development activities in these areas in 2018. Restrictions in land access, rapid changes in drilling and completion technology, significant increases in drilling and completion costs, lack of availability of downstream services, changes in regulations and other risks impacting these areas, as enumerated in certain risk factors described herein, can have immediate, significant negative impacts on our production, cash flows, profitability and financial position.

A cyber incident could result in information theft, data corruption, operational disruption and/or financial loss.

We depend on digital technology, including information systems and related infrastructure as well as cloud applications and services, to process and record financial and operating data, communicate with our employees and business partners, analyze seismic and drilling information, estimate quantities of oil and gas reserves as well as other activities related to our business. Our business partners, including vendors, service providers, purchasers of our production, and financial institutions, are also dependent on digital technology. The technologies needed to conduct oil and gas exploration and development activities in deepwater, ultra-deepwater and shale, as well as technologies supporting midstream operations and global competition for oil and gas resources make certain information the target of theft or misappropriation.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, also has increased. A cyber attack could include gaining unauthorized access to digital systems for purposes of misappropriating assets or sensitive information, corrupting data, or causing operational disruption, or result in denial-of-service on websites. SCADA-based systems are potentially vulnerable to targeted cyber attacks due to their critical role in operations.

Our technologies, systems, networks, and those of our business partners may become the target of cyber attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period.

Our implementation of various controls and processes to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure is costly and labor intensive. Moreover, there can be no assurance that such measures will be sufficient to prevent security breaches from occurring. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

Our operations may be adversely affected by violent acts such as from civil disturbances, terrorist acts, regime changes, cross-border violence, war, piracy, or other conflicts that may occur in regions that encompass our operations.

Certain regions, such as the Middle East and Africa, continue to experience varying degrees of political instability, public protests and terrorist attacks. We operate in regions of the world that have experienced such incidents or are in close proximity to areas where violence has occurred. Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign, as well as military or other actions taken in response to these acts, could cause instability in the global financial and energy markets. Continued or escalated civil and political unrest and acts of terrorism in the regions in which we operate could result in curtailment of our operations. In the event that regions in which we operate experience civil or political unrest or acts of terrorism, especially in areas where such unrest leads to regime change, our operations in such regions could be materially impaired.

We monitor the economic and political environments of the countries in which we operate. However, we are unable to predict the occurrence of disturbances such as those noted above. In addition, we have limited ability to mitigate their impact.

Civil disturbances, terrorist acts, regime changes, war, or conflicts, or the threats thereof, could have the following results, among others:

- increased volatility in global crude oil, natural gas and NGL prices which could negatively impact the global economy, resulting in slower economic growth rates, which could reduce demand for our products;
- negative impact on the global crude oil supply if infrastructure or transportation are disrupted, leading to further commodity price volatility;
- difficulty in attracting and retaining qualified personnel to work in areas with potential for conflict;
- inability of our personnel or supplies to enter or exit the countries where we are conducting operations;
- disruption of our operations due to evacuation of personnel;
- inability to deliver our production due to disruption or closing of transportation routes;
- reduced ability to export our production due to efforts of countries to conserve domestic resources;
- damage to or destruction of our wells, production facilities, receiving terminals or other operating assets;
- damage to or destruction of property belonging to our natural gas purchasers leading to interruption of natural gas deliveries, claims of force majeure, and/or termination of natural gas sales contracts, resulting in a reduction in our revenues;
- inability of our service and equipment providers to deliver items necessary for us to conduct our operations;
- lack of availability of drilling rigs, oilfield equipment or services if third party providers decide to exit the region;
- shutdown of a financial system, communications network, or power grid causing a disruption to our business activities; and
- capital market reassessment of risk and reduction of available capital making it more difficult for us and our partners to obtain financing for potential development projects.

Loss of property and/or interruption of our business plans resulting from civil unrest could have a significant negative impact on our earnings and cash flow. In addition, we may not have enough insurance to cover any loss of property or other claims resulting from these risks.

Exploration, development and production activities carry inherent risk. These activities, as well as natural disasters or adverse weather conditions, could result in liability exposure or the loss of production and revenues.

Our crude oil and natural gas operations are subject to hazards and risks inherent in the drilling, production and transportation of crude oil, natural gas and NGLs, including:

- pipeline ruptures and spills;
- fires, explosions, blowouts and well cratering;
- equipment malfunctions and/or mechanical failure on high-volume, high-impact wells;
- malfunctions of, or damage to, gathering, processing, compression and transportation facilities and equipment and other facilities and equipment utilized in support of our crude oil, natural gas and NGL operations;
- leaks or spills occurring during the transfer of hydrocarbons from an FPSO to an oil tanker;
- loss of product occurring as a result of transfer to a rail car or train derailments;
- formations with abnormal pressures and basin subsidence which could result in leakage or loss of access to hydrocarbons;
- release of pollutants; and
- spills, leaks or discharges of fluids used in or produced in the course of operations, especially those that reach surface water or groundwater.

Some of these risks or hazards could materially and adversely affect our revenues and expenses by reducing or shutting in production from wells, loss of equipment or otherwise negatively impacting the projected economic performance of our projects. In addition, our ability to deliver product pursuant to long-term supply contracts could be negatively impacted resulting in additional financial exposure in the event we cannot fully deliver the contract quantities.

Any of these risks or hazards can result in injuries and/or deaths of employees, supplier personnel or other individuals, loss of hydrocarbons, environmental pollution and other damage to our properties or the properties of others, regulatory investigations and administrative, civil and criminal penalties or restricted access to our properties.

In addition, our operations and financial results could be significantly impacted by adverse weather conditions and natural disasters in the areas we operate including:

- hurricanes, tropical storms, cyclones, windstorms, or "superstorms" which could affect our operations in areas such as Texas and the Gulf of Mexico;
- winter storms and snow which could affect our operations in the DJ Basin;
- extremely high temperatures, which could affect third party gathering and processing facilities in the DJ Basin and Texas;
- severe droughts resulting in new restrictions on water usage in the DJ Basin and Texas;
- harsh weather and rough seas offshore certain international locations, which could limit exploration activities; and
- other natural disasters.

Any of these can result in loss of hydrocarbons, environmental pollution and other damage to our properties or the properties of others, or restricted access to our properties.

Development drilling may not result in commercially productive quantities of crude oil and natural gas reserves from unconventional or conventional resources.

We depend on development projects to provide sustained cash flows after investment and attractive financial returns. However, development drilling is not always successful and the profitability of development projects may change over time.

In new development areas, available data may not allow us to completely know the extent of the reservoir or the best locations for drilling development wells. Therefore, a development well we drill may be a dry hole or result in noncommercial quantities of hydrocarbons.

We are planning to invest significant amounts of capital to continue development of our US onshore unconventional resources as well as to progress the development of the Leviathan field project. In unconventional basins, development is highly dependent on the use of new technologies to drive cost efficiencies in drilling and completion as well as on the availability of third party infrastructure to provide flow assurance and transportation of production to end markets.

Development of offshore resources is capital and resource-intensive and may require several years to complete. In order to timely advance significant offshore discoveries, we may progress multiple development concepts simultaneously, with the realization that only one concept may ultimately be approved or be economically feasible. This approach may result in our writing off costs related to certain development concepts that must be eliminated from further consideration once a final development option has been determined.

Even if development drilling is successful and we find commercial quantities of reserves, we may encounter difficulties or delays in completing development wells. For example, frontier areas or less developed onshore areas may not have adequate infrastructure for gathering, processing or transportation, and production may be delayed until such infrastructure is constructed.

Exploratory drilling, either within existing or new ventures in countries which have no history of hydrocarbon sector investment, subjects us to risks and may not result in the discovery of commercially productive reservoirs.

Exploratory drilling requires significant capital investment and does not always result in commercial quantities of hydrocarbons or new development projects. In addition, exploratory drilling activities may be curtailed, delayed or canceled, or development plans may change, resulting in significant exploration expense, as a result of a variety of factors, including unexpected drilling conditions and pressure or other irregularities in formations. Furthermore, remote locations may make it more difficult and time-consuming to transport personnel, equipment and supplies, and we may face more difficult environments, such as oil sands, deepwater, or ultra-deepwater in our efforts to seek new reserves, and may need to develop or invest in new technologies. These operating environments, and potential for harsh weather, increase cost as well as drilling risk.

Exploratory dry holes can occur because seismic data and other technologies we use to determine potential exploratory drilling locations do not allow us to know conclusively prior to drilling a well that crude oil or natural gas is present or may be produced economically. In addition, a well may be successful in locating hydrocarbons, but we and our partners may decide not to develop the prospect due to other considerations.

In addition, for certain capital-intensive offshore projects, it may take several years to evaluate the future potential of an exploratory well and make a determination of its economic viability, resulting in delays in cash flows from production start-up and a lower return on our investment.

We hold working interests in certain areas, including offshore areas of Cyprus, Cameroon, Gabon and Newfoundland (Canada) where there is minimal or no crude oil, natural gas or NGL production, and in certain cases, limited infrastructure. If commercial quantities of hydrocarbons are discovered, societies with minimal or no current production must begin to address such topics as sector regulation and distribution of government proceeds from hydrocarbon sales, the results of which could have a negative impact on our business. We may not be able to compensate for or fully mitigate these risks. See Item 8. Financial Statements and Supplementary Data – Note 6. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs .

Our operations require us to comply with a number of US and international laws and regulations, violations of which could result in substantial fines or sanctions and/or impair our ability to do business.

Our operations require us to comply with complex and frequently-changing US and international laws and regulations, such as those involving anti-corruption, competition and antitrust, anti-boycott, anti-money laundering, import-export control, marketing, environmental and/or taxation.

For example, the US Foreign Corrupt Practices Act (FCPA) and similar laws and regulations enacted or promulgated by countries pursuant to the 1997 Organisation for Economic Cooperation and Development Anti-Bribery Convention generally prohibit improper payments to foreign officials for the purpose of obtaining or keeping business. We conduct some of our operations in developing countries that have relatively underdeveloped legal and regulatory systems compared to more developed countries. These countries generally are perceived as presenting an increased risk of corruption. Additionally, certain of our operations involve the use of agents and other intermediaries whose conduct and actions could be imputed to us by anti-corruption enforcement authorities. Violations of the FCPA or other anti-corruption laws could subject us to substantial fines or sanctions and impair our ability to do business.

The import/export of equipment and supplies necessary for oil and gas exploration and development activities, as well as the export of crude oil, natural gas, and liquids production are regulated by the import/export laws of the US and other countries in which we operate. In the US, certain items required for oil and gas development activities may be considered “dual-use”, having both commercial and military applications and, therefore, may be subject to specific import or export restrictions. In addition, the US government imposes economic and trade sanctions against certain foreign countries and regimes. The sanctions are based on US foreign policy and national security goals and may change over time.

Mergers of businesses often require the approval of certain government or regulatory agencies and such approval could contain terms, conditions, or restrictions that would be detrimental to our business after a merger. US antitrust laws require waiting periods and even after completion of a merger, governmental authorities could seek to block or challenge a merger as they deem necessary or desirable in the public interest. We have merged with or acquired other companies in the past. Prevention of a merger by antitrust laws could impair our ability to do business. Furthermore, mergers and acquisitions expose us to potential lawsuits or other obligations not yet anticipated at time of merger or acquisition. Such liabilities and obligations could hinder our ability to fully benefit from the acquired business or assets and negatively impact our financial performance.

As a developer, owner and operator of crude oil and natural gas properties, we are subject to various laws and regulations relating to the discharge of materials into, and the protection of, the environment. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and, in some instances, issuance of orders or injunctions limiting or requiring discontinuation of certain operations. See *We are subject to increasing governmental regulations and environmental requirements that may cause us to incur substantial incremental costs,* below, and Item 8. Financial Statements and Supplementary Data – Note 17. Commitments and Contingencies .

Federal, state and local hydraulic fracturing and water disposal legislation and regulation could increase our costs or restrict our ability to produce crude oil, natural gas and NGLs economically and in commercial quantities.

While hydraulic fracturing has been utilized in oil and gas development for decades, certain parties have called for further study of the technique's alleged environmental and health effects, for additional regulation of the technique and, in some cases, for a moratorium or ban on the use of hydraulic fracturing. Because of elevated public sensitivity around the topic, federal, state and local governments are continually conducting studies, evaluating their regulatory programs and considering additional requirements on and regulation of hydraulic fracturing practices.

At the national level, proposals have been introduced from time to time in the US Congress that, if implemented, would subject hydraulic fracturing to further regulation, thereby limiting its use or increasing its cost.

Federal agencies addressing hydraulic fracturing under existing authorities include the EPA, which has issued technical reports and developed various rules and guidelines regarding hydraulic fracturing activities, and the BLM, under the US Department of the Interior, which has issued final rules impacting hydraulic fracturing on federal and Indian lands. Some of these rules are subject to pending challenges and, on March 28, 2017, an executive order was signed directing the EPA and the BLM to review their rules and, if appropriate, to initiate rulemaking to rescind or revise them consistent with the stated policy of promoting clean and safe development of the nation’s energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production. Accordingly, the EPA and the BLM have taken actions to delay or rescind certain requirements related to hydraulic fracturing activities. See Items 1. and 2. Business and Properties - Hydraulic Fracturing.

Each of the states, as well as certain localities, where we operate have adopted or may adopt regulations on drilling activities in general or hydraulic fracturing in particular that could restrict or prohibit hydraulic fracturing in certain circumstances, impose more stringent operating standards and/or require the disclosure of the composition of hydraulic fracturing fluids. For example, a number of local communities in Colorado have attempted to increase regulatory requirements on crude oil and natural gas development. In addition, some state regulatory agencies have modified their regulations to account for potential induced seismicity with regard to the operation of injection wells used for waste disposal.

We are dependent on the use of hydraulic fracturing practices to produce commercial quantities of crude oil and natural gas, particularly from wells in our US onshore basins. Additional federal, state or local restrictions on hydraulic fracturing, water disposal or other drilling activities that may be imposed in areas where we conduct business, such as US onshore, could significantly increase our operating, capital and compliance costs as well as delay or halt our ability to develop crude oil, natural gas and NGL reserves. See Items 1. and 2. Business and Properties – Regulations and – Hydraulic Fracturing .

The marketability of our production is dependent upon transportation and processing facilities over which we may have no direct control.

The marketability of our production from our US onshore areas and Gulf of Mexico depends in part upon the availability, proximity and capacity of pipelines, natural gas gathering systems, rail service, and processing facilities. We deliver crude oil, natural gas and NGLs produced from these areas through gathering systems and pipelines, the majority of which we do not own.

In Israel, we rely on a state-owned pipeline and transportation system to deliver our production to customers and end users. Offshore Equatorial Guinea, our natural gas production is delivered to onshore processing and storage facilities operated by our partner, and the resulting products, as well as our crude oil production from Aseng and Alen, are lifted to tankers owned by third-parties.

Third-party systems and facilities may not be available to us in the future at a price that is acceptable to us. In addition, the lack of availability of, or capacity on, third-party systems and facilities could reduce the price offered for our production or result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Even where we have some contractual control over the transportation of our production through firm transportation arrangements, third-party systems and facilities may be temporarily unavailable due to market conditions or mechanical reliability or other reasons, including adverse weather conditions.

Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities, could delay or curtail production, thereby harming our business and, in turn, our results of operations, cash flows, and financial condition.

Our ability to produce crude oil, natural gas and NGLs economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling operations or are unable to dispose of or recycle the water we use economically and in an environmentally safe manner.

Drilling and development activities require the use of water and results in the production of waste water. For example, the hydraulic fracturing process, which we employ to produce commercial quantities of crude oil, natural gas and NGLs from many reservoirs, requires the use and disposal of significant quantities of water. In certain regions, there may be insufficient local capacity to provide a source of water for drilling activities. In those cases, water must be obtained from other sources and transported to the drilling site, adding to the development cost. Waste water from oil and gas operations often is disposed of via underground injection. Some studies have linked earthquakes or induced seismicity in certain areas to underground injection, which is leading to increased public scrutiny of injection safety.

The development of new environmental initiatives or regulations related to acquisition, withdrawal, storage and use of surface water or groundwater, or treatment and discharge of water waste, may limit our ability to use techniques such as hydraulic fracturing, increase our development and operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial condition. See Items 1. and 2. Business and Properties – Hydraulic Fracturing .

Failure to adequately fund continued capital expenditures could adversely affect our properties.

Our exploration, development, and acquisition activities require capital expenditures to achieve production and cash flows. In particular, major offshore projects have a multi-year long development cycle time, which means that development spending occurs for several years before the project begins producing hydrocarbons and generating cash flows. As examples, assets and infrastructure for export of natural gas from Leviathan require a multi-billion dollar investment prior to production startup. Furthermore, while the majority of our assets are held by production, certain of our 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 and failure to meet these obligations may result in the loss of a lease.

Historically, we have funded our capital expenditures through a combination of cash flows from operations, our unsecured revolving credit facility (Revolving Credit Facility), debt and equity issuances, and occasional sales of assets. Future cash flows from operations are subject to a number of variables, such as the level of production from existing wells, commodity prices, and our success in finding, developing and producing new reserves.

For 2018, our capital investment program is flexible to address potential commodity price changes. If commodity prices decline for an extended period of time, we will evaluate our level of capital spending and likely reduce our investment program. As a result, we will have less ability to replace our reserves through drilling operations and may elect to forfeit our ownership interests or rights to participate in some properties, resulting in lower production over time as compared with prior years. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Operating Outlook – 2018 Capital Investment Program .

A negative shift in investor sentiment of the oil and gas industry could adversely affect our ability to raise equity and debt capital.

Certain segments of the investor community have recently developed negative sentiment towards investing in our industry. Recent equity returns in the sector versus other industry sectors have led to lower oil and gas representation in certain key equity market indices. Some investors, including certain pension funds, university endowments and family foundations, have stated policies to disinvest in the oil and gas sector based on their social and environment considerations. Certain other stakeholders have also pressured commercial and investment banks to stop funding oil and gas projects.

Such developments could result in downward pressure on the stock prices of oil and gas companies, including ours. This may also potentially result in a reduction of available capital funding for potential development projects impacting our future financial results.

Indebtedness may limit our liquidity and financial flexibility.

At December 31, 2017 , we had $6.8 billion of consolidated debt, and indebtedness represented 39% of our total book capitalization (sum of debt plus shareholders' equity).

Our indebtedness affects our operations in several ways, including the following:

- a portion of our cash flows from operating activities must be used to service our indebtedness and is not available for other purposes;
- we may be at a competitive disadvantage as compared to similar companies that have less debt;
- a covenant contained in our Credit Agreement provides that our total debt to capitalization ratio (as defined in the Credit Agreement) will not exceed 65% at any time, which may make additional borrowings more expensive, thereby affecting our flexibility in planning for, and reacting to, changes in the economy and our industry;
- additional future financing for working capital, capital expenditures, acquisitions, general corporate or other purposes may have higher costs and more restrictive covenants;
- changes in our debt credit ratings may negatively affect the cost, terms, conditions and/or availability of future financing, and lower ratings will increase the interest rate and fees we pay on our Revolving Credit Facility; and
- we may be more vulnerable to general adverse economic and industry conditions.

We may incur additional debt in order to fund our exploration, development and acquisition activities. A higher level of indebtedness increases the risk that our financial flexibility may deteriorate. Our ability to meet our debt obligations and service our debt depends on future performance. General economic conditions, commodity prices, and financial, business and other factors will affect our operations and our future performance. Many of these factors are beyond our control and we may not be able to generate sufficient cash flow to pay the interest on our debt, and future working capital, borrowings and equity financing may not be available to pay or refinance such debt. See Item 8. Financial Statements and Supplementary Data – Note 10. Long-Term Debt .

A downgrade or other negative action with respect to our credit rating could negatively impact our business and financial condition.

A downgrade or other negative rating action could affect our requirements to post collateral as financial assurance of performance under certain contractual arrangements, such as pipeline transportation contracts, crude oil and natural gas sales contracts, work commitments and certain abandonment obligations, and potentially subject us to additional bonding and other assurance requirements with respect to our Gulf of Mexico assets. A lowering of our credit rating may negatively affect the cost, terms, conditions and availability of future financing.

We face significant competition and many of our competitors have resources in excess of our available resources.

We operate in highly competitive areas of crude oil and natural gas exploration, development, acquisition and production. We face intense competition from:

- large multi-national, integrated oil and gas companies;
- state-controlled national oil companies;
- US independent oil and gas companies;
- US onshore midstream companies;
- service companies engaging in exploration and production activities; and
- private investing in oil and gas equity funds.

We face competition in a number of areas such as:

- seeking to acquire desirable producing properties or new leases for future exploration;
- acquiring or increasing access to gathering, processing and transportation services and capacity;
- marketing our crude oil, natural gas and NGL production;
- seeking to acquire the equipment and expertise necessary to operate and develop properties; and
- attracting and retaining employees with certain skills.

Many of our competitors have financial and other resources substantially in excess of those available to us. Such companies may be able to pay more for seismic information and lease rights on crude oil and natural gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. This highly competitive environment could have an adverse impact on our business.

Estimates of crude oil, natural gas and NGL reserves are not precise.

Reservoir engineering is a subjective process of estimating underground accumulations of crude oil, natural gas and NGLs that cannot be measured in an exact manner, and there are numerous uncertainties inherent in estimating reserves quantities and their value, including factors that are beyond our control.

In accordance with the SEC's rules for oil and gas reserves reporting, our reserves estimates are based on 12-month average commodity prices; therefore, reserves quantities will change when actual prices increase or decrease. As estimated production, development and abandonment costs are based on year-end economic conditions, reserves quantities will also change when these costs increase or decrease.

Reserves estimates depend on a number of factors and assumptions that may vary considerably from actual results, including:

- historical production from the area compared with production from other areas;
- the assumed effects of regulations by governmental agencies, including the SEC;
- assumptions concerning future crude oil, natural gas, and NGL prices;
- anticipated development cycle time;
- future development costs;
- future operating and abandonment costs;
- impacts of cost recovery provisions in contracts with foreign governments;
- severance and excise taxes; and
- workover and remedial costs.

For these reasons, estimates of the economically recoverable quantities of crude oil, natural gas and NGLs attributable to any particular group of properties, classifications of those reserves based on risk of recovery, and estimates of the future net cash flows expected from them prepared by different petroleum engineers, or by the same petroleum engineers but at different times, may vary substantially. Estimation of crude oil, natural gas and NGL reserves in emerging areas or areas with limited historical production is inherently more difficult, and we may have less experience in such areas. Accordingly, reserves estimates may be subject to positive or negative revisions, and actual production, revenues and expenditures with respect to our reserves likely will vary, possibly materially, from estimates. Any such negative revisions could result in an asset impairment charge.

Additionally, some of our reserves estimates are calculated using volumetric analysis, which involves estimating the volume of a reservoir based on the net feet of pay of the structure and an estimation of the area covered by the structure. Reserves estimates using volumetric analysis are less reliable than estimates based on a lengthy production history.

In addition, realization or recognition of PUDs will depend on our development schedule and plans. A change in future development plans for PUDs could cause the discontinuation of the classification of these reserves as proved. See Items 1. and 2. Business and Properties – Proved Reserves Disclosures .

We operate in a litigious environment.

Some of the jurisdictions within which we operate have proven to be litigious environments. Oil and gas companies, such as us, can be involved in various legal proceedings, such as title, royalty, or contractual disputes, in the ordinary course of business. For example, in certain states, oil and gas companies are often the target of “legacy lawsuits,” by which a landowner claims that oil and gas operations, often performed many years ago and by another operator, caused pollution or contamination of a property. Various properties we have owned over the past decades potentially expose us to “legacy lawsuit” claims. Similarly, neighboring landowners may allege that current operations cause contamination or create a nuisance.

Because we maintain a diversified portfolio of assets that includes both US and international projects, the complexity and types of legal procedures with which we may become involved may vary, and we could incur significant legal and support expenses in different jurisdictions. For instance, we historically have had to address certain fiscal, antitrust and other regulatory challenges in Israel, including a current class action lawsuit filed by petitioners alleging we and our partners in Tamar violated antitrust laws through the monopolistic pricing of natural gas to the citizens of Israel. Legal proceedings such as this could result in a substantial liability and/or negative publicity about us and adversely affect the price of our common stock. In addition, legal proceedings distract management and other personnel from their primary responsibilities. These proceedings are subject to the uncertainties inherent in any litigation. We will defend ourselves vigorously in all such matters. However, if we are not able to successfully defend ourselves, there could be a delay or even halt in our exploration, development or production activities or other business plans, resulting in a reduction in reserves, loss of production and reduced cash flows.

One of our subsidiaries acts as the general partner of a publicly traded master limited partnership, Noble Midstream Partners, which may involve a greater exposure to legal liability than our historic business operations.

One of our subsidiaries acts as the general partner of Noble Midstream Partners, a publicly traded master limited partnership. Our control of the general partner of Noble Midstream Partners may increase the possibility that we could be subject to claims of breach of fiduciary duties, including claims of conflicts of interest, related to Noble Midstream Partners. Any liability resulting from such claims could have a material adverse effect on our future business, financial condition, results of operations and cash flows.

We may be subject to risks in connection with acquisition and divestiture activities.

As part of our business strategy, we have made, and will likely continue to make, acquisitions of oil and gas properties and/or entities that own them. Furthermore, if we are unable to make attractive acquisitions, our future growth could be limited. Moreover, even if we do make acquisitions, they may not result in an increase in our cash flows from operations or otherwise result in the benefits anticipated due to various risks, including, but not limited to:

- incorrect estimates or assumptions about reserves, exploration potential or potential drilling locations;
- incorrect assumptions regarding future revenues, including future commodity prices and differentials, or regarding future development and operating costs;
- incorrect assumptions regarding potential synergies and the overall costs of equity or debt;
- difficulties in integrating the operations, technologies, products and personnel of the acquired assets or business; and
- unknown and unforeseen liabilities or other issues related to any acquisition for which contractual protections prove inadequate, including environmental liabilities and title defects.

The acquisition of a property or business requires management to make complex judgments and assessments, and the accuracy of the assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be consistent with industry practices. Our review will not reveal all existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities.

We also maintain an ongoing portfolio management program to ensure our company is well-positioned with assets that offer growth at financially attractive investment options. Therefore, we may periodically divest certain material assets which may help to generate organizational and operational efficiencies as well as cash for use in our capital investment program or to repay outstanding debt.

We strive to obtain the most attractive prices for our assets; however, various factors can materially affect our ability to dispose of assets on terms acceptable to us. Such factors may include:

- current commodity prices;
- laws and regulations impacting oil and gas operations in the areas where the assets are located;
- willingness of the purchaser to assume certain liabilities such as asset retirement obligations;
- our willingness to indemnify buyers for certain matters; and
- delays in closing.

Inability to achieve a desired price for the assets, or underestimation of amounts of retained liabilities or indemnification obligations, can result in a reduction of cash proceeds, a loss on sale due to an excess of the asset's net book value over proceeds, or liabilities which must be settled in the future at amounts that are higher than we anticipated. In addition, although we may successfully divest oil and gas assets, we may retain certain related contracts. For example, although we sold our Marcellus Shale upstream properties in 2017, we retained significant obligations under firm transportation contracts. Our inability to fully commercialize these contracts and reduce the associated financial commitments could result in a decrease in cash flows from operations. In addition, we may be required to recognize losses in accordance with exit or disposal activities. See Item 7. Management's Discussion of Financial Condition and Results of Operations – Liquidity and Capital Resources – Contractual Obligations .

An uneconomic or unsuccessful acquisition or divestiture effort may divert management’s attention and our financial resources away from existing operations, which could have a material adverse effect on our financial condition and results of operations.

We are exposed to counterparty credit risk as a result of our receivables, hedging transactions and cash investments.

We are exposed to risk of financial loss from joint venture and other receivables. We are the operator on a majority of our joint venture development projects, including Leviathan. As operator of the joint ventures, we pay joint venture expenses and make cash calls on our nonoperating partners for their respective shares of joint venture costs. These projects are capital cost intensive and, in some cases, a nonoperating partner may experience a delay in obtaining financing for its share of the joint venture costs or have liquidity problems resulting in slow payment of joint venture costs that can result in potential delays in our development projects.

In addition, some of our joint venture partners are not as creditworthy as we are and may experience credit rating downgrades or liquidity problems that may hinder their ability to obtain financing. Counterparty liquidity problems could result in a delay in our receiving proceeds from reimbursement of joint venture costs. Nonperformance by a joint venture partner could result in significant financial losses.

Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. During periods of falling commodity prices, our commodity derivative receivable positions increase, which increases our counterparty credit exposure. We also had approximately $675 million in cash and cash equivalents at December 31, 2017 deposited with financial institutions, a majority of which was invested in money market funds and short-term deposits with major financial institutions. While we monitor the creditworthiness of the banks and financial institutions with which we invest and engage in hedging transactions, and maintain credit insurance, we are unable to predict sudden changes in solvency of the financial institutions and may be exposed to associated risks.

If one or more of our joint venture partners, hedge counterparties and financial institutions were to experience a sudden deterioration in liquidity, it could impair their ability to perform under the terms of our contracts. We are unable to predict sudden changes in creditworthiness or ability of these parties to perform and could incur significant financial losses.

Credit enhancements have been obtained from some parties in the form of parental guarantees, letters of credit or credit insurance; however, not all of our counterparty credit is protected through guarantees or credit support. In addition, we maintain credit insurance associated with specific purchasers. However, nonperformance by a hedge counterparty or financial institution could result in significant financial losses.

Commodity hedging transactions may limit our potential gains or fail to protect us from declines in commodity prices.

In order to reduce the impact of commodity price uncertainty and increase cash flow predictability relating to the marketing of our crude oil and natural gas, we enter into hedging arrangements with respect to a portion of our expected revenues. Our hedges, consisting of a series of derivative instrument contracts, are limited in duration, usually for periods of one to three years. While intended to reduce the effects of volatile crude oil and natural gas prices, such transactions may limit our potential gains if prices rise over the price established by the arrangements. Conversely, our hedging program may be inadequate to protect us from continuing and prolonged declines in the price of crude oil or natural gas.

Global commodity prices are volatile. Such volatility challenges our ability to forecast and, as a result, it may become more difficult to manage our hedging program. In trying to manage our exposure to commodity price risk, we may end up hedging too much or too little, depending upon how our crude oil or natural gas volumes and our production mix fluctuate in the future. Hedging transactions may also expose us to the risk of financial loss in certain circumstances, including instances in which: our production is less than expected; there is a widening of price basis differentials between delivery points for our production and the delivery points assumed in the hedge arrangement; the counterparties to our futures contracts fail to perform under the contracts; or a sudden unexpected event materially impacts crude oil or natural gas prices. See Item 8. Financial Statements and Supplementary Data – Note 8. Derivative Instruments and Hedging Activities .

The insurance we carry is insufficient to cover all of the risks we face, which could result in significant financial exposure.

Exploration for and production of crude oil and natural gas can be hazardous, involving natural disasters or other catastrophic events such as hurricanes, earthquakes, blowouts, well cratering, fire and explosion, loss of well control, pipeline disruptions, mishandling of fluids and chemicals, and possible underground migration of hydrocarbons and chemicals, any of which can result in damage to or destruction of wells or formations or production facilities, injury to persons, loss of life, or damage to property and the environment. Exploration and production activities are also subject to risk from political developments such as terrorist acts, piracy, civil disturbances, war, and expropriation or nationalization of assets, or other interruptions, such as cyber security breaches, which can cause loss of or damage to our property.

Our insurance program and memberships in domestic and international dedicated oil spill and emergency response organizations may not minimize or fully protect us from losses resulting from damages to or the loss of physical assets or loss of human life, liability claims of third parties, and business interruption (loss of production) attributed to certain assets and including such occurrences as well blowouts and resulting oil spills. We do not have insurance protection against all the risks we face, because we choose not to insure certain risks, insurance is not available at a level that balances the cost of insurance and our desired rates of return, or actual losses may exceed coverage limits.

We expect the future availability and cost of insurance to be impacted by such events as hurricanes, earthquakes, tsunami and other natural disasters. Impacts could include tighter underwriting standards; limitations on scope and amount of coverage; and higher premiums, and will depend, in part, on future changes in laws and regulations regarding exploration and production activities in the Gulf of Mexico and other areas in which we operate, including possible increases in liability caps for claims of damages from oil spills. We will continue to monitor for any legislative or regulatory changes related to offshore exploration and production and its potential impact on the insurance market and our overall risk profile, and adjust our risk and insurance program to provide protection, at a level that we can afford considering the cost of insurance and our desired rates of return, against disruption to our operations and cash flows.

If an event, for example, a major offshore incident resulting in significant personal injury and/or environmental and physical damage, occurs that is not covered by insurance or not fully protected by insured limits, it could have a significant adverse impact on our financial condition, results of operations and cash flows. See Risk and Insurance Program , above.

Provisions in our Certificate of Incorporation and Delaware law may inhibit a takeover of us.

Under our Certificate of Incorporation, our Board of Directors is authorized to issue shares of our common or preferred stock without approval of our shareholders. Issuance of these shares could make it more difficult to acquire us without the approval of our Board of Directors as more shares would have to be acquired to gain control. In addition, Delaware law imposes restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock. These provisions may deter hostile takeover attempts that could result in an acquisition of us that would have been financially beneficial to our shareholders.

Item1B. Unresolved Staff Comments

None.

Item 3. 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. For discussion of material legal proceedings, see Item 8. Financial Statements and Supplementary Data – Note 17. Commitments and Contingencies .

Item 4. Mine Safety Disclosures

Not Applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Common Stock Our common stock, $0.01 par value, is listed and traded on the NYSE under the symbol "NBL." The declaration and payment of dividends will be determined on a quarterly basis and are at the discretion of our Board of Directors and the amount thereof will depend on our results of operations, financial condition, contractual restrictions, cash requirements, future prospects and other factors deemed relevant by the Board of Directors.

Stock Prices and Dividends by Quarters The high and low sales price per share of our common stock on the NYSE and quarterly dividends paid per share were as follows:

	High	Low	Dividends Per Share
2016			
First Quarter	$ 35.04	$ 23.77	$ 0.10
Second Quarter	38.62	29.47	0.10
Third Quarter	37.50	32.71	0.10
Fourth Quarter	42.03	33.75	0.10
2017			
First Quarter	$ 40.89	$ 32.33	$ 0.10
Second Quarter	35.74	27.66	0.10
Third Quarter	30.06	22.99	0.10
Fourth Quarter	29.58	22.99	0.10

On January 30, 2018, our Board of Directors declared a quarterly cash dividend of $0.10 per common share. The dividend will be paid February 26, 2018, to shareholders of record on February 12, 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.

Transfer Agent and Registrar The transfer agent and registrar for our common stock is Wells Fargo Bank, N.A., 1110 Centre Pointe Curve, Suite 101 Mendota Heights, MN 55120.

Stockholders' Profile Pursuant to the records of the transfer agent, as of February 9, 2018, the number of holders of record of our common stock was 561.

Stock Repurchases The following table summarizes repurchases of our common stock occurring in fourth quarter 2017 :

Period	Total Number of Shares Purchased [(1)]	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
				(in thousands)
10/1/2017 - 10/31/2017	390	$ 28.33	—	—
11/1/2017 - 11/30/2017	85	28.30	—	—
12/1/2017 - 12/31/2017	20,173	25.68	—	—
Total	20,648	$ 25.74	—	—

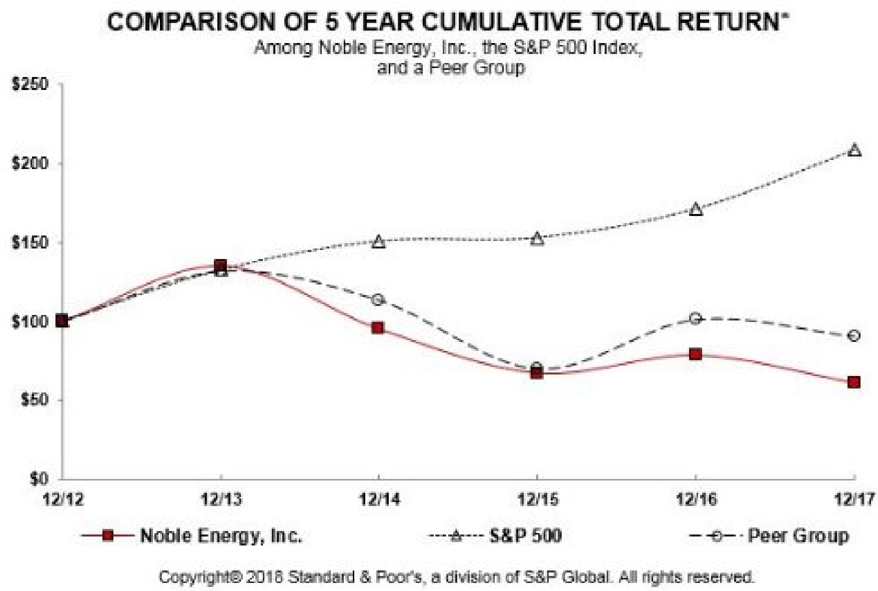
(1) Stock repurchases during the period related to stock received by us from employees for the payment of withholding taxes due on shares of restricted stock issued under our stock-based compensation plans.

Stock Performance Graph This graph shows our cumulative total shareholder return over the five-year period from December 31, 2012 to December 31, 2017. The graph also shows the cumulative total returns for the same five-year period of the S&P 500 Index and a peer group of companies. The cumulative total return of the common stock of our peer group of companies includes the cumulative total return of our common stock.

Our peer group includes a broad group of US onshore and global exploration and production companies which are further diversified by location and number of resource plays as well as level of integration within the crude oil and natural gas business cycle. Our peer group consists of the following:

Anadarko Petroleum Corp.	Hess Corp.
Apache Corp.	Marathon Oil Corp.
Cabot Oil & Gas Corp.	Murphy Oil Corp.
Chesapeake Energy Corp.	Noble Energy, Inc.
Continental Resources, Inc.	Pioneer Natural Resources Co.
Devon Energy Corp.	Range Resources Corp.
EOG Resources, Inc.	Southwestern Energy Co.

The comparison assumes $100 was invested on December 31, 2012 in our common stock, in the S&P 500 Index and in our peer group of companies and assumes that all of the dividends were reinvested. In addition, the peer group investment is weighted based upon the market capitalization of each individual company within the peer group.



Year Ended December 31,	2013	2014	2015	2016	2017
Noble Energy, Inc.	$ 135.07	$ 95.06	$ 67.16	$ 78.54	$ 60.93
S&P 500	132.39	150.51	152.59	170.84	208.14
Peer Group	131.72	113.35	70.13	101.33	90.55

Equity Compensation Plan Information The information required by this item is incorporated herein by reference to the 2018 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2017 .

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[Index to Financial Statements](#)

Item 6. Selected Financial Data

	Year Ended December 31,				
(millions, except as noted)	2017	2016	2015	2014	2013
Revenues and Income					
Total Revenues	$ 4,256	$ 3,491	$ 3,183	$ 5,115	$ 5,015
(Loss) Income from Continuing Operations Including Noncontrolling Interests	(1,050)	(985)	(2,441)	1,214	907
Net (Loss) Income Including Noncontrolling Interests	(1,050)	(985)	(2,441)	1,214	978
Net (Loss) Income Attributable to Noble Energy	(1,118)	(998)	(2,441)	1,214	978
Per Share Data, Attributable to Noble Energy					
(Loss) Earnings Per Share - Basic					
(Loss) Income from Continuing Operations	$ (2.38)	$ (2.32)	$ (6.07)	$ 3.36	$ 2.53
(Loss) Earnings Per Share - Basic	(2.38)	(2.32)	(6.07)	3.36	2.72
(Loss) Earnings Per Share - Diluted					
(Loss) Income from Continuing Operations	(2.38)	(2.32)	(6.07)	3.27	2.50
(Loss) Earnings Per Share - Diluted	(2.38)	(2.32)	(6.07)	3.27	2.69
Cash Dividends Per Share	0.40	0.40	0.72	0.68	0.55
Year-End Stock Price Per Share	29.14	38.06	32.93	47.43	68.11
Weighted Average Shares Outstanding					
Basic	469	430	402	361	359
Diluted	469	430	402	367	363
Cash Flows					
Net Cash Provided by Operating Activities	$ 1,951	$ 1,351	$ 2,062	$ 3,506	$ 2,937
Additions to Property, Plant and Equipment	2,649	1,541	2,979	4,871	3,947
Proceeds from Divestitures [(1)]	2,073	1,241	151	321	327
Proceeds from Issuance of Noble Energy Common Stock, Net of Offering Costs	—	—	1,112	—	—
Proceeds from Issuance of Noble Midstream Partners Common Units, Net of Offering Costs	312	299	—	—	—
Financial Position					
Cash and Cash Equivalents	$ 675	$ 1,180	$ 1,028	$ 1,183	$ 1,117
Property, Plant, and Equipment, Net	17,502	18,548	21,300	18,143	15,725
Goodwill [(2)]	1,310	—	—	620	627
Total Assets	21,476	21,011	24,196	22,518	19,642
Long-term Obligations					
Long-Term Debt	6,746	7,011	7,976	6,068	4,566
Deferred Income Taxes	1,127	1,819	2,826	2,516	2,441
Asset Retirement Obligations, Noncurrent	824	775	861	670	547
Other	421	328	358	417	562
Total Equity	10,619	9,600	10,370	10,325	9,184

(1) Proceeds for 2017 relate to the Marcellus Shale upstream divestiture and proceeds received from other transactions. Proceeds for 2016 primarily relate to US onshore non-strategic asset divestiture activity and the sell-down of Tamar interest. See Item 8. Financial Statements and Supplementary Data – Note 4. Acquisitions, Divestitures and Merger

(2) Goodwill at December 31, 2017 related to the Clayton Williams Energy Acquisition. Our previous goodwill balance was fully impaired at December 31, 2015. See Item 8. Financial Statements and Supplementary Data – Note 1. Summary of Significant Accounting Policies .

	Year Ended December 31,				
	2017	2016	2015	2014	2013
Operations Information - Consolidated Operations					
Consolidated Crude Oil Sales (MBbl/d)	129	125	112	103	99
Average Realized Price ($/Bbl)	$ 49.73	$ 40.39	$ 45.00	$ 91.58	$ 100.29
Consolidated NGL Sales (MBbl/d)	58	54	39	23	16
Average Realized Price ($/Bbl)	$ 23.40	$ 14.92	$ 13.91	$ 33.75	$ 35.53
Consolidated Natural Gas Sales (MMcf/d)	1,118	1,397	1,187	992	901
Average Realized Price ($/Mcf)	$ 3.01	$ 2.42	$ 2.44	$ 3.38	$ 2.97
Proved Reserves					
Crude Oil and Condensate Reserves (MMBbls)	457	333	307	304	322
NGL Reserves (MMBbls)	229	219	189	128	113
Natural Gas Reserves (Bcf)	7,680	5,308	5,549	5,833	5,828
Total Reserves (MMBoe)	1,965	1,437	1,421	1,404	1,406
Number of Employees	2,277	2,274	2,395	2,735	2,527

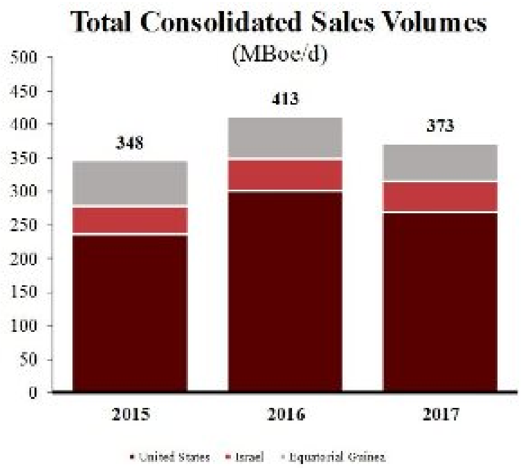
Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) is intended to provide a narrative about our business from the perspective of our management. Our MD&A is presented in the following major sections:

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

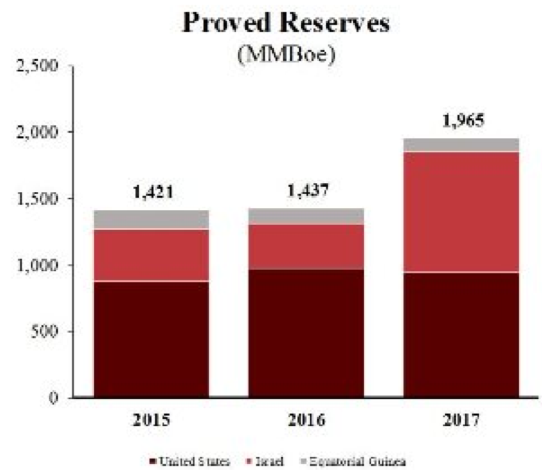
EXECUTIVE SUM MA RY

Noble Energy Key Metrics (see links below for further information)



Excludes sales volumes from equity method investees for all periods.

Sales volumes attributable to Marcellus Shale upstream assets were 77 MMBoe/d, 91 MMBoe/d, and 34 MMBoe/d for 2015, 2016 and 2017, respectively, which were divested in 2017.

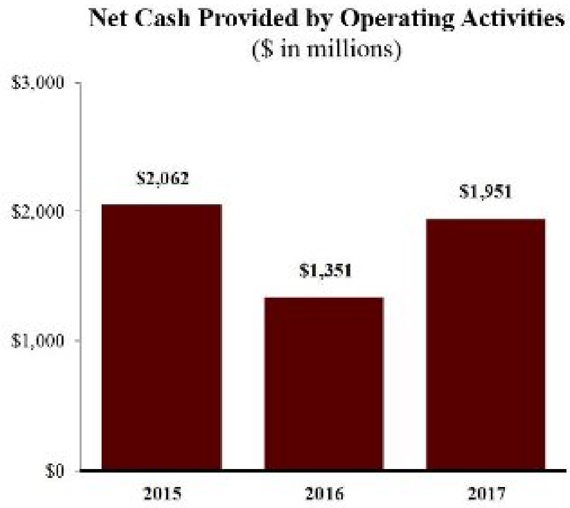


Items 1. and 2. Business and Properties – Sales Volume, Price and Cost Data

Results of Operations - E&P

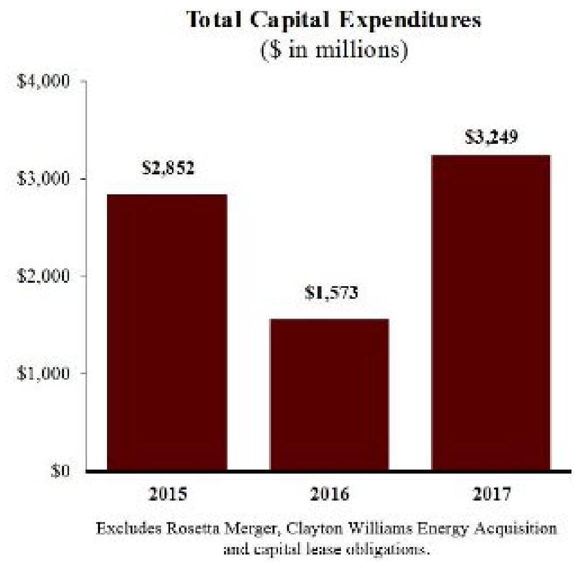
Items 1. and 2. Business and Properties – Proved Reserves Disclosures

Item 8. Financial Statements and Supplementary Data – Supplementary Oil and Gas Information (Unaudited)



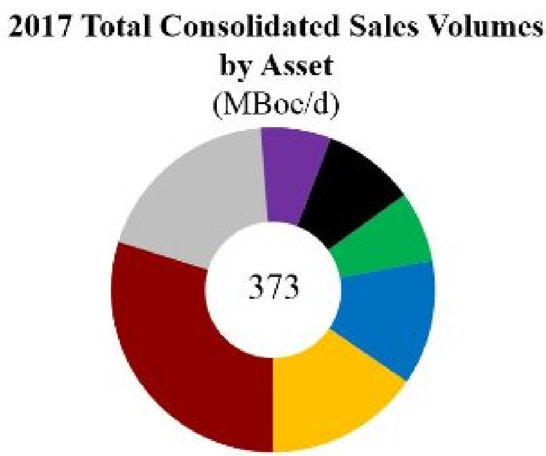
Liquidity and Capital Resources – Cash Flows

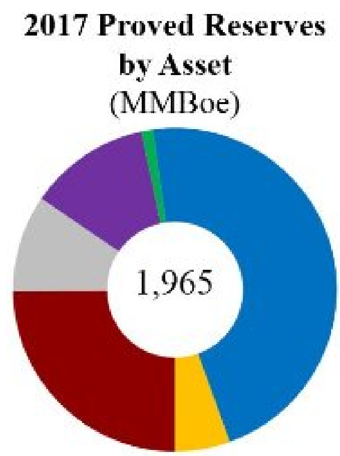
Item 8. Financial Statements and Supplementary Data – Consolidated Statements of Cash Flows



Items 1. and 2. Business and Properties – Domestic and International

Liquidity and Capital Resources – Acquisition, Capital Expenditures and Other Exploration Expenditures





■ DJ Basin ■ Eagle Ford Shale ■ Delaware Basin ■ Marcellus Shale ■ Gulf of Mexico ■ Eastern Mediterranean ■ West Africa

Excludes sales volumes from equity method investees.

Items 1. and 2. Business and Properties – Sales Volume, Price and Cost Data

Results of Operations - E&P

Items 1. and 2. Business and Properties – Proved Reserves Disclosures

Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Information (Unaudited)

EXECUTIVE OVERVIEW

Industry Outlook

Crude Oil The global oil and gas industry is cyclical, and crude oil prices are volatile, driven by crude oil supply, which includes OPEC and non-OPEC producers, and global crude oil demand.

In 2014, our industry entered a downturn due to oversupplied crude oil production from non-OPEC producers, primarily driven by US unconventional oil production growth from tight formations and the de-bottlenecking of transportation infrastructure. Coupled with OPEC's decision not to reduce production quotas and muted global crude oil demand growth, crude oil prices began falling rapidly in late 2014.

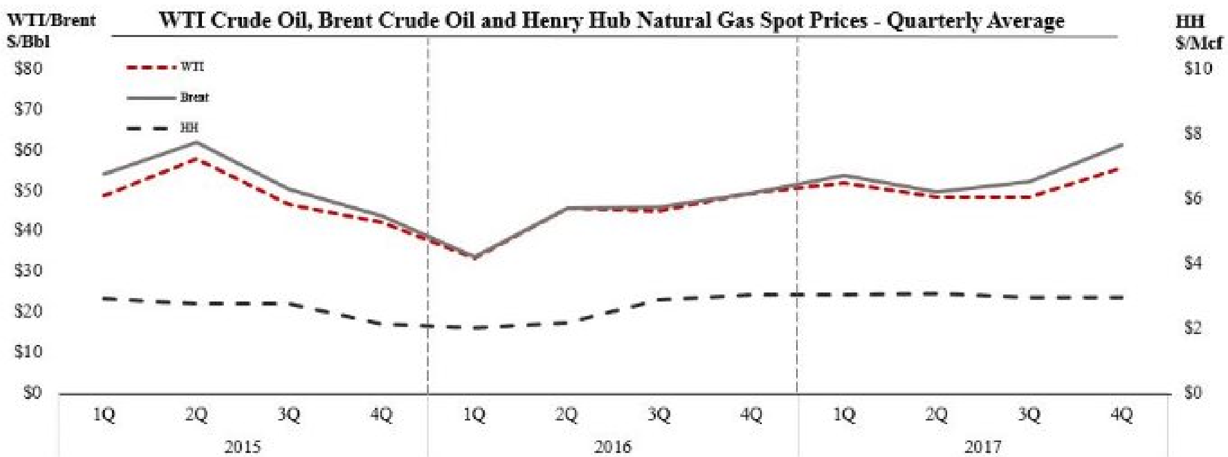
The rapid decline in crude oil prices impacted US and other non-OPEC producers' capital budgets, which resulted in lower crude oil production. Further, in late 2016, OPEC announced voluntary production curtailments in an effort to stabilize excess crude oil supply and crude oil prices and to rebalance crude oil inventories. The decline in supply from these producers has aided in stabilizing the crude oil market. As a result, crude oil prices have recently recovered to three-year record highs, while production from the US has increased, allowing US producers to absorb global market share.

Global crude oil products demand has increased, supported by lower crude oil prices and a synchronized global economic recovery, leading to increased refinery utilization and crude oil demand. Increased demand has further contributed to stabilizing crude oil prices.

The outlook for 2018 crude oil prices will continue to depend on supply and demand dynamics, as well as global geopolitical and security factors in crude oil-producing nations. Reductions in industry investment, particularly for conventional crude oil development, will, over time, contribute to production declines, helping to balance supply and demand in the crude oil market.

Natural Gas The US domestic natural gas market remains oversupplied as domestic production has continued to grow due to drilling efficiencies, completion of DUC well inventory and de-bottlenecking of transportation infrastructure. In contrast to crude oil supply curtailments, there has been little to offset natural gas supply growth, which continues to outpace demand domestically. As a result, natural gas prices remained range-bound in 2017. We expect this situation to continue into 2018, with natural gas prices at or near current or recent trading levels.

Impact of Current Commodity Prices Modest commodity price improvement has increased both our consolidated average realized crude oil and consolidated average natural gas prices by approximately 20% in 2017 as compared to 2016. The chart below shows the historical trend in benchmark prices for West Texas Intermediate (WTI) crude oil, Brent crude oil and US Henry Hub natural gas.



Because the global economic outlook and commodity price environment are uncertain, we have maintained a robust financial liquidity position to ensure financial flexibility. We have also planned a 2018 capital investment program that will be flexible and responsive to positive or negative price conditions that may develop and support continued business investment in a volatile commodity price environment. See 2018 Capital Investment Program, below.

See [Item 1A. Risk Factors](#) – *The oil and gas industry is cyclical and an extended period of suppressed commodity prices could have material adverse effects on our operations, our liquidity, and the price of our common stock.*

Development and Operating Costs Third party oilfield service and supply costs are also subject to supply and demand dynamics. During 2017, increases in US onshore drilling and completion activity resulted in higher demand for oilfield services. As a result, the costs of drilling, equipping and operating wells and infrastructure experienced some inflation, which, along with commodity prices, impacted industry operating margins. Conversely, the industry has reduced capital-intensive offshore exploration and drilling activities in response to the commodity price environment. Demand for and costs associated with offshore conventional oil services have declined and, in the near-term, will likely not be subject to cost inflation.

Recent Activities Implementation of our focused strategy has enhanced our future outlook. Over the past three years, we have made significant changes and enhancements to our business:

Portfolio Transformation, Including:

- entered the liquids-rich Eagle Ford Shale and Delaware Basin through the Rosetta Merger;
- expanded our Delaware Basin position through the Clayton Williams Energy Acquisition;
- exited the Marcellus Shale upstream and are exiting the Marcellus Shale midstream, thereby accelerating monetization of assets not attracting capital;
- established the Noble Midstream business, including an initial public offering of Noble Midstream Partners, and executed the first asset drop down transaction; and
- accelerated DJ Basin value through numerous acreage exchanges and sales.

Operational Accomplishments, Including:

- focused capital and resources on highest-margin assets within US onshore liquids plays and the Eastern Mediterranean;
- sanctioned the initial phase of Leviathan development, with first natural gas sales targeted for the end of 2019;
- excluding the impact of the Marcellus Shale upstream divestiture, increased proved reserves by more than 65% from 2016;
- excluding the impact of the Marcellus Shale upstream divestiture, increased total US onshore sales volumes by more than 15% from 2016 and shifted to an oilier production mix, with more than 40% of our US onshore consolidated sales volumes attributable to crude oil; and
- improved well level and corporate returns with technology advancements and structural cost savings.

Financial Strength, Including:

- proactive and strategic action to manage within cash flows;
- made net repayments of debt totaling $1.69 billion , since beginning of 2016 through cash on hand, proceeds from asset sales, and cash generated by our midstream business;
- maintained a strong liquidity position including cash on hand and unused borrowing capacity; and
- maintained our investment grade credit ratings.

In summary, during 2017 , we closed several strategic portfolio transactions demonstrating our continued focus on enhancing company margins and returns. Our current portfolio includes assets which are well-positioned on the industry cost of supply curve, offering growth at financially attractive rates of return. Operationally, we continued to drive efficiencies in our US onshore drilling and completions, while advancing our Eastern Mediterranean regional natural gas developments. Financially, we continued to maintain our strong balance sheet and robust liquidity position.

Subsequent Events The Company has evaluated the period after the balance sheet date, noting no subsequent events or transactions that required recognition or disclosure in the financial statements, other than as previously disclosed or noted below.

Share Repurchase Program On February 15, 2018, we announced the Company's Board of Directors authorized a share repurchase program of $750 million which expires December 31, 2020. All purchases will be made in accordance with applicable securities laws from time to time in open market or private transactions, depending on market conditions, and may be discontinued at any time.

Gulf of Mexico Divestiture On February 15, 2018, we announced the Company signed a definitive agreement to sell its assets in the Gulf of Mexico for cash consideration of $480 million. As part of the transaction, the buyer will assume all abandonment obligations associated with the properties which we estimate to approximate $230 million as of December 31, 2017. The net book value of the Gulf of Mexico assets as of December 31, 2017 was approximately $750 million. We expect to incur a charge in early 2018, subject to customary closing adjustments. The transaction is expected to close during second quarter 2018, contingent upon the buyer’s successful implementation of its contemplated restructuring, and will be effective as of January 1, 2018.

GSPAs - Israel Export On February 19, 2018, we executed two independent 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 139 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 114 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, similar to other export contracts in the region. The GSPAs are subject to satisfaction of conditions precedent, including regulatory approvals and licenses, and finalizing gas transportation agreements.

OPERATING OUTLOOK

Growing Long-Term Value We believe the following guiding principles will contribute to growing long-term value:

- Execution of a disciplined capital allocation process by:
  - designing a flexible investment program aligned with the current commodity price environment; and
  - maintaining a strong balance sheet and liquidity position.
- Enhancing capital efficiencies through:
  - utilizing our technical competencies and applying historical learnings from unconventional US shale plays to reduce US onshore finding and development costs; and
  - driving Delaware Basin economics through development cycle efficiencies.
- Leveraging the benefits of our well-positioned and diversified portfolio including:
  - exercising investment optionality and flexibility afforded by our assets, which are largely held by production; and
  - continuing portfolio optimization actions to maximize strategic value.
- Capitalizing on a currently low-cost offshore environment with execution of high-quality, long-cycle development projects, such as:
  - progressing Leviathan field development.
- Maintaining financial strength through:
  - focusing operational activities on high-margin, high-return assets;
  - improving overall corporate returns; and
  - ensuring cash flow sources and uses remain balanced.

As we enter 2018, we believe we have positioned the Company for sustainability, operational efficiency, and long-term success throughout the oil and gas business cycle. However, 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 otherwise. Our production and our stock price could decline as a result of these potential developments. See Item 1A. Risk Factors – *The oil and gas industry is cyclical and an extended period of suppressed commodity prices could have material adverse effects on our operations, our liquidity, and the price of our common stock.*

2018 Production Production may be impacted by factors including:

- commodity prices, which, if subject to decline, could result in current production becoming uneconomic;
- overall level and timing of capital expenditures which, as discussed below and dependent upon our drilling success, will impact near-term production volumes;
- increased drilling activity, 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 the conversion of Israel's electricity portfolio from coal to natural gas;
- timing of the divestiture of the remaining 7.5% working interest in the Tamar and Dalit fields, in accordance with the Framework, which will leave us with a 25% working interest and will accelerate value realization, but lower our forward sales volumes;
- timing of crude oil and condensate liftings impacting sales volumes in West Africa;
- natural field decline in US onshore, Gulf of Mexico and offshore Equatorial Guinea;
- additional purchases of producing properties or divestments of operating assets;
- potential weather-related volume curtailments due to hurricanes in the Gulf of Mexico and Gulf Coast areas, or winter storms and flooding impacting US onshore operations;
- availability or reliability of supplier services, including access to support equipment and facilities, occurrence of pipeline disruptions, and/or potential pipeline and processing facility capacity constraints, which may cause delays, restrictions or interruptions in production and/or midstream processing;
- timing and completion of midstream expansion projects by Noble Midstream Partners in areas that provide services to our assets;
- malfunctions and/or mechanical failures at terminals or other US onshore delivery points;
- impact of enhanced completion efforts for US onshore assets;
- 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 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 for potential development post 2020, as well as other corporate activities.

2018 Budget Principles Our 2018 capital program anticipates a similar level of investment directed to our US onshore assets, as compared with 2017. We will continue to advance our US onshore program through investments in liquids-rich and high-return projects, improve execution efficiency, enhance our midstream business value, grow our high margin Delaware Basin position and invest capital supporting drilling commitments to retain leases in line with our strategy. In the Eastern Mediterranean, our 2018 capital program accommodates increased investment as we progress toward development of the Leviathan project. We expect our level of capital investment in the Leviathan project to peak in 2018 and will be supported by proceeds received from the divestiture of the remaining 7.5% working interest in the Tamar field.

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.

We plan to fund our capital investment program from cash flows from operations, cash on hand, proceeds from divestments of assets, borrowings under our Revolving Credit Facility, and/or other sources of funding. See Liquidity and Capital Resources – Cash Flows - Financing Activities , and – Contractual Obligations – Exploration Commitments and Continuous Development Obligations .

Impact of Recent Changes in US Tax Law

On December 22, 2017, the US Congress enacted the Tax Reform Legislation, making significant changes to US federal income tax law beginning in 2018. See Item 1A. Risk Factors

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 8. Financial Statements and Supplementary Date – Note 11. Income Taxes .

Potential for Future Impairments

We have had in the past, and may incur in the future, various impairments of proved and unproved properties, related to the following:

- *Exploration Activities and Unproved Properties* We may impair and/or relinquish certain undeveloped leases prior to expiration based upon changes 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. In addition, in the event we conclude that an exploratory well did not encounter hydrocarbons or that a discovery or prospect is not economically or operationally viable, the associated capitalized exploratory well costs would be charged to expense.
- *Development Concept Selection Costs* We may write-off costs related to certain development concepts, including costs of related pre-FEED and FEED studies, associated with significant offshore projects, particularly those in remote or under-developed areas, when such development concepts are eliminated from further consideration based on the

determination of the final development concept or when the concept itself is determined to be economically unfeasible.

- *Producing Properties* We may impair a proved property based on a decrease in forward commodity prices, or widening of basis differentials, or an increase in abandonment costs, among other factors.
- *Divestments* We may periodically divest certain assets to reposition our portfolio. When properties meet the criteria for reclassification as assets held for sale, they are valued at the lower of net book value or anticipated sales proceeds less transaction-related costs to sell. Impairment expense would be recorded for any excess of net book value over anticipated sales proceeds less transaction-related costs to sell. In addition, a further loss, which could be material, could occur upon closing of a sales transaction.

See also: Item 1A. Risk Factors ; Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Exploration Expense ; Item 8. Financial Statements and Supplementary Data – Note 5. Asset Impairments and – Note 6. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs .

RESULTS OF OPERATIONS – E&P

Highlights for our E&P business were as follows:

2017 Significant E&P Operating Highlights Included:

- total average daily sales volumes of 381 MBoe/d;
- record average daily sales volumes for US onshore crude oil of 90 MBbl/d; and
- average daily sales volumes for natural gas of 272 MMcf/d, net, in Israel, and an all-time record for full year average daily gross sales volumes for natural gas of 956 MMcfe/d, primarily from the Tamar field.

2017 E&P Financial Results Included:

- average realized crude oil price increase of 23% as compared to 2016;
- average realized NGL price increase of 56% as compared to 2016;
- average realized natural gas price increase of 24% as compared to 2016;
- pre-tax loss of $1.8 billion , as compared with pre-tax loss of $1.3 billion for 2016; and
- capital expenditures of $2.4 billion , excluding acquisitions, as compared with $1.2 billion for 2016 .

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

	Year Ended December 31,		
(millions)	2017	2016	2015
Oil, NGL and Gas Sales to Third Parties	$ 4,060	$ 3,389	$ 3,093
Income from Equity Method Investees	120	50	39
Total Revenues	4,180	3,439	3,132
Production Expense	1,270	1,200	1,067
Exploration Expense	188	925	488
Depreciation, Depletion and Amortization	1,965	2,395	2,073
Loss on Marcellus Shale Upstream Divestiture (1)	2,379	—	—
Asset Impairments (2)	70	92	533
(Gain) Loss on Commodity Derivative Instruments	(63)	139	(501)
Goodwill Impairment	—	—	779
Clayton Williams Energy Acquisition Expenses (3)	100	—	—
Income (Loss) Before Income Taxes	(1,803)	(1,271)	(1,699)

(1) See Item 8. Financial Statements and Supplementary Data – Note 4. Acquisitions, Divestitures and Merger .
(2) See Item 8. Financial Statements and Supplementary Data – Note 5. Asset Impairments .
(3) See Item 8. Financial Statements and Supplementary Data – Note 3. Clayton Williams Energy Acquisition .

Revenues

Oil, Gas and NGL Sales Agreements We generally sell crude oil, natural gas, and NGLs under two types of agreements common in our industry. Both types of agreements may include transportation charges. One type of agreement is a netback agreement, under which we sell crude oil and natural gas at the wellhead and receive a price, net of transportation expense incurred by the purchaser. In the case of NGLs, we may receive a price from the purchaser, which is net of fractionation and processing costs. We record crude oil, natural gas and NGL sales without deductions relating to transportation, fractionation or processing. These deductions are recorded as production expense.

In addition, commodity prices we receive may be reduced by location-basis differentials, which can be significant. For example, transportation bottlenecks or infrastructure limitations may increase demand for available transportation and gathering facilities, which could lead to competitive pricing between operators of a particular area. As a result of location-basis differentials, our reported sales prices may differ significantly from published commodity price benchmarks for the same period.

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Average Oil, Gas and NGL Sales Volumes and Prices Average daily sales volumes and average realized sales prices were as follows:

	Sales Volumes				Average Realized Sales Prices		
	Crude Oil & Condensate (MBbl/d)	NGLs (MBbl/d)	Natural Gas (MMcf/d)	Total (MBoe/d) [1]	Crude Oil & Condensate (Per Bbl)	NGLs (Per Bbl)	Natural Gas (Per Mcf)
Year Ended December 31, 2017							
United States	111	58	607	270	$ 49.11	$ 23.40	$ 3.02
Israel	—	—	272	46	—	—	5.32
Equatorial Guinea [2]	18	—	239	57	53.68	—	0.27
Total Consolidated Operations	129	58	1,118	373	49.73	23.40	3.01
Equity Investee [3]	2	6	—	8	55.13	38.48	—
Total	131	64	1,118	381	$ 49.84	$ 24.81	$ 3.01
Year Ended December 31, 2016							
United States	99	54	881	301	$ 39.59	$ 14.92	$ 2.11
Israel	—	—	281	47	—	—	5.21
Equatorial Guinea [2]	26	—	235	65	43.54	—	0.27
Total Consolidated Operations	125	54	1,397	413	40.39	14.92	2.42
Equity Investee [3]	2	5	—	7	45.44	26.30	—
Total	127	59	1,397	420	$ 40.46	$ 15.96	$ 2.42
Year Ended December 31, 2015							
United States	81	39	708	237	$ 43.46	$ 13.91	$ 2.10
Israel	—	—	252	42	—	—	5.34
Equatorial Guinea [2]	31	—	227	69	48.85	—	0.27
Total Consolidated Operations	112	39	1,187	348	45.00	13.91	2.44
Equity Investee [3]	2	5	—	7	48.85	28.40	—
Total	114	44	1,187	355	$ 45.05	$ 15.59	$ 2.44

(1) Natural gas is converted on the basis of six Mcf of gas per one barrel of crude oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency. Given commodity price disparities, the price for a barrel of crude oil equivalent for US natural gas and NGLs is significantly less than the price for a barrel of crude oil. In Israel, we sell natural gas under contracts where the majority of the price is fixed, resulting in less commodity price disparity.

(2) Natural gas from the Alba field is under contract for $0.25 per MMBtu to a methanol plant, an LPG plant, an LNG plant and a power generation plant. The methanol and LPG plants are owned by affiliated entities accounted for under the equity method.

(3) Volumes represent sales of condensate and LPG from Alba Plant in Equatorial Guinea.

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

	Crude Oil & Condensate	NGLs	Natural Gas	Total
(millions)				
2015 Sales Revenues	$ 1,840	$ 197	$ 1,056	$ 3,093
Changes due to				
Increase in Sales Volumes	153	84	190	427
(Decrease) Increase in Sales Prices	(139)	15	(7)	(131)
2016 Sales Revenues	$ 1,854	$ 296	$ 1,239	$ 3,389
Changes due to				
Increase (Decrease) in Sales Volumes	55	17	(182)	(110)
Increase in Sales Prices	437	180	164	781
2017 Sales Revenues	$ 2,346	$ 493	$ 1,221	$ 4,060

Crude Oil and Condensate Sales Revenues Revenues from crude oil and condensate sales increased in 2017 as compared with 2016 due to the following:

- 23% increase in average realized prices due to the partial rebalancing of global supply and demand factors;
- higher US onshore sales volumes of 16 MBbl/d, including 5 MBbl/d contributed by recently acquired Clayton Williams Energy assets, primarily attributable to increased development and enhanced well design and completion techniques; and
- higher sales volumes of 2 MBbl/d due to full year of production at Gunflint, a Gulf of Mexico project that started production in July 2016;

partially offset by:

- lower sales volumes of 14 MBbl/d primarily due to natural field decline in the Gulf of Mexico and Equatorial Guinea.

Revenues from crude oil and condensate sales remained relatively flat in 2016 as compared with 2015 due to the following:

- higher sales volumes of 9 MBbl/d in the Eagle Ford Shale and Delaware Basin, primarily attributable to full year consolidation following the Rosetta Merger;
- sales volumes from the Big Bend and Dantzler developments (Gulf of Mexico), which began producing fourth quarter 2015 and contributed 12 MBbl/d, net, collectively in 2016; and
- sales volume from the start up of the Gulf of Mexico Gunflint development in July 2016 which contributed 3 MBbl/d;

partially offset by:

- 10% decrease in total consolidated average realized prices, primarily due to the decline in global crude oil prices that began in the second half of 2014 and continued into 2016; and
- decrease in sales volumes due to natural field decline at the Aseng and Alen fields, offshore Equatorial Guinea.

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

- 56% increase in average realized prices due to the partial rebalancing of global supply and demand factors; and
- higher US onshore sales volumes of 7 MBbl/d, including 1 MBbl/d contributed by recently acquired Clayton Williams Energy assets, primarily attributable to increased development and enhanced well design and completion techniques;

partially offset by:

- lower sales volumes of 4 MBbl/d due to the divestiture of the Marcellus Shale upstream assets in second quarter 2017.

Revenues from NGL sales increased in 2016 as compared with 2015 due to the following:

- higher sales volumes of 14 MBbl/d in the Eagle Ford Shale and Delaware Basin, primarily attributable to a full year of production as well as increased development activity;
- 7% increase in total consolidated average realized prices, primarily due to higher spot prices in the Marcellus Shale; and
- higher sales volumes of 2 MBbl/d in the DJ Basin, primarily attributable to increased well productivity due to enhanced completion techniques and increased processing capacity;

partially offset by:

- slightly lower sales volumes in the Marcellus Shale due to the higher dry gas composition of wells that were brought online in 2016.

Natural Gas Sales Revenues Revenues from natural gas sales decreased slightly in 2017 as compared with 2016 due to the following:

- lower sales volumes of 312 MMcf/d due to the divestiture of the Marcellus Shale upstream assets in second quarter 2017; and

- lower sales volumes of 29 MMcf/d as a result of the sale of a 3.5% working interest in the Tamar field, offshore Israel, in December 2016, partially offset by higher gross sales volumes from the field;

partially offset by:

- 24% increase in average realized prices due to the partial rebalancing of global supply and demand factors; and
- higher US onshore sales volumes of 40 MMcf/d, including 6 MMcf/d contributed by recently acquired Clayton Williams Energy assets.

Revenues from natural gas sales in 2016 as compared with 2015 due to the following:

- higher sales volumes of 93 MMcf/d in the Marcellus Shale, primarily attributable to well completion and infrastructure development;
- higher sales volumes of 81 MMcf/d in the Eagle Ford Shale and Delaware Basin, primarily attributable to full year consolidation following the Rosetta Merger;
- record sales volumes from the Tamar field, offshore Israel, which contributed an incremental 29 MMcf/d, in response to higher power generation needs; and
- higher sales volumes offshore Equatorial Guinea due to the completion of the Alba B3 compression project.

Income from Equity Method Investees Our share of operations of equity method investees was as follows:

	Year Ended December 31,		
	2017	2016	2015
Net Income (in millions)			
AMPCO and Affiliates	$ 58	$ 16	$ 8
Alba Plant	65	34	31
Dividends (in millions)			
AMPCO and Affiliates	47	16	31
Alba Plant	68	40	29
Sales Volumes			
Methanol (MMgal)	163	162	117
Condensate (MBbl/d)	2	2	2
LPG (MBbl/d)	6	5	5
Average Realized Prices			
Methanol (per gallon)	$ 0.97	$ 0.63	$ 0.92
Condensate (per Bbl)	55.13	45.44	48.85
LPG (per Bbl)	38.48	26.30	28.40

Changes for 2017 as compared with 2016 included the following:

- net income from AMPCO and affiliates increased primarily due to higher realized methanol prices; and
- net income from Alba Plant increased primarily due to higher LPG sales volumes and higher realized commodity prices.

Changes for 2016 as compared with 2015 included the following:

- net income from AMPCO and affiliates increased in 2016 as compared with 2015 primarily due to higher methanol sales volumes, partially offset by lower methanol prices; and
- net income from Alba Plant remained relatively flat.

Production Expense Components of production expense were as follows:

(millions, except unit rate)	Total per BOE [1]	Total	United States [1]	Israel	Equatorial Guinea	Other Int'l [2]
Year Ended December 31, 2017						
Lease Operating Expense [3]	$ 4.29	$ 585	$ 466	$ 29	$ 90	$ —
Production and Ad Valorem Taxes	0.99	135	135	—	—	—
Gathering, Transportation and Processing Expense	4.04	550	550	—	—	—
Total Production Expense	$ 9.32	$ 1,270	$ 1,151	$ 29	$ 90	$ —
Total Production Expense per BOE		$ 9.32	$ 11.68	$ 1.74	$ 4.28	$ —
Year Ended December 31, 2016						
Lease Operating Expense [3]	$ 3.72	$ 560	$ 418	$ 37	$ 105	$ —
Production and Ad Valorem Taxes	0.50	76	76	—	—	—
Gathering, Transportation and Processing Expense	3.73	564	564	—	—	—
Total Production Expense	$ 7.95	$ 1,200	$ 1,058	$ 37	$ 105	$ —
Total Production Expense per BOE		$ 7.95	$ 9.63	$ 2.14	$ 4.42	$ —
Year Ended December 31, 2015						
Lease Operating Expense [3]	$ 4.52	$ 575	$ 398	$ 42	$ 131	$ 4
Production and Ad Valorem Taxes	0.99	126	126	—	—	—
Gathering, Transportation and Processing Expense	2.88	366	366	—	—	—
Total Production Expense	$ 8.39	$ 1,067	$ 890	$ 42	$ 131	$ 4
Total Production Expense per BOE		$ 8.39	$ 10.29	$ 2.72	$ 5.21	N/M

N/M Amount is not meaningful.

(1) United States upstream production expense includes charges from our midstream operations that are eliminated on a consolidated basis. See Item 1. Financial Statements – Note 15. Concentration of Risk .

(2) Other International includes the North Sea in 2015.

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

Lease Operating Expense Lease operating expense increased in 2017 as compared with 2016 primarily due to the following:

- increase of $82 million in US onshore, primarily in the DJ Basin, Delaware Basin and Eagle Ford Shale due to increased activity;

partially offset by:

- decrease of $19 million due to natural field decline in the Gulf of Mexico;
- decrease of $17 million related to the divestiture of the Marcellus Shale upstream assets in second quarter 2017;
- decrease of $15 million due to various cost reduction initiatives offshore West Africa; and
- decrease of $11 million due to a 3.5% lower working interest in the Tamar field, offshore Israel, following the partial divestiture in December 2016.

Lease operating expense decreased in 2016 as compared with 2015 due to the following:

- decrease of $92 million in US onshore, primarily in the DJ Basin and Marcellus Shale, and $27 million offshore Equatorial Guinea due to cost reduction initiatives, including lower equipment utilization and saltwater disposal costs;

partially offset by:

- increase of $74 million attributable to new production from US onshore and Gulf of Mexico development activities; and
- increase of $38 million related to the acquisition of Eagle Ford Shale and Delaware Basin production third quarter 2015.

Production and Ad Valorem Tax Expense Production and ad valorem taxes increased in 2017 as compared with 2016 , primarily due to higher commodity prices and a $28 million US onshore severance tax refund recorded in first quarter 2016 versus a $7 million US onshore severance tax charge recorded in first quarter 2017.

Production and ad valorem taxes decreased in 2016 as compared with 2015, primarily due to lower revenues and a US onshore severance tax refund, both driven by a decline in US commodity prices.

Gathering, Transportation and Processing Expense Gathering, transportation and processing expense remained relatively flat in 2017 as compared with 2016 primarily due to:

- decrease of $120 million related to the divestiture of the Marcellus Shale upstream assets in second quarter 2017;

partially offset by:

- increase of $57 million in the DJ Basin due to the shifting of crude oil volumes onto a new export pipeline and contractual increases of pipeline fees; and
- increase of $47 million related to higher production in the Delaware Basin and Eagle Ford Shale.

Gathering, transportation and processing expense increased in 2016 as compared with 2015 due to:

- increase of $66 million related to higher production from our Marcellus Shale assets;
- increase of $57 million related to change in mix of transportation methods used for our DJ Basin production;
- increase of $49 million related to higher production from our Eagle Ford Shale assets acquired third quarter 2015; and
- increase of $17 million related to production from new Gulf of Mexico projects at Big Bend and Dantzler (which began producing fourth quarter 2015) and Gunflint (which began producing in July 2016).

Unit Rate Per BOE Production expense on a per BOE basis increased in 2017 compared to 2016, primarily due to the increases in certain production expenses noted above. In addition, the Marcellus Shale upstream divestiture resulted in the removal of lower-cost, natural gas-focused sales volumes from our portfolio, while an increase in Delaware Basin and Eagle Ford Shale volumes contributed higher-cost, crude oil-focused sales volumes, thereby increasing our average production expense per BOE. Also, higher commodity prices led to higher production and ad valorem taxes per BOE.

The unit rate of total production expense per BOE decreased for 2016 as compared with 2015, primarily driven by lower production and ad valorem taxes as a result of lower commodity prices and lower lease operating expenses as a result of cost reductions in certain areas, such as equipment utilization and saltwater disposal. The decrease in the unit rate per BOE was partially offset by higher transportation and gathering expenses due to higher-cost production volumes from certain US onshore assets.

Exploration Expense Components of exploration expense were as follows:

(millions)	Total	United States	Eastern Mediterranean [1]	West Africa [2]	Other Int'l [3]
Year Ended December 31, 2017					
Leasehold Impairment and Amortization	$ 62	$ 60	$ —	$ —	$ 2
Dry Hole Cost [4]	9	—	—	—	9
Seismic, Geological and Geophysical	27	8	—	—	19
Staff Expense	55	1	2	4	48
Other [5]	35	33	—	1	1
Total Exploration Expense	$ 188	$ 102	$ 2	$ 5	$ 79
Year Ended December 31, 2016					
Leasehold Impairment and Amortization	$ 148	$ 123	$ —	$ —	$ 25
Dry Hole Cost [4]	579	85	26	468	—
Seismic, Geological and Geophysical	76	—	—	10	66
Staff Expense	77	3	1	5	68
Other [5]	45	34	7	—	4
Total Exploration Expense	$ 925	$ 245	$ 34	$ 483	$ 163
Year Ended December 31, 2015					
Leasehold Impairment and Amortization	$ 113	$ 105	$ 5	$ 3	$ —
Dry Hole Cost [4]	266	93	—	33	140
Seismic, Geological and Geophysical	34	5	—	10	19
Staff Expense	43	—	1	—	42
Other [5]	32	—	6	—	26
Total Exploration Expense	$ 488	$ 203	$ 12	$ 46	$ 227

(1) Eastern Mediterranean includes Israel and Cyprus.
(2) West Africa includes Equatorial Guinea, Cameroon and Gabon.
(3) Other International includes Newfoundland, Suriname and other new ventures.

(4) For a discussion of dry hole cost, see Items 1. and 2. Business and Properties – International – West Africa and Item 8. Financial Statements and Supplementary Data – Note 6. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs .
(5) Includes lease rental and other exploration expense.

Exploration expense for 2017 included:

- leasehold impairment expense related primarily to Gulf of Mexico unproved properties; and
- dry hole cost of $7 million for the Araku-1 exploration well, offshore Suriname.

Exploration expense for 2016 included:

- leasehold impairment expense including the write-off of leases and licenses of $58 million for the Gulf of Mexico, $25 million for other international locations, and $10 million for other US onshore; and
- dry hole cost including costs related to the Silvergate exploratory well, Gulf of Mexico, the Dolphin 1 natural gas discovery, offshore Israel, and certain discoveries offshore West Africa.

Exploration expense for 2015 included:

- leasehold impairment expense including the write-off of our northeast Nevada leases of $21 million;
- US dry hole cost including amounts related to northeast Nevada exploration efforts which we elected to discontinue after assessing commercial viability in the current commodity price environment; and
- dry hole cost including the Cheetah well, offshore West Africa, and Other International dry hole cost.

Exploration expense included stock-based compensation expense of $7 million in 2017 , $10 million in 2016 and $13 million in 2015 .

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

(millions, except unit rate)	Total	United States	Eastern Mediter- ranean	West Africa	Other Int'l
Twelve Months Ended December 31, 2017					
DD&A Expense	$ 1,965	$ 1,739	$ 76	$ 146	$ 4
Unit Rate per BOE (1)	$ 14.42	$ 17.65	$ 4.56	$ 6.95	N/M
Twelve Months Ended December 31, 2016					
DD&A Expense	$ 2,395	$ 2,103	$ 81	$ 205	$ 6
Unit Rate per BOE (1)	$ 15.87	$ 19.14	$ 4.69	$ 8.63	N/M
Twelve Months Ended December 31, 2015					
DD&A Expense	$ 2,073	$ 1,677	$ 70	$ 326	$ —
Unit Rate per BOE (1)	$ 16.29	$ 19.40	$ 4.53	$ 12.93	N/M

N/M Amount is not meaningful.
(1) DD&A expense includes accretion of discount on asset retirement obligations of $ 47 million in 2017 , $ 48 million in 2016 , and $ 43 million in 2015 .

Total DD&A expense decreased in 2017 as compared with 2016 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. For more information, see reserves discussion in Supplemental Oil and Gas Information (Unaudited) ;
- slightly lower sales volumes in the DJ Basin and the impact of certain property divestitures since the second quarter 2016;
- the Marcellus Shale upstream divestiture in second quarter 2017, which reduced 2017 DD&A expense by $291 million;
- the sale of a 3.5% working interest in the Tamar field, offshore Israel, in December 2016, which reduced 2017 DD&A expense by approximately $7 million;
- a reduction in depletable costs of $153 million in the second quarter 2017 due to the reallocation of common asset costs from the Alen field, offshore Equatorial Guinea, to the West Africa natural gas monetization development project, which reduced 2017 DD&A expense by $37 million; and
- lower sales volumes in the Gulf of Mexico due to natural field decline and reduction in the depletable costs due to downward revisions in estimates of asset retirement costs;

partially offset by:

- higher US onshore sales volumes of 29 MBoe/d during 2017, including 7 MBoe/d contributed by recently acquired Clayton Williams Energy assets;
- an increase in sales volumes from the Gunflint development, Gulf of Mexico, which commenced production in July 2016; and
- higher gross sales volumes from the Tamar field, offshore Israel, due to higher domestic demand.

The unit rate per BOE for 2017 decreased 9% as compared with 2016, primarily due to year-end reserve additions in US onshore, a reduction in the Alen field net book value in second quarter 2017, and certain DJ Basin property divestitures since second quarter 2016. These decreases were offset by the commencement of sales volumes from new crude oil-focused wells in US onshore, as well as the divestiture of natural gas-focused sales volumes from Marcellus Shale upstream assets.

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

- increase of $178 million related to higher sales volumes resulting from commencement of production from the Big Bend, Dantzler and Gunflint development projects in the Gulf of Mexico in 2016 and 2015;
- increase of $134 million related to the acquisition of Eagle Ford Shale and Delaware Basin production in third quarter 2015; and
- $121 million related to the reduction in proved reserves in fourth quarter 2015, primarily due to downward price revisions in DJ Basin and Marcellus Shale;

partially offset by:

- an overall lower segment rate for offshore Equatorial Guinea due to the fluctuation in production from higher DD&A rate assets, the Aseng and Alen fields, to a lower DD&A rate asset, the Alba field.

The unit rate per BOE for 2016 decreased as compared with 2015 , primarily due to lower-cost production volumes from the Tamar and Alba fields and net book value impairments in fourth quarter 2015 related to downward commodity price revisions. The decrease in the unit rate per BOE was partially offset by increased higher-cost production volumes from certain US onshore properties and recently commenced production from Gulf of Mexico assets, including Big Bend, Dantzler and Gunflint.

RESULTS OF OPERATIONS – MIDSTREAM

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

Major Midstream Activities - Noble Midstream Partners During 2017 , major activities included the following:

- progressed the construction and development of multiple major projects in the DJ and Delaware Basins;
- began providing crude oil and produced water gathering services to an unaffiliated third party;
- entered into the Advantage Joint Venture; and
- entered into the Black Diamond Gathering arrangement with definitive agreements to acquire the Saddle Butte system.

Major Midstream Activities - Noble Energy During 2017 , we entered into an agreement to sell our 50% interest in CONE Gathering. We closed the sale in January 2018, receiving cash proceeds of $308 million .

Results of Operations

Highlights for the Midstream segment were as follows:

2017 Midstream Financial Results Included:

- pre-tax income of $233 million , as compared with pre-tax income of $176 million for 2016; and
- capital expenditures, excluding acquisitions, of $399 million compared with capital expenditures of $42 million for 2016 .

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

	Year Ended December 31,		
(millions)	2017	2016	2015
Midstream Services Revenues – Third Party	$ 19	$ —	$ —
Income from Equity Method Investees	57	52	51
Intersegment Revenues	277	200	119
Total Revenues	353	252	170
Gathering, Transportation and Processing Expense	70	44	25
Depreciation, Depletion and Amortization	30	19	14
Income Before Income Taxes	233	176	123

Midstream Services and Intersegment Revenues 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 our E&P business and to third party customers. These volumes are affected by the level of drilling and completion activity in our 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, excluding income from equity method investees, for 2017 increased from 2016 by $96 million mainly due to increases of $60 million and $17 million driven by our drilling and completion activities in the DJ and Delaware Basins, respectively, and an increase of $19 million primarily due to commencement of services in the DJ Basin to an unaffiliated third party.

Total revenues, excluding income from equity method investees, for 2016 increased from 2015 by $81 million due to our drilling and completion activities in the DJ Basin.

Income from Equity Method Investees and Other Midstream's share of operations of equity method investees was as follows:

	Year Ended December 31,		
	2017	2016	2015
Net Income (in millions)			
CONE Gathering and CONE Midstream	$ 51	$ 48	$ 46
Advantage Pipeline	2	—	—
White Cliffs	4	5	—
Dividends (in millions)			
CONE Gathering and CONE Midstream	25	27	17

Gathering, Transportation and Processing Expense

Total expense for 2017 increased by $26 million as compared with 2016 due to the following:

- an increase of $20 million in water services expense due to increased services provided by third parties as well as higher throughput volumes associated with fresh water services; and
- an increase of $6 million in gathering and facilities operating expense due to higher gathered volumes, as well as due to new systems placed in service and expansion of the gathering infrastructure in 2017.

Total expense for 2016 increased by $19 million as compared with 2015 due to the following:

- an increase of $12 million in water services expense due to an expanded scope of water services delivered; and
- an increase of $7 million in gathering systems and facilities operating expense associated with higher gathered volumes as well as general repairs and maintenance of our gathering systems and facilities.

DD&A Expense

Depreciation. depletion and amortization expense for 2017 increased by $11 million as compared with 2016 due to the assets placed in service in 2017, specifically assets associated with the construction of the Greeley Crescent facilities and the Delaware Basin gathering systems, including completion of two CGFs, and expansion of gathering and fresh water systems in the Wells Ranch, East Pony and Mustang IDP areas.

Depreciation, depletion and amortization expense for 2016 increased by $5 million as compared with 2015 due to assets placed in service as a result of the expansion of Wells Ranch CGF in 2016 and in second half 2015 and commissioning of the East Pony crude oil gathering system during 2016.

RESULTS OF OPERATIONS – CORPORATE

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

	Year Ended December 31,		
	2017	2016	2015
G&A Expense (millions)	$ 415	$ 399	$ 396
Unit Rate per BOE [1]	$ 3.05	$ 2.64	$ 3.11

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

G&A expense for 2017 increased slightly as compared with 2016 primarily due to increased employee costs driven by acquisition activities. The increase in the unit rate per BOE for 2017 as compared with 2016 was due primarily to the decrease in total sales volumes driven by the divestiture of the Marcellus Shale upstream assets. Our total number of employees increased from 2,274 at December 31, 2016 to 2,277 at December 31, 2017.

G&A expense for 2016 was flat as compared with 2015 primarily due to sustained cost savings initiatives and decreases in employee personnel costs. Our total number of employees decreased from 2,395 at December 31, 2015 to 2,274 at December 31, 2016.

G&A expense is impacted by the number of stock-based awards, the market price of our common stock and price volatility which may result in a higher or lower fair value of stock-based awards as calculated using various valuation models. G&A expense included stock-based compensation expense of $54 million in 2017 , $62 million in 2016 and $50 million in 2015 . See Item 8. Financial Statements and Supplementary Data – Note 12. Stock-Based and Other Compensation Plans .

Other Operating Expense See Item 8. Financial Statements and Supplementary Data – Note 2. Additional Financial Statement Information for a discussion of our other operating expense.

Loss (Gain) on Extinguishment of Debt See Item 8. Financial Statements and Supplementary Data – Note 10. Long-Term Debt for discussion of our extinguishment of debt activities.

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

	Year Ended December 31,		
(millions, except per unit)	2017	2016	2015
Interest Expense	$ 403	$ 412	$ 407
Capitalized Interest	(49)	(84)	(144)
Interest Expense, Net	$ 354	$ 328	$ 263
Unit Rate per BOE [1]	$ 2.60	$ 2.17	$ 2.07

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

The decrease in interest expense in 2017 as compared with 2016 is due to the repayment of our Term Loan Facility due January 6, 2019 (Term Loan Facility) and refinancing of our 8.25% senior notes. See Liquidity and Capital Resources - Capital Structure/Financing Strategy .

The decrease in capitalized interest in 2017 as compared with 2016 is primarily due to the write off of discoveries offshore Equatorial Guinea, lower work in progress amounts related to major long-term projects, including Gunflint, Gulf of Mexico, and the Alba B3 compression project, offshore Equatorial Guinea, offset by a higher work in progress amount related to the Leviathan major long-term development project, offshore Israel.

The increase in interest expense in 2016 as compared with 2015 is primarily due to the impact of senior notes assumed in the Rosetta Merger during third quarter 2015, a portion of which were subsequently tendered during first quarter 2016 through proceeds derived from our Term Loan Facility.

The decrease in capitalized interest in 2016 as compared with 2015 is primarily due to lower work in progress amounts related to major long-term projects, including Big Bend and Dantzler, Gulf of Mexico, which were completed in fourth quarter 2015, and Gunflint, Gulf of Mexico, and the Alba B3 compression project, offshore Equatorial Guinea, which were completed in July 2016. Additional items that contributed to the decrease in capitalized interest include the farm-out of a portion of Block 12, offshore Cyprus, during fourth quarter 2015, the write-off of the Humpback dry hole, offshore Falkland Islands, during fourth quarter 2015 and timing of US onshore activities.

Interest is capitalized on exploration and development projects using an interest rate equivalent to the average rate paid on long-term debt. Capitalized interest is included in the cost of oil and gas assets and amortized with other costs on a unit-of-production basis. The majority of the capitalized interest is related to long lead-time projects in the Gulf of Mexico, offshore

West Africa and offshore Eastern Mediterranean. See Item 8. Financial Statements and Supplementary Data – Note 6. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs .

Income Taxes See Item 8. Financial Statements and Supplementary Data – Note 11. Income Taxes .

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 periodic mergers and acquisitions opportunities, such as the recent Clayton Williams Energy Acquisition. We endeavor to maintain a strong balance sheet and investment grade credit 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 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 may 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 .

During 2017, we focused on implementation of our portfolio transformation strategy and executed a number of divestitures which generated cash proceeds of over $2 billion . We utilized the proceeds from divestitures to improve our capital structure by repayment of $1.3 billion of borrowing under our Revolving Credit Facility associated with the Clayton Williams Energy Acquisition and $550 million of the remaining balance outstanding under our Term Loan Facility due January 6, 2019. To further strengthen our liquidity profile we performed a series of financing transactions, including retirement of $1 billion of our 8.25% senior notes due March 1, 2019 with the proceeds from issuance of $600 million of 3.85% and $500 million of 4.95% senior notes due January 15, 2028 and August 15, 2047, respectively. Through the repayment of our Term Loan Facility and refinancing of our 8.25% senior notes, we effectively eliminated our near-term debt maturities and lowered our future interest expense by $48 million on an annual basis.

We aim to fund our capital program through operating cash flows and utilize borrowings under our Revolving Credit Facility to fund additional requirements. In 2017, we borrowed and repaid amounts under our Revolving Credit Facility resulting in $230 million remaining outstanding as of December 31, 2017 . Funds were utilized for general corporate purposes and for funding of our capital development program. As a result of our 2017 financing activities, we ended 2017 with over $4.5 billion in liquidity, including almost $3.8 billion of availability under our Revolving Credit Facility.

During 2017, we also focused on the continued execution of our integrated midstream strategy through Noble Midstream Partners. In addition to completion of several key infrastructure assets in the DJ and Delaware Basins, as well as continuing significant construction activities in the DJ Basin, Noble Midstream Partners purchased certain midstream assets from Noble Energy for $270 million and expanded its business through entry into certain arrangements to acquire and operate midstream assets. Funding for these transactions included $312 million raised through the issuance of Noble Midstream Partners common units and borrowings under the Noble Midstream Services LLC Revolving Credit Facility (Noble Midstream Services Revolving Credit Facility). As of December 31, 2017 , $85 million was outstanding under the Noble Midstream Services Revolving Credit Facility. Funds were used to partially fund 2017 acquisitions and to finance the midstream capital investment program. See Item 8. Financial Statements and Supplementary Data - Note 4. Acquisitions, Divestitures and Merger .

In addition, we received $300 million in payments from foreign operations on an outstanding note payable in 2017, leaving a balance of approximately $434 million that can be repaid without additional US tax impact.

As of December 31, 2017 , our outstanding debt (excluding capital lease and other obligations) totaled $6.5 billion . While we have no near-term debt maturities, we may periodically seek to access the capital markets to refinance a portion of our outstanding indebtedness.

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

Sources and Uses of Liquidity

Our operating cash flows are a significant source of our liquidity. In 2017, we experienced strengthening crude oil prices and completed several transformative transactions, repositioning our portfolio from low-margin natural gas-focused assets to high margin crude oil-rich assets, which significantly contributed to the funding of our capital program. Additional sources of funding were available through debt financing activities, including borrowings under our Revolving Credit Facility, and divestment of certain non-strategic oil and gas properties. During 2017, we continued investment in our high cash flow growth assets and, excluding effects of divestitures, increased production levels from prior years, while also increasing per unit profit margins. We also improved our financial profile by reducing our debt balance by $255 million with the use of proceeds from divestments, and decreasing our future interest expense.

For 2018, we will continue our effort to manage our cash flows through capital efficiencies, cost management endeavors, and focusing on the growth of production from high-margin, high-return assets. With such an approach, nearly all of our 2018 capital investment is allocated to our US onshore plays and the Eastern Mediterranean, specifically the Leviathan development project, offshore Israel.

Our 2018 production target is in the range of 343 MBoe/d to 353 MBoe/d and we expect our 2018 capital spending program (excluding acquisitions and Noble Midstream Partners capital), to be in the range of $2.7 to $2.9 billion, or approximately $400 million higher than the 2017 budget. Should WTI and Brent oil prices continue to improve in 2018, we expect future operating cash flows to increase and provide additional sources of liquidity compared to 2017. We expect to support our investment program with operating cash flows resulting from our US onshore and Israel offshore assets, with the remainder of the future capital commitments funded with cash on hand, borrowings under our Revolving Credit Facility and divestment of non-strategic assets.

We believe our current liquidity level and balance sheet, along with our ability to access the capital markets, provide flexibility and that we are well-positioned to fund our business throughout the commodity price cycle. We will continue to evaluate the commodity price environment and our level of capital spending throughout 2018. However, a downgrade or other negative action with respect to our credit rating could trigger requirements to post collateral as financial assurance of performance under certain contractual arrangements, potentially impacting our liquidity and/or negatively impacting our cost, terms, conditions and availability of future financing. See Item 1A. Risk Factors – *A downgrade or other negative action with respect to our credit rating could negatively impact our business and financial condition.*

The table below summarizes our cash, debt balances and available liquidity:

	December 31,		
	2017	2016	2015
(millions, except percentages)			
Total Cash [(1)]	$ 713	$ 1,209	$ 1,028
Amount Available to be Borrowed Under Revolving Credit Facility [(2)]	3,770	4,000	4,000
Total Liquidity	$ 4,483	$ 5,209	$ 5,028
Total Debt [(3)]	$ 6,859	$ 7,114	$ 7,976
Noble Energy Share of Equity	10,619	9,600	10,370
Ratio of Debt-to-Book Capital [(4)]	39%	43%	43%

(1) Total cash at December 31, 2017 includes $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. Total cash at December 31, 2016 includes $57 million cash of Noble Midstream Partners, and restricted cash of $30 million related to the Delaware Basin property acquisition that closed in January 2017.

(2) In 2017, amount available to be borrowed under the Revolving Credit Facility excludes $265 million and $625 million available to be borrowed under the Noble Midstream Services Revolving Credit Facility and Leviathan Term Loan Facility (defined below), respectively, which are not available to Noble Energy for general corporate purposes. In 2016, it excludes $350 million available to be borrowed under the Noble Midstream Services Revolving Credit Facility. See discussion below.

(3) Total debt includes capital lease and other obligations and excludes unamortized debt discount/premium, and issuance costs.
Our long-term debt (excluding capital lease and other obligations) totaled $6.5 billion at December 31, 2017, with maturities ranging from 2020 to 2097.

(4) We define our ratio of debt-to-book capital as total debt (which includes long-term debt excluding unamortized discount/premium and issuance costs, 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. Significant changes in our financial position impacting the ratio included $255 million net decrease in debt, $1.9 billion increase in shareholders' equity due to issuance of stock as part of consideration paid for Clayton Williams Energy Acquisition, $312 million increase due to issuance of Noble Midstream Partners Common Units and $100 million increase due to stock based compensation, offset by $190 million decrease in shareholders' equity from dividends paid and $1.1 billion decrease in shareholders' equity from current year net loss.

Cash and Cash Equivalents Our cash is primarily denominated in US dollars and invested in money market funds and short-term deposits with major financial institutions. Approximately $493 million of this cash was attributable to foreign subsidiaries at December 31, 2017.

Revolving Credit Facilities Noble Energy's Revolving Credit Facility of $4.0 billion matures in 2020. The Noble Midstream Services Revolving Credit Facility of $350 million matures in 2021. These facilities are used to fund capital investment programs and acquisitions and may periodically provide amounts for working capital purposes. At December 31, 2017, $230 million was outstanding under the Revolving Credit Facility and $85 million was outstanding under the Noble Midstream Services Revolving Credit Facility, leavin g $3.8 billion and $265 million in remaining availability under the respective credit facilities . See Item 8. Financial Statements and Supplementary Data - Note 10. Long-Term Debt .

Leviathan Term Loan Facility On February 24, 2017, we entered into a facility agreement (Leviathan Term Loan Facility) providing for a limited recourse secured term loan facility with an aggregate principal borrowing amount of up to $1 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 December 31, 2017 , no amounts were drawn under this facility.

Term Loan Facility In fourth quarter 2017, we utilized proceeds received from sale of non-strategic acreage in the DJ Basin to repay the remaining outstanding balance of $550 million under this $1.4 billion facility. See Item 8. Financial Statements and Supplementary Data - Note 10. Long-Term Debt .

Senior Notes During 2017 we took steps in managing our long-term debt maturities and liquidity through a series of financing transactions. We issued $600 million of 3.85% senior unsecured notes that will mature on January 15, 2028 and $500 million of 4.95% senior unsecured notes that will mature on August 15, 2047. We used the proceeds to redeem $1 billion of our 8.25% senior unsecured notes which were due March 1, 2019. Through these transactions, we effectively enhanced our financial flexibility and lowered our future cash interest expense by approximately $35 million on an annual basis. See Item 8. Financial Statements and Supplementary Data - Note 10. Long-Term Debt .

Cash Flows

The following table summarizes our cash flows from operating, investing and financing activities:

	Year Ended December 31,		
	2017	2016	2015
(millions)			
Total Cash Provided By (Used in)			
Operating Activities	$ 1,951	$ 1,351	$ 2,062
Investing Activities	(1,606)	(431)	(2,871)
Financing Activities	(850)	(768)	654
Increase (Decrease) in Cash and Cash Equivalents	$ (505)	$ 152	$ (155)

Operating Activities Cash flows from operating activities include all transactions and other events that are not defined as investing or financing activities and are generally the cash effects of transactions and other events that enter into the determination of net income.

In 2017, net cash provided by operating activities increased as compared with 2016. The change in cash flows from operating activities was primarily the result of higher average realized commodity prices partially offset by lower sales volumes and lower settlements of commodity derivative instruments. The reduction of our sales volumes was mainly driven by the decrease in sale of natural gas as a result of Marcellus Shale upstream asset divestiture. The increase in cash flows from sales was offset by the decrease in settlements proceeds from our commodity derivative instruments. The decrease in cash received from derivative settlements is reflective of an increase in the commodity prices as crude oil and natural gas prices strengthened in the second half of 2017.

Working capital changes resulted in a $ 150 million operating cash flow decrease in 2017 as compared with a $460 million operating cash flow decrease in 2016. The changes in working capital were primarily due to an increase in our current liabilities, including accrued liabilities and trade payables for drilling and development costs and midstream capital expenditures. The increase in current liabilities was partially offset by the increase in accounts receivable resulting from higher revenues and higher joint interest billing receivables, primarily due to billings associated with Leviathan development project costs.

In 2017, we made cash interest payments related to outstanding debt of $394 million as compared to $412 million in 2016.

In 2016, net cash provided by operating activities for 2016 decreased as compared with 2015 . Decreases in average realized commodity prices and lower settlements of commodity derivative instruments were partially offset by increases in sales volumes. Working capital changes resulted in a $460 million operating cash flow reduction in 2016 as compared with a negative impact of $129 million in 2015 and were due primarily to decreases in capital accruals related to reduced development activity, as well as an increase in accounts receivable related to higher revenues.

In 2016, we made cash interest payments related to outstanding debt of $412 million as compared to $404 million in 2015.

Investing Activities Our investing activities include capital spending on a cash basis for oil and gas properties and midstream infrastructure and investments in unconsolidated subsidiaries accounted for by the equity method. These investing activities may be offset by proceeds from property sales or dispositions, including farm-out arrangements, which may result in reimbursement for capital spending that had occurred in prior periods.

In 2017, capital spending for additions to property, plant and equipment, excluding acquisitions, totaled $2.6 billion compared to $1.5 billion in 2016. Approximately $700 million of the increase was due to increased US onshore development activity in response to a more favorable commodity price environment, as well as our focus on development of high margin areas in the DJ and Delaware Basins, and approximately $416 million increase was related to the initial Leviathan project development.

In addition, we used $637 million of cash, net of $21 million of cash acquired, to fund a portion of the consideration paid in the Clayton Williams Energy Acquisition, and we acquired Delaware Basin and other assets for $327 million .

In 2017, we received net cash proceeds of over $2 billion from divestitures of non-core assets, including:

- $1.0 billion from the Marcellus Shale upstream divestiture;
- $568 million on the sale of Greeley Crescent and Bronco acreage in the DJ Basin; and
- $335 million from the sale of mineral and royalty assets.

See Item 8. Financial Statements and Supplementary Data - Note 3. Clayton Williams Energy Acquisition and Note 4. Acquisitions, Divestitures and Merger .

We utilized these sales proceeds to partially fund our Clayton Williams Energy Acquisition, support our development activities in core operational areas, repay outstanding balances under the Term Loan Facility and further strengthen our liquidity position.

Other investing activities provided a net $87 million of cash as of December 31, 2017 .

In comparison, capital expenditures in 2016 were $1.5 billion or nearly half of capital spent in 2015 due to the timing of completion of major project development activities in the Gulf of Mexico, DJ Basin and Marcellus Shale. We received approximately $1.2 billion of proceeds from asset divestitures during 2016 as compared with $151 million of proceeds from divestitures during 2015. In 2016, we invested $8 million in CONE Gathering, and received cash distributions of $70 million, accounted for as investing activity, from CONE Midstream.

In 2015, capital spending for property, plant and equipment was $3.0 billion , representing a decrease of $1.9 billion as compared with 2014, primarily due to decreased major project development activity in our operational areas. We received $151 million of proceeds from asset divestitures during 2015 as compared with $321 million proceeds from divestitures during 2014, and acquired cash of $61 million in the Rosetta Merger. We also invested $104 million in CONE Gathering in 2015.

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

In 2017, our primary financing activities included $230 million net Revolving Credit Facility borrowings (including the borrowing and repayment of $1.3 billion associated with the Clayton Williams Energy Acquisition), $85 million net Noble Midstream Services Revolving Credit Facility borrowings used primarily to fund an acquisition, a $1.1 billion senior note refinancing, $595 million related to the repayment of Clayton Williams Energy debt, and a $550 million Term Loan Facility repayment. In addition, we received $312 million net proceeds from the issuance of Noble Midstream Partners common units, paid $190 million of cash dividends and $28 million of cash distributions, and made $60 million of capital lease principal payments.

We also received $10 million cash proceeds from the exercise of stock options and purchased 1,031,000 shares of treasury stock with a value of $36 million. These shares included 719,849 shares with a value of $25 million related to vesting of Clayton Williams Energy restricted stock and options in connection with the Clayton Williams Energy Acquisition. The remaining shares were surrendered for the payment of withholding taxes due on the vesting of employee restricted stock awards.

In 2016 , we used Term Loan Facility proceeds of $1.4 billion to redeem $1.4 billion of senior notes. We subsequently repaid $850 million of the Term Loan Facility from cash on hand. We received $299 million net proceeds from the issuance of Noble Midstream Partners common units in a public offering. Funds were also provided by cash proceeds from, and tax benefits related to, the exercise of stock options ($18 million). We used cash to pay dividends on our common stock ($172 million), make principal payments related to capital lease obligations ($53 million), and repurchase 237,000 shares of our common stock ($4 million).

In 2015, we received approximately $1.1 billion net proceeds from the issuance of shares of common stock in a public offering. Funds were also provided by cash proceeds from, and tax benefits related to, the exercise of stock options ($7 million). We used cash to pay dividends on our common stock ($291 million), make principal payments related to capital lease obligations ($67 million), and repurchase 491,000 shares of our common stock ($21 million). Subsequent to the Rosetta Merger, we incurred financing cash outflows to facilitate the exchange of Rosetta's debt ($12 million) as well as repay the balance outstanding under Rosetta's credit facility ($70 million).

See Item 8. Financial Statements and Supplementary Data – Consolidated Statements of Cash Flows .

Dividends We paid cash dividends totaling 40 cents per common share in 2017, 40 cents per common share in 2016 , and 72 cents per common share in 2015 . See Item 5. Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities .

Acquisition, Capital Expenditures and Other Exploration Expenditures

Our capital expenditures (on an accrual basis) were as follows for the year ended December 31, 2017:

	Year Ended December 31,		
	2017	2016	2015
(millions)			
Acquisition, Capital and Exploration Expenditures			
Unproved Property Acquisition (1)	$ 1,817	$ 234	$ 1,480
Proved Property Acquisition (2)	839	—	1,613
Exploration	42	222	322
Development	2,310	1,017	2,055
Midstream (3)	480	42	356
Corporate and Other	34	50	97
Total	$ 5,522	$ 1,565	$ 5,923
Other			
Investment in Equity Method Investee (4)	$ 68	$ 8	$ 104
Increase in Capital Lease Obligations (5)	—	5	55

(1) 2017 costs include $1.6 billion related to the Clayton Williams Energy Acquisition and $246 million related to the Delaware Basin asset acquisition.
2016 costs relate to properties exchanged with CONSOL upon termination of the Marcellus Shale joint development agreement.
2015 costs includ e $ 1.4 billion related to the Rosetta Merger.

(2) 2017 costs include $722 million of proved properties and $63 million of asset retirement obligations acquired in the Clayton Williams Energy Acquisition and $58 million related to the Delaware Basin asset acquisition.
2015 costs of $1.6 billion are related to the Rosetta Merger.

(3) 2017 includes gathering and processing assets of $48 million related to the Clayton Williams Energy Acquisition.
2016 includes Noble Midstream Partners expenditures.
2015 includes midstream assets acquired in the Rosetta Merger.

(4) 2017 includes our contribution to the Advantage Joint Venture, in which Noble Midstream Partners owns a 50% interest.
2015 includes investments in CONE Gathering, in which we previously owned a 50% interest. See Item 8. Financial Statements and Supplementary Data - Note 4. Acquisitions, Divestitures and Merger .

(5) Relates to US onshore assets.

Total capital expenditures increased during 2017 as compared with 2016 as we pursued strategic portfolio repositioning through a number of acquisitions in our core onshore operational areas in the Delaware Basin and also continued execution of our midstream capital investment program through Noble Midstream Partners. T he increase in development capital is in response to the strengthening of commodity prices in the second half of 2017 and is primarily related to drilling and development costs of $1.9 billion incurred mainly in our three US onshore plays (DJ Basin, Delaware Basin and Eagle Ford Shale). Additionally, $416 million of capital expenditures in 2017 was associated with the initial Leviathan project development, while in 2016 we incurred $106 million of project development costs, offshore Israel.

In 2016, total expenditures decreased as compared with 2015, excluding acquisition costs of $3.2 billion related to the Rosetta Merger, as we responded to the lower commodity price environment.

2015 expenditures, excluding the Rosetta Merger, reflect our reduced capital spending program. Given the 2015 commodity price environment and an industry cost structure that had yet to fully reset to lower revenue levels, we designed a substantially reduced capital investment program that was appropriate for the price environment.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2017 , material off-balance sheet arrangements and transactions that we have entered into included drilling rig contracts, transportation and gathering agreements, operating lease agreements, and undrawn letters of credit, all of which are customary in the oil and gas industry (see cross references to the Notes to the Financial Statements in the table below). Other than these aforementioned arrangements, we have no transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect our financial condition, results of operations, liquidity or availability of or requirements for capital resources. See also Contractual Obligations below.

Contractual Obligations

The following table summarizes certain contractual obligations as of December 31, 2017 that are reflected in the consolidated balance sheets and/or disclosed in the accompanying notes. Unless otherwise noted, all amounts shown are net to our interest.

Obligation	Note Reference [1]	Total	2018	2019 and 2020	2021 and 2022	2023 and beyond
(millions)						
Long-Term Debt [2]	Note 10	$ 6,586	$ —	$ 230	$ 1,464	$ 4,892
Interest Payments [3]	Note 10	5,804	324	645	555	4,280
Capital Lease and Other Obligations [4]	Note 10	335	74	87	50	124
Drilling and Equipment Obligations [5]	Note 17	448	343	105	—	—
Purchase Obligations [6]	Note 17	448	293	101	22	32
Transportation and Gathering [7]	Note 17	2,474	215	499	405	1,355
Operating Lease Obligations [8]	Note 17	330	44	65	65	156
Other Liabilities [9]	Note 12					
Asset Retirement Obligations [10]	Note 9	875	51	267	99	458
Commodity Derivative Instruments [11]	Note 8	68	53	15	—	—
Total Contractual Obligations		$ 17,368	$ 1,397	$ 2,014	$ 2,660	$ 11,297

(1) References are to the Notes accompanying Item 8. Financial Statements and Supplementary Data.

(2) Long-term debt excludes capital lease obligations and includes our fixed rate debt and revolving credit facilities balances based on the maturity dates of the facilities.

(3) Interest payments are based on the total debt balance, scheduled maturities and interest rates in effect at December 31, 2017.

(4) Annual capital lease payments, net to our interest, exclude regular maintenance and operational costs.

(5) Drilling and equipment obligations represent our working interest share of contractual agreements with third-party service providers to procure drilling rigs and other related equipment for exploratory and development drilling activities. See Counterparty Credit Risk, above.

(6) Purchase obligations represent our working interest share of contractual agreements to purchase goods or services that are enforceable, are legally binding and specify all significant terms, including fixed and minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transaction. See Counterparty Credit Risk, above.

(7) Transportation and gathering obligations represent minimum charges for firm transportation and gathering agreements related to our production. See Items 1. and 2. Business and Properties – Delivery and Firm Transportation Commitments .

(8) Operating lease obligations represent non-cancelable leases for office buildings and facilities and oil and gas operations equipment used in our daily operations. Amounts have not been discounted.

(9) The table excludes deferred compensation liabilities of $197 million as specific payment dates are unknown.

(10) Asset retirement obligations are discounted.

(11) Amount represents open commodity derivative instruments that were in a net payable position with the counterparty at December 31, 2017.

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

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.

Leviathan Natural Gas Project The initial development of the Leviathan field requires substantial infrastructure and capital. We have executed major equipment and installation contracts in support of development activities. As of December 31, 2017, we had entered into contracts with remaining obligations of approximately $464 million , net, to support development and bring first production online by the end of 2019.

Marcellus Shale Firm Transportation Agreements In connection with the Marcellus Shale upstream divestiture, we reduced our firm transportation financial commitments through the transfer of several contracts to the acquirer and retained certain other firm transportation contracts representing a total financial commitment of approximately $1.4 billion, undiscounted, primarily with remaining contract terms of two to 16 years.

One of the retained contracts relates to the Texas Eastern Pipeline, a major interstate natural gas transmission pipeline delivering natural gas to the northeastern US. This contract will be fully utilized through an agreement with the acquirer, whereby the acquirer will deliver quantities of natural gas to us and receive a netback sales price that reflects the value received by us at the sales point, less our effective fixed transportation fees and other expenses, plus a margin. This contract represents an undiscounted financial commitment of approximately $114 million as of December 31, 2017, before offset by the netback agreement, thus reducing the remaining overall commitment noted above.

Two of the retained contracts relate to the Leach Xpress and Rayne Xpress projects. These are interstate natural gas transmission pipelines, which were completed and placed in service in late 2017 and early 2018 to transport production from the Marcellus Shale to markets outside the basin. In fourth quarter 2017, we permanently assigned a portion of our retained capacity to a third party and reduced our remaining undiscounted financial commitment to approximately $418 million. At this time, we are unable to predict with certainty the outcome of our commercialization activities, our ability to utilize retained capacity and the timing of when we may recognize a non-cash exit cost in line with accounting for exit costs associated with these two pipeline projects.

Two additional retained contracts relate to the NEXUS and WB Xpress projects. These projects also include interstate natural gas transmission pipelines designed to transport production from the Marcellus Shale to markets outside the basin. Both projects have received FERC approval, will undergo construction activities and are targeted for in-service late 2018. These contracts represent an undiscounted financial commitment of approximately $870 million.

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. In addition, we have a “call” or right to purchase natural gas, priced at a regional index, from the acquirer of the Marcellus Shale upstream assets. This call extends through July 1, 2022 and may be exercised on quantities of the acquirer's production between 431,100 MMBtu/d and 832,645 MMBtu/d.

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

In accordance with US GAAP, we recognize the fair value of a liability for an exit cost in the period in which a liability is incurred. As a result, in second quarter 2017, we accrued non-cash exit costs of $41 million, discounted, relating to our transportation contract with the Appalachian Gateway Project (Gateway). Gateway, another natural gas transmission pipeline, is currently in service. We no longer have production to satisfy this commitment and do not plan to utilize this capacity in the future. In addition, we recorded a $52 million accrual, discounted, in fourth quarter 2017 relating to future commitments to the third party who assumed a portion of our capacity on the Leach Xpress and Rayne Xpress Projects. Both charges are included in loss on Marcellus Shale upstream divestiture in our consolidated statements of operations. See Item 8. Financial Statements and Supplementary Data – Note 17. Commitments and Contingencies.

Other US Transportation Agreements Certain of these contracts require us to make payments for any shortfalls in delivering or transporting minimum volumes under the commitments. As properties are undergoing development activities, we may experience temporary shortfalls until production volumes increase to meet or exceed the minimum volume commitments and will incur expense related to volume deficiencies and/or unutilized commitments. These amounts are recorded as marketing expense in our consolidated statements of operations. We expect to continue to incur expense related to deficiency and/or unutilized commitments in the near-term. Should commodity prices decline or if we are unable to continue to develop our properties as planned, or certain wells become uneconomic and are shut-in, we could incur additional shortfalls in delivering or transporting the minimum volumes, and we could be required to make payments in the event that these commitments are not otherwise offset. We continually seek to optimize under-utilized assets through capacity release and third-party arrangements, as well as, for example, through the shifting of transportation of production from rail cars to pipelines when we receive a higher netback price. We may continue to experience these shortfalls both in the near and long-term. Item 8. Financial Statements and Supplementary Data – Note 2. Additional Financial Statement Information

OIL Contingency As of December 31, 2017, we accrued approximately $19 million for an insurance contingency due to our membership in OIL. OIL is a mutual insurance company which insures specific property, pollution liability and other catastrophic risks. As part of our membership, we are contractually committed to pay termination fees should we elect to withdraw from OIL. We do not anticipate withdrawing from OIL; however, the potential termination fee is calculated annually based on OIL’s past losses, and the liability reflecting this potential charge has been accrued as of December 31, 2017.

Letters of Credit In the ordinary course of business, we maintain letters of credit and bank guarantees with a variety of banks in support of certain performance obligations of our subsidiaries. Outstanding letters of credit and bank guarantees totaled approximately $90 million at December 31, 2017.

Ratings Triggers We do not have triggers on any of our corporate debt that would cause an event of default in the 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.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of the consolidated financial statements requires our management to make a number of estimates and assumptions relating to the reported amounts of assets and liabilities and the disclosures of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. When alternatives exist among various accounting methods, the choice of accounting method can have a significant impact on reported amounts. The following is a discussion of the accounting policies, estimates and judgments which management believes are most significant in the application of US GAAP used in the preparation of the consolidated financial statements.

Reserves

Description All of the reserves data in this Annual Report on Form 10-K are estimates. Estimates of our crude oil, natural gas and NGL reserves are prepared by our qualified petroleum engineers in accordance with guidelines established by the SEC. Reservoir engineering is a subjective process with numerous uncertainties inherent in estimating underground accumulations of crude oil, natural gas and NGLs, including the projection of future production rates and the expected timing of development expenditures. In addition, economic producibility of reserves is dependent on the commodity prices used in the reserves estimate. Our reserves estimates are based on historical 12-month average commodity prices, unless contractual arrangements designate the price to be used, in accordance with SEC rules.

Reserves estimates impact our financial statements and disclosures, as the estimates are used as an input in calculation of our DD&A expense, assessment of impairment of crude oil and natural gas properties and in preparation of Supplemental Oil and Gas Disclosures.

Judgment and Uncertainties The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Commodity prices and development and production costs are factors used in determining reserves economics and reserves estimates. As a result, our reserves estimates will change in the future due to commodity price volatility and cost changes, as well as due to new information obtained from development drilling and production history.

Effect if Actual Results Differ from Assumptions Our reserves estimates are based on year-end cost, development, production and historical 12-month average price data. Results of drilling, testing, and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserves estimates are often different from the quantities of crude oil, natural gas and NGLs that are ultimately recovered due to reservoir performance and new geological and geophysical data. Additionally, increases in future drilling, development, production and abandonment costs and changes in commodity prices may result in future revisions to our reserves.

Estimates of proved crude oil, natural gas and NGL reserves significantly affect our DD&A expense. For example, if estimates of proved reserves decline, the DD&A rate will increase, resulting in a decrease in net income. A decline in estimates of proved reserves could also cause us to perform an impairment analysis to determine if the carrying amount of crude oil and natural gas properties exceeds the fair value and could result in an impairment charge, which would reduce earnings. See Item 8. Financial Statements and Supplementary Data - Supplemental Oil and Gas Information (Unaudited) .

Oil and Gas Properties - Successful Efforts Method of Accounting

Description We account for crude oil and natural gas properties under the successful efforts method of accounting. Application of the successful efforts method results in the capitalization of costs directly related to specific oil and gas reserves when results are positive and expensing of certain costs, including geological and geophysical costs and delay rentals, during the periods the costs are incurred, and, in the case of dry hole costs, in the period the well is deemed non-commercial.

Under the successful efforts method, we capitalize the following:

- Acquisition costs - Costs associated with the purchase, lease or other costs to acquire mineral interests in crude oil and natural gas properties are initially capitalized as unproved property acquisition costs. These costs are commonly attributable to undeveloped leasehold costs or are derived from allocated fair values as a result of business combinations. Continued capitalization of these costs is dependent upon discovery of proved reserves. For example:

    - If no proved reserves are discovered after exploration, drilling or lapse of the lease, then costs are impaired. As part of our periodic impairment review, we review undeveloped leasehold costs for potential impairment and 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 will record impairment expense related to the respective lease.

      When we have allocated fair values to a significant unproved property (probable and/or possible reserves) as the result of a business combination or other purchase of proved and/or unproved properties, we use a future cash flows analysis to assess the property for impairment. Cash flows used in the impairment analysis are determined based upon management's estimates of probable and possible reserves, future commodity prices, and future costs to produce the reserves. *Probable reserves* are defined in SEC Regulation S-X, Rule 4-10(a)(18) as those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are more likely than not (generally having more than 50% probability) to be recovered. *Possible reserves* are defined in SEC Regulation S-X, Rule 4-10(a)(17) as those additional reserves that are less certain to be recovered than probable reserves. Estimates of cash flows related to probable and possible reserves are reduced by additional risk-weighting factors.

      If undiscounted future net cash flows are less than the carrying value of the property, indicating impairment, the cash flows are discounted using a risk-adjusted rate and compared to the carrying value to determine the amount of the impairment loss to record.

    - If proved reserves are discovered, the related acquisition costs are reclassified to proved properties. We assess proved crude oil and natural gas properties and other investments for possible impairment whenever events or circumstances indicate that the recorded carrying values of the assets may not be recoverable. We recognize an impairment loss as a result of an event that causes us to consider the possibility that impairment may have occurred and when the estimated undiscounted future net cash flows from a property or other investment are less than the carrying value.

      If impairment is indicated, the carrying values are written down to fair value, which, in the absence of comparable market data, is estimated using a discounted cash flow method. In our cash flow method, cash flows are discounted using a risk-adjusted rate and compared to the carrying value for determining the amount of the impairment loss to record. Estimated future net cash flows are based on management's expectations for the future and include estimates of crude oil, natural gas and NGL reserves and future commodity prices, adjusted for location and quality differentials, revenues and operating and development costs.

- Exploratory well costs - Costs associated with drilling an exploratory well may be capitalized temporarily, or "suspended," pending a determination of whether crude oil or natural gas have been discovered and can be estimated with reasonable certainty to be economically producible. We carry the costs of an exploratory well as an asset if we have found a sufficient quantity of reserves to justify its completion as a producing well and as long as we are making sufficient progress assessing the reserves and the economic and operating viability of the project. For certain capital-intensive Gulf of Mexico or international projects, it may take several years to evaluate the future potential of the exploratory well and make a determination of its economic viability. Our ability to move forward on a project may be dependent on gaining access to transportation or processing facilities or obtaining permits and government or partner approval, the timing of which is beyond our control. In such cases, exploratory well costs remain suspended as long as we are actively pursuing access to necessary facilities and submitting requests for permits and approvals and believe they will be obtained.

- Development well costs - Costs associated with drilling a development well to obtain access to and to produce proved reserves are capitalized. Development well costs are included in our periodic proved property impairment test noted above.

These costs, along with those for support equipment and facilities, are amortized to expense by the unit-of-production method on a field-by-field basis, based on total proved crude oil, natural gas and NGL reserves, as estimated by our qualified petroleum engineers. Costs of certain gathering facilities or processing plants serving a number of properties or used for third-party processing are depreciated using the straight-line method over the useful lives of the assets.

The alternative method of accounting for crude oil and natural gas properties is the full cost method. Under the full cost method, geological and geophysical costs, exploratory dry holes and delay rentals are capitalized as assets and charged to earnings in future periods as a component of DD&A expense. In addition, under the full cost method, capitalized costs are accumulated in pools on a country-by-country basis. DD&A is computed on a country-by-country basis, and capitalized costs are limited on the same basis through the application of a ceiling test.

Judgment and Uncertainties The determination of the carrying value of our oil and gas properties includes assessment of impairment and the calculation of amortization expense.

In determination of whether significant unproved crude oil and natural gas properties are impaired, we apply a significant amount of judgment in assessing entity-specific assumptions and assumptions related to the future economic environment, as well as potential impacts of the political and regulatory climate on future development activity. We also consider numerous factors including, but not limited to, current exploration plans, favorable or unfavorable exploration activity on the property being evaluated and/or adjacent properties, our geologists' evaluation of the property, and the remaining months in the lease term for the property. In addition, impairment assessment involves a high degree of estimation uncertainty as it requires us to make assumptions and apply judgment to estimate future cash flows related to proved and unproved reserves. Such assumptions include commodity prices, capital spending, production and abandonment costs and reservoir data. Significant judgment is involved in estimating these factors, and they include uncertainties. In cases where probable and possible reserves cash flows are utilized to assess properties for impairment, we use the same pricing, cost and future production assumptions.

We apply significant judgment in determining whether sufficient progress has been made in assessing the reserves and the economic and operational viability of a project to continue capitalization of the exploratory well costs. Such assessment requires consideration of the following factors: commitment of project personnel, costs incurred to assess reserves and potential development, assessment process in progress covering economic, legal, political and environmental aspects of potential development, existence or active negotiations of agreements with governments and venture partners or sales contracts with customers, identification of existing transportation and other infrastructure that is or will be available for the project and other factors. Consideration of these factors requires us to make assumptions and apply judgment to assess industry and economic conditions, as well as our future drilling and development plans. Future changes in our exploratory and drilling activities or economic conditions may result in determination not to pursue certain projects, resulting in future write-offs of the capitalized exploratory well costs.

Calculation of unit-of-production rates is performed on a field-by-field basis and includes estimation of the period-end reserves base and production data for each respective field, including estimates of production for non-operated properties.

Effect if Actual Results Differ from Assumptions We have not made any material changes in the accounting methodology we use to account for our oil and gas properties. We believe the successful efforts method is the most appropriate method to use in accounting for our crude oil and natural gas properties because it provides a better representation of our results of operations, especially during periods of active exploration. If we had used the full cost method, our financial position and results of operations could have been significantly different.

At December 31, 2017, the net book value of our unproved properties includes significant amounts allocated in previous business combinations or acquisitions, including the Clayton Williams Energy Acquisition and the Rosetta Merger. See Supplemental Oil and Gas Information (Unaudited) - Capitalized Costs Relating to Oil and Gas Producing Activities . Unfavorable revisions to our reserves and/or changes in our exploration and development plans or the economic, political or regulatory environment in areas where we operate, or changes in the availability of funds for future activities may result in abandonment and impairment of unproved leases and oil and gas properties. During 2017 we recognized undeveloped leasehold impairment expense of $62 million primarily attributable to Gulf of Mexico leases. We recorded leasehold impairment expense of $93 million in 2016 and $21 million in 2015.

Impairment assessment incorporates expected future cash flows using expected prices, cost rates and future production. For the purpose of impairment testing, we used the five-year strip prices for crude oil and natural gas, with prices subsequent to the fifth year held constant as the benchmark price, unless contractual arrangements designate the price to be used, in the undiscounted future net cash flows. Capital and operating costs were estimated assuming 0% escalation. Unfavorable changes in these pricing and cost assumptions in the future may result in negative revisions to our reserves and associated cash flows, causing us to record impairment of proved oil and gas properties. We recorded total pre-tax (non-cash) impairment charges of $70 million in 2017, $92 million in 2016, and $533 million in 2015 for proved oil and gas properties. See Item 8. Financial Statements and Supplementary Data - Note 5. Asset Impairments .

At December 31, 2017, the balance of property, plant and equipment included $520 million of suspended exploratory well costs, $510 million of which had been capitalized for a period greater than one year. The wells relating to these suspended costs continue to be evaluated by various means, including additional seismic work, drilling additional appraisal wells to confirm the size of the hydrocarbon deposit, or evaluating the potential commerciality of the exploratory wells. During 2017, previously capitalized exploratory well costs of $65 million were expensed. See Item 8. Financial Statements and Supplementary Data - Note 6. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs .

Additionally, the carrying value of our oil and gas properties is sensitive to reserves estimates. Unit-of-production rates are revised at least once a year or when the reserves estimates are updated due to major revisions or transactions. The change in unit-of-production rates will affect the carrying value of our oil and gas properties and DD&A expense. If the estimates of proved reserves used in the unit-of-production calculations had been lower by 10% across all properties, 2017 DD&A expense would have increased by approximately $210 million.

Furthermore, a change in groupings of our oil and gas properties for the purpose of the DD&A calculation and impairment review could affect the calculation of unit-of-production rates, DD&A expense and determination of impairment.

Asset Retirement Obligations

Description Our asset retirement obligations (AROs) consist of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. We recognize the fair value of an ARO liability in the period in which it is incurred, which is when we have an existing legal obligation associated with the retirement of our oil and gas properties and the obligation can be reasonably estimated.

The associated asset retirement cost is capitalized as part of the carrying cost of the oil and gas asset. In determining the fair value of an ARO, we utilize the estimated future cash flows method. The recognition of an ARO requires that management make numerous estimates, assumptions and judgments regarding such factors as: the existence of a legal obligation for an ARO; estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates.

In periods subsequent to initial measurement of the ARO, we recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted future cash flows. Revisions also result in increases or decreases in the carrying cost of the oil and gas asset. Increases in the ARO liability due to passage of time impact net income as accretion expense. The related capitalized cost, including revisions thereto, is charged to expense through DD&A or exploration expense.

Judgment and Uncertainties The process for determining the fair value of an ARO requires us to make subjective judgments and assumptions concerning field life, timing of abandonment activities, cost structures, future labor rates and heavy equipment rental costs, expected inflation rates and changes in the regulatory environment. ARO estimates must be continually revised to reflect changes in these factors. Accordingly, we perform a comprehensive review of ARO estimates semi-annually with the proposed estimates and changes reflected in June 30 and December 31 period-end financial statements.

Effect if Actual Results Differ from Assumptions As of December 31, 2017, our consolidated balance sheet includes ARO liabilities of $875 million. Changes in the fair value of our ARO balance from prior year included both upward and downward revisions primarily due to revised timing and scope of remediation work resulting from assessment of abandonment work performed to-date and current cost experience on retirement obligations in the same operational areas. Future changes in rig rates, labor rates, inflation and interest rates, timing of settlements, scope of work, technological developments and changes in the environmental and regulatory climate may result in revisions to our ARO estimates which can be material to our financial position.

For the year ended December 31, 2017, we recorded $ 47 million of accretion expense in our consolidated statements of operations. A 10% increase in our ARO estimate as of December 31, 2017 would have impacted net loss by approximately $4 million. See Item 8. Financial Statements and Supplementary Data - Note 9. Asset Retirement Obligations .

Purchase Price Allocations and Resulting Goodwill

Description We occasionally acquire assets and assume liabilities in transactions accounted for as business combinations, such as the Clayton Williams Energy Acquisition in 2017 and the Rosetta Merger in 2015. In connection with a purchase business combination, the acquiring company must allocate the cost of the acquisition to assets acquired and liabilities assumed, based on fair values as of the acquisition date. Deferred taxes must be recorded for any differences between the assigned values and tax bases of assets and liabilities. Any excess of the purchase price over amounts assigned to assets and liabilities is recorded as goodwill. The amount of goodwill or gain on bargain purchase recorded in any particular business combination can vary significantly depending upon the values attributed to assets acquired and liabilities assumed.

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

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

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

Judgment and Uncertainties Preparing a purchase price allocation requires estimating the fair values of assets acquired and liabilities assumed in a business combination, and we must make various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved and unproved crude oil and natural gas properties. In most cases, sufficient market data is not available regarding the fair values of proved and unproved properties, and we prepare estimates of such properties based on the fair value of associated crude oil, natural gas and NGL reserves utilizing the income approach.

The primary assumptions used to arrive at estimates of future net cash flows are reserves quantities, commodity prices, and capital and operating costs. For estimated proved reserves, the future net cash flows are discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the acquisition. The market-based weighted average cost of capital rate is subjected to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved reserves, the discounted future net cash flows of probable and possible reserves are reduced by additional risk-weighting factors.

Estimated deferred taxes are based on available information concerning the tax bases of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

Resulting goodwill from a purchase price allocation must be assessed for impairment. We perform our annual goodwill impairment test at the end of the third quarter of each year unless events or circumstances trigger the need for an interim impairment test.

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

- *Income Approach* Under the income approach, the fair value of the Texas reporting unit is estimated based on the present value of expected future cash flows. The income approach is dependent on a number of factors, including estimates of forecasted revenue and operating costs and proved reserves, as well as the success of future exploration for and development of unproved reserves, discount rates and other variables. Negative revisions of estimated reserves quantities, increases in future cost estimates, divestiture of a significant component of the reporting unit, or sustained decreases in crude oil or natural gas prices could lead to a reduction in expected future cash flows and possibly an impairment of all or a portion of goodwill in future periods. Key assumptions used in the discounted cash flow model described above include estimated quantities of crude oil, natural gas and NGL reserves, including both proved reserves and risk-adjusted unproved reserves; estimates of market prices considering forward commodity price curves as of the measurement date; and estimates of operating, administrative and capital costs adjusted for inflation. We discount the resulting future cash flows using a peer group based weighted average cost of capital.

- *Market Approach* Under the market approach, we estimate the fair value of the Texas reporting unit by comparison to similar businesses whose securities are actively traded in the public market The market approach requires management to make certain judgments about the selection of comparable companies and/or comparable recent company and asset transactions and transaction premiums, thereby creating a group of guideline public companies or transactions, or a peer group, that are engaged in similar operations with comparable risks and returns as our reporting unit.

  We use the peer group multiple method for the market approach. Market multiples represent market estimates of fair value based on selected financial metrics. We use earnings before interest, taxes, DD&A and exploration expense (also known as EBITDAX) as our financial metric as we believe it more accurately compares companies using successful efforts and full cost accounting methods, both of which are in our peer group. Determination of fair value under the income approach and the market approach is subject to a high degree of estimation uncertainty as it requires us to make assumptions and apply judgment to various parameters that are sensitive to industry, market and economic conditions. The change in these factors in the future may have a negative impact on estimated future cash flows and the enterprise value of our reporting unit, which could result in future goodwill impairment.

Effect if Actual Results Differ from Assumptions The resulting estimated fair values assigned to assets acquired and liabilities assumed in a purchase price allocation can have a significant effect on results of operations in the future. A higher fair value assigned to a property results in higher DD&A expense, which results in lower net earnings. Fair values are based on estimates of future commodity prices, reserves quantities, operating expenses and development costs. This increases the likelihood of impairment if future commodity prices or reserves quantities are lower than those originally used to determine fair value, or if future operating expenses or development costs are higher than those originally used to determine fair value. Impairment would have no effect on cash flows, but would result in a decrease in net income for the period in which the impairment is recorded. See Item 8. Financial Statements and Supplementary Data - Note 3. Clayton Williams Energy Acquisition and Item 8. Financial Statements and Supplementary Data - Note 4. Acquisitions, Divestitures and Merger .

As of December 31, 2017, our consolidated balance sheet includes goodwill of $1.3 billion, resulting from the Clayton Williams Energy Acquisition in second quarter 2017. All of our recorded goodwill is assigned to the Texas reporting unit.

We conducted a qualitative and quantitative goodwill impairment assessment as of September 30, 2017 and based on the results of our goodwill impairment test, we concluded that our goodwill at September 30, 2017 was not impaired as the fair value of our Texas reporting unit was in excess of its respective net book value, including goodwill. While not required under Accounting Standards Codification (“ASC”) 350 “Intangibles - Goodwill and Other", we also performed a reconciliation of the determined enterprise fair value as compared to our total company market capitalization. From this additional analysis, we have concluded that the determination of the enterprise fair value closely aligns with our market capitalization.

The estimates used in our goodwill impairment test do not constitute forecasts or projections of future results of operations, but are rather estimates and assumptions based on historical results and assessments of macroeconomic factors affecting the Texas reporting unit as of the valuation date. We believe that our estimates and assumptions are reasonable, but they are subject to change from period to period. Actual results of operations and other factors will likely differ from the estimates used in our discounted cash flow valuation and it is possible that differences could be material. Although we base the fair value estimate of the Texas reporting unit on assumptions we believe to be reasonable, those assumptions are inherently unpredictable and uncertain and actual results could differ from the estimate. In the event of a prolonged industry downturn, commodity prices again become depressed or decline, thereby causing the fair value of the Texas reporting unit to decline, which could result in an impairment of goodwill.

If, in the future, we dispose of a reporting unit or a portion of a reporting unit that constitutes a business, we will include goodwill associated with that business in the carrying amount of the business in order to determine the gain or loss on disposal. The amount of goodwill allocated to the carrying amount of a business can significantly impact the amount of gain or loss recognized on the sale of that business. The amount of goodwill to be included in that carrying amount will be based on the relative fair value of the business to be disposed of and the portion of the reporting unit that will be retained. See Item 8. Financial Statements and Supplementary Data - Note 3. Clayton Williams Energy Acquisition .

Exit Costs

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

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

In addition, we have retained other Marcellus Shale firm transportation contracts, relating to pipeline projects that either were recently placed in service in late 2017/early 2018 or are not yet commercially available to us. These projects that are not yet available will undergo construction and, as these projects become commercially available to us, we will assess, based upon the facts and circumstances, the recognition of any potential exit cost liabilities. 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 amount of the estimated remaining financial commitment and include the related expense in operating expense in our consolidated statements of operations.

Any additional exit cost liability will be initially recorded at fair value, and, in periods subsequent to initial measurement, changes to the liability, including changes resulting from revisions to either the timing or the amount of estimated cash flows over the future contract period, will be recognized as an adjustment to the liability in the period of the change.

Judgment and Uncertainties We are required to make significant judgments and estimates regarding the timing and amount of recognition of any additional exit cost liabilities, taking into consideration our commercialization activities and/or the potential occurrence of a cease-use date. We must consider, among other factors, the following:

- the status of negotiations with counterparties regarding partial or permanent release of our contract commitments;
- the status of FERC approval of prospective pipeline projects;
- the timing of commercial availability of approved pipelines upon completion of construction; and
- the likelihood of capacity utilization through purchase of third party gas, which would reduce unutilized volume commitments.

Additionally, any subsequent changes in interest rates and/or credit risk will affect the discount rate used to calculate the present value of expected future cash flows associated with our existing contract commitments.

There are inherent uncertainties surrounding the recording of exit cost liabilities, and in future periods, a number of factors could significantly change our estimate of such obligations or result in recognition of additional liability

Effect if Actual Results Differ from Assumptions As of December 31, 2017 our financial commitment associated with Marcellus Shale firm transportation contracts was approximately $1.4 billion, undiscounted. We are currently engaged in actions to commercialize and address these remaining commitments, which would reduce our undiscounted 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, with the offsetting charge reducing our earnings. See Item 8. Financial Statements and Supplementary Data - Note 17. Commitments and Contingencies .

Income Tax Expense and Deferred Tax Assets

Description We are subject to income and other taxes in numerous taxing jurisdictions worldwide. For financial reporting purposes, we provide taxes at rates applicable for the appropriate tax jurisdictions. Estimates of amounts of income tax to be recorded involve interpretation of complex tax laws, including the recently enacted Tax Cuts and Jobs Act, as well as assessment of the effects of foreign taxes on domestic taxes, and estimates regarding the timing and amounts of future repatriation of earnings from controlled foreign corporations.

Our consolidated balance sheets include deferred tax assets. Deferred tax assets arise when expenses are recognized in the financial statements before they are recognized in the tax returns or when income items are recognized in the tax returns before they are recognized in the financial statements. Deferred tax assets also arise when operating losses or tax credits are available to offset tax payments due in future years. Ultimately, realization of a deferred tax asset depends on the existence of sufficient taxable income within the future periods to absorb future deductible temporary differences, loss carryforwards or credits.

In assessing the realizability of deferred tax assets, management must consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized.

Management considers all available evidence (both positive and negative) in determining whether a valuation allowance is required. Such evidence includes the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment, and judgment is required in considering the relative weight of negative and positive evidence. We continue to monitor facts and circumstances in the reassessment of the likelihood that operating loss carryforwards, credits and other deferred tax assets will be utilized prior to their expiration. As a result, we may determine, and we have determined in the past, that a deferred tax asset valuation allowance should be established.

Judgment and Uncertainties In assessing facts and circumstances surrounding realizability of our deferred tax assets we are required to apply judgment to determine the weight of both positive and negative evidence in order to conclude whether the valuation allowance is necessary relative to net operating loss carryforwards and other deferred tax assets.

In determining whether a valuation allowance is required for our deferred tax asset balances, we consider, among other factors, current financial position, results of operations, projected future taxable income, tax planning strategies and new tax legislation. Significant judgment is involved in this determination as we are required to make assumptions about future commodity prices, projected production, development activities, profitability of future business strategies and forecasted economics in the oil and gas industry. Additionally changes in the effective tax rate resulting from changes in tax law and our level of earnings may limit utilization of deferred tax assets and will affect valuation of deferred tax balances in the future.

Effect if Actual Results Differ from Assumptions As of December 31, 2017, our US federal income tax net operating loss carryforwards totaled approximately $3.2 billion and foreign net operating loss carryforwards were $662 million. The deferred tax asset associated with our federal and foreign net operating loss carryforwards was approximately $672 million and $187 million, respectively, classified, net, in our consolidated balance sheet within noncurrent deferred income tax liability balance. We currently have a valuation allowance on the deferred tax assets associated with foreign loss carryforwards and foreign tax credits. The valuation allowance on foreign loss carryforwards totaled $183 million in 2017 and $242 million in 2016. The changes to the valuation allowance for the loss carryforwards between periods was attributable to the offset of the valuation allowance against the NOL in a jurisdiction in which we are no longer active. Deemed foreign tax credits of $164 million were recognized along with the additional taxable income associated with the transition tax. A full valuation allowance of $366 million has been recorded against all foreign tax credits based on current interpretation of US Tax Reform law and the expected future utilization of net operating loss carryforwards. Any increase or decrease in a deferred tax asset valuation allowance would impact net income through offsetting changes in income tax expense, which could have a negative impact on our financial position and results of operations. See Item 8. Financial Statements and Supplementary Data - Note 11. Income Taxes .

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

Derivative Instruments Held for Non-Trading Purposes We are exposed to commodity price risk in the normal course of business operations. Due to commodity price volatility, we may use derivative instruments as a means of managing our exposure to price changes.

At December 31, 2017 , we had various open commodity derivative instruments related to global crude oil and domestic 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 at December 31, 2017 with a fair value of $71 million . Based on the December 31, 2017 published commodity futures price curves for the underlying commodities, a hypothetical price increase of 10% per Bbl for crude oil would increase the fair value of our net commodity derivative liability by approximately $146 million. A hypothetical price increase of 10% per MMBtu for natural gas would increase the fair value of our net commodity derivative liability by approximately $5 million.

Our derivative instruments are executed under master agreements which allow us to net settle by counterparty. Net settlements take into account deferred premiums we have agreed to pay for put options. In addition, in the event of default, these master agreements allow us 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. None of our counterparty agreements contain margin requirements.

Even with certain hedging arrangements in place to mitigate the effect of commodity price volatility, our 2018 revenues and results of operations could be adversely affected if commodity prices were to decline. See Item 1A. Risk Factors – *Commodity hedging transactions may limit our potential gains or fail to protect us from declines in commodity prices* and Item 8. Financial Statements and Supplementary Data – Note 8. Derivative Instruments and Hedging Activities .

Interest Rate Risk

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

At December 31, 2017 , we had approximately $6.5 billion (excluding capital lease and other obligations) of long-term debt outstanding. Of this amount, approximately $6.3 billion was fixed-rate debt, with a weighted average interest rate of 5.04% at December 31, 2017 . Although near term changes in interest rates may affect the fair value of our fixed-rate debt, they do not expose us to the risk of earnings or cash flow loss. See Item 8. Financial Statements and Supplementary Data – Note 10. Long-Term Debt .

We are also exposed to interest rate risk related to our interest-bearing cash and cash equivalents balances and amounts outstanding under our credit facilities. As of December 31, 2017 , our cash and cash equivalents total ed approximately $675 million , approximately 59% of which was invested in money market funds and short-term investments with major financial institutions. A change in the interest rate applicable to our short term investments or amounts outstanding under our credit facilities would have a de minimis impact on our earnings and cash flows. We currently have no interest rate derivative instruments outstanding. However, we may enter into interest rate derivative instruments in the future if we determine that it is necessary to invest in such instruments in order to mitigate our interest rate risk.

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, a re 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. This risk may be mitigated to the extent commodity prices increase in response to a devaluation of the US dollar.

Net foreign transaction (gains) losses were de minimis for 2017 , 2016 and 2015 . Foreign transaction (gains) losses are included in other (income) expense, net in the consolidated statements of operations.

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.

Item 8. Financial Statements and Supplementary Data

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Consolidated Financial Statements of Noble Energy, Inc.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed under the supervision of our Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America.

Because of its inherent limitations, internal control over financial reporting may not detect or prevent misstatements. Projections of any evaluation of the effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or processes may deteriorate.

As of December 31, 2017 , our management assessed the effectiveness of our internal control over financial reporting based on the criteria for effective internal control over financial reporting established in *Internal Control – Integrated Framework (2013)* , issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, management determined that we maintained effective internal control over financial reporting as of December 31, 2017 , based on those criteria.

KPMG LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of internal control over financial reporting as of December 31, 2017 which is included herein.

Noble Energy, Inc.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders
Noble Energy, Inc.:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Noble Energy, Inc. and subsidiaries (the "Company") as of December 31, 2017 and 2016 , the related consolidated statements of operations, comprehensive income (loss), shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2017 , and the related notes (collectively, the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016 , and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2017 , in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2017 , based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 20, 2018 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ KPMG LLP

We have served as the Company's auditor since 2002.

Houston, Texas
February 20, 2018

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders
Noble Energy, Inc.:

Opinion on Internal Control Over Financial Reporting

We have audited Noble Energy, Inc.'s and subsidiaries' (the "Company") internal control over financial reporting as of December 31, 2017 , based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017 , based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated balance sheets of the Company as of December 31, 2017 and 2016 , the related consolidated statements of operations, comprehensive income (loss), shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2017 , and the related notes (collectively, the "consolidated financial statements"), and our report dated February 20, 2018 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying management's report on internal controls over financial reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ KPMG LLP

Houston, Texas

February 20, 2018

Noble Energy, Inc.
Consolidated Statements of Operations
(millions, except per share amounts)

	Year Ended December 31,		
	2017	2016	2015
Revenues			
Oil, Gas and NGL Sales	$ 4,060	$ 3,389	$ 3,093
Income from Equity Method Investees and Other	196	102	90
Total Revenues	4,256	3,491	3,183
Costs and Expenses			
Production Expense	1,141	1,100	996
Exploration Expense	188	925	488
Depreciation, Depletion and Amortization	2,053	2,454	2,131
General and Administrative	415	399	396
Loss on Marcellus Shale Upstream Divestiture	2,379	—	—
Asset Impairments	70	92	533
Goodwill Impairment	—	—	779
Other Operating (Income) Expense, Net	(188)	(103)	332
Total Operating Expenses	6,058	4,867	5,655
Operating Loss	(1,802)	(1,376)	(2,472)
Other Expense (Income)			
(Gain) Loss on Commodity Derivative Instruments	(63)	139	(501)
Loss (Gain) on Extinguishment of Debt	98	(80)	—
Interest, Net of Amount Capitalized	354	328	263
Other Non-Operating Expense (Income), Net	—	9	(15)
Total Other Expense (Income)	389	396	(253)
Loss Before Income Taxes	(2,191)	(1,772)	(2,219)
Income Tax (Benefit) Provision	(1,141)	(787)	222
Net Loss Including Noncontrolling Interests	(1,050)	(985)	(2,441)
Less: Net Income Attributable to Noncontrolling Interests	68	13	—
Net Loss Attributable to Noble Energy	$ (1,118)	$ (998)	$ (2,441)
Net Loss Attributable to Noble Energy per Share of Common Stock			
Basic and Diluted	$ (2.38)	$ (2.32)	$ (6.07)
Weighted Average Number of Shares Outstanding			
Basic and Diluted	469	430	402

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

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

	Year Ended December 31,		
	2017	2016	2015
Net Loss Including Noncontrolling Interests	$ (1,050)	$ (985)	$ (2,441)
Other Items of Comprehensive Loss			
Net Change in Mutual Fund Investment	—	—	(11)
Less Tax Expense	—	—	4
Net Change in Pension and Other	3	3	99
Less Tax Benefit	(1)	(1)	(35)
Other Comprehensive Income	2	2	57
Comprehensive Loss Including Noncontrolling Interests	$ (1,048)	$ (983)	$ (2,384)
Less: Comprehensive Income Attributable to Noncontrolling Interests	68	13	—
Comprehensive Loss Attributable to Noble Energy	$ (1,116)	$ (996)	$ (2,384)

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

Noble Energy, Inc.
Consolidated Balance Sheets
(millions)

	December 31, 2017	December 31, 2016
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 675	$ 1,180
Accounts Receivable, Net	748	615
Other Current Assets	780	160
Total Current Assets	2,203	1,955
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method of Accounting)	29,678	30,355
Property, Plant and Equipment, Other	879	909
Total Property, Plant and Equipment, Gross	30,557	31,264
Accumulated Depreciation, Depletion and Amortization	(13,055)	(12,716)
Total Property, Plant and Equipment, Net	17,502	18,548
Goodwill	1,310	—
Other Noncurrent Assets	461	508
Total Assets	$ 21,476	$ 21,011
LIABILITIES AND SHAREHOLDERS’ EQUITY		
Current Liabilities		
Accounts Payable - Trade	$ 1,161	$ 736
Other Current Liabilities	578	742
Total Current Liabilities	1,739	1,478
Long-Term Debt	6,746	7,011
Net Deferred Income Tax Liability	1,127	1,819
Other Noncurrent Liabilities	1,245	1,103
Total Liabilities	10,857	11,411
Shareholders’ Equity		
Preferred Stock - Par Value $1.00 per share; 4 Million Shares Authorized, None Issued	—	—
Common Stock - Par Value $0.01; 1 Billion Shares Authorized; 529 Million and 471 Million Shares Issued, Respectively	5	5
Additional Paid in Capital	8,438	6,450
Accumulated Other Comprehensive Loss	(30)	(31)
Treasury Stock, at Cost; 39 Million and 38 Million Shares, Respectively	(725)	(692)
Retained Earnings	2,248	3,556
Noble Energy Share of Equity	9,936	9,288
Noncontrolling Interests	683	312
Total Equity	10,619	9,600
Total Liabilities and Equity	$ 21,476	$ 21,011

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

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

	Year Ended December 31,		
	2017	2016	2015
Cash Flows From Operating Activities			
Net Loss Including Noncontrolling Interests	$ (1,050)	$ (985)	$ (2,441)
Adjustments to Reconcile Net Loss to Net Cash Provided by Operating Activities			
Depreciation, Depletion and Amortization	2,053	2,454	2,131
Asset Impairments	70	92	533
Loss on Marcellus Shale Upstream Divestiture	2,379	—	—
Goodwill Impairment	—	—	779
Dry Hole Cost	9	579	266
Deferred Income Taxes	(1,227)	(984)	116
(Gain) Loss on Commodity Derivative Instruments	(63)	139	(501)
Net Cash Received in Settlement of Commodity Derivative Instruments	13	569	1,009
Gain on Divestitures	(326)	(238)	—
Stock Based Compensation	104	77	86
Non-cash Pension Plan Termination Expense	—	—	82
Loss (Gain) on Debt Extinguishment	98	(80)	—
Undeveloped Leasehold Impairment	62	93	21
Expiration and Amortization of Undeveloped Leaseholds	—	55	92
Other Adjustments for Noncash Items Included in Income	(21)	40	18
Changes in Operating Assets and Liabilities, Net of Assets Acquired and Liabilities Assumed			
(Increase) Decrease in Accounts Receivable	(171)	(164)	453
Increase (Decrease) in Accounts Payable	248	(111)	(364)
(Decrease) Increase in Current Income Taxes Payable	(36)	(32)	(94)
(Decrease) Increase in Other Current Liabilities	(101)	(63)	(70)
Other Operating Assets and Liabilities, Net	(90)	(90)	(54)
Net Cash Provided by Operating Activities	1,951	1,351	2,062
Cash Flows From Investing Activities			
Additions to Property, Plant and Equipment	(2,649)	(1,541)	(2,979)
Proceeds from Divestitures	2,073	1,241	151
Clayton Williams Energy Acquisition, Net of Cash Received	(616)	—	—
Other Acquisitions	(327)	—	—
Marcellus Shale Acreage Exchange Consideration	—	(213)	—
Other	(87)	82	(43)
Net Cash Used in Investing Activities	(1,606)	(431)	(2,871)
Cash Flows From Financing Activities			
Dividends Paid, Common Stock	(190)	(172)	(291)
Proceeds from Issuance of Noble Energy Common Stock, Net of Offering Costs	—	—	1,112
Proceeds from Revolving Credit Facility	1,585	—	—
Repayment of Revolving Credit Facility	(1,355)	—	(70)
Repayment of Clayton Williams Energy Long-term Debt	(595)	—	—
Proceeds from Term Loan Facility	—	1,400	—
Repayment of Term Loan Facility	(550)	(850)	—
Proceeds from Issuance of Senior Notes, Net	1,086	—	—
Repayment of Senior Notes	(1,114)	(1,383)	(12)
Proceeds from Noble Midstream Services Revolving Credit Facility	325	—	—
Repayment of Noble Midstream Services Revolving Credit Facility	(240)	—	—
Proceeds from Issuance of Noble Midstream Partners Common Units, Net of Offering Costs	312	299	—
Other	(114)	(62)	(85)
Net Cash (Used in) Provided By Financing Activities	(850)	(768)	654

(Decrease) Increase in Cash and Cash Equivalents		(505)		152		(155)
Cash and Cash Equivalents at Beginning of Period		1,180		1,028		1,183
Cash and Cash Equivalents at End of Period	$	675	$	1,180	$	1,028

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

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

	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, 2014	$ 4	$ 3,624	$ (90)	$ (671)	$ 7,458	—	$ 10,325
Net Loss	—	—	—	—	(2,441)	—	(2,441)
Rosetta Merger	1	1,528	—	—	—	—	1,529
Stock-based Compensation	—	86	—	—	—	—	86
Exercise of Stock Options	—	8	—	—	—	—	8
Dividends (72 cents per share)	—	—	—	—	(291)	—	(291)
Issuance of Shares of Noble Energy Common Stock to Public, Net of Offering Costs	—	1,112	—	—	—	—	1,112
Net Change in Other	—	2	57	(17)	—	—	42
December 31, 2015	$ 5	$ 6,360	$ (33)	$ (688)	$ 4,726	—	$ 10,370
Net (Loss) Income	—	—	—	—	(998)	13	(985)
Stock-based Compensation	—	68	—	—	—	—	68
Exercise of Stock Options	—	24	—	—	—	—	24
Dividends (40 cents per share)	—	—	—	—	(172)	—	(172)
Issuance of Noble Midstream Partners Common Units, Net of Offering Costs	—	—	—	—	—	299	299
Net Change in Other	—	(2)	2	(4)	—	—	(4)
December 31, 2016	$ 5	$ 6,450	$ (31)	$ (692)	$ 3,556	312	$ 9,600
Net (Loss) Income	—	—	—	—	(1,118)	68	(1,050)
Clayton Williams Energy Acquisition	—	1,876	—	(25)	—	—	1,851
Stock-based Compensation	—	100	—	—	—	—	100
Exercise of Stock Options	—	10	—	—	—	—	10
Dividends (40 cents per share)	—	—	—	—	(190)	—	(190)
Issuance of Noble Midstream Partners Common Units, Net of Offering Costs	—	—	—	—	—	312	312
Distributions to Noncontrolling Interest Owners	—	—	—	—	—	(28)	(28)
Net Change in Other	—	2	1	(8)	—	19	14
December 31, 2017	$ 5	$ 8,438	$ (30)	$ (725)	$ 2,248	683	$ 10,619

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

Note 1. Summary of Significant Accounting Policies

General Noble Energy, Inc. (Noble Energy, we or us) is a leading independent energy company engaged in worldwide crude oil and natural gas exploration and production. Our historical operating areas include: US onshore, primarily the DJ Basin, Delaware Basin, Eagle Ford Shale and Marcellus Shale (until June 2017); US offshore Gulf of Mexico; Eastern Mediterranean; and West Africa. Our Midstream segment owns, operates, develops and acquires domestic midstream infrastructure assets with current focus areas being the DJ and Delaware Basins.

Basis of Presentation and Consolidation Accounting policies used by us and our subsidiaries conform to US GAAP. Significant policies are discussed below. Our consolidated accounts include our accounts and the accounts of our wholly-owned subsidiaries. All significant intercompany balances and transactions have been eliminated upon consolidation.

Equity Method of Accounting We use the equity method of accounting for investments in entities that we do not control but over which we exert significant influence. Our equity investees own and operate various midstream assets which we consider an essential component of our business and a necessary and integral element to our value chain involving the monetization of natural gas. With our partners, we engage in joint strategic operational and financial decision making for these entities.

In order to reflect the economics associated with our integrated upstream value chain described above, we include income from equity method investees as a component of revenues in our consolidated statements of operations.

We carry equity method investments at our share of net assets of the equity investees plus loans and advances, and include the investments in other noncurrent assets in our consolidated balance sheets. 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. Differences in the basis of the investment and the separate net asset value of the investee, if any, are amortized into income over the remaining useful life of the underlying assets. Our share of income taxes incurred directly by the equity method investees is reported in income from equity method investees and is not included in our income tax provision in our consolidated statements of operations. See Note 7. Equity Method Investments .

Noncontrolling Interests In third quarter 2016, Noble Midstream Partners LP (Noble Midstream Partners), a subsidiary of Noble Energy, completed its initial public offering of common units. As a result, we present our consolidated financial statements with a noncontrolling interest section representing the public's ownership in Noble Midstream Partners. See Note 16. Additional Shareholders' Equity Information.

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

Use of 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.

Estimated quantities of crude oil, natural gas and NGL reserves are the most significant of our estimates. All the reserves data included in this Annual Report Form 10-K are estimates. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil, natural gas and NGLs. There are numerous uncertainties inherent in estimating quantities of proved crude oil, natural gas and NGL reserves. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserves estimates may be different from the quantities of crude oil, natural gas and NGLs that are ultimately recovered. Qualified petroleum engineers in our Houston and Denver offices prepare all reserves estimates for our different geographical regions. These reserves estimates are reviewed and approved by senior engineering staff and division management with final approval by the Senior Vice President – Corporate Development and certain members of senior management. See Supplemental Oil and Gas Information (Unaudited) .

Other items subject to estimates and assumptions include the carrying amounts of inventory, property, plant and equipment, goodwill, exit costs and asset retirement obligations (AROs), valuation allowances for receivables and deferred income tax assets, and valuation of derivative instruments, among others. Management evaluates estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic and commodity price environment. The volatility of commodity prices results in increased uncertainty inherent in such estimates and assumptions. Declines in commodity prices could result in a reduction in our fair value estimates and cause us to perform analyses to determine if our oil and gas properties are impaired. As future commodity prices cannot be determined accurately, actual results could differ significantly from our estimates. See Supplemental Oil and Gas Information (Unaudited) .

Reclassifications

In Note 14. Segment Information , we report a new Midstream segment, established second quarter 2017, and present prior period amounts on a comparable basis. Certain other prior-period amounts have been reclassified to conform to the current period presentation.

Fair Value Measurements Fair value measurements are based on a hierarchy which prioritizes the inputs to valuation techniques used to measure fair value into three levels. The fair value hierarchy is as follows:

- Level 1 measurements are fair value measurements which use quoted market prices (unadjusted) in active markets for identical assets or liabilities.
- 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.
- Level 3 measurements are fair value measurements which use unobservable inputs.

The fair value hierarchy gives the highest priority to Level 1 measurements and the lowest priority to Level 3 measurements. We use Level 1 inputs when available, as Level 1 inputs generally provide the most reliable evidence of fair value. See Note 13. Fair Value Measurements and Disclosures .

Cash and Cash Equivalents For purposes of reporting cash flows, cash and cash equivalents include unrestricted cash on hand and investments with original maturities of three months or less at the time of purchase.

Allowance for Doubtful Accounts We routinely assess the recoverability of all material trade and other receivables to determine their collectibility. We accrue a reserve on a receivable when, based on management's judgment, it is probable that a receivable will not be collected and the amount of such reserve may be reasonably estimated.

Inventories Inventories consist primarily of tubular goods and production equipment used in our oil and gas operations, and crude oil produced but not yet sold. Materials and supplies inventories are stated at the lower of cost or net realizable value. The cost of crude oil inventory includes production costs and DD&A of oil and gas properties. See Note 2. Additional Financial Statement Information .

Property, Plant and Equipment Significant accounting policies for our property, plant and equipment are as follows:

Successful Efforts Method We account for crude oil and natural gas properties under the successful efforts method of accounting. Under this method, costs to acquire mineral interests in crude oil and natural gas properties, drill and equip exploratory wells that find proved reserves, and drill and equip development wells are capitalized. Capitalized costs of producing crude oil and natural gas properties, along with support equipment and facilities, are amortized to expense by the unit-of-production method based on proved crude oil, natural gas and NGL reserves on a field-by-field basis, as estimated by our qualified petroleum engineers. Our policy is to use quarter-end reserves and add back current period production to compute quarterly DD&A expense. Costs of certain gathering facilities or processing plants serving a number of properties or used for third-party processing are depreciated using the straight-line method over the useful lives of the assets ranging from three to thirty years. Upon sale or retirement of depreciable or depletable property, the cost and related accumulated DD&A are eliminated from the accounts and the resulting gain or loss is recognized. Costs related to repair and maintenance activities are expensed as incurred.

Property Impairment For our proved properties, we routinely assess whether impairment indicators arise during any given quarter and have processes in place to ensure that we become aware of such indicators. Impairment indicators include, but are not limited to, sustained decreases in commodity prices, negative revisions of proved reserves, and increases in development or operating costs. In the event that impairment indicators exist, we conduct an impairment test. To that end, we estimate future net cash flows expected in connection with the property and compare such future net cash flows to the carrying amount of the property to determine if the carrying amount is recoverable.

When the carrying amount of a property exceeds its estimated undiscounted future net cash flows, the carrying amount is reduced to estimated fair value. Fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two. In the discounted cash flow method, estimated future cash flows are based on management's expectations for the future and include estimates of future crude oil and natural gas production, commodity prices based on published forward commodity price curves or contract prices as of the date of the estimate, operating and development costs, and a risk-adjusted discount rate.

Other long-lived assets, such as our midstream assets, are evaluated for potential impairment whenever events or changes in circumstances indicate that their carrying value may be greater than the undiscounted future net cash flows. Impairment, if any, is measured as the excess of an asset's carrying amount over its estimated fair value, which is estimated as described above.

We recorded property impairment charges in 2017 , 2016 and 2015 and it is possible that other proved oil and gas properties could become impaired in the future due to commodity price declines and/or field performance. See Note 5. Asset Impairments .

Unproved Property Impairment Our unproved properties consist of leasehold costs and allocated value to probable and possible reserves resulting from acquisitions. We assess individually significant unproved properties for impairment on a quarterly basis and recognize a loss at the time of impairment by providing an impairment allowance. In determining whether a significant unproved property is impaired we consider numerous factors including, but not limited to, current exploration plans, favorable or unfavorable exploration activity on the property being evaluated and/or adjacent properties, our geologists' evaluation of the property, and the remaining months in the lease term for the property.

When we have allocated fair value to an unproved property as the result of a transaction accounted for as a business combination, we use a future cash flow analysis to assess the unproved property for impairment. Cash flows used in the impairment analysis are determined based on management's estimates of crude oil, natural gas and NGL reserves, future commodity prices and future costs to produce the reserves. Cash flow estimates related to probable and possible reserves are reduced by additional risk-weighting factors. Other individually insignificant unproved properties are amortized on a composite method over an average holding period.

We recorded undeveloped leasehold impairment expense in 2017 . It is possible that unproved oil and gas properties, including undeveloped leases, could become impaired in the future if commodity prices decline or if there are changes in exploration plans or the timing and extent of development activities. See Note 6. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs .

Properties Acquired in Business Combinations When sufficient market data is not available, we determine the fair values of proved and unproved properties acquired in transactions accounted for as business combinations by preparing our own estimates of cash flows from the production of crude oil, natural gas and NGL reserves. We estimate future prices to apply to the estimated reserves quantities acquired, and estimate future operating and development costs, to arrive at estimates of future net cash flows. For the fair value assigned to proved reserves, future net cash flows are discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the business combination. To compensate for the inherent risk of estimating and valuing unproved reserves, discounted future net cash flows of probable and possible reserves are reduced by additional risk-weighting factors.

Assets Held for Sale We occasionally market oil and gas properties for sale. At the end of each reporting period, we evaluate properties being marketed to determine whether any should be reclassified as held for sale. The held-for-sale criteria include: a commitment to a plan to sell; the asset is available for immediate sale; an active program to locate a buyer exists; the sale of the asset is probable and expected to be completed within one year; the asset is being actively marketed for sale; and it is unlikely that significant changes to the plan will be made. If each of these criteria is met, the property is reclassified as held for sale in our consolidated balance sheets and will be valued at the lower of net book value or anticipated sales proceeds less costs to sell. Impairment expense would be recorded for any excess of net book value over anticipated sales proceeds less costs to sell. See Note 4. Acquisitions, Divestitures and Merger .

Exploration Costs Geological and geophysical costs, delay rentals, amortization of unproved leasehold costs, and costs to drill exploratory wells that do not find proved reserves are expensed as oil and gas exploration. We carry the costs of an exploratory well as an asset if the well finds a sufficient quantity of reserves to justify its capitalization as a producing well and as long as we are making sufficient progress assessing the reserves and the economic and operating viability of the project. For certain capital-intensive Gulf of Mexico or international projects, it may take us more than one year to evaluate the future potential of the exploratory well and make a determination of its economic viability. Our ability to move forward on a project may be dependent on gaining access to transportation or processing facilities or obtaining permits and government or partner approval, the timing of which is beyond our control. In such cases, exploratory well costs remain suspended as long as we are actively pursuing access to necessary facilities and access to such permits and approvals and believe they will be obtained. We assess the status of suspended exploratory well costs on a quarterly basis. See Note 6. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs .

Other Property Other property includes automobiles, trucks, airplanes, office furniture, computer equipment and other fixed assets such as buildings and leasehold improvements. These items are recorded at cost and are depreciated on the straight-line method based on expected lives of the individual assets or group of assets, which range from three to thirty years. Other property also includes linefill, which is recorded at cost to produce into the production line. Linefill is not subject to depreciation but is reviewed for impairment.

Capitalization of Interest We capitalize interest costs associated with the development and construction of significant properties or projects to bring them to a condition and location necessary for their intended use, which for crude oil and natural gas assets is at first production from the field. Interest is capitalized using an interest rate equivalent to the weighted average rate we pay on long-term debt, including our unsecured revolving credit facility (Revolving Credit Facility) and bonds. Capitalized interest is included in the cost of oil and gas assets and amortized with other costs on a unit-of-production basis. Capitalized interest totaled $49 million in 2017 , $84 million in 2016 , and $144 million in 2015 .

Asset Retirement Obligations AROs consist of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. We recognize the fair value of a liability for an ARO in the period in which it is incurred when we have an existing legal obligation associated with the retirement of our oil and gas properties that can reasonably be estimated, with the associated asset retirement cost capitalized as part of the carrying cost of the oil and gas asset. The asset retirement cost is recorded at estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligation discounted at our credit-adjusted risk-free rate. After initial recording, the liability is increased for the passage of time, with the increase being reflected as accretion expense and included in DD&A expense in the consolidated statements of operations. Subsequent adjustments in the cost estimate are reflected in the liability, and the amounts continue to be amortized over the useful life of the related long-lived asset. See Note 9. Asset Retirement Obligations .

Goodwill

2017 Goodwill As of December 31, 2017, our consolidated balance sheet includes goodwill of $1.3 billion . This goodwill resulted from the acquisition (Clayton Williams Energy Acquisition) of Clayton Williams Energy, Inc. (Clayton Williams Energy) completed on April 24, 2017, and represents the excess of the consideration paid for Clayton Williams Energy over the net amounts assigned to identifiable assets acquired and liabilities assumed. All of our recorded goodwill is assigned to the Texas reporting unit, a component of our US reportable and operating segment. See Note 3. Clayton Williams Energy Acquisition .

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

We conducted a qualitative goodwill impairment assessment as of September 30, 2017 by examining relevant events and circumstances which could have a negative impact on our goodwill such as: macroeconomic conditions as pertinent to current and expected regulations, industry and market conditions, including overall global and regional supply and demand and impact of such on commodity prices; as well as microeconomic factors relevant to the enterprise such as cost factors that have a negative effect on earnings and cash flows, overall financial performance, reporting unit dispositions, acquisitions, portfolio restructuring and other decisions / circumstances specific to the entity and the reporting unit containing goodwill.

Certain negative indicators as of September 30 2017 included the current onshore service cost inflation resulting in pressure on operating margins impacting our financial results associated with the Texas reporting unit and our stock price. However, we in turn also noted positive indicators such as the current commodity price environment, our current and future drilling and development plans for the Texas assets and synergies we expect from the Clayton Williams Energy Acquisition driven by our unconventional expertise and position in the adjacent properties, which further increase opportunities to drill longer lateral wells on our combined acreage positions, which would contribute to profitability.

Furthermore, we see value creation to be derived from expected midstream build-out opportunities for the gathering, processing and servicing of future production in the Delaware Basin. Having assessed the totality of such events and circumstances described above, we determined that, while there existed certain negative factors, the overall qualitative assessment did not indicate that it is more likely than not that the fair value of the reporting unit is less than its carrying value. However, regardless of the outcome of the qualitative review, we decided to proceed with Step 1 of the impairment test as part of our annual review.

As such, we performed Step 1 of the goodwill impairment test, used to identify potential impairment. The result of the Step 1 test indicated that the fair value of the Texas reporting unit exceeded its carrying value, including goodwill, and therefore, the Texas reporting unit goodwill was not considered to be impaired as of September 30, 2017.

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

2015 Goodwill At December 31, 2015, we reviewed our goodwill balance of $779 million for impairment in accordance with our accounting policy and identified factors, including continuing declines in commodity prices and the market value of our common stock, indicating that the fair value of goodwill could have fallen below its book value. We determined that the goodwill was fully impaired and recognized a loss of $779 million . This goodwill related primarily to the excess purchase price over amounts assigned to assets acquired and liabilities assumed in the merger of Rosetta Resources Inc. (Rosetta) into a subsidiary of Noble Energy (Rosetta Merger) in 2015 and the Patina Merger in 2005 and was associated with our US reporting unit. During 2015, prior to the impairment, goodwill increased $163 million due to the Rosetta Merger and decreased $4 million due to allocations of goodwill to US onshore properties sold.

For purposes of determining the 2015 goodwill impairment, we estimated the implied fair value of the goodwill using a variety of valuation methods, including the income and market approaches. Our estimate of fair value required us to use significant unobservable inputs, representative of a Level 3 fair value measurement, including assumptions for future crude oil and natural gas production, commodity prices based on forward commodity price curves, operating and development costs and other factors. The analysis supported that the implied fair value of goodwill was zero and, as such, goodwill was fully impaired.

Exit Costs We recognize the fair value of a liability for an exit cost in the period in which a liability is incurred. Accrued exit costs at December 31, 2017 relate primarily to estimated costs associated with retained Marcellus Shale firm transportation contracts.

The recognition and fair value estimation of an exit cost liability require that management take into account certain estimates and assumptions such as: the determination of whether a cease-use date has occurred (defined as the date the entity ceases using the right conveyed by the contract, for example, the right to use a leased property or to receive future goods or services); the amount, if any, of economic benefit that is expected to be obtained from a contract through partial use or release; and our estimate of costs that will continue to be incurred under the contract. We record the liability at estimated fair value, based on expected future cash outflows required to satisfy the obligation, net of estimated recoveries, and discounted. Exit costs, and associated accretion expense, are included in operating expense in our consolidated statements of operations. See Note 17. Commitments and Contingencies .

Derivative Instruments and Hedging Activities All derivative instruments (including certain derivative instruments embedded in other contracts) are recorded in our consolidated balance sheets as either an asset or liability and measured at fair value. We account for our commodity derivative instruments using mark-to-market accounting and recognize all gains and losses in earnings during the period in which they occur. Our consolidated statements of cash flows include the non-cash portion of gain and loss on commodity derivative instruments, which represents the difference between the total gain and loss on commodity derivative instruments and the cash received or paid on settlements of commodity derivative instruments during the period.

We offset the fair value amounts recognized for derivative instruments and the fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral. The cash collateral (commonly referred to as a “margin”) must arise from derivative instruments recognized at fair value that are executed with the same counterparty under a master agreement with netting clauses.

Stock-Based Compensation Restricted stock and stock options issued to employees and directors are recorded at grant-date fair value. Expense is recognized on a straight-line basis over the employee’s and director’s requisite service period (generally the vesting period of the award) in the consolidated statements of operations. In 2016, we issued cash-settled awards to certain employees in lieu of a portion of restricted stock and stock options. We recognize the value of cash-settled awards utilizing the liability method as defined under Accounting Standards Codification Topic 718, *Compensation – Stock Compensation* . The fair value of liability awards is remeasured at each reporting date, based on the fair market value of a share of common stock of the Company as of the reporting date, through the settlement date with the change in fair value recognized as compensation expense over that period. See Note 12. Stock-Based and Other Compensation Plans .

Pension and Other Postretirement Benefit Plans We recognize the funded status (the difference between the fair value of plan assets and the projected benefit obligation) of restoration and other postretirement benefit plans in the consolidated balance sheets, with a corresponding adjustment to accumulated other comprehensive loss (AOCL), net of tax. The amount remaining in AOCL at December 31, 2017 represents unrecognized net actuarial loss and unrecognized prior service cost related to our restoration plan. These amounts are currently being recognized as net periodic benefit cost pursuant to our historical accounting policy for amortizing such amounts. Any actuarial gains and losses that arise during the plan year, but which are not required to be recognized as net periodic benefit cost in the same period, are recognized as a component of AOCL. In third quarter 2015, we completed the process of terminating our noncontributory, tax-qualified defined benefit pension plan through the purchase of annuities for the remaining participants. As a result, we reclassified all remaining unamortized prior service cost and actuarial losses relating to the pension plan from AOCL to earnings.

Income Taxes and Impact of Tax Reform Legislation Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized when items of income and expense are recognized in the financial statements in different periods than when recognized in the applicable tax return. Deferred tax assets arise when expenses are recognized in the financial statements before the tax return or when income items are recognized in the tax return prior to the financial statements. Deferred tax assets also arise when operating losses or tax credits are available to offset tax payments due in future years. Deferred tax liabilities arise when income items are recognized in the financial statements before the tax returns or when expenses are recognized in the tax return prior to the financial statements. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the date when the change in the tax rate was enacted.

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 affecting us. See Note 11. Income Taxes .

Treasury Stock We record treasury stock purchases at cost, which includes incremental direct transaction costs. Amounts are recorded as reductions in shareholders' equity in the consolidated balance sheets.

Revenue Recognition and Imbalances We record revenues from the sales of crude oil, natural gas and NGLs when the product is delivered at a fixed or determinable price, title has transferred and collectibility is reasonably assured.

Basic and Diluted Earnings (Loss) Per Share Attributable to Noble Energy Basic earnings (loss) per share (EPS) of our common stock is computed on the basis of the weighted average number of shares outstanding during each period. The diluted EPS of our common stock includes the effect of outstanding common stock equivalents such as stock options, shares of restricted stock, and/or shares of our stock held in a rabbi trust, except in periods in which there is a net loss.

Contingencies We are subject to legal proceedings, claims and liabilities that arise in the ordinary course of business. We accrue for losses associated with legal claims when such losses are considered probable and the amounts can be reasonably estimated. See Note 17. Commitments and Contingencies .

We self-insure the medical and dental coverage provided to certain employees, and the deductibles for workers' compensation, automobile liability and general liability coverage. Liabilities are accrued for self-insured claims, or when estimated losses exceed coverage limits, and when sufficient information is available to reasonably estimate the amount of the loss.

Foreign Currency The US dollar is considered the functional currency for each of our international operations. Transactions that are completed in foreign currencies are remeasured into US dollars and recorded in the financial statements at prevailing foreign exchange rates. Transaction gains or losses are included in other non-operating (income) expense, net in the consolidated statements of operations.

Segment Information Accounting policies for geographical segments are the same as those described above. Transfers between segments are accounted for at market value. We do not consider interest income and expense or income tax benefit or expense in our evaluation of the performance of geographical segments. See Note 14. Segment Information .

Revolving Credit Facilities In accordance with our accounting policy, we net intra-quarter revolving credit facility activity to zero for purposes of consolidated statements of cash flows disclosure.

Recently Issued Accounting Standards

Revenue Recognition In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2014-09 (ASU 2014-09), which creates Topic 606, *Revenue from Contracts with Customers* . In summary, revenue recognition would occur upon the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. Additionally, ASU 2014-09 requires enhanced financial statement disclosures over revenue recognition.

We continue to evaluate the impact of ASU 2014-09 on our accounting policies, internal controls, and consolidated financial statements and related disclosures. We are performing a review of contracts for each of our revenue streams and developing accounting policies to address the provisions of ASU 2014-09. ASU 2014-09 also includes provisions regarding future revenues and expenses under a gross-versus-net presentation. We are evaluating the impact, if any, on the presentation of future revenues and expenses under this gross-versus-net presentation guidance. Based upon assessments performed to date, we do not expect

ASU 2014-09 to have an effect on the timing of revenue recognition or our financial position. In addition, we expect the impact regarding gross-versus-net presentation to involve certain presentation changes specifically related to domestic natural gas processing revenues and expenses. The impact of such presentation changes will not impact our net income. The standard is required to be adopted using either the full retrospective approach, with all prior periods presented adjusted, or the modified retrospective approach, with a cumulative adjustment to retained earnings on the opening balance sheet. We will adopt the new standard on January 1, 2018, using the modified retrospective approach.

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

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

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

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

Leases In February 2016, the FASB issued Accounting Standards Update No. 2016-02 (ASU 2016-02): Leases. The guidance requires lessees to recognize assets and liabilities on the balance sheet for the rights and obligations created by leases with terms of more than 12 months. 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. 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 ASU 2016-02 will have on our consolidated financial statements; however, we believe adoption and implementation of ASU 2016-02 will have a material impact on our consolidated balance sheet resulting from an increase in both assets and liabilities relating to leasing activities. As part of our assessment to date, we have formed an implementation work team, prepared educational and training materials pertinent to ASU 2016-02 and have begun contract review and documentation.

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

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

SAB 118 On December 22, 2017, the SEC staff issued Staff Accounting Bulletin No. 118 (SAB 118) to address the application of US GAAP in situations when a registrant does not have the necessary information available, prepared, or analyzed (including computations) in reasonable detail to complete the accounting for certain income tax effects relating to the Tax Reform Legislation. SAB 118 provides guidance for registrants under three scenarios:

1) if measurement of certain income tax effects is complete, registrants must reflect the tax effects of the Tax Reform Legislation for which the accounting is complete;
2) if measurement of certain income tax effects can be reasonably estimated, registrants must report provisional amounts for those specific income tax effects of the Tax Reform Legislation for which the accounting is incomplete but a reasonable estimate can be determined. Provisional amounts or adjustments to provisional amounts identified in the measurement period, as defined, should be included as an adjustment to tax expense or benefit from continuing operations in the period the amounts are determined; and
3) if measurement of certain income tax effects cannot be reasonably estimated, registrants are not required to report provisional amounts for any specific income tax effects of the Tax Reform Legislation for which a reasonable estimate cannot be determined, and would continue to apply ASC 740 – Income Taxes based on the provisions of the tax laws that were in effect immediately prior to the enactment of the Tax Reform Legislation. Registrants would report the provisional amounts of the tax effects of the Tax Reform Legislation in the first reporting period in which a reasonable estimate can be determined.

The SEC staff believes that in no circumstances should the measurement period extend beyond December 22, 2018, one year from the enactment of the Tax Reform Legislation. See Note 11. Income Taxes .

Note 2. Additional Financial Statement Information

Additional statements of operations information is as follows:

	Year Ended December 31,		
(millions)	2017	2016	2015
Production Expense			
Lease Operating Expense	$ 571	$ 542	$ 563
Production and Ad Valorem Taxes	138	78	127
Gathering, Transportation and Processing Expense (1)	432	480	306
Total	$ 1,141	$ 1,100	$ 996
Exploration Expense			
Leasehold Impairment and Amortization (2)	$ 62	$ 148	$ 113
Dry Hole Cost	9	579	266
Seismic, Geological and Geophysical	27	76	34
Staff Expense	55	77	43
Other	35	45	32
Total	$ 188	$ 925	$ 488
Loss on Marcellus Shale Upstream Divestiture			
Loss on Sale	$ 2,270	$ —	$ —
Firm Transportation Commitment (2)	93	—	—
Other (3)	16	—	—
Total	$ 2,379	$ —	$ —
Other Operating (Income) Expense, Net			
Marketing Expense (4)	$ 47	$ 58	$ 33
Clayton Williams Acquisition Expenses (5)	100	—	—
Corporate Restructuring Expense (6)	—	8	51
Pension Plan Expense (7)	—	—	88
Impact of Rosetta Merger (8)	—	(25)	81
North Sea Remediation Project Revision (9)	(42)	—	—
Loss on Asset Due to Terminated Contract (10)	—	41	—
Gain on Divestitures, Net (11)	(326)	(238)	—
Other, Net	33	53	79
Total	$ (188)	$ (103)	$ 332

(1) Certain of our gathering and processing expenses were historically presented as components of other operating expense, net, in our consolidated statement of operations. Beginning in 2017, we changed our presentation to reflect these as components of production expense. These costs are now included within gathering, transportation and processing expense. For the years ended December 31, 2016 and 2015, these costs totaled $17 million and $17 million , respectively, and have been reclassified from other operating expense, net to conform to current presentation.
(2) See Note 6. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs .
(3) Expense relates to unutilized commitments associated with Marcellus Shale firm transportation contracts. See Note 17. Commitments and Contingencies .
(4) Amount includes costs for legal and advisory services and employee severance charges.
(5) Expense relates to unutilized firm transportation and shortfalls in delivering or transporting minimum volumes under certain commitments.
(6) See Note 3. Clayton Williams Energy Acquisition .
(7) Expenses are associated with corporate organizational activities.
(8) Amount includes reclassification of the actuarial loss from AOCL related to the re-measurement and termination of our defined benefit pension plan to net income (loss).
(9) Amounts represent a purchase price allocation adjustment in 2016 and merger expenses in 2015. See Note 4. Acquisitions, Divestitures and Merger .
(10) See Note 9. Asset Retirement Obligations .
(11) Amount relates to the termination of a rig contract offshore Falkland Islands as a result of a supplier's non-performance.
(12) See Note 4. Acquisitions, Divestitures and Merger .

Additional balance sheet information is as follows:

	December 31,	
(millions)	2017	2016
Accounts Receivable, Net		
Commodity Sales	$ 455	$ 403
Joint Interest Billings	207	106
Proceeds Receivable [1]	—	40
Other	103	86
Allowance for Doubtful Accounts	(17)	(20)
Total	$ 748	$ 615
Other Current Assets		
Inventories, Materials and Supplies	$ 66	$ 71
Inventories, Crude Oil	16	18
Assets Held for Sale [2]	629	18
Restricted Cash [3]	38	30
Prepaid Expenses and Other Assets, Current	31	23
Total	$ 780	$ 160
Other Noncurrent Assets		
Equity Method Investments	$ 305	$ 400
Mutual Fund Investments	57	71
Net Deferred Income Tax Asset	25	—
Other Assets, Noncurrent	74	37
Total	$ 461	$ 508
Other Current Liabilities		
Production and Ad Valorem Taxes	$ 84	$ 115
Commodity Derivative Liabilities, Current	58	102
Income Taxes Payable	18	53
Asset Retirement Obligations, Current	51	160
Interest Payable	67	76
Compensation and Benefits Payable	98	110
Current Portion of Capital Lease and Other Obligations	61	63
Other Liabilities, Current	141	63
Total	$ 578	$ 742
Other Noncurrent Liabilities		
Deferred Compensation Liabilities, Noncurrent	$ 197	$ 218
Asset Retirement Obligations, Noncurrent	824	775
Production and Ad Valorem Taxes	69	47
Marcellus Firm Transportation Commitment, Noncurrent [4]	76	—
Other Liabilities, Noncurrent	79	63
Total	$ 1,245	$ 1,103

(1) Proceeds relate to the farm-out of a 35% interest in Block 12 offshore Cyprus and were received in January 2017. See Note 4. Acquisitions, Divestitures and Merger .

(2) 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 and Dalit fields, offshore Israel, certain non-strategic assets acquired in the Clayton Williams Energy Acquisition and the CONE investments. Assets held for sale at December 31, 2016 include assets in the Greeley Crescent area of the DJ Basin. See Note 4. Acquisitions, Divestitures and Merger .

(3) Balance at December 31, 2017 represents amount held in escrow for the purchase of a midstream entity. Balance at December 31, 2016 represents amount held in escrow for the purchase of certain Delaware Basin properties. See Note 4. Acquisitions, Divestitures and Merger .

(4) Relates to unutilized commitments associated with Marcellus Shale firm transportation contracts. See Note 4. Acquisitions, Divestitures

and Merger .

Supplemental statements of cash flow information is as follows:

	Year Ended December 31,		
(millions)	2017	2016	2015
Cash Paid During the Year For			
Interest, Net of Amount Capitalized	$ 346	$ 327	$ 260
Income Taxes Paid, Net	121	236	202
Non-Cash Financing and Investing Activities			
Increase in Capital Lease and Other Obligations	—	5	55

Note 3. Clayton Williams Energy Acquisition

In January 2017, we announced the Clayton Williams Energy Acquisition, which was approved by Clayton Williams Energy stockholders and closed on April 24, 2017 . Acquired assets include 71,000 highly contiguous net acres in the core of the Delaware Basin adjacent to our Reeves County holdings in Texas, and an additional 100,000 net acres in other areas of the United States. In total, the acquisition increased our Delaware Basin position to approximately 117,000 net acres.

See Supplemental Oil and Gas Information (Unaudited) , below for discussion of proved reserves acquired. In addition, upon closing of the acquisition, approximately 64,000 net acres in Reeves County, Texas were dedicated to Noble Midstream Partners for infield crude oil, natural gas and produced water gathering.

The acquisition was effected through the issuance of approximately 56 million shares of Noble Energy common stock with a fair value of approximately $1.9 billion and cash consideration of $637 million , for total consideration of approximately $2.5 billion , in exchange for all outstanding Clayton Williams Energy shares, including stock options, restricted stock awards and warrants. The closing price of our stock on the New York Stock Exchange (NYSE) was $34.17 on April 24, 2017 . In connection with the transaction, we borrowed $1.3 billion under our Revolving Credit Facility (defined below) to fund the cash portion of the acquisition consideration, redeem outstanding Clayton Williams Energy debt, pay associated make-whole premiums and pay related fees and expenses. See Note 10. Long-Term Debt .

In connection with the Clayton Williams Energy Acquisition, we have incurred acquisition-related costs of $100 million to date, including $64 million of severance, consulting, investment, advisory, legal and other merger-related fees and $36 million of noncash share-based compensation expense, all of which were expensed and are included in other operating expense, net in our consolidated statements of operations. In addition, we received approximately 720,000 shares of common stock from Clayton Williams Energy shareholders for the payment of withholding taxes due on the vesting of their restricted stock and options pursuant to the purchase and sale agreement, resulting in a $25 million increase in our treasury stock balance.

Purchase Price Allocation The transaction has been accounted for as a business combination, using the acquisition method. The following table represents the preliminary allocation of the total purchase price of Clayton Williams Energy to the assets acquired and the 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.

Certain data necessary to complete the purchase price allocation is not yet available, and includes, but is not limited to, analysis of the underlying tax basis of Clayton Williams Energy's assets and liabilities, and final appraisals of assets acquired and liabilities assumed. We expect to complete the purchase price allocation during the 12-month period following the acquisition date, during which time the value of the assets and liabilities, including any goodwill, may be revised as appropriate.

The following table sets forth our preliminary purchase price allocation:

(millions, except per share amounts)		
Fair Value of Common Stock Issued	$	1,876
Plus: Cash Consideration Paid to Clayton Williams Energy Stockholders		637
Total Purchase Price	$	2,513
Plus Liabilities Assumed by Noble Energy:		
Accounts Payable		99
Other Current Liabilities		38
Long-Term Deferred Tax Liability		509
Long-Term Debt		595
Asset Retirement Obligations		63
Total Purchase Price Plus Liabilities Assumed	$	3,817

The fair values of Clayton Williams Energy's identifiable assets are as follows:

(millions)		
Cash and Cash Equivalents	$	21
Other Current Assets		70
Oil and Gas Properties:		
Proved Reserves		722
Undeveloped Leasehold Cost		1,571
Gathering and Processing Assets		48
Asset Retirement Costs		63
Other Property Plant and Equipment		12
Implied Goodwill		1,310
Total Asset Value	$	3,817

In connection with the acquisition, we assumed, and then subsequently retired, all of Clayton Williams Energy's long-term debt at a cost to us 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 are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair values of crude oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert 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 are the most sensitive and may be subject to change.

Based upon the preliminary purchase price allocation, we have recognized $1.3 billion of goodwill, all of which is assigned to the Texas reporting unit. As a result of the acquisition, we expect to realize certain synergies which may result from our control of the combined assets as well as future midstream opportunities. The oil-rich geology of these assets, coupled with our unconventional expertise and position in the adjacent properties, significantly enhances our crude oil focus and growth outlook. The acquisition provides for synergies related to administrative and capital efficiencies, and increased opportunities to drill longer lateral wells on our combined acreage positions, enhances our crude oil production base and future crude oil growth potential. It also adds to our midstream assets and provides future midstream build-out opportunities for the gathering, processing and servicing of future production in the basin.

Results of Operations The results of operations attributable to Clayton Williams Energy are included in our consolidated statements of operations beginning on April 24, 2017 . We generated revenues of $99 million and a pre-tax loss of $19 million from the Clayton Williams Energy assets during the period April 24, 2017 to December 31, 2017.

Pro Forma Financial Information The following pro forma condensed combined financial information was derived from the historical financial statements of Noble Energy and Clayton Williams Energy and gives effect to the acquisition as if it had occurred on January 1, 2016. The 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.

Additionally, pro forma earnings for the year ended December 31, 2017 were adjusted to exclude acquisition-related costs of $100 million incurred by Noble Energy and $23 million incurred by Clayton Williams Energy. 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, 2016; furthermore, the financial information is not intended to be a projection of future results.

	Year Ended December 31,	
(millions, except per share amounts)	2017	2016
Revenues	$ 4,304	$ 3,651
Net Loss and Comprehensive Loss Attributable to Noble Energy	(678)	(1,082)
Net Loss Attributable to Noble Energy per Common Share		
Basic and Diluted	$ (1.39)	$ (2.23)

Note 4. Acquisitions, Divestitures and Merger

We maintain an ongoing portfolio management program and have engaged in various transactions over recent years.

Year Ended December 31, 2017

Marcellus Shale Upstream Divestiture On June 28, 2017, we closed the sale of all of our Marcellus Shale upstream assets, which were primarily natural gas properties. The sales price totaled $1.2 billion , and we received $1.0 billion of net cash proceeds, after consideration of customary adjustments, at closing. The sales price includes additional contingent consideration of up to $100 million structured as three separate payments of $33.3 million each. The contingent payments are in effect should the average annual price of the Appalachia Dominion, South Point index exceed $3.30 per MMBtu in the individual annual periods from 2018 through 2020. To date, conditions for the recognition of the contingent consideration are not probable and, therefore, no amounts have been accrued related to the contingent consideration. Proceeds from the transaction were used to repay borrowings resulting from the Clayton Williams Energy Acquisition. See Note 10. Long-Term Debt .

For the year ended December 31, 2017, we recognized a total loss of $2.4 billion , or $1.5 billion after-tax, on this divestiture. The aggregate net book value of the properties sold was approximately $3.4 billion , which included approximately $883 million of undeveloped leasehold cost.

As part of the loss, we accrued non-cash exit costs of $41 million , discounted, relating to a retained transportation contract that is currently in service; however, we no longer have production to satisfy this commitment and do not plan to utilize this capacity in the future. In addition, we recorded a $52 million accrual, discounted, relating to future commitments to a third party who assumed a portion of our retained capacity relating to other pipeline projects. Both charges are included in loss on Marcellus Shale upstream divestiture in our consolidated statements of operations in accordance with accounting for exit or disposal activities under ASC 420 – Exit or Disposal Cost Obligations.

Other retained Marcellus Shale firm transportation contracts relate to pipeline projects that are not yet commercially available to us. These projects that are not yet available will undergo construction and, as these projects become commercially available to us, we will assess, based upon the facts and circumstances, the recognition of any potential exit cost liabilities. It is likely we will incur additional firm transportation costs associated with this exit activity in the future. See Note 2. Additional Financial Statement Information and Note 17. Commitments and Contingencies .

Production from the Marcellus Shale upstream assets represented 204 MMcfe/d of total consolidated sales volumes for the year ended December 31, 2017. See Supplemental Oil and Gas Information (Unaudited) , below for discussion of reserves divested.

Divestiture of 7.5% Interest in Tamar and Dalit Fields The terms of the Israel Natural Gas Framework (Framework) require us to reduce our current ownership interest in the Tamar and Dalit fields from 32.5% to 25% by year-end 2021. On January 29, 2018, we signed a definitive agreement to divest a 7.5% working interest in each of the fields to Tamar Petroleum Ltd. (TASE: TMRP) (Tamar Petroleum) for cash proceeds of approximately $560 million and 38.5 million shares of Tamar Petroleum. Closing of the transaction is expected by the end of first quarter 2018, subject to satisfactory conclusion of Tamar Petroleum's debt financing and customary approvals, terms and conditions. As of December 31, 2017, the net book value of the 7.5% interest, $293 million , was included in assets held for sale.

Divestiture of Southwest Royalties In January 2018, we signed an agreement to sell our interest in Southwest Royalties, Inc. (Southwest Royalties), a subsidiary of Clayton Williams Energy, and acquired as part of Clayton Williams Energy Acquisition. We received proceeds of $60 million on sale of these assets. As of December 31, 2017, the asset value of these properties of $102 million and associated asset retirement obligation of $42 million were included in assets and liabilities held for sale.

Other US Onshore Transactions We conducted the following additional transactions in 2017:

- *US Onshore Divestitures* During 2017, we received total proceeds of $671 million resulting from the sale of certain US onshore properties, including $568 million related to divestment of non-core acreage in the DJ Basin. Proceeds were applied to reduce field basis with no recognition of gain or loss. A subsequent closing for certain non-core DJ Basin operated properties, in the amount of approximately $40 million , is expected to occur in mid-2018.

- *Sale of Mineral and Royalty Assets* We received $335 million and recognized a gain of $334 million on the sale of mineral and royalty assets covering approximately 140,000 net mineral acres concentrated primarily in Texas, Oklahoma and North Dakota.

- *Delaware Basin Acquisition* In January 2017, we completed the acquisition of Delaware Basin properties, including seven producing wells, thus increasing our contiguous acreage position in the Reeves County area. Consideration totaled $301 million , approximately $246 million of which was allocated to undeveloped leasehold cost. Initial consideration of $30 million was paid into an escrow account in fourth quarter 2016 and reflected as a restricted asset in our consolidated balance sheet as of December 31, 2016.

Marcellus Shale CONE Gathering Divestiture In December 2017, we signed an agreement to sell our 50% interest in CONE Gathering LLC (CONE Gathering) to CNX Resources Corporation. CONE Gathering owns the general partner of CONE Midstream Partners LP (CONE Midstream), which constructs, owns and operates natural gas gathering and other midstream energy assets in the Marcellus Shale. At December 31, 2017 , our total investment of $181 million in the CONE entities was included in assets held for sale. We closed the sale in January 2018, receiving proceeds of $308 million in cash and utilized proceeds to pay down borrowings under the Revolving Credit Facility. We now hold 21.7 million common units representing a 33.5% limited partner interests in CNX Midstream Partners LP (NYSE: CNXM). As of December 31, 2017, the net book value of the limited partner interests was approximately $70 million .

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

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

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

Noble Midstream Partners Advantage Joint Venture On April 3, 2017, Noble Midstream Partners and Plains Pipeline, L.P., a wholly owned subsidiary of Plains All American Pipeline, L.P., acquired Advantage Pipeline, L.L.C. (Advantage Pipeline) for $133 million through a newly formed 50 /50 joint venture (Advantage Joint Venture). Noble Midstream Partners contributed approximately $67 million of cash to the Advantage Joint Venture, funded by available cash on hand and the Noble Midstream Services Revolving Credit Facility. The Advantage Joint Venture is accounted for under the equity method and is included within our Midstream segment. See Note 7. Equity Method Investments .

Noble Midstream Partners serves as operator of the Advantage Pipeline System, which includes a 70 -mile crude oil pipeline in the Delaware Basin from Reeves County, Texas to Crane County, Texas with 150 MBbls per day of shipping capacity and 490 MBbls of storage capacity.

Noble Midstream Partners Black Diamond Gathering In December 2017, Noble Midstream Partners and Greenfield Midstream, LLC, a portfolio company of EnCap Flatrock Midstream Gathering, formed an entity, Black Diamond Gathering, LLC (Black Diamond Gathering). Black Diamond Gathering subsequently entered into definitive agreements to acquire Saddle Butte Rockies Midstream, LLC and affiliates (collectively, Saddle Butte). The Saddle Butte purchase closed on January 31, 2018, for total cash consideration of approximately $638.5 million . Noble Midstream Partners funded its share of the purchase price with proceeds from its December 2017 common unit offering, cash on hand and borrowings under its unsecured revolving credit facility. See Note 10. Long-Term Debt .

Noble Midstream partners received a 54.4% ownership interest in Black Diamond. Noble Midstream Partners fully consolidates the assets and liabilities of Black Diamond Gathering.

Noble Midstream Partners will serve as operator of Saddle Butte assets which include a large-scale integrated crude oil gathering system in the DJ Basin, consisting of approximately 160 miles of pipeline in operation, 300 MBbls per day of delivery capacity and approximately 210 MBbls of crude oil storage capacity. Saddle Butte has approximately 141,000 dedicated acres from six customers under fixed fee arrangements.

Subsequent Event - Gulf of Mexico Divestiture On February 15, 2018, we announced the Company signed a definitive agreement to sell its assets in the Gulf of Mexico for cash consideration of $480 million . As part of the transaction, the buyer will assume all abandonment obligations associated with the properties which we estimate to approximate $230 million as of December 31, 2017. The net book value of the Gulf of Mexico assets as of December 31, 2017 was approximately $750 million . We expect to incur a charge in early 2018, subject to customary closing adjustments. The transaction is expected to close during second quarter 2018, contingent upon the buyer's successful implementation of its contemplated restructuring, and will be effective as of January 1, 2018.

Year Ended December 31, 2016

Termination of Marcellus Shale JDA In fourth quarter 2016, we and CONSOL Energy Inc. (CONSOL) agreed to terminate our 50-50 Joint Development Agreement (JDA) in the Marcellus Shale. In connection with the terminated JDA, we executed and closed an exchange agreement whereby we and CONSOL each transferred all of our interest in a portion of co-owned properties to one another. In addition to the acreage and production realignment between the two companies, we remitted a cash payment of approximately $213 million to CONSOL at closing. Terminating the JDA resulted in the elimination of the remaining outstanding carried cost obligation due from us. No gain or loss was recognized on the exchange.

DJ Basin Acreage Exchange We closed a cashless acreage exchange in the DJ Basin receiving approximately 11,700 net acres within our Wells Ranch development area in exchange for approximately 13,500 net acres primarily from our Bronco area. No gain or loss was recognized.

2016 Divestitures During 2016, we engaged in the following sales transactions:

- entered an agreement to divest certain producing and non-producing properties covering approximately 33,100 net acres in the DJ Basin for proceeds of $505 million . We closed the sale on a portion of the properties in 2016, receiving proceeds of $486 million , with the remainder of the sale closing in 2017. Proceeds were applied to reduce field basis with no recognition of gain or loss;
- sold additional DJ Basin non-producing properties, certain Eagle Ford properties, our Bowdoin property in northern Montana, and certain other smaller US onshore properties, generating total net proceeds of $152 million , a net loss of $23 million on the Bowdoin sale, and no further gain or loss recognized on the remaining transactions;
- sold our 47% interest in the Alon A and Alon C licenses, which included the Karish and Tanin fields, offshore Israel, for a total sales price of $73 million ($67 million for asset consideration and $6 million from cost adjustments). Proceeds were applied to reduce field basis with no recognition of gain or loss;
- sold a 3.5% working interest in the Tamar and Dalit fields, offshore Israel, in compliance with the terms of the Framework, which requires us to reduce our ownership interest in the fields to 25% by year-end 2021. The sales price totaled $431 million , and we received net cash proceeds of $316 million , after consideration of timing and tax adjustments, at closing. Proceeds were ratably applied to the fields basis and resulted in the recognition of a $261 million gain; and

- received proceeds of $131 million related to the farm-out of a 35% interest in Block 12, which includes the Aphrodite natural gas discovery, offshore Cyprus. We received the remaining proceeds of $40 million in January 2017. Proceeds were applied to reduce field basis with no recognition of gain or loss.

Year Ended December 31, 2015

2015 Divestitures In 2015, we sold certain non-strategic US onshore properties, receiving proceeds of $151 million , with no gain or loss recorded.

Rosetta Merger On July 20, 2015, Noble Energy completed the Rosetta Merger. The merger was effected through the issuance of approximately 41 million shares of Noble Energy common stock in exchange for all outstanding shares of Rosetta using a ratio of 0.542 of a share of Noble Energy common stock for each share of Rosetta common stock and the assumption of Rosetta's liabilities, including approximately $2 billion fair value of outstanding debt.

The merger added two new US onshore shale positions to our portfolio including approximately 50,000 net acres in the Eagle Ford Shale and 54,000 net acres in the Delaware Basin (45,000 acres in the Delaware Basin and 9,000 acres in the Midland Basin). In connection with the Rosetta Merger, we incurred merger-related costs of approximately $81 million , including (i) $66 million of severance, consulting, investment, advisory, legal and other merger-related fees, and (ii) $15 million of noncash share-based compensation expense, all of which were expensed and are included in other operating (income) expense, net.

Purchase Price Allocation The merger was accounted for as a business combination, using the acquisition method. The allocation of the total purchase price of Rosetta to the assets acquired and the liabilities assumed was based on the fair values at the merger date, with the excess of the purchase price over the fair values of the identifiable net assets acquired recorded as goodwill.

Results of Operations The results of operations attributable to Rosetta are included in our consolidated statements of operations beginning on July 21, 2015. Revenues of $457 million and pre-tax net loss of $20 million , exclusive of a $25 million purchase price allocation adjustment, from Rosetta were generated for the year ended December 31, 2016. Revenues of $181 million and pre-tax net loss of $120 million , inclusive of a $163 million goodwill impairment, from Rosetta were generated from July 21, 2015 to December 31, 2015.

See Supplemental Oil and Gas Information (Unaudited) , below, for discussion of proved reserves added or divested in connection with the above transactions.

Note 5. Asset Impairments

Pre-tax (non-cash) asset impairment charges were as follows:

	Year Ended December 31,		
(millions)	2017	2016	2015
Gulf of Mexico	$ 63	$ —	$ 158
Israel	—	88	36
Equatorial Guinea	—	—	339
Other International	7	4	—
Total	$ 70	$ 92	$ 533

2017 Asset Impairments During 2017, we recorded a non-cash property impairment charge related to our decision not to pursue development of the Troubadour natural gas discovery in the Gulf of Mexico.

2016 Asset Impairments While the Leviathan natural gas development project, offshore Israel, was not formally sanctioned at December 31, 2016, in fourth quarter 2016, we selected the initial development concept for the first phase of development and wrote off $88 million associated with certain development concepts that were not selected.

2015 Asset Impairments During 2015, certain properties were written down to their estimated fair values using a discounted cash flow model. The cash flow model included management's estimates of future crude oil and natural gas production, commodity prices based on forward commodity price curves or contract prices as of the date of the estimate, operating and development costs, and discount rates. Impairment charges of $481 million resulted from reductions in the forward crude oil prices as of December 31, 2015.

We also recorded impairment charges of approximately $47 million primarily related to revisions in expected field abandonment and other costs for properties in the Gulf of Mexico and offshore Israel and $5 million related to the pending sale of our interest in the Alon A and Alon C licenses, offshore Israel, which included the Karish and Tanin fields.

Note 6. 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. If a well is deemed to be noncommercial, the well costs are immediately charged to exploration expense as dry hole cost. In addition, wells costs associated with a discovery may be charged to impairment expense if we choose not to pursue development activities.

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

	Year Ended December 31,		
(millions)	2017	2016	2015
Capitalized Exploratory Well Costs, Beginning of Period	$ 768	$ 1,353	$ 1,337
Additions to Capitalized Exploratory Well Costs Pending Determination of Proved Reserves	20	84	123
Divestitures and Other [1]	—	(143)	—
Reclassified to Proved Oil and Gas Properties Based on Determination of Proved Reserves or to Assets Held for Sale [2]	(203)	(1)	(19)
Capitalized Exploratory Well Costs Charged to Expense [3]	(65)	(525)	(88)
Capitalized Exploratory Well Costs, End of Period	$ 520	$ 768	$ 1,353

(1) The 2016 amount relates to the farm-down of a 35% interest in Block 12 offshore Cyprus to a new partner.

(2) The 2017 amount relates to the approval and sanction of the first phase of development of the Leviathan field, offshore Israel.

The 2015 amount relates primarily to US onshore exploration activity.

(3) Capitalized exploratory well costs charged to expense are included within exploration or impairment expense in our consolidated statements of operations.

The 2017 amount relates primarily to the write-off of costs associated with the Troubadour natural gas discovery, Gulf of Mexico, for which we chose not to pursue development activities. See Note 5. Asset Impairments .

The 2016 amount relates primarily to discoveries offshore West Africa. Following review of additional 3D seismic data, we determined these discoveries were impaired in the current forward outlook for crude oil prices. We also incurred expenses associated with the Silvergate exploratory well in the Gulf of Mexico. The well did not encounter commercial hydrocarbons and was plugged and abandoned.

The 2015 amount relates primarily to a property in northeast Nevada. After assessing its commercial viability in the current commodity price environment, we elected to discontinue exploration efforts.

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

	December 31,		
(millions)	2017	2016	2015
Exploratory Well Costs Capitalized for a Period of One Year or Less	$ 10	$ 69	$ 95
Exploratory Well Costs Capitalized for a Period Greater Than One Year Since Commencement of Drilling	510	699	1,258
Balance at End of Period	$ 520	$ 768	$ 1,353
Number of Projects with Exploratory Well Costs That Have Been Capitalized for a Period Greater Than One Year Since Commencement of Drilling	8	10	14

The following table provides a further aging of those exploratory well costs that have been capitalized for a period greater than one year since the commencement of drilling as of December 31, 2017 :

Country/Project *(millions)*	Total	Suspended Since 2015 - 2016	Suspended Since 2013 - 2014	Suspended Since 2012 & Prior	**Progress**
Gulf of Mexico					
Katmai	$ 147	$ 56	$ 91	$ —	Progressing a development scenario for this 2014 crude oil discovery. We are currently conducting feasibility and front-end engineering and design studies on host platform options.
Offshore Equatorial Guinea					
Felicita (Block O)	47	3	12	32	Evaluating regional development scenarios for this 2008 gas discovery. During 2014, we conducted additional seismic activity over Blocks I and O and in early 2016, we began analyzing, interpreting and evaluating the acquired seismic data.
Yolanda (Block I)	23	1	6	16	A data exchange agreement for the 2007 Yolanda condensate and natural gas discovery has been executed between the governments of Equatorial Guinea and Cameroon. Our natural gas development team is working with the governments of Equatorial Guinea and Cameroon to evaluate natural gas monetization options for both Yolanda and YoYo (Cameroon) discoveries.
Offshore Cameroon					
YoYo (YoYo Block)	55	4	6	45	A data exchange agreement for the 2007 YoYo condensate and natural gas discovery has been executed between the governments of Equatorial Guinea and Cameroon. Our natural gas development team is working with both governments to evaluate natural gas monetization options for both Yolanda (Equatorial Guinea) and YoYo discoveries. In June 2017, we converted our mining concession license for the YoYo block into a PSC.
Offshore Israel					
Leviathan-1 Deep	91	8	10	73	The well did not reach the target interval in 2012. We continue to reprocess and review seismic information for this discovery, based on information obtained from other recent discoveries in the region, and develop future drilling plans to test this deep oil concept, which is held by the Leviathan Development and Production Leases.
Dalit	32	3	5	24	Our future development plan was approved by the Government of Israel to develop this 2009 natural gas discovery with a tie-in to existing infrastructure at Tamar. See also Note 4. Acquisitions, Divestitures and Merger.
Offshore Cyprus					
Cyprus	97	15	52	30	In 2016, we farmed-down a 35% interest in Block 12 and submitted an updated development plan. We continue to work with the Government of Cyprus to obtain approval of the development plan and the subsequent issuance of an Exploitation License. Receiving an Exploitation License will allow us and our partners to perform the necessary engineering and design studies and progress the project to final investment decision. During 2017, we submitted an updated development plan, progressed capital project cost improvement and continued regional natural gas marketing efforts.
Other					
Projects less than $20 million	18	(9)	21	6	Continuing to assess and evaluate wells.
Total	$ 510	$ 81	$ 203	$ 226	

Undeveloped Leasehold Costs We reclassify undeveloped leasehold costs to proved property costs when proved reserves, including PUDs, become attributable to the property as a result of our exploration and development activities. 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 December 31, 2017 , we had remaining undeveloped leasehold costs, to which proved reserves had not been attributed, of $2.8 billion , including $1.6 billion related to Delaware Basin assets acquired in the Clayton Williams Energy Acquisition in 2017, and $1.1 billion and $149 million attributable to Delaware Basin and Eagle Ford Shale assets, respectively, acquired in the Rosetta Merger 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 December 31, 2017 included $44 million related to Gulf of Mexico unproved properties and $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.

During 2017 , we completed geological evaluations of certain Gulf of Mexico leases and licenses and leases and licenses associated with other international unproved properties. We determined that several leases and licenses should be relinquished or exited. As a result, we recognized undeveloped leasehold impairment expense of $62 million primarily attributable to Gulf of Mexico leases. We recorded leasehold impairment expense of $93 million in 2016 and $21 million in 2015. This expense is included in exploration expense in the consolidated statements of operations.

Note 7. Equity Method Investments

Equity Method Investments Investments accounted for under the equity method consist primarily of the following:

- 50% interest in Advantage Pipeline, which owns and operates a 70-mile crude oil pipeline in Texas (See Note 4 – Acquisitions, Divestitures and Merger);
- 50% interest in CONE Gathering, which owns and operates natural gas gathering facilities servicing the Marcellus Shale (See Note 4 – Acquisitions, Divestitures and Merger);
- 34% interest in CONE Midstream, a public master limited partnership, which constructs, owns and operates natural gas gathering and other midstream energy assets in the Marcellus Shale;
- 45% interest in Atlantic Methanol Production Company, LLC (AMPCO), which owns and operates a methanol plant and related facilities in Equatorial Guinea; and
- 28% interest in Alba Plant LLC (Alba Plant), which owns and operates a liquefied petroleum gas (LPG) processing plant in Equatorial Guinea.

CONE Midstream Dropdown Transaction In fourth quarter 2016, CONE Midstream completed an acquisition of midstream assets (dropdown) from CONE Gathering. CONE Gathering subsequently distributed $70 million cash and additional CONE Midstream common units to us.

Equity method investments are as follows:

	December 31,	
(millions)	2017	2016
Equity Method Investments		
CONE Investments [1]	$ —	$ 172
AMPCO	129	120
Alba Plant	80	82
Advantage Pipeline	70	—
Other	26	26
Total Equity Method Investments	$ 305	$ 400

(1) CONE Investments include CONE Midstream and CONE Gathering. The investments are included in assets held for sale at December 31, 2017.

Other At December 31, 2017 , consolidated retained earnings included $90 million related to the undistributed earnings of equity method investees.

The carrying value of our AMPCO investment was $12 million higher than the underlying net assets of the investee at December 31, 2017 . The difference is related to capitalized interest which is being amortized into earnings over the remaining useful life of the plant.

Summarized, 100% combined financial information for equity method investees is as follows:

	December 31,	
(millions)	2017	2016
Balance Sheet Information		
Current Assets	$ 390	$ 313
Noncurrent Assets	588	1,390
Current Liabilities	171	149
Noncurrent Liabilities	90	256

	Year Ended December 31,		
(millions)	2017	2016	2015
Statements of Operations Information			
Operating Revenues	$ 790	$ 667	$ 645
Operating Expenses	303	355	393
Operating Income	487	312	252
Other (Income) Net	(15)	(7)	(9)
Income Before Income Taxes	502	319	261
Income Tax Provision	136	60	46
Net Income	$ 366	$ 259	$ 215

Note 8. Derivative Instruments and Hedging Activities

Objective and Strategies for Using Derivative Instruments We may enter into crude oil and natural gas price hedging arrangements in an effort to mitigate the effects of commodity price volatility and enhance the predictability of cash flows relating to the marketing of a portion of our crude oil and natural gas production. The derivative instruments we use may include variable to fixed price commodity swaps, enhanced swaps, two-way and three-way collars, basis swaps and/or put options.

The fixed price swap and two-way collar contracts entitle us (floating price payor) to receive settlement from the counterparty (fixed price payor) for each calculation period in amounts, if any, by which the settlement price for the scheduled trading days applicable for each calculation period is less than the fixed strike price or floor price. We would pay the counterparty if the settlement price for the scheduled trading days applicable for each calculation period is more than the fixed strike price or ceiling price. The amount payable by us, if the floating price is above the fixed or ceiling price, is the product of the notional quantity per calculation period and the excess of the floating price over the fixed or ceiling price in respect of each calculation period. The amount payable by the counterparty, if the floating price is below the fixed or floor price, is the product of the notional quantity per calculation period and the excess of the fixed or floor price over the floating price in respect of each calculation period.

A three-way collar consists of a two-way collar contract combined with a put option contract sold by us with a strike price below the floor price of the two-way collar. We receive price protection at the purchased put option floor price of the two-way collar if commodity prices are above the sold put option strike price. If commodity prices fall below the sold put option strike price, we receive the cash market price plus the delta between the two put option strike prices. This type of instrument allows us to capture more value in a rising commodity price environment, but limits our benefits in a downward commodity price environment.

For put options, we typically pay a premium to the counterparty in exchange for the sale of the instrument. If the index price is below the floor price of the put option, we receive the difference between the floor price and the index price multiplied by the contract volumes less the option premium at the time of settlement. If the index price settles at or above the floor price of the put option, we pay only the put option premium at the time of settlement. We had no outstanding put options as of December 31, 2017 .

While these instruments mitigate the cash flow risk of future reductions in commodity prices, they may also curtail benefits during periods of increasing commodity prices.

See Note 13. Fair Value Measurements and Disclosures for a discussion of methods and assumptions used to estimate the fair values of our derivative instruments.

Counterparty Credit Risk Derivative instruments expose us to counterparty credit risk. Our commodity derivative instruments are currently with a diversified group of major banks or market participants, and we monitor and manage our level of financial exposure. Our commodity derivative contracts 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 settled at the time of election.

We monitor the creditworthiness of our commodity derivatives counterparties. However, we are not able to predict sudden changes in counterparties' creditworthiness. In addition, even if such changes are not sudden, we may be limited in our ability to mitigate an increase in counterparty credit risk.

Possible actions would be to transfer our position to another counterparty or request a voluntary termination of the derivative contracts resulting in a cash settlement. Should one of these financial counterparties not perform, we may not realize the benefit of some of our derivative instruments under lower commodity prices and could incur a loss.

Unsettled Derivative Instruments As of December 31, 2017 , we had entered into the following crude oil derivative instruments:

				Swaps	Collars		
Settlement Period	Type of Contract	Index	Bbls Per Day	Weighted Average Fixed Price	Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
2018	Three-Way Collars	NYMEX WTI	10,000	$ —	$ 45.50	$ 52.50	$ 69.09
2018	Swaps	NYMEX WTI	24,000	57.09	—	—	—
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	3,000	55.07	—	—	—
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)	—	—	—

(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.

As of December 31, 2017 , we had entered into the following natural gas derivative instruments:

				Collars		
Settlement Period	Type of Contract	Index	MMBtu Per Day	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 Gains and Losses on Derivative Instruments The fair values of derivative instruments in our consolidated balance sheets were as follows:

Fair Value of Derivative Instruments [1]

	Asset Derivative Instruments				Liability Derivative Instruments			
	December 31, 2017		December 31, 2016		December 31, 2017		December 31, 2016	
(millions)	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity Derivative Instruments	Current Assets	$ 2	Current Assets	$ —	Current Liabilities	$ 58	Current Liabilities	$ 102
	Noncurrent Assets	—	Noncurrent Assets	—	Noncurrent Liabilities	15	Noncurrent Liabilities	14
Total		$ 2		$ —		$ 73		$ 116

[1] See Note 1. Summary of Significant Accounting Policies – Derivative Instruments and Hedging Activities for a discussion of our netting policy.

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

	Year Ended December 31,		
(millions)	2017	2016	2015
Cash (Received) Paid in Settlement of Commodity Derivative Instruments			
Crude Oil	$ (14)	$ (499)	$ (844)
Natural Gas	1	(70)	(147)
NGLs [1]	—	—	(18)
Total Cash Received in Settlement of Commodity Derivative Instruments	(13)	(569)	(1,009)
Non-cash Portion of (Gain) Loss on Commodity Derivative Instruments			
Crude Oil	18	582	423
Natural Gas	(68)	126	65
NGLs [1]	—	—	20
Total Non-cash Portion of (Gain) Loss on Commodity Derivative Instruments	(50)	708	508
(Gain) Loss on Commodity Derivative Instruments			
Crude Oil	4	83	(421)
Natural Gas	(67)	56	(82)
NGLs [1]	—	—	2
Total (Gain) Loss on Commodity Derivative Instruments	$ (63)	$ 139	$ (501)

[1] Amounts for NGLs relate to commodity derivative instruments, acquired in the Rosetta Merger, which expired as of December 31, 2015.

Note 9. Asset Retirement Obligations

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

	Year Ended December 31,	
(millions)	2017	2016
Asset Retirement Obligations, Beginning Balance	$ 935	$ 989
Liabilities Incurred	94	21
Liabilities Settled	(82)	(120)
Revision of Estimate	(65)	(3)
Reclassification to Liabilities Associated with Assets Held for Sale	(54)	—
Accretion Expense	47	48
Asset Retirement Obligations, Ending Balance	$ 875	$ 935

Year Ended December 31, 2017 Liabilities incurred include $63 million related to the Clayton Williams Energy Acquisition and $31 million primarily for other US onshore wells and midstream facilities placed into service.

Liabilities settled include $43 million related to abandonment of US onshore properties, $19 million related to properties sold in the Greeley Crescent (DJ Basin) acreage divestiture, $12 million related to properties sold in the Marcellus Shale upstream divestiture and $8 million related to other offshore domestic and international properties.

Revisions of estimates include a $42 million decrease related to changes in cost and timing associated with the North Sea abandonment project and a $38 million decrease for US onshore and Gulf of Mexico properties, partially offset by an increase of $15 million for West Africa.

In 2017, we also transferred $42 million and $12 million of ARO liabilities associated with Southwest Royalties and Tamar field, offshore Israel, respectively, to liabilities associated with assets held for sale. Refer to Item 8. Financial Statements and Supplementary Data - Note 4. Acquisitions, Divestitures and Merger .

Year Ended December 31, 2016 Liabilities incurred were due to new wells and facilities placed into service for US onshore, Gulf of Mexico, and offshore Israel.

Liabilities settled were related to wells and facilities permanently abandoned at the end of their useful lives and to assets sold. Settlements included $ 65 million related to abandonment of Gulf of Mexico properties, $49 million related to US onshore properties abandoned or sold, $5 million related to offshore Israel properties and $1 million related to the North Sea.

Note 10. Long-Term Debt

Our debt consists of the following:

	December 31, 2017			December 31, 2016		
(millions, except percentages)		Debt	Interest Rate		Debt	Interest Rate
Revolving Credit Facility, due August 27, 2020	$	230	2.27%	$	—	—%
Noble Midstream Services Revolving Credit Facility, due September 20, 2021		85	2.49%		—	—%
Term Loan Facility, due January 6, 2019 (1)		—	—%		550	2.01%
Leviathan Term Loan Facility, due February 23, 2025		—	—%		—	—
Senior Notes, due March 1, 2019 (2)		—	—%		1,000	8.25%
Senior Notes, due May 1, 2021		379	5.63%		379	5.63%
Senior Notes, due December 15, 2021		1,000	4.15%		1,000	4.15%
Senior Notes, due June 1, 2022 (1)		—	—%		18	5.88%
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 (2)		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 (2)		500	4.95%		—	—%
Other Senior Notes and Debentures (3)		92	7.13%		92	7.13%
Capital Lease and Other Obligations (4)		273	—%		375	—%
Total	$	6,859		$	7,114	
Unamortized Discount		(24)			(23)	
Unamortized Premium (2)		12			17	
Unamortized Debt Issuance Costs		(40)			(34)	
Total Debt, Net of Discount	$	6,807		$	7,074	
Less Amounts Due Within One Year						
Capital Lease and Other Obligations		(61)			(63)	
Long-Term Debt Due After One Year	$	6,746		$	7,011	

(1) In fourth quarter 2017, we repaid $550 million of borrowings under the Term Loan Facility and $18 million of our outstanding Senior Notes due June 1, 2022.

(2) In third quarter 2017, we redeemed all of our Senior Notes due March 1, 2019 and issued Senior Notes due January 15, 2028 and August 15, 2047.

(3) 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% .

(4) The reduction from 2016 includes $41 million related to other obligations for drilling commitments assumed by the acquirer of the Marcellus Shale upstream assets and $60 million of capital lease principal payments.

All of our long-term debt is senior unsecured debt and is, therefore, *pari passu* with respect to the payment of both principal and interest. The indenture documents of each of our notes provide that we may prepay the instruments by creating a defeasance trust. The defeasance provisions require that the trust be funded with securities sufficient, in the opinion of a nationally recognized accounting firm, to pay all scheduled principal and interest due under the respective agreements. Interest on each of these issues is payable semi-annually.

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

The Revolving Credit Facility requires that our total debt to capitalization ratio (as defined in the Revolving Credit Facility), expressed as a percentage, not exceed 65% at any time. A violation of this covenant could result in a default under the Credit Agreement, which would permit the participating banks to restrict our ability to access the Revolving Credit Facility and require the immediate repayment of any outstanding advances under the Revolving Credit Facility. As of December 31, 2017 , we were in compliance with our debt covenants.

The Revolving Credit Facility is available for general corporate purposes. Certain lenders that are a party to the Revolving Credit Facility have in the past performed, and may in the future from time to time perform, investment banking, financial advisory, lending or commercial banking services for us for which they have received, and may in the future receive, customary compensation and reimbursement of expenses.

Noble Midstream Services Revolving Credit Facility On September 20, 2016, Noble Midstream Services LLC (Noble Midstream Services), a subsidiary of Noble Midstream Partners, entered into a credit agreement for a $350 million revolving credit facility (Noble Midstream Services Revolving Credit Facility). The Noble Midstream Services Revolving Credit Facility has a five year maturity and includes a letter of credit sublimit of up to $100 million for issuances of letters of credit. The borrowing capacity on the Noble Midstream Services Revolving Credit Facility may be increased by an additional $350 million , subject to certain conditions, and is available to fund working capital and to finance acquisitions and other capital expenditures of Noble Midstream Partners.

Borrowings by Noble Midstream Services under the Noble Midstream Services Revolving Credit Facility bear interest at a rate equal to an applicable margin plus, at Noble Midstream Service's option, either:

- 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 London interbank offered rate (LIBOR) for an interest period of one month plus 1.00% ; or
- in the case of LIBOR borrowings, the offered rate per annum for deposits of dollars for the applicable interest period.

The Noble Midstream Services Revolving Credit Facility includes certain financial covenants as of the end of each fiscal quarter, including a (1) consolidated leverage ratio to consolidated adjusted earnings before interest expense, income taxes, depreciation, depletion, and amortization (EBITDA) and (2) consolidated interest coverage ratio (each covenant as described in the Noble Midstream Services Revolving Credit Facility). All obligations of Noble Midstream Services, as the borrower under the Noble Midstream Services Revolving Credit Facility, are guaranteed by Noble Midstream Partners and all wholly-owned material subsidiaries of Noble Midstream Partners. Debt issuance costs associated with this facility were de minimis.

On January 31, 2018, in connection with the acquisition of Saddle Butte, Noble Midstream Partners drew an additional $300 million under the Noble Midstream Services Revolving Credit Facility and partially exercised the accordion feature, increasing the commitments under the credit agreement to $530 million .

Senior Notes Issuance and Completed Tender Offer On August 15, 2017, we issued $600 million of 3.85% senior unsecured notes that will mature on January 15, 2028 and $500 million of 4.95% senior unsecured notes that will mature on August 15, 2047. Interest on the 3.85% senior notes and 4.95% senior notes is payable semi-annually beginning January 15, 2018 and February 15, 2018, respectively. We may redeem some or all of the senior notes at any time at the applicable redemption price, plus accrued interest, if any. The senior notes were issued at a discount of $4 million and debt issuance costs incurred totaled $11 million , both of which are reflected as a reduction of long-term debt and are amortized over the life of the notes. Proceeds of $1 billion from the issuance of senior notes were used solely to fund the tender offer and the redemption of $1 billion of our 8.25% senior notes due March 1, 2019. As a result, we paid a premium of $96 million to the holders of the 8.25% senior notes and recognized a loss of $98 million in third quarter 2017, which is reflected in other non-operating (income) expense in our consolidated statements of operations.

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

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

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

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

Term Loan Facility and Completed Tender Offers On January 6, 2016, we entered into a term loan agreement (Term Loan Facility), which provided for a three - year term loan facility for a principal amount of $1.4 billion . Provisions of the Term Loan Facility were consistent with those in the Revolving Credit Facility. Borrowings under the Term Loan Facility could be prepaid prior to maturity without premium. The Term Loan Facility accrued interest, at our option, at either (a) a base rate equal to the highest of (i) the rate announced by Citibank, N.A., as its prime rate, (ii) the Federal Funds Rate plus 0.5% , and (iii) a LIBOR plus 1.0% , plus a margin that ranged from 10 basis points to 75 basis points depending upon our credit rating, or (b) a LIBOR, plus a margin that ranged from 100 basis points to 175 basis points depending upon our credit rating.

Borrowings under the Term Loan Facility were used solely to fund tender offers for approximately $1.38 billion of notes assumed in the Rosetta Merger in 2015. As a result of the tender offers, we recognized a gain of $80 million in first quarter 2016 which is reflected in other non-operating (income) expense in our consolidated statements of operations. In fourth quarter 2016, we prepaid $850 million of the amount outstanding under the Term Loan Facility from cash on hand. In fourth quarter 2017, we repaid the remaining outstanding balance of $550 million under this facility using proceeds received from the sale of non-core Greeley Crescent and Bronco acreage in the DJ Basin.

Fair Value of Debt See Note 13. Fair Value Measurements and Disclosures for a discussion of methods and assumptions used to estimate the fair values of debt.

Capital Lease and Other Obligations The amount of the capital lease obligation is based on the discounted present value of future minimum lease payments, and therefore does not reflect future cash lease payments. Amounts due within one year equal the amount by which the capital lease obligation is expected to be reduced during the next 12 months. See Note 17. Commitments and Contingencies for future capital lease payments.

Annual Debt Maturities Annual maturities of outstanding debt, excluding capital lease payments, as of December 31, 2017 are as follows:

(millions)	Debt Principal Payments
2018	$ —
2019	—
2020	230
2021	1,464
2022	—
Thereafter	4,892
Total	$ 6,586

Note 11. Income Taxes

Recent Changes in US Tax Law On December 22, 2017, the US Congress enacted the 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. Under US GAAP, we are required to recognize the effect of a rate change on deferred tax assets and liabilities in the period in which the tax rate change is enacted. Therefore, the rate change enacted by the Tax Reform Legislation resulted in the recognition of a deferred tax benefit of $500 million at December 31, 2017.

Further, the Tax Reform Legislation provides for a transition tax (toll tax) on a one-time “deemed repatriation” of accumulated foreign earnings for the year ended December 31, 2017. Based on current interpretations of the law, we have recognized additional taxable income of $767 million associated with the transition tax, which is fully offset by current year net operating losses and have recorded corresponding deemed foreign tax credits of $164 million , against which we have recorded a full valuation allowance.

The Tax Reform Legislation also repealed corporate alternative minimum tax (AMT) for tax years beginning January 1, 2018, and provides that existing AMT credit carryovers are refundable beginning in 2018. We have approximately $3 million of AMT credit carryovers that are expected to be fully refunded by 2022.

In addition, the Tax Reform Legislation preserves deductibility of intangible drilling costs and provides for 100% bonus depreciation on tangible personal property expenditures through 2022. The bonus depreciation percentage is phased down from 100% beginning in 2023 to 0% for years after 2026.

The Tax Reform Legislation is a comprehensive bill containing other provisions, such as limitations on the deductibility of interest expense and certain executive compensation, that are not expected to materially affect us. 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 in future periods, as an adjustment to income tax expense or benefit, in the period in which the final amounts are determined.

Income Tax Disclosures

Components of income (loss) from operations before income taxes are as follows:

	Year Ended December 31,		
(millions)	2017	2016	2015
Domestic	$ (2,831)	$ (1,859)	$ (2,338)
Foreign	640	87	119
Total	$ (2,191)	$ (1,772)	$ (2,219)

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

	Year Ended December 31,		
(millions)	2017	2016	2015
Current Taxes			
Federal	$ (11)	$ (4)	$ (1)
State	1	5	—
Foreign	96	196	107
Total Current	$ 86	$ 197	$ 106
Deferred Taxes			
Federal	$ (1,258)	$ (784)	$ 216
State	(8)	(24)	(5)
Foreign	39	(176)	(95)
Total Deferred	$ (1,227)	$ (984)	$ 116
Total Income Tax (Benefit) Provision Attributable to Noble Energy	$ (1,141)	$ (787)	$ 222
Effective Tax Rate	52.1%	44.4%	(10.0)%

A reconciliation of the federal statutory tax rate to the effective tax rate is as follows:

	Year Ended December 31,		
(percentages)	2017	2016	2015
Federal Statutory Rate (1)	35.0 %	35.0 %	35.0 %
Effect of			
Earnings of Equity Method Investees	1.9	1.0	0.6
Noncontrolling Interests	1.1	0.4	—
US and Foreign Statutory Rate Change (1)	23.5	1.6	—
Transition Tax (1)	(4.8)	—	—
State Taxes, Net of Federal Benefit	0.3	1.3	0.3
Difference Between US and Foreign Rates	1.8	(0.1)	2.6
Foreign Exploration Loss	—	0.1	2.7
Change in Valuation Allowance (1)	(17.4)	(2.0)	—
Oil Profits Tax - Israel	(0.1)	—	0.1
Tax Contingency	0.1	0.2	0.4
Accumulated Undistributed Foreign Earnings (1)	11.0	7.2	(37.7)
Goodwill Impairment	—	—	(12.3)
Other, Net	(0.3)	(0.3)	(1.7)
Effective Rate	52.1 %	44.4 %	(10.0)%

(1) See Recent Changes in US Tax Law, above. Rate will decrease to 21.0% for fiscal year 2018. In addition, see discussion regarding accumulated undistributed foreign earnings above.

Deferred tax assets and liabilities resulted from the following:

	December 31,	
(millions)	2017	2016
Deferred Tax Assets		
Loss Carryforwards	$ 902	$ 474
Employee Compensation and Benefits	97	150
Mark to Market of Commodity Derivative Instruments	7	44
Foreign Tax Credits	366	—
Other	104	49
Total Deferred Tax Assets	$ 1,476	$ 717
Valuation Allowance - Foreign Loss Carryforwards and Foreign Tax Credits	(549)	(242)
Net Deferred Tax Assets	$ 927	$ 475
Deferred Tax Liabilities		
Accumulated Undistributed Foreign Earnings (1)	—	(240)
Property, Plant and Equipment, Principally Due to Differences in Depreciation, Amortization, Lease Impairment and Abandonments	(2,029)	(2,054)
Total Deferred Tax Liability	$ (2,029)	$ (2,294)
Net Deferred Tax Liability	$ (1,102)	$ (1,819)

(1) At December 31, 2017, we reversed the deferred tax liability associated with the removal of the assertion of indefinitely reinvested earnings, resulting in recognition of a deferred tax benefit of $240 million .

Net deferred tax assets and liabilities were classified in the consolidated balance sheets as follows:

	December 31,	
(millions)	2017	2016
Deferred Income Tax Asset - Noncurrent	$ 25	$ —
Deferred Income Tax Liability - Noncurrent	(1,127)	(1,819)
Net Deferred Tax Liability	$ (1,102)	$ (1,819)

Deferred Tax Assets Our estimated US federal income tax net operating loss (NOL) carryforwards totaled approximately $3.2 billion at December 31, 2017 . Included in the resulting deferred tax assets are acquired NOLs associated with the Clayton Williams Energy Acquisition in 2017 and the Rosetta Merger in 2015.

In assessing the realizability of deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income in the appropriate tax jurisdictions during the periods in which those temporary differences become deductible. We consider the scheduled reversal of deferred tax liabilities, current financial position, results of operations, projected future taxable income and tax planning strategies as well as current and forecasted business economics in the oil and gas industry. Based on the level of historical taxable income and projections for future taxable income, we believe it is more likely than not that we will realize the benefits of these NOL carryforwards. However, the amount of the deferred tax assets considered realizable could be reduced in the future if estimates of future taxable income during the carryforward period are reduced.

We currently have a valuation allowance on the deferred tax assets associated with foreign loss carryforwards and foreign tax credits. The valuation allowance on foreign loss carryforwards totaled $183 million in 2017 and $242 million in 2016 . The changes to the valuation allowance for the loss carryforwards between periods was attributable to the offset of the valuation allowance against the NOL in a jurisdiction in which we are no longer active. Deemed foreign tax credits of $164 million were recognized along with the additional taxable income associated with the transition tax. A full valuation allowance of $366 million has been recorded against all foreign tax credits based on current interpretation of the Tax Reform Legislation and the expected future utilization of NOL carryforwards.

Clayton Williams Energy Acquisition On April 24, 2017 , we completed the Clayton Williams Energy Acquisition. For federal income tax purposes, the transaction qualified as a tax free merger and we acquired carryover tax basis in Clayton Williams Energy's assets and liabilities. After the fair market valuation, we have currently recorded an opening balance sheet deferred tax liability of $307 million , adjusted for the new US statutory tax rate, which includes a deferred tax asset for federal pre-tax net operating losses of approximately $450 million . The merger resulted in a change of control for federal income tax purposes, and the NOL usage will be subject to an annual limitation in part based on Clayton Williams Energy's value at the date of the merger. We anticipate full utilization of the total NOL prior to expiration.

Accumulated Undistributed Earnings of Foreign Subsidiaries In 2015, we changed our indefinite reinvestment assertion (APB 23 assertion) based on the continued and prolonged decline in global commodity prices and an evaluation of our operations' anticipated capital requirements and projected foreign cash positions given the adoption of the Israel Natural Gas Framework in December 2015.

During 2016, we reviewed capital requirements and foreign cash positions, and reduced the deferred tax liability associated with unremitted earnings, net of foreign tax credits, to $240 million as of December 31, 2016 .

In 2017, as a result of Tax Reform Legislation, which establishes a new territorial tax regime, the deferred tax liability recorded as of December 31, 2016 was reversed, resulting in a deferred tax benefit of $240 million for the year ended December 31, 2017 . We do not expect a withholding tax impact upon actual distribution of earnings and as such have not recorded any additional tax associated with the unremitted earnings.

Effective Tax Rate Our effective tax rate increased in 2017 as compared with 2016 primarily due to the recognition of a deferred tax benefit related to the Tax Reform Legislation. The deferred tax benefit resulted from the revaluation of the ending deferred tax liability at the reduced future tax rate and the transition to the new territorial tax regime.

Our effective tax rate increased in 2016 as compared with 2015 primarily due to adjustments to deferred taxes for removal of the APB 23 assertion, as noted above, decreased earnings in foreign jurisdictions with rates that vary from the US statutory rate, a decrease in the Israeli income tax rate, and the 2015 impact of foreign dividend repatriation and goodwill impairment.

Israeli Tax Law Effective December 21, 2016, the Israeli government decreased the corporate income tax rate from 25% to 24% for 2017 and announced a further rate decrease from 24% to 23% effective January 2018. The change decreased the deferred tax expense for 2017 by $12 million .

Furthermore, our Israeli operations are subject to the Natural Resources Profits Taxation Law, 2011 (the Law), which imposes a separate additional tax on profits from oil and gas activities (Profits Tax). The Profits Tax is calculated by dividing net accumulated revenue generated by each separate project by its cumulative investments as defined within the Law. Once the revenue factor (R Factor) reaches 1.5, a tax rate of 20% is imposed; as the ratio increases to a maximum of 2.3, the Profits Tax increases progressively up to a maximum rate of 50%. The Profits Tax provides for a corporate tax rate adjustment based on the corporate income tax rate, which is currently 23%. To the extent the corporate income tax rate exceeds 18%, a reduction in the Profits Tax rate is calculated. At the current corporate tax rate, the Profits Tax rate is 46.8%. The Profits Tax is deductible for corporate Israeli tax purposes. Our Tamar and Leviathan projects are both subject to the Profits Tax and are expected to pay at the maximum rate.

Unrecognized Tax Benefits We file a consolidated income tax return in the US federal jurisdiction, and we file income tax returns in various states and foreign jurisdictions. Our income tax returns are routinely audited by the applicable revenue authorities, and provisions are made in the financial statements for differences between positions taken in tax returns and amounts recognized in the financial statements in anticipation of audit results.

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

Our policy is to recognize any interest and penalties related to unrecognized tax benefits in income tax expense.

A reconciliation of our beginning and ending amounts of unrecognized tax benefits follows:

(millions)		Twelve Months Ended December 31, 2017
Unrecognized Tax Benefits, Beginning Balance	$	3
Reductions for Tax Positions of Prior Years		(3)
Unrecognized Tax Benefits, Ending Balance	$	—

The changes to our unrecognized tax benefits during 2017 primarily resulted from changes in various foreign tax return filings, positions and audit settlements. The adjustments to our reserves for uncertain tax positions had a de minimis impact on our net income.

During 2017 , we recognized and accrued a de minimis amount of interest and no penalties.

Note 12. Stock-Based and Other Compensation Plans

We recognized total stock-based compensation expense as follows:

	Year Ended December 31,					
(millions)		2017		2016		2015
Stock-Based Compensation Expense Included in:						
General and Administrative Expense	$	56	$	62	$	50
Exploration Expense and Other		48		15		36
Total Stock-Based Compensation Expense	$	104	$	77	$	86
Tax Benefit Recognized	$	(36)	$	(27)	$	(30)

Stock Option and Restricted Stock Plans Our stock option and restricted stock plans are described below.

2017 Long-Term Incentive Plan On April 25, 2017, our stockholders approved the Noble Energy, Inc. 2017 Long-Term Incentive Plan (the 2017 Plan). Upon stockholder approval, the 2017 Plan superceded and replaced the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan, as amended (the 1992 Plan) which was frozen so that no future grants would be made under the 1992 Plan. The 1992 Plan continues to govern awards that were outstanding as of the date of its suspension, which remain in effect pursuant to their terms. Under the 2017 Plan, the Compensation, Benefits and Stock Option Committee of the Board of Directors (the Committee) may grant stock options, stock appreciation rights, restricted stock, restricted stock units, performance awards, stock awards and other incentive awards to our officers or other employees and those of our subsidiaries. The maximum number of shares that may be granted under the 2017 Plan is 29 million shares of common stock. At December 31, 2017 , 28,987,609 shares of our common stock were reserved for issuance, including 28,972,832 shares available for future grants and awards, under the 2017 Plan.

Stock options are issued with an exercise price equal to the fair market value of our common stock on the date of grant, and are subject to such other terms and conditions as may be determined by the Committee. Unless granted by the Committee for a shorter term, the options expire 10 years from the grant date. Option grants generally vest ratably over a three -year period.

Restricted stock awards made under the 2017 Plan are subject to such restrictions, terms and conditions, including forfeitures, if any, as may be determined by the Committee. During the period in which such restrictions apply, unless specifically provided otherwise in accordance with the terms of the 2017 Plan, the recipient of restricted stock would be the record owner of the shares and have all the rights of a stockholder with respect to the shares, including the right to vote and the right to receive dividends or other distributions made or paid with respect to the shares. The dividends or other distributions pertaining to the restricted shares will be held by the Company until the restriction period ends and the shares vest or forfeit. If the restricted shares forfeit, then the recipient shall not be entitled to receive the dividend or distribution, which will transfer to the Company. Restricted stock awards with a time-vested restriction vest over a two or three -year period. Performance share awards cliff vest after a three -year period if the Company achieves certain levels of total shareholder return relative to a pre-determined industry peer group.

2015 Stock Plan for Non-Employee Directors The 2015 Stock Plan for Non-Employee Directors of Noble Energy, Inc., as amended (the 2015 Plan) provides for grants of stock options and awards of restricted stock to our non-employee directors. The 2015 Plan superseded and replaced the 2005 Stock Plan for Non-Employee Directors of Noble Energy, Inc. The total number of shares of our common stock that may be issued under the 2015 Plan is 708,996 . At December 31, 2017 , 674,025 shares of our common stock were reserved for issuance, including 463,096 shares available for future grants and awards, under the 2015 Plan.

Stock Option Grants The fair value of each stock option granted is estimated on the date of grant using a Black-Scholes-Merton option valuation model that used the assumptions described below:

- *Expected term* The expected term represents the period of time that options granted are expected to be outstanding, which is the grant date to the date of expected exercise or other expected settlement for options granted. The hypothetical midpoint scenario we use considers our actual exercise and post-vesting cancellation history and expectations for future periods, which assumes that all vested, outstanding options are settled halfway between the current date and their expiration date.
- *Expected volatility* The expected volatility represents the extent to which our stock price is expected to fluctuate between the grant date and the expected term of the award. We use the historical volatility of our common stock for a period equal to the expected term of the option prior to the date of grant. We believe that historical volatility produces an estimate that is representative of our expectations about the future volatility of our common stock over the expected term.
- *Risk-free rate* The risk-free rate is the implied yield available on US Treasury securities with a remaining term equal to the expected term of the option. We base our risk-free rate on a weighting of five and seven year US Treasury securities as of the date of grant.
- *Dividend yield* The dividend yield represents the value of our stock's annualized dividend as compared to our stock's average price for the three -year period ended prior to the date of grant. It is calculated by dividing one full year of our expected dividends by our average stock price over the three -year period ended prior to the date of grant.

The assumptions used in valuing stock options granted were as follows:

	Year Ended December 31,		
(weighted averages)	2017	2016	2015
Expected Term (in Years)	6.4	6.3	6.0
Expected Volatility	33.2%	32.4%	32.6%
Risk-Free Rate	2.2%	1.6%	1.4%
Expected Dividend Yield	0.9%	0.7%	1.2%
Weighted Average Grant-Date Fair Value	$ 13.26	$ 10.10	$ 13.93

Stock option activity was as follows:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
		(per share)	*(in years)*	*(in millions)*
Outstanding at December 31, 2016	15,088,862	$ 43.49		
Granted	1,819,819	39.40		
Exercised	(382,882)	37.57		
Forfeited	(976,577)	43.93		
Outstanding at December 31, 2017	15,549,222	$ 43.42	5.0	$ 6
Exercisable at December 31, 2017	12,101,890	$ 44.98	4.0	$ 6

The total intrinsic value of options exercised was $4 million in 2017, $10 million in 2016 and $7 million in 2015. As of December 31, 2017 , $21 million of compensation cost related to unvested stock options granted under the Plans remained to be recognized. The cost is expected to be recognized over a weighted-average period of 1.3 years. We issue new shares of our common stock to settle option exercises. Dividends are not paid on unexercised options.

Restricted Stock Awards Awards of time-vested restricted stock (shares subject to service conditions) are valued at the price of our common stock at the date of award. The fair value of the market based restricted stock awards was estimated on the date of award using a Monte Carlo valuation model that uses the assumptions in the following table. The Monte Carlo valuation model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. Expected volatility represents the extent to which our stock price is expected to fluctuate between now and the award's anticipated term. We use the historical volatility of Noble Energy common stock for the three -year period ended prior to the date of award. The risk-free rate is based on a three-year period for US Treasury securities as of the year ended prior to the date of award.

The assumptions used in valuing market based restricted stock awards granted were as follows:

	Year Ended December 31,		
	2017	2016	2015
Number of Simulations	500,000	500,000	500,000
Expected Volatility	35%	38%	30%
Risk-Free Rate	1.5%	1.0%	0.8%

Restricted stock activity was as follows:

	Subject to Time Vesting		Subject to Market Conditions	
	Number of Shares	Weighted Average Award Date Fair Value	Number of Shares	Weighted Average Award Date Fair Value
		(per share)		*(per share)*
Outstanding at December 31, 2016	1,371,780	$ 36.37	1,502,992	$ 27.43
Awarded (1)	3,201,504	36.26	464,608	24.25
Vested (1)	(2,515,383)	34.93	(219,883)	44.61
Forfeited	(218,164)	37.66	(535,012)	33.12
Outstanding at December 31, 2017	1,839,737	$ 37.21	1,212,705	$ 25.55

(1) During 2017, we awarded approximately 1.9 million shares of restricted stock for the conversion of Clayton Williams Energy shares into Noble Energy shares as part of the Clayton Williams Energy Acquisition. All awards subsequently vested during 2017. These awards are included in the above table. See Note 3. Clayton Williams Energy Acquisition .

The total fair value of restricted stock that vested was $34 million in 2017 , $24 million in 2016 , and $62 million in 2015 .

The weighted average award-date fair value of restricted stock awarded was $35.45 per share in 2017 , $29.99 per share in 2016 , and $35.53 per share in 2015 .

As of December 31, 2017 , $41 million of compensation cost related to all of our unvested restricted stock awarded under the Plans remained to be recognized. The cost is expected to be recognized over a weighted-average period of 1.4 years. Common stock dividends accrue on restricted stock awards and are paid upon vesting. We issue new shares of our common stock when awarding restricted stock.

Cash-Settled Awards On February 1, 2016, we issued cash-settled awards to certain employees under the 1992 Plan in lieu of a portion of restricted stock and stock options. We issued approximately one million awards (so called phantom units, the nomenclature used in accounting literature), a portion of which are subject to the Company's achievement of certain levels of total shareholder return relative to a pre-determined industry peer group. The fair value of the market based phantom unit awards was estimated on the date of award using a Monte Carlo valuation model and assumed 500,000 simulations, 38% expected volatility and a risk-free rate of 0.9% .

These phantom units represent a hypothetical interest in the Company, and, once vested, are settled in cash. The phantom unit value at vesting will equal the lesser of the fair market value of a share of common stock of the Company as of the vesting date (2 -year cliff vesting for officers and 3 -year cliff vesting for non-officers) or up to four times the fair market value of a share of common stock of the Company, which was $31.65 , as of the grant date.

As of December 31, 2017 , we had accrued a liability of $10 million related to the phantom units. No phantom units were awarded in 2017.

Phantom unit activity was as follows:

	Subject to Time Vesting		Subject to Market Conditions	
	Number of Units	Weighted Average Award Date Fair Value	Number of Units	Weighted Average Award Date Fair Value
		(per share)		*(per share)*
Outstanding at December 31, 2016	712,089	$ 31.65	209,504	$ 6.82
Vested	(13,305)	31.65	—	—
Forfeited	(88,625)	31.65	(42,021)	6.82
Outstanding at December 31, 2017	610,159	$ 31.65	167,483	$ 6.82

As of December 31, 2017 , $6 million of compensation cost related to phantom units remained to be recognized. The cost is expected to be recognized over a weighted-average period of 1.1 years. The total fair value of phantom units that vested in 2017 was de minimis. Common stock dividends accrue on phantom units and will be paid upon vesting.

Other Compensation Plans

401(k) Plan We sponsor a 401(k) savings plan. All regular employees are eligible to participate. We make contributions to match employee contributions up to the first 6% of compensation deferred into the plan, and certain profit sharing contributions for employees hired on or after May 1, 2006, based upon their ages and salaries. We made cash contributions of $31 million in 2017 , $32 million in 2016 , and $35 million in 2015 .

Deferred Compensation Plan We have a non-qualified deferred compensation plan for which participant-directed investments are held in a rabbi trust and are available to satisfy the claims of our creditors in the event of bankruptcy or insolvency. Participants in that nonqualified deferred compensation plan may elect to receive distributions in either cash or shares of our common stock. Components of that rabbi trust are as follows:

	December 31,	
(millions, except share amounts)	2017	2016
Rabbi Trust Assets		
Mutual Fund Investments	$ 57	$ 62
Noble Energy Common Stock (at Fair Value)	14	26
Total Rabbi Trust Assets	$ 71	$ 88
Liability Under Related Deferred Compensation Plan	$ 71	$ 88
Number of Shares of Noble Energy Common Stock Held by Rabbi Trust	470,030	671,269

Assets of that rabbi trust, other than our common stock, are invested in certain mutual funds that cover an investment spectrum ranging from equities to money market instruments. These mutual funds have published market prices and are reported at fair value. See Note 13. Fair Value Measurements and Disclosures . The mutual funds are included in the mutual fund investments account in other noncurrent assets in the consolidated balance sheets.

Shares of our common stock held by the rabbi trust holding common stock are accounted for as treasury stock (recorded at cost, $16.72 per share) in the shareholders' equity section of the consolidated balance sheets. Amounts payable to plan participants are included in other noncurrent liabilities in the consolidated balance sheets and include the market value of the shares of our common stock.

Approximately 400,000 shares, or 85% , of our common stock held in respect of one nonqualified deferred compensation plan at December 31, 2017 were attributable to a member of our Board of Directors. The shares are being distributed in equal installments over the next two years. Distributions of 200,000 shares were made in each of 2017 , 2016 and 2015 . In addition, plan participants sold 1,238 shares of our common stock in 2017 , 1,009 shares in 2016 , and 1,009 shares in 2015 . Proceeds were invested in mutual funds and/or distributed to plan participants. Distributions to plan participants were valued at $21 million in 2017 , $22 million in 2016 and $18 million in 2015 .

All fluctuations in market value of the deferred compensation liability have been reflected in other non-operating (income) expense, net in the consolidated statements of operations. We recognized deferred compensation expense (income) of $9 million in 2017 , $11 million in 2016 and $(12) million in 2015 .

We also maintain other nonqualified deferred compensation plans for the benefit of certain of our employees. Deferred compensation liabilities of $116 million and $121 million were outstanding at December 31, 2017 and 2016 , respectively, under those other plans.

Note 13. 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 8. Derivative Instruments and Hedging Activities .

Deferred Compensation Liability The value is dependent upon the fair values of mutual fund investments and shares of our common stock held in a rabbi trust. See *Mutual Fund Investments* above .

Stock-Based Compensation Liability A portion of the value of the liability associated with our phantom unit plan is dependent upon the fair value of Noble Energy common stock as of the end of each reporting period. See Note 12. Stock-Based and Other Compensation Plans .

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) [1]	Significant Unobservable Inputs (Level 3) [1]	Adjustment [2]	Fair Value Measurement
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)
December 31, 2016					
Financial Assets					
Mutual Fund Investments	$ 71	$ —	$ —	$ —	$ 71
Commodity Derivative Instruments	—	5	—	(5)	—
Financial Liabilities					
Commodity Derivative Instruments	—	(121)	—	5	(116)
Portion of Deferred Compensation Liability Measured at Fair Value	(88)	—	—	—	(88)
Stock Based Compensation Liability Measured at Fair Value	(9)	—	—	—	(9)

(1) See Note 1. Summary of Significant Accounting Policies – Fair Value Measurements for a description of the fair value hierarchy.
(2) Amount represents the impact of netting clauses within our master agreements that allow us to net cash settle asset and liability positions with the same counterparty.

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

Asset Impairments In 2017, 2016, and 2015, we determined that the carrying amounts of certain oil and gas assets were not recoverable from future cash flows and, therefore, were impaired. The assets were reduced to their estimated fair values as noted below.

Inventory Impairment In 2016, and 2015, we determined that the carrying amount of certain of our materials and supplies inventory was greater than its net realizable value or not recoverable from future cash flows. These assets were, therefore, adjusted as noted below.

Marcellus Shale Firm Transportation Liability As of December 31, 2017 , we had recorded a $90 million liability representing the discounted present value of our remaining obligation under firm transportation contracts. See Note 17 – Commitments and Contingencies .

Information about the impaired assets is as follows:

Description	Fair Value Measurements Using: Quoted Prices in Active Markets (Level 1) [1]	Significant Other Observable Inputs (Level 2) [1]	Significant Unobservable Inputs (Level 3) [1]	Net Book Value [2]	Total Pre-tax (Non-cash) Impairment Loss
(millions)					
Year Ended December 31, 2017					
Impaired Oil and Gas Properties	$ —	$ —	$ —	$ 70	$ 70
Year Ended December 31, 2016					
Impaired Oil and Gas Properties	—	—	—	92	92
Impaired Materials and Supplies Inventory	—	—	91	105	14
Year Ended December 31, 2015					
Impaired Oil and Gas Properties	—	—	752	1,285	533
Impaired Materials and Supplies Inventory	—	—	61	81	20

(1) See Note 1. Summary of Significant Accounting Policies – Fair Value Measurements for a description of the fair value hierarchy.
(2) Amount represents net book value at the date of assessment.

The fair values of properties held and used were determined as of the date of the assessment using discounted cash flow models. The discounted cash flows were based on management's expectations for the future. Inputs included estimates of future crude oil and natural gas production, commodity prices based on commodities sales contract terms or commodity price curves as of the date of the estimate, estimated operating and development costs, and a risk-adjusted discount rate of 10% . The fair values of assets held for sale were based on anticipated sales proceeds less costs to sell. Costs associated with abandoned properties were completely written off. See Note 5. Asset Impairments .

Additional Fair Value Disclosures

Debt The fair value of fixed-rate, public debt is estimated based on the published market prices for the same or similar issues. As such, we consider the fair value of our public, fixed-rate debt to be a Level 1 measurement on the fair value hierarchy.

At December 31, 2017, our variable-rate, non-public debt included the Revolving Credit Facility and the Noble Midstream Services Revolving Credit Facility. 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 10. Long-Term Debt .

Fair value information regarding our debt is as follows:

	December 31, 2017		December 31, 2016	
(millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt, Net [1]	$ 6,586	$ 7,142	$ 6,739	$ 7,112

(1) Excludes unamortized discount, premium, debt issuance costs and capital lease obligations.

Note 14. Segment Information

During second quarter 2017 , as a result of the strategic changes in our US onshore portfolio, we established our Midstream business as a new reportable segment. The Midstream segment, which includes the consolidated accounts of Noble Midstream Partners, additional US onshore midstream assets and US onshore equity method investments, was previously reported within the United States reportable segment. As a result, we now 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 (Newfoundland (Canada), Suriname, Falkland Islands and new ventures); and Midstream.

The geographical reportable segments are in the business of crude oil and natural gas exploration, development, production, and acquisition (Oil and Gas Exploration and Production or E&P). The Midstream reportable segment owns, operates, develops and acquires 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		
(In millions)	Consolidated	United States	Eastern Mediter-ranean	West Africa	Other Int'l	United States	Intersegment Eliminations and Other [(1)]	Corporate
Year Ended December 31, 2017								
Oil, NGL and Gas Sales from Third Parties [(2)]	$ 4,060	$ 3,156	$ 534	$ 370	$ —	$ —	$ —	$ —
Income from Equity Method Investees and Other [(3)]	196	—	—	120	—	76	—	—
Intersegment Revenues	—	—	—	—	—	277	(277)	—
Total Revenues	4,256	3,156	534	490	—	353	(277)	—
Lease Operating Expense	571	466	29	90	—	—	(14)	—
Production and Ad Valorem Taxes	138	135	—	—	—	3	—	—
Gathering, Transportation and Processing Expense	432	550	—	—	—	70	(188)	—
Total Production Expense	1,141	1,151	29	90	—	73	(202)	—
DD&A	2,053	1,739	76	146	4	30	(5)	63
Clayton Williams Energy Acquisition Expenses	100	100	—	—	—	—	—	—
Loss on Debt Extinguishment	98	—	—	—	—	—	—	98
Loss on Marcellus Shale Upstream Divestiture	2,379	2,379	—	—	—	—	—	—
Asset Impairments	70	63	—	—	7	—	—	—
Gain on Commodity Derivative Instruments	(63)	(92)	—	29	—	—	—	—
(Loss) Income Before Income Taxes	(2,191)	(2,365)	413	203	(54)	233	(62)	(559)
Equity Method Investments	305	—	—	225	—	80	—	—
Additions to Long Lived Assets	2,851	1,994	411	34	(34)	423	(79)	102
Goodwill [(4)]	1,310	1,310	—	—	—	—	—	—
Total Assets at End of Year [(5)]	21,476	15,767	2,846	1,308	114	1,357	(163)	247
Year Ended December 31, 2016								
Oil, NGL and Gas Sales from Third Parties [(2)]	$ 3,389	$ 2,416	$ 540	$ 433	$ —	$ —	$ —	$ —
Income from Equity Method Investees and Other	102	—	—	50	—	52	—	—
Intersegment Revenues	—	—	—	—	—	200	(200)	—
Total Revenues	3,491	2,416	540	483	—	252	(200)	—
Lease Operating Expense	542	418	37	105	—	—	(18)	—
Production and Ad Valorem Taxes	78	76	—	—	—	2	—	—
Gathering, Transportation and Processing Expense	480	564	—	—	—	44	(128)	—
Total Production Expense	1,100	1,058	37	105	—	46	(146)	—
DD&A	2,454	2,103	81	205	6	19	—	40
Asset Impairments	92	—	88	—	4	—	—	—
Loss on Commodity Derivative Instruments	139	126	—	13	—	—	—	
(Loss) Income Before Income Taxes	(1,772)	(1,277)	543	(338)	(199)	176	(51)	(626)
Equity Method Investments	400	—	—	217	—	183	—	—
Additions to Long Lived Assets	1,526	1,353	88	54	(6)	58	(53)	32
Total Assets at End of Year [(5)]	21,011	16,153	2,233	1,479	89	851	(98)	304

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		Oil and Gas Exploration and Production				Midstream		
(In millions)	Consolidated	United States	Eastern Mediter-ranean	West Africa	Other Int'l	United States	Intersegment Eliminations and Other [(1)]	Corporate
Year Ended December 31, 2015								
Oil, NGL and Gas Sales from Third Parties [(2)]	$ 3,093	$ 2,011	$ 497	$ 580	$ 5	$ —	$ —	$ —
Income from Equity Method Investees and Other	90	—	—	39	—	51	—	—
Intersegment Revenues	—	—	—	—	—	119	(119)	—
Total Revenues	3,183	2,011	497	619	5	170	(119)	—
Lease Operating Expense	563	398	42	131	4	—	(12)	—
Production and Ad Valorem Taxes	127	126	—	—	—	1	—	—
Gathering, Transportation and Processing Expense	306	366	—	—	—	25	(85)	—
Total Production Expense	996	890	42	131	4	26	(97)	—
DD&A	2,131	1,677	70	326	—	14	—	44
Asset Impairments	533	158	36	339	—	—	—	—
Gain on Commodity Derivative Instruments	(501)	(347)	—	(154)	—	—	—	—
(Loss) Income Before Income Taxes	(2,219)	(1,693)	313	(90)	(229)	123	(21)	(622)
Equity Method Investments	453	—	—	227	—	226	—	—
Additions to Long Lived Assets	3,062	2,409	147	124	177	146	(21)	80
Total Assets at End of Year [(5)]	24,196	18,043	2,676	2,299	205	799	(46)	220

(1) Intersegment eliminations related to (loss) income before income taxes are the result of Midstream expenditures. These costs are presented as property, plant and equipment within the E&P business on an unconsolidated basis, in accordance with the successful efforts method of accounting, and are eliminated upon consolidation.
(2) Revenues from third parties for all foreign countries, in total, were $904 million in 2017, $973 million in 2016, and $1.1 billion in 2015.
(3) The midstream segment includes revenues of $19 million from third party customers.
(4) Goodwill is associated with the Texas reporting unit. See Note 1. Summary of Significant Accounting Policies .
(5) Long-lived assets located in all foreign countries, in total, were $2.8 billion , $3.0 billion , and $3.9 billion at December 31, 2017, 2016, and 2015, respectively.

Note 15. Concentration of Risk

Concentration of Market Risk The largest single non-affiliated purchasers of our production were as follows:

	Percentage of Crude Oil Sales	Percentage of Total Oil, Gas & NGL Sales
Year Ended December 31, 2017		
BP [(1)]	15%	10%
Shell [(2)]	22%	13%
Year Ended December 31, 2016		
Glencore Energy UK Ltd	22%	12%
Shell [(2)]	24%	13%
Year Ended December 31, 2015		
Glencore Energy UK Ltd	30%	18%
Shell [(2)]	18%	11%

[(1)] Includes sales to BP North American Funding Company, BP Company Commercial and/or BP Company.

[(2)] Includes sales to Shell Trading (US) Company and/or Shell International Trading and Shipping Limited.

We believe the loss of any one purchaser would not have a material effect on our financial position or results of operations since there are numerous potential purchasers of our production.

Concentration of Credit Risk Certain of our financial instruments, including cash equivalents, trade and joint interest receivables and derivative instruments, may expose us to credit risk.

A significant portion of our cash is located in our foreign subsidiaries. The cash is denominated in US dollars and invested in highly liquid money market funds and short term deposits with original maturities of three months or less at the time of purchase. Although our cash and cash equivalents are deposited with major international banks and financial institutions, concentrations of cash in certain foreign locations may increase credit risk. We monitor the creditworthiness of the banks and financial institutions with which we invest and review the securities underlying our investment accounts. We believe that losses from nonperformance are unlikely to occur; however, we are not able to predict sudden changes in creditworthiness.

Our accounts receivable result from sales of crude oil, NGL and natural gas production, and joint interest billings to our partners for their share of expenses on joint venture projects for which we are the operator. Joint venture projects, especially in deepwater or remote international locations, can be very capital cost intensive. Thus the receivables from our joint venture partners can become significant.

Our accounts receivable reflect a broad national and international customer base, which limits our exposure to concentrations of credit risk. The majority of these receivables have payment terms of 30 days or less . We continually monitor the creditworthiness of the counterparties, some of which are not as creditworthy as we are and may experience liquidity problems. We have obtained credit enhancements from some parties, including one of our significant crude oil purchasers, in the way of parental guarantees or letters of credit. However, we do not have all of our trade credit or joint interest receivables protected through guarantees or credit support. Nonperformance by a trade creditor or joint venture partner could result in losses.

Our hedging activity may increase counterparty credit risk, especially during periods of falling commodity prices. We conduct our hedging activities with a diverse group of investment grade major banks and market participants. We monitor the creditworthiness of our hedge counterparties, and our internal hedge policies provide for mark-to-market exposure limits. We use 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 settled” at the time of election.

Note 16. Additional Shareholders’ Equity Information

Common Stock and Treasury Stock Activity in shares of our common stock and treasury stock was as follows:

	Year Ended December 31,	
	2017	2016
Common Stock Shares Issued		
Shares, Beginning of Period	471,360,427	469,718,512
Exercise of Common Stock Options	382,882	954,898
Restricted Stock Awarded, Net of Forfeitures [1]	2,912,936	687,017
Shares Exchanged in Clayton Williams Energy Acquisition	54,087,136	—
Shares, End of Period	528,743,381	471,360,427
Treasury Stock		
Shares, Beginning of Period	37,961,316	37,925,625
Shares Received in Payment of Withholding Taxes Due on Vesting of Shares of Restricted Stock [2]	1,026,891	236,700
Rabbi Trust Shares Distributed and/or Sold	(201,238)	(201,009)
Shares, End of Period	38,786,969	37,961,316
Additional Information		
Incremental Shares From Assumed Conversion of Dilutive Stock Options, Restricted Stock, and Shares of Common Stock in Rabbi Trust [2]	—	—
Number of Antidilutive Stock Options, Shares of Restricted Stock and Shares of Common Stock in Rabbi Trust excluded from Dilutive Loss per Share	15,619,276	14,218,319

(1) The 2017 amount includes approximately 1.9 million shares of restricted stock awarded to former holders of Clayton Williams Energy outstanding stock awards as part of the Clayton Williams Energy Acquisition. See Note 3. Clayton Williams Energy Acquisition .

(2) The 2017 amount includes approximately 720,000 shares of common stock from Clayton Williams Energy shareholders for the payment of withholding taxes due on the vesting of Clayton Williams Energy restricted shares and options pursuant to the purchase and sale agreement.

(3) For the years ended December 31, 2017 and 2016, all outstanding options and non-vested restricted shares have been excluded from the calculation of diluted earnings (loss) per share as Noble Energy incurred a loss. Therefore, inclusion of outstanding options and non-vested restricted shares in the calculation of diluted earnings (loss) per share would be anti-dilutive.

Issuance of Noble Midstream Partners Common Units On December 15, 2017, Noble Midstream Partners closed an offering of 3,680,000 common units, generating net proceeds of approximately $174 million, net of offering costs. On June 26, 2017, Noble Midstream Partners engaged in a private placement offering of 3,525,000 common units, generating proceeds of approximately $138 million , net of offering costs.

In third quarter 2016, Noble Midstream Partners completed its initial public offering of 14,375,000 common units, generating proceeds of $299 million , net of offering costs.

Subsequent Event - Share Repurchase Program On February 15, 2018, we announced the Company's Board of Directors authorized a share repurchase program of $750 million which expires December 31, 2020. All purchases will be made in accordance with applicable securities laws from time to time in open market or private transactions, depending on market conditions, and may be discontinued at any time.

Accumulated Other Comprehensive Loss (AOCL) AOCL in the shareholders’ equity section of the balance sheet included:

	Accumulated Other Comprehensive Loss		
(millions)	Interest Rate Cash Flow Hedges	Pension-Related and Other	Total
December 31, 2014	$ (23)	$ (67)	$ (90)
Realized Amounts Reclassified Into Earnings	1	62	63
Unrealized Change in Fair Value	—	(6)	(6)
December 31, 2015	(22)	(11)	(33)
Realized Amounts Reclassified Into Earnings	1	4	5
Unrealized Change in Fair Value	—	(3)	(3)
December 31, 2016	(21)	(10)	(31)
Realized Amounts Reclassified Into Earnings	1	4	5
Unrealized Change in Fair Value	—	(4)	(4)
December 31, 2017	$ (20)	$ (10)	$ (30)

All amounts in the table above are reported net of tax, using an effective income tax rate of 35% .

AOCL at December 31, 2017 included deferred losses of $20 million , net of tax, related to interest rate derivative instruments. This amount is being reclassified to earnings as an adjustment to interest expense over the term of our senior notes due March 2041.

Note 17. 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.

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 $4.95 million in civil penalties which were paid in 2015. Mitigation costs of $4.5 million and SEP costs of $4 million are being expended in accordance with schedules established in the Consent Decree. Costs associated with the injunctive relief are also being expended in accordance with schedules established in the Consent Decree. Over the last three years, 2015 through 2017, we spent approximately $72.0 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 & Gas Conservation Commission Administrative Order on Consent In November 2017, we received a proposed Administrative Order on Consent (AOC) from the 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.

Colorado Air Compliance Order on Consent In April 2017, we received a proposed Compliance Order on Consent (COC) from the Colorado Department of Public Health and Environment's Air Pollution Control Division (APCD) to resolve allegations of noncompliance associated with compliance testing of certain engines subject to various General Permit 02 conditions and/or individual permit conditions. In May 2017, we reached a final resolution with the APCD and executed the COC, which requires payment of a civil penalty of $24,710 and an expenditure of no less than $98,840 on an approved SEP(s). This resolution is not believed to have a material adverse effect on our financial position, results of operations or cash flows.

Transportation and Gathering Obligations As part of our Marcellus Shale upstream divestiture, we retained certain transportation and gathering 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 recently 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. The associated commitments are included in the table below. See Note 1. Summary of Significant Accounting Policies – Exit Costs .

We also have transportation and gathering obligations to flow DJ Basin, Eagle Ford Shale, and Gulf of Mexico production to various markets. Our financial commitment for these agreements, which have remaining terms of one to 11 years, is approximately $781 million , undiscounted. The commitment is included in the table below.

Non-Cancelable Leases and Other Commitments We hold leases and other commitments for drilling rigs, buildings, equipment and other property. Rental expense for office buildings and oil and gas operations equipment was $69 million in 2017 , $76 million in 2016 , and $84 million in 2015 .

Minimum commitments as of December 31, 2017 consist of the following:

(millions)	Drilling, Equipment, and Purchase Obligations	Transportation and Gathering Obligations	Operating Lease Obligations	Capital Lease and Other Obligations [1]	Total
2018	$ 636	$ 215	$ 44	$ 74	$ 969
2019	167	252	33	45	497
2020	40	247	32	42	361
2021	13	223	32	29	297
2022	8	182	33	21	244
2023 and Thereafter	32	1,355	156	124	1,667
Total	$ 896	$ 2,474	$ 330	$ 335	$ 4,035

(1) Annual lease payments, net to our interest, exclude regular maintenance and operational costs. See Note 10. Long-Term Debt .

In accordance with US GAAP for disclosures about oil and gas producing activities, and SEC rules for oil and gas reporting disclosures, we are making the following disclosures about our crude oil, NGL and natural gas reserves and exploration and production activities. In 2017 we established our Midstream business as a new reportable segment. The results of operations, costs incurred and capitalized costs associated with our Midstream reportable segment are not included in this disclosure. Prior period amounts are presented on a comparable basis.

Reserves There are numerous uncertainties inherent in estimating quantities of proved crude oil, NGL and natural gas reserves and reserves engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be precisely measured. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserves estimates are often different from the quantities of crude oil, NGL and natural gas that are ultimately recovered.

Economic producibility of reserves is dependent on the crude oil, NGL and natural gas prices used in the reserves estimate. We based our December 31, 2017 , 2016 , and 2015 reserves estimates on 12-month average commodity prices, unless contractual arrangements designate the price to be used, in accordance with SEC rules. However, commodity prices are volatile and declines in crude oil, NGL and natural gas prices could result in negative reserves revisions. Production, development and abandonment costs are based on year-end economic conditions; therefore increases in these costs could also result in negative reserves revisions.

Reserves Estimates Estimates of our proved reserves and associated future net cash flows are made solely by our engineers and are the responsibility of management. For additional information regarding our reserves estimation process and internal controls see Items 1. and 2. Business and Properties – Proved Reserves Disclosures – Internal Controls Over Reserves Estimates and Technologies Used in Reserves Estimation .

Third-Party Reserves Audit We retained Netherland, Sewell & Associates, Inc. (NSAI), independent, third-party petroleum engineers, to perform a reserves audit of proved reserves as of December 31, 2017 . See Items 1. and 2. Business and Properties – Proved Reserves Disclosures .

Definitions The following definitions apply to the terms used in the paragraphs above:

Reserves Estimate The determination of an estimate of a quantity of oil or gas reserves that are thought to exist at a certain date, considering existing prices and reservoir conditions.

Reserves Audit The process of reviewing certain of the pertinent facts interpreted and assumptions underlying a reserves estimate prepared by another party and the rendering of an opinion about the appropriateness of the methodologies employed, the adequacy and quality of the data relied upon, the depth and thoroughness of the reserves estimation process, the classification of reserves appropriate to the relevant definitions used, and the reasonableness of the estimated reserves quantities.

The following definitions apply to our categories of proved reserves:

Proved Oil and Gas Reserves Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to produce the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

Developed Oil and Gas Reserves Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well.

Undeveloped Oil and Gas Reserves PUDs are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

For complete definitions of proved reserves, refer to SEC Regulation S-X, Rule 4-10(a)(6), (22) and (31).

Proved Oil Reserves (Unaudited) The following reserves schedule was developed by our qualified petroleum engineers and sets forth the changes in estimated quantities of proved crude oil reserves **:**

	Crude Oil and Condensate (MMBbls)			
	United States	Equatorial Guinea	Israel	Total
Proved Reserves as of:				
December 31, 2014	236	65	3	304
Revisions of Previous Estimates [1]	(56)	(5)	—	(61)
Extensions, Discoveries and Other Additions [2]	42	—	—	42
Purchase of Minerals in Place [3]	65	—	—	65
Sale of Minerals in Place	(2)	—	—	(2)
Production [5]	(29)	(12)	—	(41)
December 31, 2015	256	48	3	307
Revisions of Previous Estimates [1]	14	(4)	—	10
Extensions, Discoveries and Other Additions [2]	66	—	—	66
Sale of Minerals in Place	(4)	—	—	(4)
Production [5]	(36)	(10)	—	(46)
December 31, 2016	296	34	3	333
Revisions of Previous Estimates [1]	29	2	—	31
Extensions, Discoveries and Other Additions [2]	104	—	6	110
Purchase of Minerals in Place [3]	43	—	—	43
Sale of Minerals in Place [4]	(12)	—	—	(12)
Production [5]	(41)	(7)	—	(48)
December 31, 2017	419	29	9	457
Proved Developed Reserves as of:				
December 31, 2014	119	52	3	174
December 31, 2015	137	34	3	174
December 31, 2016	138	34	3	175
December 31, 2017	176	29	3	208
Proved Undeveloped Reserves as of:				
December 31, 2014	117	13	—	130
December 31, 2015	119	14	—	133
December 31, 2016	158	—	—	158
December 31, 2017	243	—	6	249

(1) The 2015 US revisions were primarily associated with negative price revisions of 70 MMBbls to our onshore programs due to a decline in the 12-month average price of crude oil; partially offset by positive revisions of 14 MMBbls due to producing well performance and optimized lateral lengths in the Delaware Basin and Eagle Ford Shale. Equatorial Guinea revisions were associated with negative price revisions.

The 2016 US revisions associated with positive performance and/or decreases in development or operating costs included revisions of 33 MMBbls in the DJ Basin, Marcellus Shale, Delaware Basin and Gulf of Mexico; partially offset by negative revisions of 19 MMBbls due to lower commodity prices. Equatorial Guinea revisions were primarily due to lower commodity prices.

The 2017 US revisions associated with positive performance totaled 17 MMBbls, of which 14 were primarily attributable to the Delaware Basin due to continued optimization of well development and improved producing well performance. Revisions also included positive price revisions of 12 MMBbls.

(2) The 2015 increase in US reserves was attributable to DJ Basin development.

The 2016 increase in US reserves included 38 MMBbls in the DJ Basin and 28 MMBbls in the Delaware Basin and Eagle Ford Shale, and was associated with increased performance from our horizontal drilling programs.

The 2017 increase in US reserves included additions of 59 MMBbls in the Delaware Basin, 42 MMBbls in the DJ Basin and 3 MMBbls in the Eagle Ford Shale primarily due to the addition of planned new locations and activity.

(3) The 2015 increase was attributable to reserves acquired in the Rosetta Merger.

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The 2017 increase was attributable to the reserves acquired in the Clayton Williams Energy Acquisition.

(4) In 2017, we sold the Marcellus Shale upstream assets and other non-strategic US onshore assets.

(5) Equatorial Guinea production included sales from Alba Plant of approximately 1 MMBbl in 2017 and 3 MMBbl in each of the years 2016 and 2015.

See Items 1. and 2. Business and Properties – Proved Reserves Disclosures , Note 3. Clayton Williams Energy Acquisition and Note 4. Acquisitions, Divestitures and Merger .

Proved NGL Reserves (Unaudited) The following reserves schedule was developed by our qualified petroleum engineers and sets forth the changes in estimated quantities of proved NGL reserves **:**

	NGLs (MMBbls)		
	United States	Equatorial Guinea	Total
Proved Reserves as of:			
December 31, 2014	113	15	128
Revisions of Previous Estimates (1)	(37)	—	(37)
Extensions, Discoveries and Other Additions (2)	15	—	15
Purchase of Minerals in Place (3)	100	—	100
Sale of Minerals in Place	(1)	—	(1)
Production (4)	(14)	(2)	(16)
December 31, 2015	176	13	189
Revisions of Previous Estimates (1)	16	1	17
Extensions, Discoveries and Other Additions (2)	31	—	31
Purchase of Minerals in Place	4	—	4
Sale of Minerals in Place	—	—	—
Production (4)	(20)	(2)	(22)
December 31, 2016	207	12	219
Revisions of Previous Estimates (1)	31	1	32
Extensions, Discoveries and Other Additions (2)	32	—	32
Purchase of Minerals in Place (3)	7	—	7
Sale of Minerals in Place (5)	(38)	—	(38)
Production (4)	(21)	(2)	(23)
December 31, 2017	218	11	229
Proved Developed Reserves as of:			
December 31, 2014	64	8	72
December 31, 2015	101	5	106
December 31, 2016	113	12	125
December 31, 2017	119	11	130
Proved Undeveloped Reserves as of:			
December 31, 2014	49	7	56
December 31, 2015	75	8	83
December 31, 2016	94	—	94
December 31, 2017	99	—	99

(1) The 2015 US revisions were primarily associated with negative price revisions of 44 MMBbls related to our onshore programs due to a decline in the 12-month average price; partially offset by a positive revision from our Marcellus Shale program due to positive well performance.

The 2016 US revisions were primarily associated with positive performance revisions of 11 MMBbls in the Marcellus Shale and 9 MMBbls in the DJ Basin; partially offset by negative commodity price revisions of 4 MMBbls.

The 2017 US revisions associated with positive performance revisions totaled 25 MMBbls, including 11 MMBbls in the Delaware Basin, 8 MMBbls in the Eagle Ford Shale and 6 MMBbls in the DJ Basin, due to continued optimization of well development and improved producing well performance. Revisions also included positive price revisions of 6 MMBbls.

(2) The 2015 additions included 14 MMBbls due to positive producing well performance and optimized lateral lengths in the DJ Basin.

The 2016 additions in US reserves primarily included an increase of 15 MMBbls in the DJ Basin and 14 MMBbls in the Delaware Basin and Eagle Ford shale due to improved well performance and/or decreases in development or operating costs.

The 2017 additions in US reserves included 19 MMBbls in the DJ Basin, 9 MMBbls in the Delaware Basin and 4 MMBbls in the Eagle Ford Shale primarily due to the addition of planned new locations and activity.

(3) The 2015 increase was attributable to reserves acquired in the Rosetta Merger.

The 2017 increase was attributable to the reserves acquired in the Clayton Williams Energy Acquisition.

(4) Equatorial Guinea production represented sales from the Alba Plant.

(5) In 2017, we sold the Marcellus Shale upstream assets and other non-strategic US onshore assets.

See Items 1. and 2. Business and Properties – Proved Reserves Disclosures , Note 3. Clayton Williams Energy Acquisitio n and Note 4. Acquisitions, Divestitures and Merger .

Proved Gas Reserves (Unaudited) The following reserves schedule was developed by our qualified petroleum engineers and sets forth the changes in estimated quantities of proved natural gas reserves:

	Natural Gas and Casinghead Gas (Bcf)			
	United States	Israel [1]	Equatorial Guinea	Total
Proved Reserves as of:				
December 31, 2014	2,804	2,416	613	5,833
Revisions of Previous Estimates [2]	(705)	(20)	4	(721)
Extensions, Discoveries and Other Additions [3]	257	—	—	257
Purchase of Minerals in Place [4]	629	—	—	629
Sale of Minerals in Place	(16)	—	—	(16)
Production	(258)	(92)	(83)	(433)
December 31, 2015	2,711	2,304	534	5,549
Revisions of Previous Estimates [2]	181	(3)	38	216
Extensions, Discoveries and Other Additions [3]	492	—	—	492
Purchase of Minerals in Place	—	—	—	—
Sale of Minerals in Place [5]	(224)	(214)	—	(438)
Production	(322)	(103)	(86)	(511)
December 31, 2016	2,838	1,984	486	5,308
Revisions of Previous Estimates [2]	124	292	13	429
Extensions, Discoveries and Other Additions [3]	299	3,271	—	3,570
Purchase of Minerals in Place [4]	46	—	—	46
Sale of Minerals in Place [5]	(1,264)	—	(1)	(1,265)
Production	(222)	(99)	(87)	(408)
December 31, 2017	1,821	5,448	411	7,680
Proved Developed Reserves as of:				
December 31, 2014	1,459	1,973	377	3,809
December 31, 2015	1,813	1,879	247	3,939
December 31, 2016	1,817	1,600	486	3,903
December 31, 2017	983	1,793	411	3,187
Proved Undeveloped Reserves as of:				
December 31, 2014	1,345	443	236	2,024
December 31, 2015	898	425	287	1,610
December 31, 2016	1,021	384	—	1,405
December 31, 2017	838	3,655	—	4,493

(1) In accordance with the terms of the Framework, we are required to reduce our ownership in the Tamar and Dalit fields from 36% to 25% by year-end 2021. During 2016, we reduced our ownership to 32.5% through the sale of a 3.5% interest. At December 31, 2017, an additional 7.5% interest is included in assets held for sale. Proved reserves associated with the interest currently held for sale total approximately 502 Bcf, including 89 Bcf of PUDs, at December 31, 2017 and are included in the table above. In January 2018, we entered into an agreement to divest the 7.5% interest. See Note 4. Acquisitions, Divestitures and Merger.

(2) The 2015 US revisions were primarily associated with negative price revisions of 1.1 Tcf to our onshore programs due to a decline in the 12-month average price, offset by a positive revision primarily to our Marcellus Shale program due to positive well performance. Equatorial Guinea revisions were associated with positive performance revisions to the Alba field. Israel revisions were primarily associated with negative performance revisions in the Mari-B field.

The 2016 US revisions were primarily associated with positive performance and/or decreases in development or operating costs and included 167 Bcf in the Marcellus Shale and 95 Bcf in the DJ Basin, partially offset by negative commodity price revisions of 81 Bcf. Equatorial Guinea revisions were associated with positive performance revisions of 58 Bcf at the Alba field, partially offset by negative commodity price revisions of 20 Bcf.

The 2017 US revisions were associated primarily with positive well performance and an increase in commodity prices. Net performance revisions of 66 Bcf primarily included 81 Bcf in the Eagle Ford Shale and 31 Bcf in the Delaware Basin, partially offset by negative performance revisions of 49 Bcf in the DJ Basin primarily associated vertical well locations. The 2017 Israel performance revisions of

292 Bcf were associated with the integration of the Tamar 8 well results into our geologic modeling across the reservoir. Positive price revisions were approximately 71 Bcf.

(3) The 2015 increase in US reserves included an increase of 176 Bcf in the DJ Basin and 81 Bcf from Marcellus Shale development due to positive producing well performance and optimized lateral lengths.

The 2016 increase in US reserves included positive performance revisions associated with our horizontal drilling programs including 230 Bcf in the Marcellus Shale, 185 Bcf in the DJ Basin, and 77 Bcf in the Delaware Basin and Eagle Ford Shale.

The 2017 increase in US reserves included additions of 224 Bcf in the DJ Basin, 53 Bcf in the Delaware Basin and 22 Bcf in the Eagle Ford Shale primarily due to the addition of planned new locations and activity. The 2017 increase in Israel reserves represented sanction of the first phase of development of the Leviathan natural gas project.

(4) The 2015 increase was attributable to reserves acquired in the Rosetta Merger.

The 2017 increase was attributable to the reserves acquired in the Clayton Williams Energy Acquisition.

(5) In 2016, we sold US onshore assets in the DJ Basin and Eagle Ford Shale. We also executed an acreage exchange in the Marcellus Shale where we relinquished 185 Bcf, and we reduced our ownership in the Tamar field, offshore Israel.

In 2017, we sold the Marcellus Shale upstream assets and other non-strategic US onshore assets.

See Items 1. and 2. Business and Properties – Proved Reserves Disclosures , Note 3. Clayton Williams Energy Acquisition and Note 4. Acquisitions, Divestitures and Merger .

Noble Energy, Inc.
Supplemental Oil and Gas Information
(Unaudited)

Results of Operations for Oil and Gas Producing Activities (Unaudited) Results of operations for crude oil and natural gas producing activities within the E&P reporting segments are as follows:

(millions)	United States	Israel	Equatorial Guinea	Other Int'l	Total
Year Ended December 31, 2017					
Revenues	$ 3,156	$ 534	$ 370	$ —	$ 4,060
Production Costs [1]	1,199	49	103	2	1,353
Exploration Expense	102	—	1	85	188
DD&A	1,739	76	146	4	1,965
Loss on Marcellus Shale Upstream Divestiture [2]	2,379	—	—	—	2,379
Asset Impairments [3]	63	—	—	7	70
(Loss) Income before Income Taxes	(2,326)	409	120	(98)	(1,895)
Income Tax Expense (Benefit) [4]	(814)	98	30	—	(686)
Results of Operations [5]	$ (1,512)	$ 311	$ 90	$ (98)	$ (1,209)
Year Ended December 31, 2016					
Revenues	$ 2,416	$ 540	$ 433	$ —	$ 3,389
Production Costs [1]	1,108	49	118	1	1,276
Exploration Expense [6]	245	26	469	185	925
DD&A	2,103	81	205	6	2,395
Asset Impairments [4]	—	88	—	4	92
(Loss) Income before Income Taxes	(1,040)	296	(359)	(196)	(1,299)
Income Tax Expense (Benefit) [4]	(364)	74	(90)	—	(380)
Results of Operations [5]	$ (676)	$ 222	$ (269)	$ (196)	$ (919)
Year Ended December 31, 2015					
Revenues	$ 2,011	$ 497	$ 580	$ 5	$ 3,093
Production Costs [1]	916	60	145	6	1,127
Exploration Expense	202	6	1	279	488
DD&A	1,677	70	326	—	2,073
Asset Impairments [3]	158	36	339	—	533
Income (Loss) before Income Taxes	(942)	325	(231)	(280)	(1,128)
Income Tax Expense [4]	(330)	86	(58)	(5)	(307)
Results of Operations [5]	$ (612)	$ 239	$ (173)	$ (275)	$ (821)

(1) Production costs consist of lease operating expense, production and ad valorem taxes, transportation and gathering expense, and general and administrative expense supporting oil and gas operations.

(2) See Note 4. Acquisitions, Divestitures and Merger.

(3) 2017 asset impairments relate primarily to the Gulf of Mexico Troubadour well.

2016 asset impairments relate to certain Leviathan development concept costs.

2015 asset impairments related to reductions in the forward crude oil prices as of December 31, 2015 and revisions in expected field abandonment and other costs for offshore properties.

See Note 5. Asset Impairments .

(4) Income tax expense is based upon respective corporate statutory tax rates. During 2017, 2016, and 2015, we incurred exploration expense in currently non-commercial other international locations; therefore, no tax benefit was included in income tax expense associated with other international as we could not conclude it was more likely than not that some portion or all of the deferred tax assets would be realized.

(5) Results of operations exclude the mark-to-market gain or loss on commodity derivative instruments, corporate overhead and interest costs. See Note 8. Derivative Instruments and Hedging Activities .

(6) Equatorial Guinea exploration expense includes amounts related to the write off of costs associated with certain discoveries. See Note 6. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs .

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities (Unaudited)

Costs incurred include both capitalized costs and costs charged to expense when incurred for oil and gas property acquisition, exploration, and development activities associated with the E&P reporting segments. Costs incurred also include new AROs established in the current year, as well as changes to AROs resulting from changes to cost estimates during the year. Exploration costs presented below include the costs of drilling and equipping successful and unsuccessful exploration wells during the year, geological and geophysical expenses, and the costs of retaining undeveloped leaseholds. Development costs include the costs of drilling and equipping development wells. Costs associated with activities of our Midstream business and other corporate activities are not included.

(millions)	United States	Israel	Equatorial Guinea	Other Int'l [1]	Total
December 31, 2017					
Property Acquisition Costs					
Proved [2]	$ 839	$ —	$ —	$ —	$ 839
Unproved [2]	1,817	—	—	—	1,817
Exploration Costs [3]	59	6	4	90	159
Development Costs [4]	1,870	483	33	(39)	2,347
Total Consolidated Operations	$ 4,585	$ 489	$ 37	$ 51	$ 5,162
December 31, 2016					
Property Acquisition Costs					
Proved [2]	$ —	$ —	$ —	$ —	$ —
Unproved [2]	234	—	—	—	234
Exploration Costs [4]	264	26	25	44	359
Development Costs [4]	905	109	31	—	1,045
Total Consolidated Operations	$ 1,403	$ 135	$ 56	$ 44	$ 1,638
December 31, 2015					
Property Acquisition Costs					
Proved [2]	$ 1,613	$ —	$ —	$ —	$ 1,613
Unproved [2]	1,478	—	—	2	1,480
Exploration Costs [3]	206	22	22	234	484
Development Costs [4]	2,111	104	75	10	2,300
Total Consolidated Operations	$ 5,408	$ 126	$ 97	$ 246	$ 5,877

(1) Other International includes Newfoundland, Suriname, Falkland Islands, other new ventures and previous North Sea operations, which are in the process of being decommissioned.

(2) 2017 proved and unproved property acquisition costs include amounts allocated from the Clayton Williams Energy Acquisition (See Note 3. Clayton Williams Energy Acquisition) and the Delaware Basin Acquisition (See Note 4. Acquisitions, Divestitures and Merger).

2016 unproved property acquisition costs relate to the termination of the Marcellus Shale joint development agreement. See Note 4. Acquisitions, Divestitures and Merger .

2015 proved and unproved property acquisition costs include amounts allocated from the Rosetta Merger. See Note 4. Acquisitions, Divestitures and Merger .

(3) 2017 exploration costs include primarily capitalized interest on Gulf of Mexico projects, and $7 million dry hole cost related to the Araku-1 exploration well, offshore Suriname. The remainder relates to seismic expense and drilling costs.

2016 exploration costs include drilling and completion of $44 million in the Gulf of Mexico.

2015 exploration costs include drilling and completion of $22 million in the Gulf of Mexico.

(4) Worldwide development costs include amounts spent to develop PUDs of approximately $1.2 billion in 2017, $656 million in 2016, and $1.5 billion in 2015.

Israel development costs include $416 million related to initial development of the Leviathan field and $63 million related to the Tamar 8 development well in 2017. Amounts incurred in 2016 and 2015 related primarily to development of the Tamar discovery.

Equatorial Guinea development costs primarily relate to the Alba field unitization project in 2017 and drilling and well completion and installation and construction of a compression platform in the Alba field in 2016 and 2015.

US development costs include a decrease of $17 million in asset retirement obligations due to downward revisions and increases of $20 million in 2016 and $194 million in 2015.

Israel development costs include increases in asset retirement obligations of $4 million in 2017 and $46 million in 2015.

Equatorial Guinea development costs include increases (decreases) in asset retirement obligations of $14 million in 2017 and $(10) million in 2015.

Other International development costs include increases (decreases) in asset retirement obligations of $(40) million in 2017 mainly associated with the North Sea abandonment project and $2 million in 2015.

Capitalized Costs Relating to Oil and Gas Producing Activities (Unaudited) Aggregate capitalized costs relating to crude oil and natural gas producing activities within the E&P reporting segments are as follows:

	December 31,	
	2017	2016
(millions)		
Unproved Oil and Gas Properties [1]	$ 2,978	$ 2,197
Proved Oil and Gas Properties [2]	26,111	27,530
Total Oil and Gas Properties	29,089	29,727
Accumulated DD&A	(12,538)	(12,265)
Net Capitalized Costs	$ 16,551	$ 17,462

(1) Unproved oil and gas property cost at December 31, 2017 include previous acquisition costs of $1.6 billion related to the Clayton Williams Energy Acquisition, and $1.1 billion and $149 million related to the Delaware Basin and Eagle Ford Shale properties.

Unproved oil and gas property cost at December 31, 2016 include previous acquisition costs of $1.2 billion related to the Eagle Ford Shale and Delaware Basin properties and $758 million related to Marcellus Shale properties.

(2) Proved oil and gas properties at December 31, 2017 include asset retirement costs of $941 million and assets held for sale of $448 million .

Proved oil and gas properties at December 31, 2016 include asset retirement costs of $884 million and $18 million of assets held for sale.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Unaudited) The following information is based on our best estimate of the required data for the Standardized Measure of Discounted Future Net Cash Flows in accordance with US GAAP. The standards require the use of a 10% discount rate. This information is not the fair value nor does it represent the expected present value of future cash flows of our proved oil and gas reserves.

(millions)	United States	Israel [1]	Equatorial Guinea	Other Int'l [2]	Total
December 31, 2017					
Future Cash Inflows [3]	$ 30,061	$ 29,998	$ 2,028	$ —	$ 62,087
Future Production Costs [4]	(11,020)	(2,517)	(932)	—	(14,469)
Future Development Costs [5]	(5,941)	(1,706)	(109)	(51)	(7,807)
Future Income Tax Expense [6]	(948)	(13,088)	(216)	—	(14,252)
Future Net Cash Flows	12,152	12,687	771	(51)	25,559
10% Annual Discount for Estimated Timing of Cash Flows	(5,202)	(8,993)	(113)	7	(14,301)
Standardized Measure of Discounted Future Net Cash Flows	$ 6,950	$ 3,694	$ 658	$ (44)	$ 11,258
December 31, 2016					
Future Cash Inflows [3]	$ 19,924	$ 10,159	$ 1,851	$ —	$ 31,934
Future Production Costs [4]	(8,756)	(764)	(1,001)	—	(10,521)
Future Development Costs [5]	(4,813)	(725)	(83)	(100)	(5,721)
Future Income Tax Expense	(941)	(4,228)	(141)	—	(5,310)
Future Net Cash Flows	5,414	4,442	626	(100)	10,382
10% Annual Discount for Estimated Timing of Cash Flows	(2,308)	(2,329)	(84)	25	(4,696)
Standardized Measure of Discounted Future Net Cash Flows	$ 3,106	$ 2,113	$ 542	$ (75)	$ 5,686
December 31, 2015					
Future Cash Inflows [3]	$ 19,099	$ 11,835	$ 2,965	$ —	$ 33,899
Future Production Costs [4]	(8,728)	(1,128)	(1,351)	—	(11,207)
Future Development Costs [5]	(4,092)	(682)	(101)	(100)	(4,975)
Future Income Tax Expense	(837)	(5,281)	(189)	—	(6,307)
Future Net Cash Flows	5,442	4,744	1,324	(100)	11,410
10% Annual Discount for Estimated Timing of Cash Flows	(2,100)	(2,452)	(262)	32	(4,782)
Standardized Measure of Discounted Future Net Cash Flows	$ 3,342	$ 2,292	$ 1,062	$ (68)	$ 6,628

(1) In accordance with the Framework, we are required to reduce our ownership in the Tamar and Dalit fields from 36% to 25% by year-end 2021. During 2016, we reduced our ownership to 32.5% through the sale of a 3.5% interest. Therefore, amounts at December 31, 2017 and 2016 reflect a 32.5% working interest, while 2015 amounts reflect a 36% working interest. At December 31, 2017, 7.5% of our 32.5% interest is included in assets held for sale. The portion of the standardized measure of discounted future net cash flows included in the table above, and associated with the interest currently held for sale, totals approximately $650 million at December 31, 2017. See Note 4. Acquisitions, Divestitures and Merger . The 2017 increase in the standardized measure of discounted future net cash inflows relates primarily to the sanction of the first phase of development of the Leviathan field.

(2) Other International represents North Sea abandonment costs.

(3) The standardized measure of discounted future net cash flows does not include cash flows relating to anticipated future methanol sales.

(4) Production costs include lease operating expense, production and ad valorem taxes, transportation expense and general and administrative expense supporting crude oil and natural gas operations.

(5) Future development costs include future abandonment costs for each location. See Note 9. Asset Retirement Obligations .

(6) Future income tax expense includes the effect of statutory tax rates and the impact of tax deductions, tax credits and allowances relating to our proved reserves. As of December 31, 2017, US future income tax expense includes the expected impact of the recent Tax Reform Legislation. As of December 31, 2017, 2016 and 2015, future income tax expense for Israel also includes the effect of estimated future profit levy taxes and changes to corporate income tax rates.

Noble Energy, Inc.
Supplemental Oil and Gas Information
(Unaudited)

Prices and Other Assumptions in Discounted Future Net Cash Flows (Unaudited) Future cash inflows are computed by applying a 12-month average commodity price, adjusted for location and quality differentials on a field-by-field basis, to year-end quantities of proved reserves, except in those instances where fixed and determinable price changes are provided by contractual arrangements at year-end. The discounted future cash flow estimates do not include the effects of derivative instruments. Average prices per region are as follows:

	United States	Israel	Equatorial Guinea	Total
December 31, 2017				
Average Crude Oil and Condensate Price per Bbl	$ 47.81	$ 46.82	$ 53.12	$ 48.13
Average Natural Gas Price per Mcf	2.83	5.43	0.27	4.54
Average NGL Price per Bbl	22.32	—	37.23	23.02
December 31, 2016				
Average Crude Oil and Condensate Price per Bbl	$ 37.36	$ 36.05	$ 42.45	$ 37.87
Average Natural Gas Price per Mcf	2.07	5.07	0.27	3.02
Average NGL Price per Bbl	14.30	—	26.12	14.94
December 31, 2015				
Average Crude Oil and Condensate Price per Bbl	$ 42.03	$ 48.23	$ 51.03	$ 43.50
Average Natural Gas Price per Mcf	2.16	5.08	0.27	3.18
Average NGL Price per Bbl	14.15	—	29.92	15.23

The discounted future net cash flows are computed using a 12-month average commodity price applied to our year-end quantities of proved reserves, unless contractual arrangements designate the price to be used. We performed a sensitivity of our discounted future net cash flows to reflect a price reduction to our 12-month average commodity price. We estimate that a 10% per Bbl reduction in the average price of crude oil and NGLs from the 12-month average price for 2017 would reduce the discounted future net cash flows before income taxes by approximately $1.2 billion and $0.3 billion , respectively. We estimate that a 10% per Mcf reduction in the average price of natural gas from the 12-month average price for 2017 would reduce the discounted future net cash flows before income taxes by approximately $1 billion .

Future production and development costs, which include dismantlement and restoration expense, are computed by estimating the expenditures to be incurred in developing and producing the proved crude oil, natural gas and NGL reserves at the end of the year, based on year-end costs, and assuming continuation of existing economic conditions.

Future development costs include amounts that we expect to spend to develop PUDs of approximately $1.7 billion in 2018 , $1.9 billion in 2019 and $1.4 billion in 2020 .

Future income tax expense is computed by applying the appropriate year-end statutory tax rates to the estimated future pre-tax net cash flows relating to proved crude oil, natural gas and NGL reserves, less the tax bases of the properties involved. Future income tax expense gives effect to tax credits and allowances, but does not reflect the impact of general and administrative costs and exploration expenses of ongoing operations.

Sources of Changes in Discounted Future Net Cash Flows (Unaudited) Principal changes in the aggregate standardized measure of discounted future net cash flows attributable to proved crude oil, natural gas and NGL reserves are as follows:

	Year Ended December 31,		
	2017	2016	2015
(millions)			
Standardized Measure of Discounted Future Net Cash Flows, Beginning of Year	$ 5,686	$ 6,628	$ 13,979
Changes in Standardized Measure of Discounted Future Net Cash Flows			
Sales of Oil and Gas Produced, Net of Production Costs	(2,674)	(2,230)	(2,026)
Net Changes in Prices and Production Costs [1]	2,436	(593)	(12,603)
Extensions, Discoveries and Improved Recovery, Less Related Costs	3,711	463	442
Changes in Estimated Future Development Costs	(537)	(373)	1,135
Development Costs Incurred During the Period	1,975	1,090	2,639
Revisions of Previous Quantity Estimates	1,462	364	(1,051)
Purchases of Minerals in Place [2]	423	161	2,747
Sales of Minerals in Place	(643)	(951)	(46)
Accretion of Discount	778	919	1,789
Net Change in Income Taxes [3]	(1,669)	414	2,075
Change in Timing of Estimated Future Production and Other [4]	310	(206)	(2,452)
Aggregate Change in Standardized Measure of Discounted Future Net Cash Flows	$ 5,572	$ (942)	$ (7,351)
Standardized Measure of Discounted Future Net Cash Flows, End of Year	$ 11,258	$ 5,686	$ 6,628

(1) The increase in 2017 and the decrease in 2015 were driven primarily by higher and lower, respectively, 12-month average commodity prices.

(2) Purchase of minerals in 2017 relates to reserves acquired in the Clayton Williams Energy Acquisition.
Purchase of minerals in 2015 relates to reserves acquired in the Rosetta Merger.

(3) The increase in 2017 future income tax expense relates primarily to the increase in profit and levy taxes in Israel, partially offset by the decrease in future corporate income tax rate in Israel. The increase in profits tax is driven by a significant increase in future cash flows related to the Leviathan project sanctioning in 2017. The increase in US tax expense due to the increase in future taxable income was offset by the decrease in tax expense associated with utilization of future net operating losses and decrease in applicable tax rate from 35% to 21% due to the changes in the US Tax Law effective January 1, 2018. For 2015, future income tax expense for Israel includes the effect of estimated future profit levy taxes which partially offset the increase in future net cash flows.

(4) The decrease in 2015 reflects revisions in our estimated timing of production and development activity.

Noble Energy, Inc.
Supplemental Quarterly Financial Information
(Unaudited)

Supplemental quarterly financial information is as follows:

	Quarter Ended				
	March 31,	June 30,	Sep 30,	Dec 31,	Total
(millions except per share amounts)					
2017 (1) (3)					
Revenues	$ 1,036	$ 1,059	$ 960	$ 1,201	$ 4,256
Income (Loss) Before Income Taxes	59	(2,334)	(208)	292	(2,191)
Net Income (Loss)	47	(1,498)	(115)	516	(1,050)
Less: Net Income Attributable to Noncontrolling Interests	11	14	21	22	68
Net Income (Loss) Attributable to Noble Energy	36	(1,512)	(136)	494	(1,118)
Net Income (Loss) Per Share, Basic	0.08	(3.20)	(0.28)	1.01	(2.38)
Net Income (Loss) Per Share, Diluted	0.08	(3.20)	(0.28)	1.01	(2.38)
2016 (2) (3)					
Revenues	$ 724	$ 847	$ 910	$ 1,010	$ 3,491
Loss Before Income Taxes	(453)	(498)	(280)	(541)	(1,772)
Net Income (Loss)	(287)	(315)	(143)	(240)	(985)
Less: Net Income Attributable to Noncontrolling Interests	—	—	1	12	13
Net Loss Attributable to Noble Energy	(287)	(315)	(144)	(252)	(998)
Net Loss Per Share, Basic and Diluted	(0.67)	(0.73)	(0.33)	(0.59)	(2.32)

(1) First quarter 2017 included the following:
- No unusual or infrequent activity.

Second quarter 2017 included the following:
- $2.4 billion loss on Marcellus Shale upstream divestiture (See Note 4. Acquisitions, Divestitures and Merger).

Third quarter 2017 included the following:
- $98 million loss on extinguishment of debt (See Note 10. Long-Term Debt).

Fourth quarter 2017 included the following:
- $270 million deferred tax benefit, net, related to recent changes in federal income tax regulations; and
- $334 million gain on sale of mineral and royalty assets (See Note 4. Acquisitions, Divestitures and Merger).

(2) First quarter 2016 included the following:
- $80 million gain on extinguishment of debt.

Second quarter 2016 included the following:
- $25 million purchase price allocation adjustment related to Rosetta Merger (See Note 4. Acquisitions, Divestitures and Merger).

Third quarter 2016 included the following:
- $81 million undeveloped leasehold impairment expense (See Note 6. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs).

Fourth quarter 2016 included the following:
- $579 million dry hole costs included in exploration expense (See Note 6. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs); and
- $92 million property impairment charges (See Note 5. Asset Impairments)

(3) T he sum of the individual quarterly earnings (loss) may not agree with year-to-date earnings (loss) as each quarterly computation is based on the earnings (loss) for the individual quarter as reported with rounding applied.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports we file or furnish to the SEC under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms, and that information is accumulated and communicated to management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

Our principal executive officer and principal financial officer have evaluated the effectiveness of our "disclosure controls and procedures," as such term is defined in Rule 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended, as of the end of the period covered by this Annual Report on Form 10-K. Based upon their evaluation, they have concluded that our disclosure controls and procedures were effective and provide an effective means to ensure that information required to be disclosed in the reports that we file or furnish under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms and that information is accumulated and communicated to management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable, and not absolute, assurance that the objectives of the control system will be met. In addition, the design of any control system is based in part upon certain assumptions about the likelihood of future events and the application of judgment in evaluating the cost-benefit relationship of possible controls and procedures. Because of these and other inherent limitations of control systems, there is only reasonable assurance that our controls will succeed in achieving their goals under all future conditions.

Management's Annual Report on Internal Control over Financial Reporting

The management report called for by Item 308(a) of Regulation S-K is incorporated herein by reference to Management's Report on Internal Control over Financial Reporting, included in Item 8. Financial Statements and Supplementary Data.

The independent auditor's attestation report called for by Item 308(b) of Regulation S-K is incorporated herein by reference to Report of Independent Registered Public Accounting Firm (Internal Control Over Financial Reporting), included in Item 8. Financial Statements and Supplementary Data.

Changes in Internal Control over Financial Reporting

Our management is also responsible for establishing and maintaining adequate internal controls over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Our internal controls were designed to provide reasonable assurance as to the reliability of our financial reporting and the preparation and presentation of the consolidated financial statements for external purposes in accordance with US GAAP.

Because of its inherent limitations, internal control over financial reporting may not detect or prevent misstatements. Projections of any evaluation of the effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Our management has assessed the effectiveness of our internal controls over financial reporting as of December 31, 2017 . Based on our assessment, our internal controls over financial reporting were effective. There were no changes in internal controls over financial reporting that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated herein by reference to the 2018 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2017 .

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the 2018 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2017 .

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required by this item is incorporated herein by reference to the 2018 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2017 .

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this item is incorporated herein by reference to the 2018 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2017 .

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated herein by reference to the 2018 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2017 .

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) The following documents are filed as a part of this report:
- (1) Financial Statements: The consolidated financial statements and related notes, together with the reports of KPMG LLP, Independent Registered Public Accounting Firm, appear in Part II, Item 8, Financial Statements and Supplementary Data, of this Form 10-K.
- (2) Financial Statement Schedules: All schedules for which provision is made in the applicable accounting regulations of the SEC are not required under the related instruction or are inapplicable and, therefore, have been omitted.
- (3) Exhibits: The exhibits listed below on the Index to Exhibits are filed or incorporated by reference as part of this Form 10-K.

INDEX TO EXHIBITS

Exhibit Number		Exhibit **
2.1	—	Agreement and Plan of Merger, dated as of January 13, 2017, by and among Noble Energy, Inc., Wild West Merger Sub Inc., NBL Permian LLC, and Clayton Williams Energy, Inc. (filed as Exhibit 2.1 to the Registrant's Current Report on Form 8-K (Date of Report: January 13, 2017) filed 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 to the Registrant's Current Report on Form 8-K (Date of Report: May 10, 2015) filed May 11, 2015 and incorporated herein by reference).
2.3	—	Exchange Agreement, executed October 29, 2016, by and between CNX Gas Company LLC and Noble Energy, Inc. (filed as Exhibit 2.3 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2016 and incorporated herein by reference).
2.4	—	Purchase and Sale Agreement among Noble Energy, Inc. and HG Energy II Appalachia, LLC dated May 1, 2017 (filed as Exhibit 2.1 to the Registrant's Current Report on Form 8-K (Date of Report: May 1, 2017) filed May 5, 2017 and incorporated herein by reference).
2.5	—	Purchase Agreement by and among Wheeling Creek Midstream, LLC, Noble Energy US Holdings, LLC and Noble Energy, Inc. dated May 17, 2017 (filed as Exhibit 2.1 to the Registrant's Current Report on Form 8-K (Date of Report: May 17, 2017) filed May 23, 2017 and incorporated herein by reference).
2.6	—	Letter Agreement by and among Wheeling Creek Midstream LLC, Noble Energy US Holdings, LLC and Noble Energy, Inc. dated December 7, 2017, filed herewith.
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 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 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 July 28, 2016 and incorporated herein by reference).
4.1	—	Indenture dated as of February 27, 2009 between Noble Energy, Inc. and Wells Fargo Bank, National Association, as Trustee, relating to senior debt securities of Noble Energy, Inc. (filed as Exhibit 4.1 to the Registrant's Current Report on Form 8-K (Date of Report: February 24, 2009) filed February 27, 2009 (File No. 001-07964) and incorporated herein by reference).
4.2	—	Second Supplemental Indenture dated as of February 18, 2011, to Indenture dated as of February 27, 2009 between Noble Energy, Inc. and Wells Fargo Bank, National Association, as Trustee, relating to the Registrant's 6.000% Notes due 2041 (including the form of 2041 Notes) (filed as Exhibit 4.1 to the Registrant's Current Report on Form 8-K (Date of Report: February 15, 2011) filed February 22, 2011 (File No. 001-07964) and incorporated herein by reference).
4.3	—	Third Supplemental Indenture dated as of December 8, 2011, to Indenture dated as of February 27, 2009 between Noble Energy, Inc. and Wells Fargo Bank, National Association, as Trustee, relating to the Registrant's 4.15% Notes due 2021 (including the form of 2021 Notes) (filed as Exhibit 4.2 to the Registrant's Current Report on Form 8-K (Date of Report: December 5, 2011) filed December 8, 2011 (File No. 001-07964) and incorporated herein by reference).
4.4	—	Fourth Supplemental Indenture dated as of November 8, 2013, to Indenture dated as of February 27, 2009 between Noble Energy, Inc. and Wells Fargo Bank, National Association, as Trustee, relating to the Registrant's 5.25% Notes due 2043 (including the form of 2043 Notes) (filed as Exhibit 4.1 to the Registrant's Current Report on Form 8-K (Date of Report: November 5, 2013) filed November 8, 2013 (File No. 001-07964) and incorporated herein by reference).
4.5	—	Fifth Supplemental Indenture dated as of November 7, 2014, to Indenture dated as of February 27, 2009 between Noble Energy, Inc. and Wells Fargo Bank, National Association, as Trustee, relating the Registrant's 3.900% Notes due 2024 and 5.050% Notes due 2044 (including the forms of 2024 Notes and 2044 Notes) (filed as Exhibit 4.1 to the Registrant's Current Report on Form 8-K (Date of Report: November 4, 2014) filed November 7, 2014 (File No. 001-07964) and incorporated herein by reference).

4.6	—	Sixth Supplemental Indenture dated as of July 29, 2015, to Indenture dated as of February 27, 2009 between Noble Energy, Inc. and Wells Fargo Bank, National Association, as Trustee, relating the Registrant's 5.625% Notes due 2021, 5.875% Senior Notes due 2022 and 5.875% Notes due 2024 (including the forms of 2021 Notes, 2022 Notes and 2024 Notes) (filed as Exhibit 4.2 to the Registrant's Current Report on Form 8-K (Date of Report: July 29, 2015) filed July 31, 2015 and incorporated herein by reference).
4.7	—	Seventh Supplemental Indenture dated as of August 15, 2017, to Indenture dated as of February 27, 2009 between Noble Energy, Inc. and Wells Fargo Bank, National Association, as Trustee, relating to senior debt securities of Noble Energy, Inc. (filed as Exhibit 4.1 to the Registrant's Current Report on Form 8-K (Date of Report: August 15, 2017) filed August 15, 2017 and incorporated herein by reference).
4.8	—	Indenture dated as of October 14, 1993 between the Registrant and US Trust Company of Texas, N.A., as Trustee, relating to the Registrant's 7¼% Notes Due 2023 (including the form of 2023 Notes) (filed in paper with the SEC as Exhibit 4.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 1993 on November 12, 1993 and incorporated herein by reference).
4.9	—	Indenture dated as of April 1, 1997 between the Registrant and US Trust Company of Texas, N.A., as Trustee, relating to senior debt securities of Noble Energy, Inc. (filed with the SEC as Exhibit 4.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 1997 on May 9, 1997 (File No. 001-07964) and incorporated herein by reference).
4.10	—	First Indenture Supplement dated as of April 2, 1997, to Indenture dated as of April 1, 1997, between the Registrant and US Trust Company of Texas, N.A., as Trustee, relating to the Registrant's 8% Senior Notes Due 2027 (including the form of 2027 Notes) (filed with the SEC as Exhibit 4.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 1997 on May 9, 1997 (File No. 001-07964) and incorporated herein by reference).
4.11	—	Second Indenture Supplement, dated as of August 1, 1997, to Indenture dated as of April 1, 1997, between the Registrant and US Trust Company of Texas, N.A. as trustee, relating to the Registrant's 7¼% Senior Debentures Due 2097 (including the form of 2097 Notes) (filed with the SEC as Exhibit 4.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 1997 on August 13, 1997 (File No. 001-07964) and incorporated herein by reference).
10.1	—	Credit Agreement, dated October 14, 2011, among Noble Energy, Inc., JPMorgan Chase Bank, N.A., as administrative agent, Citibank N.A., as syndication agent, Bank of America, N.A., Mizuho Corporate Bank, LTD., and Morgan Stanley MUFG Loan Partners, LLC, as documentation agents, and certain other commercial lending institutions named therein (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Report: October 14, 2011) filed October 18, 2011 (File No. 001-07964) and incorporated herein by reference).
10.2	—	Commitment Increase Agreement (Existing Lenders) dated September 28, 2012, among Noble Energy, Inc., JPMorgan Chase Bank, N.A., as administrative agent, and certain other commercial lending institutions party thereto (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Report: September 28, 2012), filed October 2, 2012 (File No. 001-07964) and incorporated herein by reference).
10.3	—	Commitment Increase Agreement (New Lenders) dated September 28, 2012, among Noble Energy, Inc., JPMorgan Chase Bank, N.A., as administrative agent, and certain other commercial lending institutions party thereto (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K (Date of Report: September 28, 2012), filed October 2, 2012 (File No. 001-07964) and incorporated herein by reference).
10.4	—	First Amendment to Credit Agreement, dated October 3, 2013, 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., 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 to the Registrant's Current Report on Form 8-K (Date of Report: October 3, 2013) filed October 9, 2013 (File No. 001-07964) and incorporated herein by reference).
10.5	—	Second Amendment to Credit Agreement, dated August 27, 2015, by and among Noble Energy, Inc., JPMorgan Chase Bank, N.A., as administrative agent, Citibank N.A., as syndication agent, and Bank of America, N.A., Bank of Tokyo-Mitsubishi UFJ, Ltd., Mizuho Bank, Ltd. and DNB Bank ASA, New York Branch as documentation agents, and the other commercial lending institutions party thereto (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Report: August 27, 2015) filed August 31, 2015 and incorporated herein by reference).
10.6	—	Term Loan Agreement as of January 6, 2016 among Noble Energy, Inc., Citibank, N.A., as administrative agent, Mizuho Bank, Ltd., as syndication agent and certain financial institutions as are or may become parties thereto (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Report: January 6, 2016) filed January 7, 2016 and incorporated herein by reference).
10.7*	—	Noble Energy, Inc. Retirement Restoration Plan dated effective as of January 1, 2009 (filed as Exhibit 10.1 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2008 (File No. 001-07964) and incorporated herein by reference).

10.8*	—	Amendment No. 1 to the Noble Energy, Inc. Retirement Restoration Plan, dated effective as of December 31, 2013 (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Report: December 20, 2013) filed December 23, 2013 (File No. 001-07964) and incorporated herein by reference).
10.9*	—	Noble Energy, Inc. Restoration Trust effective August 1, 2002 (filed as Exhibit 10.3 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2002 (File No. 001-07964) and incorporated herein by reference).
10.10*	—	Form of Indemnity Agreement entered into between the Registrant and each of the Registrant's directors and bylaw officers (filed in paper with the SEC as Exhibit 10.18 to the Registrant's Annual Report on Form 10-K405 for the year ended December 31, 1995 on March 25, 1996 (File No. 001-07964) and incorporated herein by reference).
10.11*	—	Noble Energy, Inc. 2005 Non-Employee Director Fee Deferral Plan, dated December 11, 2008, and effective as of January 1, 2009 (filed as Exhibit 10.20 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2008 (File No. 001-07964) and incorporated herein by reference).
10.12*	—	2015 Stock Plan for Non-Employee Directors of Noble Energy, Inc. (as amended and restated effective October 20, 2015) (filed as Exhibit 10.4 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2015 and incorporated herein by reference).
10.13*	—	Form of Stock Option Agreement under the Noble Energy, Inc. 2015 Non-Employee Director Stock Plan (filed as Exhibit 10.7 to the Registrant's Current Report on Form 8-K (Date of Report: January 25, 2016) filed January 29, 2016 and incorporated herein by reference).
10.14*	—	Form of Restricted Stock Agreement under the Noble Energy, Inc. 2015 Non-Employee Director Stock Plan (filed as Exhibit 10.6 to the Registrant's Current Report on Form 8-K (Date of Report: January 25, 2016) filed January 29, 2016 and incorporated herein by reference).
10.15*	—	2005 Stock Plan for Non-Employee Directors of Noble Energy, Inc. (as amended and restated effective October 20, 2015) (filed as Exhibit 10.3 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2015 and incorporated herein by reference).
10.16*	—	Form of Stock Option Agreement under the Noble Energy, Inc. 2005 Non-Employee Director Stock Plan (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005 (File No. 001-07964) and incorporated herein by reference).
10.17*	—	Form of Restricted Stock Agreement under the Noble Energy, Inc. 2005 Non-Employee Director Stock Plan (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Report: January 27, 2009) filed February 2, 2009 (File No. 001-07964) and incorporated herein by reference).
10.18*	—	Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (as amended and restated effective October 20, 2015) (filed as Exhibit 10.2 to Registrant's Quarterly report on Form 10-Q for the quarter ended September 30, 2015 (File No. 001-07964) and incorporated herein by reference).
10.19*	—	Form of Nonqualified Stock Option Agreement under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Report: February 1, 2005) filed February 7, 2005 (File No. 001-07964) and incorporated herein by reference).
10.20*	—	Form of Non-Qualified Stock Option Agreement under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (filed as Exhibit 10.24 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2012 (File No. 001-07964) and incorporated herein by reference).
10.21*	—	Form of Restricted Stock Agreement (two-year vested) under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (filed as Exhibit 10.25 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2012 (File No. 001-07964) and incorporated herein by reference).
10.22*	—	Form of Restricted Stock Agreement (three-year vested awards) under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (filed as Exhibit 10.26 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2012 (File No. 001-07964) and incorporated herein by reference).
10.23*	—	Form of Restricted Stock Agreement (performance-vested) under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (filed as Exhibit 10.27 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2012 (File No. 001-07964) and incorporated herein by reference).
10.24*	—	Form of Non-Qualified Stock Option Agreement under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (effective February 1, 2016) (filed as Exhibit 10.5 to the Registrant's Current Report on Form 8-K (Date of Report: January 25, 2016) filed January 29, 2016 (File No. 001-07964) and incorporated herein by reference).
10.25*	—	Form of Restricted Stock Agreement (two-year time vested for non-PEO executive officers) under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (effective February 1, 2016) (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K (Date of Report: January 25, 2016) filed January 29, 2016 and incorporated herein by reference).
10.26*	—	Form of Restricted Stock Agreement (two-year time vested) under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (effective February 1, 2016) (filed as Exhibit 10.26 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2016 and incorporated herein by reference).

10.27*	—	Form of Performance Award Agreement (3-year performance vested stock and cash) under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (effective February 1, 2016) (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Report: January 25, 2016) filed January 29, 2016 and incorporated herein by reference).
10.28*	—	Form of Cash Award Agreement (two-year vested) under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (effective February 1, 2016) (filed as Exhibit 10.4 to the Registrant's Current Report on Form 8-K (Date of Report: January 25, 2016) filed January 29, 2016 and incorporated herein by reference).
10.29*	—	Form of Restricted Stock Agreement (three-year performance-vested) under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (effective February 1, 2016) (filed as Exhibit 10.8 to the Registrant's Current Report on Form 8-K/A (Date of Report: January 25, 2016) filed February 4, 2016 and incorporated herein by reference).
10.30*	—	Noble Energy, Inc. 2017 Long-Term Incentive Plan (incorporated by reference to Appendix C to the Company's Definitive Proxy Statement on Schedule 14A filed on March 2, 2017).
10.31*	—	Form of Restricted Stock Award (two-year vested) under the Noble Energy, Inc. 2017 Long-Term Incentive Plan (filed as Exhibit 10.5 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017 and incorporated herein by reference).
10.32*	—	Form of Restricted Stock Award (three-year vested) under the Noble Energy, Inc. 2017 Long-Term Incentive Plan (filed as Exhibit 10.6 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017 and incorporated herein by reference).
10.33*	—	Form of Stock Option Award under the Noble Energy, Inc. 2017 Long-Term Incentive Plan (filed as Exhibit 10.7 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017 and incorporated herein by reference).
10.34*	—	Form of Performance Share Award under the Noble Energy, Inc. 2017 Long-Term Incentive Plan (filed as Exhibit 10.8 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017 and incorporated herein by reference).
10.35*	—	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).
10.36*	—	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).
10.37*	—	Amendment to the Noble Energy, Inc. Change of Control Agreement dated effective February 1, 2011 (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K (Date of Report: February 1, 2011), filed February 4, 2011 (File No. 001-07964) and incorporated herein by reference).
10.38*	—	Form of Noble Energy, Inc. Change of Control Agreement (as amended effective January 1, 2008), (filed as Exhibit 10.41 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2007 (File No. 001-07964) and incorporated herein by reference).
10.39*	—	Noble Energy, Inc. Change of Control Severance Plan for Executives, as amended and restated (effective January 30, 2018) filed herewith.
10.40*	—	Termination of Change of Control Agreement dated effective October 21, 2014 by and between Noble Energy, Inc. and David L. Stover (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Report: October 21, 2014) filed October 27, 2014 (File No. 001-07964) and incorporated herein by reference).
10.41*	—	Noble Energy, Inc. Deferred Compensation Plan (formerly known as the Noble Affiliates, Inc. Deferred Compensation Plan) as restated effective August 1, 2001 (filed as Exhibit 10.4 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2002 (File No. 001-07964) and incorporated herein by reference).
10.42*	—	Amendment No. 1 to the Noble Energy, Inc. Deferred Compensation Plan (formerly known as the Noble Affiliates, Inc. Deferred Compensation Plan), dated effective as of January 1, 2014 (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K (Date of Report: December 20, 2013) filed December 23, 2013 (File No. 001-07964) and incorporated herein by reference).
10.43*	—	Noble Energy, Inc. 2005 Deferred Compensation Plan (as amended effective January 1, 2009) (filed as Exhibit 10.31 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2008 (File No. 001-07964) and incorporated herein by reference).
10.44*	—	Amendment No. 1 to the Noble Energy, Inc. 2005 Deferred Compensation Plan, dated effective as of January 1, 2014 (filed as Exhibit 10.3 to the Registrant's Current Report on Form 8-K (Date of Report: December 20, 2013) filed December 23, 2013 (File No. 001-07964) and incorporated herein by reference).
10.45*	—	Amendment No. 2 to the Noble Energy, Inc. 2005 Deferred Compensation Plan, dated effective as of January 1, 2015 (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2016 (File No. 001-07964) and incorporated herein by reference).

10.46*	—	Amendment No. 3 to the Noble Energy, Inc. 2005 Deferred Compensation Plan, dated effective as of August 1, 2016 (filed as Exhibit 10.2 to the Registrant’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2016 (File No. 001-07964) and incorporated herein by reference).
10.47	—	Gas Sale and Purchase Agreement dated March 14, 2012, by and between Noble Energy Mediterranean Ltd. Isramco Negev 2 Limited Partnership, Delek Drilling Limited Partnership, Avner Oil Exploration Limited Partnership, and Dor Gas Exploration Limited Partnership (Sellers) and The Israel Electric Corporation Limited (Purchaser) (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q/A for the quarter ended March 31, 2012 (File No. 001-07964) and incorporated herein by reference).
10.48	—	Amendment No. 1 dated July 22, 2012 to the Gas Sale and Purchase Agreement dated March 14, 2012, by and between Noble Energy Mediterranean Ltd. Isramco Negev 2 Limited Partnership, Delek Drilling Limited Partnership, Avner Oil Exploration Limited Partnership, and Dor Gas Exploration Limited Partnership (Sellers) and The Israel Electric Corporation Limited (Purchaser) (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2012 (File No. 001-07964) and incorporated herein by reference).
10.49*	—	Retention and Confidentiality Agreement between Noble Energy, Inc. and Charles D. Davidson, Chairman and Chief Executive Officer, effective as of August 14, 2014 (filed as Exhibit 10.1 to the Registrant’s Current Report on Form 8-K (Date of Report: August 14, 2014) filed August 19, 2014 (File No. 001-07964) and incorporated herein by reference).
10.50	—	Support Agreement, dated as of January 13, 2017, by and among certain stockholders affiliated with Ares Management, LLC, Noble Energy, Inc., and solely for certain purposes specified therein, Clayton Williams Energy, Inc. (filed as Exhibit 10.1 to the Registrant’s Current Report on Form 8-K (Date of Report: January 13, 2017) filed January 17, 2017 and incorporated herein by reference).
10.51	—	Agreement Not to Dissent, dated as of January 13, 2017, by and among Clayton W. Williams, Jr., Noble Energy, Inc., and solely for certain purposes specified therein, Clayton Williams Energy, Inc. (filed as Exhibit 10.2 to the Registrant’s Current Report on Form 8-K (Date of Report: January 13, 2017) filed January 17, 2017 and incorporated herein by reference).
10.52	—	Agreement Not to Dissent, dated as of January 13, 2017, by and among The Williams Children’s Partnership, Ltd., Noble Energy, Inc., and solely for certain purposes specified therein, Clayton Williams Energy, Inc. (filed as Exhibit 10.3 to the Registrant’s Current Report on Form 8-K (Date of Report: January 13, 2017) filed January 17, 2017 and incorporated herein by reference).
10.53†	—	Noble Energy Mediterranean Ltd. Facility Agreement, dated February 24, 2017 by and between NEML Leviathan Finance Company LTD as Borrower and BNP Paribas, Credit Agricole Corporate and Investment Bank, ING Bank N.V. Natixis and Societe Generale London Branch as Mandated Lead Arrangers (filed as Exhibit 10.9 to the Registrant’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2017 and incorporated herein by reference).
12.1	—	Calculation of ratio of earnings to fixed charges, filed herewith.
21	—	Subsidiaries, filed herewith.
23.1	—	Consent of Independent Registered Public Accounting Firm—KPMG LLP, filed herewith.
23.2	—	Consent of Independent Petroleum Engineers and Geologists—Netherland, Sewell & Associates, Inc., filed herewith.
31.1	—	Certification of the Registrant's Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 USC. Section 7241), filed herewith.
31.2	—	Certification of the Registrant's Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 USC. Section 7241), filed herewith.
32.1	—	Certification of the Registrant’s Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 USC. Section 1350), filed herewith.
32.2	—	Certification of the Registrant’s Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 USC. Section 1350), filed herewith.
99.1	—	Report of Netherland, Sewell & Associates, Inc., filed herewith.
101.INS	—	XBRL Instance Document
101.SCH	—	XBRL Schema Document
101.CAL	—	XBRL Calculation Linkbase Document
101.LAB	—	XBRL Label Linkbase Document
101.PRE	—	XBRL Presentation Linkbase Document
101.DEF	—	XBRL Definition Linkbase Document

* 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.

† Confidential treatment granted under Rule 24b-2 as to certain portions of this exhibit, which are omitted and filed separately with the Commission.

Item 16. Form 10-K Summary

See Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Executive Summary .

GLOSSARY

In this report, the following abbreviations are used:

Bbl	Barrel
BBoe	Billion barrels oil equivalent
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
BCM	Billion cubic meters
BOE	Barrels oil equivalent. Natural gas is converted on the basis of six Mcf of gas per one barrel of crude oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency. Given commodity price disparities, the price for a barrel of crude oil equivalent for natural gas is significantly less than the price for a barrel of crude oil. The price for a barrel of NGL is also less than the price for a barrel of crude oil.
Boe/d	Barrels oil equivalent per day
Btu	British thermal unit
FPSO	Floating production, storage and offloading vessel
GHG	Greenhouse gas emissions
GSPA	Gas Sales Purchase Agreement
HH	Henry Hub index
IDP	Integrated Development Plan
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
MBbl/d	Thousand barrels per day
MBoe/d	Thousand barrels oil equivalent per day
Mcf	Thousand cubic feet
MMBbls	Million barrels
MMBoe	Million barrels oil equivalent
MMBtu	Million British thermal units
MMBtu/d	Million British thermal units per day
MMcf/d	Million cubic feet per day
MMcfe/d	Million cubic feet equivalent per day
MMgal	Million gallons
NGLs	Natural gas liquids
NYMEX	The New York Mercantile Exchange
OPEC	The Organization of Petroleum Exporting Countries
PSC	Production sharing contract
Tcf	Trillion cubic feet
US GAAP	United States generally accepted accounting principles
WTI	West Texas Intermediate index

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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:	February 20, 2018	By: /s/ David L. Stover David L. Stover, Chairman of the Board, President and Chief Executive Officer
Date:	February 20, 2018	By: /s/ Kenneth M. Fisher Kenneth M. Fisher, Executive Vice President, Chief Financial Officer
Date:	February 20, 2018	By: /s/ Dustin A. Hatley Dustin A. Hatley, Vice President, Chief Accounting Officer and Controller

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Capacity in which signed	Date
/s/ David L. Stover David L. Stover	Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)	February 20, 2018
/s/ Kenneth M. Fisher Kenneth M. Fisher	Executive Vice President, Chief Financial Officer (Principal Financial Officer)	February 20, 2018
/s/ Dustin A. Hatley Dustin A. Hatley	Vice President, Chief Accounting Officer and Controller (Principal Accounting Officer)	February 20, 2018
/s/ Jeffrey L. Berenson Jeffrey L. Berenson	Director	February 20, 2018
/s/ Michael A. Cawley Michael A. Cawley	Director	February 20, 2018
/s/ Edward F. Cox Edward F. Cox	Director	February 20, 2018
/s/ James E. Craddock James E. Craddock	Director	February 20, 2018
/s/ Thomas J. Edelman Thomas J. Edelman	Director	February 20, 2018
/s/ Kirby L. Hedrick Kirby L. Hedrick	Director	February 20, 2018
/s/ Holli C. Ladhani Holli C. Ladhani	Director	February 20, 2018
/s/ Scott D. Urban Scott D. Urban	Director	February 20, 2018

/s/ William T. Van Kleef William T. Van Kleef	Director	February 20, 2018
/s/ Molly K. Williamson Molly K. Williamson	Director	February 20, 2018

Wheeling Creek Midstream, LLC
1401 McKinney Street, Suite 2700
Houston, TX 77010

December 7, 2017

Noble Energy, Inc.
Noble Energy US Holdings, LLC
1001 Noble Energy Way
Houston, Texas 77070
Attention: Secretary

Re: Amendment and Additional Agreements Related to the Purchase Agreement

Ladies and Gentlemen:

Reference is made to that certain Purchase Agreement (as amended, the " Purchase Agreement "), made and entered into as of May 17, 2017, by and among Wheeling Creek Midstream, LLC, a Delaware limited liability company (" Buyer "), and each of Noble Energy US Holdings, LLC, a Delaware limited liability company (" Noble Holdings "), and Noble Energy, Inc., a Delaware Corporation (" Noble Parent " and, each and together with Noble Holdings as the context may require, " Seller "). Capitalized terms used herein but not otherwise defined herein shall have the meaning ascribed to them in the Purchase Agreement.

Notwithstanding anything to the contrary in the Purchase Agreement or any other agreement between the Parties (collectively, " Transaction Documents "), the Parties hereby agree that:

A. Outside Date . The Outside Date shall be 5:00 p.m., Houston time, on June 30, 2018 (the " New Outside Date ") and Section 7.1(b)(i) of the Purchase Agreement shall be deemed amended to reflect the New Outside Date.

B. Deposit .

1. The amount of the Deposit as defined in Section 1.3(a) of the Purchase Agreement shall be $5,000,000 (the " New Deposit Amount ").

2. In any event, the Deposit shall be returned to Buyer upon the earlier to occur of (i) the New Outside Date and (ii) termination of the Purchase Agreement for any reason, free and clear of any claims thereon by Seller.

3. Upon execution of this letter agreement, and as a condition to the effectiveness of this letter agreement with respect to Buyer, Buyer and Noble Holdings shall execute and deliver Joint Instructions to the Bank, instructing the Bank to disburse (by wire transfer of immediately available funds in Dollars to an account designated by Buyer) all amounts in the Deposit Account other than the New Deposit Amount, which funds shall be disbursed free and clear of any claims thereon by Seller.

4. Notwithstanding the foregoing, references in Section 7.3(c) of the Purchase Agreement to "the amount of the Deposit" shall be deemed to continue to refer to $38,250,000.

C. Seller Discussions .

1. Section 5.14 of the Purchase Agreement shall be deleted in its entirety and replaced with the following: "[Reserved]".

2. Without limiting the other provisions of the Purchase Agreement, Seller, Seller's Affiliates and its and their Representatives may discuss and negotiate with, and furnish information to, CNX Gas Company LLC and its Affiliates (collectively, the " CONSOL Parties ") and its and their Representatives, with respect to a settlement of the CONSOL Litigation and certain other disputes (which may include discussions and negotiations with respect to a potential sale of the CONE Interests and/or Subject Units) and a potential reorganization or other business restructuring of CONE Gathering, the General Partner and the Partnership Entities; *provided* , that Seller shall keep Buyer reasonably apprised of all such discussions and negotiations with the CONSOL Parties.

3. At any time while the Purchase Agreement is in effect, if Seller desires to enter into a *bona fide* definitive written agreement with a CONSOL Party regarding terms of a settlement or other transaction with the CONSOL Parties, and such settlement or other transaction involves the direct or indirect sale, transfer or other disposition of the interests of Seller or its Affiliates with respect to the NBLM Interests, CONE Interests, General Partner Interest or Subject Units to the CONSOL Parties, Seller shall have the right to terminate the Purchase Agreement upon entry into such definitive agreement by written notice delivered to Buyer.

D. Closing . In addition to the obligations of Buyer to consummate the transactions contemplated by the Purchase Agreement being subject to the fulfillment, at or prior to the Closing, of the conditions set forth in Section 6.1 of the Purchase Agreement and each of the conditions in Section 6.2 of the Purchase Agreement being met or waived by Buyer, Buyer's obligation is also subject to (and Section 6.2 of the Purchase Agreement will be deemed amended to include) the restructuring with respect to the governance, operational and economic structure of CONE Gathering, the General Partner and the Partnership Entities in a manner acceptable to Buyer in its sole discretion.

E. Miscellaneous . Article IX of the Purchase Agreement is hereby incorporated by reference herein *mutatis mutandis* . The provisions of this letter agreement shall be deemed agreements and covenants for all purposes under the Purchase Agreement. Further, this letter agreement shall be deemed an amendment of the Purchase Agreement; provided that, other than as expressly set forth in this letter agreement, this letter agreement shall not constitute an amendment or waiver of any provisions of the Transaction Documents and shall not abrogate or modify any Party's rights or claims with respect to the Transaction Documents or transactions contemplated thereby (which such rights and claims are expressly reserved), and each Transaction Document, as specifically modified by this letter agreement, shall continue to be in full force and effect.

[Signature Page Follows]

Sincerely,

Wheeling Creek Midstream, LLC

By: /s/ Dheeraj Verma
Name: Dheeraj Verma
Title:

Agreed to and accepted as of the date first written above:

Noble Energy US Holdings, LLC

By: /s/ Aaron G. Carlson
Name: Aaron G. Carlson
Title: Secretary

Noble Energy, Inc.

By: /s Aaron G. Carlson
Name: Aaron G. Carlson
Title: Vice President

Exhibit 10.39

NOBLE ENERGY, INC.
2016 CHANGE OF CONTROL SEVERANCE PLAN FOR EXECUTIVES

THIS 2016 CHANGE OF CONTROL SEVERANCE PLAN FOR EXECUTIVES, made and executed at Houston, Texas, by Noble Energy, Inc., a Delaware corporation (the "Company"),

WITNESSETH THAT:

WHEREAS, the Company maintains the Noble Energy, Inc. Change of Control Severance Plan for Executives to provide for the payment of severance benefits to certain executives of the Company and its participating affiliates whose employment with the Company or such an affiliate terminates under certain circumstances following a Change of Control of the Company;

WHEREAS, Section 4.5 of the Plan provides that the Plan may be amended by resolution adopted by the Board provided that no such amendment that would adversely affect the benefits or protections provided under the Plan to any individual who is a Covered Employee on the date the amendment is adopted shall be effective as it relates to such individual unless no Change of Control occurs within one year after such adoption; and

WHEREAS, the Company now desires to amend and restate the Plan;

NOW, THEREFORE, the Plan is hereby amended and restated in its entirety to update Schedule A to reflect the addition of new positions to the list of Senior Executives identified as Covered Employees (the "List") and remove a position from the List that is no longer utilized as a position or title by the Company effective as of January 30, 2018.

ARTICLE I.

DEFINITIONS

1.1 **Definitions** . Where the following words and phrases appear in the Plan, they shall have the respective meanings set forth below, unless their context clearly indicates to the contrary.

(a) ***"Administrator"*** shall mean the Chief Executive Officer or his or her designee.

(b) ***"Affiliated Company"*** shall mean any incorporated or unincorporated trade or business or other entity or person, other than the Company, that along with the Company is considered a single employer under Code section 414(b) or Code section 414(c); provided, however, that (i) in applying Code section 1563(a)(1), (2), and (3) for the purposes of determining a controlled group of corporations under Code section 414(b), the phrase "at least 50 percent" shall be used instead of the phrase "at least 80 percent" in each place the phrase "at least 80 percent" appears in Code section 1563(a)(1), (2), and (3), and (ii) in applying Treas. Reg. section 1.414(c)-2 for the purposes of determining trades or businesses (whether or not incorporated) that are under common control for the purposes of Code section 414(c), the phrase "at least 50 percent" shall be used instead of the phrase "at least 80 percent" in each place the phrase "at least 50 percent" appears in Treas. Reg. section 1.414(c)-2.

(c) " ***Annual Cash Compensation*** " shall mean, with respect to a Covered Employee, such Covered Employee's annualized salary in effect on the date of the earliest Change of Control to occur during the 18-month period prior to the date of such Covered Employee's Involuntary Termination, plus the greater of (1) such Covered Employee's annual target bonus for the then-current annual bonus period, or (2) the average annual bonus paid or payable by the Employer to such Covered Employee for the three-year period (or for the period of such Covered Employee's employment, if such Covered Employee has not been employed for all of such three-year period) immediately preceding the date of such Change of Control.

(d) " ***Applicable Factor*** " shall mean the factor specified as applicable to the Chief Executive Officer, a Senior Executive and a Key Executive, respectively, on the attached Schedule A.

(e) " ***Board*** " shall mean the Board of Directors of the Company.

(f) A " ***Change of Control*** " shall be deemed to have occurred if:

(1) individuals who, as of the Effective Date, constitute the Board (the "Incumbent Board") cease for any reason to constitute at least fifty-one percent (51%) of the Board, provided that any person becoming a director subsequent to the Effective Date whose election, or nomination for election, by the Company's stockholders was approved by a vote of at least a majority of the directors then comprising the Incumbent Board shall be, for purposes of the Plan, considered as though such person were a member of the Incumbent Board;

(2) the stockholders of the Company shall approve a reorganization, merger or consolidation, in each case, with respect to which persons who were the stockholders of the Company immediately prior to such reorganization, merger or consolidation do not, immediately thereafter, own outstanding voting securities representing at least fifty-one percent (51%) of the combined voting power entitled to vote generally in the election of directors ("Voting Securities") of the reorganized, merged or consolidated company;

(3) the stockholders of the Company shall approve a liquidation or dissolution of the Company or a sale of all or substantially all of the stock or assets of the Company; or

(4) any “person,” as that term is defined in Section 3(a)(9) of the Securities Exchange Act of 1934, as amended (the “Exchange Act”) (other than the Company, any of its subsidiaries, any employee benefit plan of the Company or any of its subsidiaries, or any entity organized, appointed or established by the Company for or pursuant to the terms of such a plan), together with all “affiliates” and “associates” (as such terms are defined in Rule 12b-2 under the Exchange Act) of such person (as well as any “Person” or “group” as those terms are used in Sections 13(d) and 14(d) of the Exchange Act), shall become the “beneficial owner” or “beneficial owners” (as defined in Rules 13d-3 and 13d-5 under the Exchange Act), directly or indirectly, of securities of the Company representing in the aggregate twenty-five percent (25%) or more of either the then outstanding shares of common stock, par value $0.01 per share, of the Company (“Common Stock”) or the Voting Securities of the Company, in either such case other than solely as a result of acquisitions of such securities directly from the Company. Without limiting the foregoing, a person who, directly or indirectly, through any contract, arrangement, understanding, relationship or otherwise has or shares the power to vote, or to direct the voting of, or to dispose, or to direct the disposition of, Common Stock or other Voting Securities of the Company shall be deemed the beneficial owner of such Common Stock or Voting Securities.

Notwithstanding the foregoing, a “Change of Control” of the Company shall not be deemed to have occurred for purposes of paragraph (4) of this Section 1.1(f) solely as the result of an acquisition of securities by the Company which, by reducing the number of shares of Common Stock or other Voting Securities of the Company outstanding, increases (i) the proportionate number of shares of Common Stock beneficially owned by any person to twenty-five percent (25%) or more of the shares of Common Stock then outstanding or (ii) the proportionate voting power represented by the Voting Securities of the Company beneficially owned by any person to twenty-five percent (25%) or more of the combined voting power of all then outstanding Voting Securities; provided, however, that if any person referred to in clause (i) or (ii) of this sentence shall thereafter become the beneficial owner of any additional shares of Common Stock or other Voting Securities of the Company (other than a result of a stock split, stock dividend or similar transaction), then a Change of Control of the Company shall be deemed to have occurred for purposes of paragraph (4) of this Section 1.1(f).

(g) “ ***Chief Executive Officer*** ” shall mean the individual who is the Chief Executive Officer of the Company.

(h) “ ***Code*** ” shall mean the Internal Revenue Code of 1986, as amended.

(i) “ ***Company*** ” shall mean Noble Energy, Inc., a Delaware corporation.

(j) A "***Constructive Termination***" shall be deemed to have occurred with respect to a Covered Employee if the Employer without the consent of the Covered Employee takes any of the following actions:

(1) within two (2) years after a Change of Control occurs, demotes such Covered Employee to a lesser position, in title or responsibility, as compared to the highest position held by him or her with the Employer at the earlier of the occurrence of a Change of Control or the date on which a tentative agreement is reached by the Employer or a public announcement is made regarding a proposed Change of Control that ultimately occurs, resulting in a material diminution in (i) the Covered Employee's authority, duties or responsibilities, (ii) the authority, duties or responsibilities of the supervisor to whom the Covered Employee is required to report, including the requirement that the Covered Employee report to a corporate officer or employee instead of reporting directly to the Board, or (iii) the budget over which the Covered Employee retains authority;

(2) within two (2) years after a Change of Control occurs, reduces such Covered Employee's total annual compensation (i.e., the sum of his or her annual salary, his or her target bonus under the Employer's annual incentive bonus plan or similar plan in effect at the applicable time and the value of other employment benefits provided to such Covered Employee by the Employer) below the level in effect at the earlier of the occurrence of a Change of Control or the date on which a tentative agreement is reached by the Employer or a public announcement is made regarding a proposed Change of Control that ultimately occurs, if such reduction in total annual compensation is a material negative change to the Covered Employee in his or her employment relationship with the Employer; or

(3) within one (1) year after a Change of Control occurs, requires such Covered Employee to relocate to a principal place of employment that is more than fifty (50) miles from the location where he or she was principally employed immediately prior to the Change of Control.

(k) "***Covered Employee***" shall mean an individual who is the Chief Executive Officer, a Senior Executive or a Key Executive, excluding, however, any individual who is a party to an individual written change of control agreement with the Employer providing severance payments upon such individual's termination of employment with the Employer.

(l) "***Effective Date***" shall mean December 7, 2016.

(m) "***Employer***" shall include the Company, Noble Energy Services, Inc. and each other entity or organization that adopts the Plan in accordance with the provisions of Section 4.4 of the Plan and their successors.

(n) "***Involuntary Termination***" shall mean a Covered Employee's Separation from Service which:

(1) occurs within two (2) years after a Change of Control occurs and does not result from a voluntary resignation by the Covered Employee; or

(2) results from a resignation by a Covered Employee under the following circumstances: (A) within thirty (30) days after the initial existence of a condition giving rise to a Constructive Termination the Covered Employee provides written notice to the Employer of his or her belief that such condition exists and describing the condition believed to constitute the basis for a Constructive Termination, (B) the Employer fails to remedy the condition within the thirty (30) day period immediately following the date its receives such notice, and (C) the Covered Employee resigns after the end of such thirty (30) day period during which the Employer failed to remedy the condition but no later than the date which is ninety (90) days after the initial existence of the condition giving rise to a Constructive Termination applicable to him or her;

provided, however, that the term "Involuntary Termination" shall not include a Termination for Cause or a Covered Employee's Separation from Service as a result of such Covered Employee's death, disability under circumstances entitling him or her to benefits under the Employer's long-term disability plan, or Retirement.

(o) ***"Key Executive"*** shall mean a Covered Employee who is employed by the Employer in a job category or position specified as a Key Executive job category or position on the attached Schedule A.

(p) ***"Payment Date"*** shall mean the date chosen by the Employer that is no later than seventy (70) days after the date of such Covered Employee's Involuntary Termination.

(q) ***"Plan"*** shall mean, as applicable, the Noble Energy, Inc. Change of Control Severance Plan for Executives and/or the Noble Energy, Inc. 2016 Change of Control Severance Plan for Executives.

(r) " ***Retirement*** " shall mean a Covered Employee's voluntary resignation on or after the date as of which he or she either (1) has attained age fifty-five (55) and completed a five (5) year Period of Service (within the meaning of the Noble Energy, Inc. 401(k) Plan as in effect immediately prior to a Change in Control), or (2) has attained age sixty-five (65) (regardless of the length of his or her prior Period of Service), excluding in either case, however, a resignation at the request of the Employer or a resignation that occurs within ninety (90) days after an event giving rise to a Constructive Termination applicable to such Covered Employee with respect to which the requirements set forth in Section 1.1(n)(2) have been satisfied.

(s) **" *Senior Executive* "** shall mean a Covered Employee who is employed by the Employer in a job category or position specified as a Senior Executive job category or position on the attached Schedule A.

(t) ***"Separation from Service"*** shall mean, with respect to a Covered Employee, such Covered Employee's separation from service (within the meaning of Code section 409A and the regulations and other guidance promulgated thereunder) with the group of employers that includes the Company and each Affiliated Company. With respect to services as an employee, an employee's Separation from Service shall be deemed to occur on the date as of which the employee and his or her employer reasonably anticipate that no further services will be performed after such date or that the level of bona fide services the employee will perform after such date (whether as an employee or an independent contractor) will permanently decrease to no more than 20 percent of the average level of bona fide services performed (whether as an employee or an independent contractor) over the immediately preceding 36-month period (or the full period of services to the employer if the employee has been providing services to the employer less than 36 months).

(u) **" *Termination for Cause* "** shall mean an Employer's or Affiliated Company's termination of a Covered Employee's employment with such Employer or Affiliated Company because of (1) the willful and continued failure by such Covered Employee to perform the duties of his or her position with such Employer or Affiliated Company or his or her continued failure to perform the duties reasonably requested or reasonably prescribed by the Board (other than as a result of such Covered Employee's death or disability), (2) the engaging by such Covered Employee in conduct involving a material misuse of the funds or property of an Employer or Affiliated Company, (3) the gross negligence or willful misconduct by such Covered Employee in the performance of his or her duties that results in, or causes, material monetary harm to an Employer or Affiliated Company, (4) such Covered Employee's commission of a felony or a civil or criminal offense involving moral turpitude, or (5) such Covered Employee's material violation of the Company's Code of Conduct. A Covered Employee's Termination for Cause shall be made only after reasonable notice to such Covered Employee and an opportunity for such Covered Employee, together with counsel, to appear before the Board. A Covered Employee's Termination for Cause shall be effective only if agreed upon by a majority of the directors of the Board.

(v) **" *Welfare Benefit Coverages* "** shall mean the medical, dental, vision and life insurance coverages provided by the Employer to its active employees.

1.2 **Number and Gender.** Wherever appropriate herein, words used in the singular shall be considered to include the plural and the plural to include the singular. The masculine gender, where appearing in the Plan, shall be deemed to include the feminine gender.

1.3 **Headings.** The headings of Articles and Sections herein are included solely for convenience and if there is any conflict between such headings and the text of the Plan, the text shall control.

ARTICLE II.

SEVERANCE BENEFITS

2.1 **Severance Benefits.** Subject to the further provisions of this Article II, if a Covered Employee's Separation from Service occurs by reason of an Involuntary Termination, the Employer shall:

(a) pay to such Covered Employee when due under the Employer's normal payroll procedures all unpaid salary due to such Covered Employee in the performance of his or her duties for the Employer through the date of such Involuntary Termination;

(b) pay to such Covered Employee on his or her Payment Date an amount in cash equal to such Covered Employee's Annual Cash Compensation multiplied by the Applicable Factor that applies to such Covered Employee;

(c) pay to such Covered Employee on his or her Payment Date an amount in cash equal to such Covered Employee's prorata (measured as the number of days expired, as of the annual date of such Involuntary Termination, in the then-current annual bonus period, divided by 365) target bonus for the then-current annual bonus period;

(d) within thirty (30) days of receiving a detailed invoice for same, reimburse such Covered Employee, up to a maximum cumulative amount of $15,000, for the reasonable fees of no more than one (1) out-placement or similar service provider engaged by such Covered Employee to assist in finding employment opportunities for such Covered Employee during the one-year period following the date of such Involuntary Termination, provided that all reimbursements to be made pursuant to this Section 2.1(d) shall be made to such Covered Employee no later than the end of the second calendar year following the calendar year in which such Covered Employee's Separation from Service occurs; and

(e) provide such Covered Employee with continued Welfare Benefit Coverages for himself or herself and, where applicable, his or her eligible dependents, for the period of months following the date of such Involuntary Termination that is specified for such Covered Employee on the attached Schedule A; provided, however, that such Covered Employee must continue to pay the premiums paid by active employees of the Employer from time to time for such coverages. Such benefit rights shall apply only to those Welfare Benefit Coverages that the Employer has in effect from time to time for active employees. If the Employer determines that providing one of the Welfare Benefit Coverages under a welfare plan maintained by the Employer will fail to satisfy a nondiscrimination requirement that the Employer intended such welfare plan to satisfy, then instead of providing such benefit under such welfare plan, the Employer may provide such benefit to or with respect to such Covered Employee under another plan or insurance arrangement. Welfare Benefit Coverages shall immediately end upon the Covered Employee's obtainment of new employment and eligibility for similar Welfare Benefit Coverages (with the Covered Employee being obligated hereunder to promptly report such eligibility to the Employer).

The severance benefits payable under this Section 2.1 shall be deemed to be severance pay subject to any required tax withholding, and shall not constitute compensation that is taken into account for the purposes of determining benefits or allocating contributions under any employee benefit plan maintained by the Employer.

2.2 **Release and Full Settlement**. Any provision of the Plan to the contrary notwithstanding, as a condition to the receipt of any severance benefit hereunder, a Covered Employee whose Separation from Service occurs by reason of an Involuntary Termination shall execute a release in such form as the Company shall determine which shall, to the extent permitted by law, waive all claims and actions against the Company, the Employers and all Affiliated Companies and such other parties and entities as the Company chooses to include in the release. The receipt by such Covered Employee of any benefit provided hereunder shall constitute full settlement of all such claims and causes of action of such Covered Employee.

2.3 **Mitigation.** A Covered Employee shall not be required to mitigate the amount of any payment provided for in this Article II by seeking other employment or otherwise, nor shall the amount of any payment provided for in this Article II be reduced by any compensation or benefit earned by the Covered Employee as the result of employment by another employer or by retirement benefits. The benefits under the Plan are in addition to any other benefits to which a Covered Employee is otherwise entitled.

2.4 **Parachute Payment Limitation**. Any provision of the Plan to the contrary notwithstanding, if a Covered Employee is a “disqualified individual” (as defined in Section 280G of the Code), and the severance benefits provided in Section 2.1, together with any other payments which the Covered Employee has the right to receive, would constitute a “parachute payment” (as defined in Section 280G of the Code), the severance benefits provided hereunder that constitute a parachute payment and are exempt from the requirements of Section 409A of the Code shall be either (a) reduced (but not below zero) so that the aggregate present value of such payments received by the Covered Employee from the Employer will be one dollar ($1.00) less than three times the Covered Employee’s “base amount” (as defined in Section 280G of the Code) and so that no portion of such payments received by the Covered Employee shall be subject to the excise tax imposed by Section 4999 of the Code, or (b) paid in full, whichever produces the better net after-tax result for the Covered Employee (taking into account any applicable excise tax under Section 4999 of the Code and any applicable income tax). The determinations as to the benefit to be reduced and the amount of reduction shall be made by the Employer in good faith, and such determinations shall be conclusive and binding on the Covered Employee. If a reduced payment is made and through error or otherwise that payment, when aggregated with other payments from the Employer (or its affiliates) used in determining if a “parachute payment” exists, exceeds one dollar ($1.00) less than three (3) times the Covered Employee’s base amount, the Covered Employee shall immediately repay such excess to the Employer upon notification that an overpayment has been made.

2.5 **Six-Month Lookback Alternate Benefits**. Any provision of the Plan to the contrary notwithstanding, if during the six-month period immediately prior to a Change of Control a Covered Employee was employed by the Employer in a job category or position that would provide greater benefits under the Plan than would be provided under the Plan for such Covered Employee with respect to his or her job category or position with the Employer immediately prior to such Change of Control, then in lieu of the benefits applicable under the Plan to such Covered Employee’s job category or position with the Employer immediately prior to such Change of Control, such Covered Employee shall be entitled to receive under the Plan the benefits under the Plan that apply to such Covered Employee's job category or position with the Employer during the six-month period immediately prior to such Change of Control that provides the greatest benefits to such Covered Employee.

2.6 **Special Payment Provisions for Covered Employees Previously Covered Under an Individual Change of Control Agreement** . Certain employees of the Employers have previously entered into individual Change of Control Agreements with their Employer. Any provision of this Plan to the contrary notwithstanding, if any such employee of an Employer who was covered by an individual Change of Control Agreement with an Employer at any time on or after January 1, 2005 becomes entitled to benefits as a Covered Employee under this Plan in replacement of and in connection with the termination of such individual Change of Control Agreement, the amount of benefits to which such Covered Employee is entitled shall be determined under this Plan but the timing of payments under Section 2.1(b) and (c) hereof shall be governed by the payment timing for similar severance benefits set forth in such individual Change of Control Agreement rather than the Payment Date set forth in this Plan.

ARTICLE III.

ADMINISTRATION OF PLAN

3.1 **Plan Administration.** This Plan shall be administered by the Administrator. The Administrator shall have discretionary and final authority to interpret and implement the provisions of this Plan and to determine eligibility for benefits under the Plan. The Administrator shall perform all of the duties and exercise all of the powers and discretion that he or she deems necessary or appropriate for the proper administration of this Plan. Every interpretation, choice, determination or other exercise by the Administrator of any power or discretion given either expressly or by implication to it shall be conclusive and binding upon all parties having or claiming to have an interest under this Plan or otherwise directly or indirectly affected by such action, without restriction, however, upon the right of the Administrator to reconsider or redetermine such action. The Administrator may adopt such rules and regulations for the administration of this Plan as are consistent with the terms hereof, and shall keep adequate records of its proceedings and acts. The Administrator may employ such agents, accountants and legal counsel (who may be agents, accountants and legal counsel for an Employer) as may be appropriate for the administration of the Plan. All reasonable administration expenses incurred by the Administrator in connection with the administration of the Plan shall be paid by the Employer.

3.2 **Mandatory Arbitration .** Any dispute arising in connection with this Plan shall be finally resolved by arbitration in Houston, Texas pursuant to and in accordance with the National Rules for the Resolution of Employment Disputes of the American Arbitration Association. Such arbitration shall be the sole and exclusive procedure available to a Covered Employee for resolving a dispute regarding a denied claim by the Administrator. The Covered Employee and the Employer shall share equally the cost of such arbitration, including but not limited to the fees of the arbitrator and reasonable attorneys' fees, unless the arbitrator determines otherwise. The arbitrator's decision shall be final and legally binding on both parties. Judgment upon the arbitrator's decision may be entered in any court of appropriate jurisdiction, and may not be challenged in any court, either at the place of arbitration or elsewhere. This Section shall be governed by the provisions of the Federal Arbitration Act.

ARTICLE IV.

GENERAL PROVISIONS

4.1 **Funding.** The benefits provided under the Plan shall be unfunded and shall be provided from the Employer's general assets.

4.2 **Cost of Plan.** The entire cost of the Plan shall be borne by the Employer and no contributions shall be required of the Covered Employees.

4.3 **Plan Year.** The Plan shall operate on a plan year consisting of the twelve consecutive month period commencing on January 1 of each year.

4.4 **Other Participating Employers.** With the written consent of the Administrator, any entity or organization eligible by law to participate in the Plan may adopt the Plan and become a participating Employer hereunder by executing and delivering a written instrument evidencing such adoption to the Secretary of the Company. Such written instrument shall specify the effective date of the adoption of the Plan by such adopting Employer, may incorporate specific provisions relating to the operation of the Plan which apply to the adopting Employer only, and shall become, as to such adopting Employer and its employees, a part of the Plan. Each adopting Employer shall be conclusively presumed to have agreed to be bound by the terms of the Plan as amended from time to time. The provisions of the Plan shall be applicable with respect to each Employer separately, and amounts payable hereunder shall be paid by the Employer which employs the particular Covered Employee.

4.5 **Amendment and Termination .**

(a) Prior to a Change of Control, the Plan may be amended or modified in any respect and may be terminated, on behalf of all Employers, by resolution adopted by the Board; provided, however, that:

(1) no such amendment, modification or termination which would adversely affect the benefits or protections provided under the Plan to any individual who is a Covered Employee on the date such amendment, modification or termination is adopted shall be effective as it relates to such individual unless no Change of Control occurs within one year after such adoption, and any such attempted amendment, modification or termination adopted within one year prior to a Change

of Control shall be null and void ab initio as it relates to such individual (it being understood that the removal of a Covered Employee from participation in the Plan shall, for the purposes of this Section, constitute an adverse affect to the benefits or protections provided under the Plan to any Covered Employee so removed); and

(2) the Plan may not be amended, modified or terminated (i) at the request of a third party who has indicated an intention or taken steps to effect a Change of Control, or who effectuates a Change of Control, or (ii) in connection with, or in anticipation of, a Change of Control which actually occurs, if such amendment, modification or termination would adversely affect the benefits or protections provided under the Plan to any individual who is a Covered Employee on the date such amendment, modification or termination is adopted, and in either case, any such attempted amendment, modification or termination shall be null and void ab initio as it relates to such individual. Any action taken to amend, modify or terminate the Plan that is taken after the execution of an agreement providing for a transaction or transactions that, if consummated, would constitute a Change of Control, shall conclusively be presumed to have been taken in connection with a Change of Control.

(b) Upon and after the occurrence of a Change in Control, the Plan may not be amended or modified in any manner which would adversely affect the benefits or protections provided under the Plan to any individual who is a Covered Employee on the date the Change of Control occurred, and any such attempted amendment, modification or termination shall be null and void ab initio as it relates to such individual.

(c) Notwithstanding the foregoing provisions of this Section 4.5, if any compensation or benefit provided by the Plan may result in being subject to the tax imposed by Section 409A of the Code, the Board may modify the Plan as necessary or appropriate in the best interests of the Covered Employees (1) to exclude such compensation or benefit from being deferred compensation within the meaning of Section 409A of the Code, or (2) to comply with the provisions of Section 409A of the Code and its related Code provisions (and the rules, regulations and other regulatory guidance relating thereto); provided, however, that no amendment made pursuant to the provisions of this Section 4.5(c) shall reduce the value of the compensation or benefits that would be payable to a Covered Employee in connection with his or her Involuntary Termination following a Change of Control without the written consent of such Covered Employee.

4.6 **No Contract of Employment .** The adoption and maintenance of the Plan shall not be deemed to be a contract of employment between the Employer and any person or to be consideration for the employment of any person. Nothing herein contained shall be deemed to give any person the right to be retained in the employ of the Employer or to restrict the right of the Employer to discharge any person at any time nor shall the Plan be deemed to give the Employer the right to require any person to remain in the employ of the Employer or to restrict any person’s right to terminate his or her employment at any time.

4.7 **Severability**. Any provision in the Plan that is prohibited or unenforceable in any jurisdiction by reason of applicable law shall, as to such jurisdiction, be ineffective only to the extent of such prohibition or unenforceability without invalidating or affecting the remaining provisions hereof, and any such prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction.

4.8 **Nonalienation**. A Covered Employee shall have no right or ability to pledge, hypothecate, anticipate, assign or otherwise transfer any benefit, interest or right under the Plan, except by will or the laws of descent and distribution, and no benefit, interest or right of a Covered Employee under the Plan shall be liable for or subject to any debt, obligation or liability of such Covered Employee.

4.9 **Effect of Plan**. In the event of the occurrence of a Change of Control prior to December 7, 2016, this restatement shall be void and of no effect and the Plan as in effect prior to this restatement shall continue in effect uninterrupted. If no Change of Control occurs prior to December 7, 2016, then this Plan shall take effect and, effective as of such date, this Plan, the Noble Energy, Inc. 2016 Change of Control Severance Plan, the Noble Energy, Inc. 2016 Severance Benefit Plan, and the individual Change of Control Agreements between an Employer and an Employee signed by the parties shall be the sole and exclusive plans, programs and agreements providing severance benefits to Employees of the Employers. All oral or written policies of the Employer and all oral or written communications to Covered Employees with respect to the subject matter of the Plan that were written or communicated prior to the Effective Date are hereby null and void and of no further force and effect. The Plan shall be binding upon the Employer and any successor of the Employer, by merger or otherwise, and shall inure to the benefit of and be enforceable by the Covered Employees. In addition, upon the occurrence of a Change of Control, all rights of a Covered Employee to eligibility and participation under the Plan shall vest and shall be considered a contract right enforceable against the Employer and any successors thereto, subject to the terms and conditions of the Plan.

4.10 **Code Section 409A**. The Plan is intended to provide compensation and benefits that are not subject to the tax imposed under Section 409A of the Code, and shall be interpreted and administered to the extent possible in accordance with such intent, and any reimbursements or in-kind benefits provided under this Plan that are not exempt from the application of Section 409A of the Code shall be made or provided in accordance with the requirements of Section 409A of the Code, including, where applicable, the requirement that (i) any reimbursement is for expenses incurred during the period of time specified in this Plan, (ii) the amount of expenses eligible for reimbursement, or in-kind benefits provided, during a calendar year may not affect the expenses eligible for reimbursement, or in-kind benefits to be provided, in any other calendar year, (iii) the reimbursement of an eligible expense will be made no later than the last day of the calendar year following the year in which the expense is incurred, and (iv) the right to reimbursement or in-kind benefits is not subject to liquidation or exchange for another benefit. Notwithstanding the preceding, no persons connected with this Plan in any capacity, including but not limited to the Company, the Employers, and any Affiliated Company, and their respective directors, officers, agents and employees, makes any representation, commitment or guarantee that any tax treatment, including but not limited to, federal, state and local income, estate and gift tax treatment, will be applicable with respect to any amounts payable under the Plan or that such tax treatment will apply to a Covered Employee.

4.11 **Governing Law.** The Plan shall be governed and construed in accordance with the laws of the State of Texas (without giving effect to any choice-of-law rules that may require the application of the laws of another jurisdiction).

IN WITNESS WHEREOF, this restated Plan has been executed by the Company on this 30 th day of January 2018

NOBLE ENERGY, INC.

By: /s/ David L. Stover
Name: David L. Stover
Title: President & Chief Executive Officer

SCHEDULE A FOR THE
NOBLE ENERGY, INC.
2016 CHANGE OF CONTROL SEVERANCE PLAN
FOR EXECUTIVES

The Applicable Factor for the Chief Executive Officer is **2.99** , the Applicable Factor for a Senior Executive is **2.5** , and the Applicable Factor for a Key Executive is **2.0** .

The period of months specified for Welfare Benefit Coverages for the purposes of Section 2.1(e) are: twenty-four (24) months for a Key Executive; thirty (30) months for a Senior Executive; and thirty-six (36) months for the Chief Executive Officer.

A Covered Employee employed by the Employer in one of the following positions is a **Senior Executive** :

Executive Vice President, Chief Financial Officer
Executive Vice President, Operations
Sr. Vice President, General Counsel and Secretary
Sr. Vice President, Eastern Mediterranean
Sr. Vice President, US Onshore
Sr. Vice President, Corporate Development
Sr. Vice President, Human Resources and Administration
Sr. Vice President, Global Operations Services
Sr. Vice President, Global Services
Sr. Vice President, Offshore
Sr. Vice President, Midstream

A Covered Employee employed by the Employer in one of the following positions is a **Key Executive** :

Vice President, Exploration

EXHIBIT 12.1

Noble Energy, Inc.

Calculation of Ratio of Earnings to Fixed Charges

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

Exhibit 21.1

NOBLE ENERGY, INC.
SUBSIDIARIES

NAME	JURISDICTION OF ORGANIZATION
Advantage Pipeline Holdings LLC*	Delaware
Advantage Pipeline Logistics LLC*	Texas
Advantage Pipeline Management, LLC*	Texas
Advantage Pipeline, L.L.C.*	Texas
Alba Associates LLC*	Cayman Islands
Alba Plant LLC*	Cayman Islands
AMPCO Marketing, L.L.C.*	Michigan
AMPCO Services, L.L.C.*	Michigan
Atlantic Methanol Associates LLC*	Cayman Islands
Atlantic Methanol Production Company LLC*	Cayman Islands
Atlantic Methanol Services B.V.*	Amsterdam
Black Diamond Gathering Holdings LLC	Delaware
Black Diamond Gathering LLC*	Delaware
Blanco River DevCo GP LLC	Delaware
Blanco River DevCo LP	Delaware
Clajon Industrial Gas, Inc. (fka Clayton Williams Company)	Texas
Clayton Williams Pipeline Corporation	Delaware
Colorado River DevCo GP LLC	Delaware
Colorado River DevCo LP	Delaware
CONE Midstream Partners LP*	Delaware
Desta Drilling GP, LLC (fka Larclay GP, LLC)	Texas
Desta Drilling, L.P. (fka Larclay L.P.)	Texas
EDC Ecuador Ltd.	Delaware
EDC South America Limited	Cayman Islands
Energy Development Corporation (Argentina), Inc.	Delaware
Energy Development Corporation (China), Inc.	Delaware
Green River DevCo GP LLC	Delaware
Green River DevCo LP	Delaware
Gunnison River DevCo GP LLC	Delaware
Gunnison River DevCo LP	Delaware
Laramie River DevCo GP LLC	Delaware
Laramie River DevCo LP	Delaware
Leviathan Transportation System Ltd.*	Tel Aviv
MachalaPower Cia. Ltda. (fka Samedan Power)	Cayman Islands
NBL C.V.	Netherlands
NBL Cheetah Limited	Cayman Islands
NBL Congo Holding LLC (fka NBL Nicaragua Holding, LLC)	Delaware
NBL Congo Limited (fka NBL Nicaragua Limited)	Cayman Islands
NBL Eastern Mediterranean Marketing Limited	Cayman Islands
NBL Energy Royalties, Inc. (fka NBL Royalties, Inc.)	Delaware
NBL Gabon Holding, LLC	Delaware
NBL Gabon Limited	Cayman Islands
NBL Gabon LLC	Delaware
NBL Humpback Limited	Cayman Islands
NBL International C.V.	Netherlands
NBL International Finance B.V.	Netherlands
NBL International Holdings, LLC	Delaware
NBL International Risk Management Limited	Cayman Islands
NBL Jordan Marketing Limited*	Cayman Islands
NBL Mexico Holding, LLC	Delaware

NBL Mexico, Inc.	Delaware
NBL Midstream Holdings LLC	Delaware
NBL Midstream, LLC	Delaware

NBL Netherlands B.V.	Netherlands
NBL North American Risk Management, LLC	Delaware
NBL NV 1 Holding LLC	Delaware
NBL NV 1 Limited	Cayman Islands
NBL NV 2 Holding LLC	Delaware
NBL NV 2 Limited	Cayman Islands
NBL Permian LLC	Delaware
NBL Permian Water LLC	Delaware
NBL Rhea Limited	Cayman Islands
NBL Suriname B.V.	Netherlands
NBL Texas, LLC	Delaware
NCWYO Assets LLC	Delaware
NEML Leviathan Finance Company Ltd.	Tel Aviv
Noble Energy (ISE) Limited	United Kingdom
Noble Energy (Oilex) Limited	United Kingdom
Noble Energy Cameroon Limited	Cayman Islands
Noble Energy Canada Inc. (fka Noble Energy Canada LLC)	Delaware
Noble Energy Canada ULC	British Columbia
Noble Energy Capital Limited	United Kingdom
Noble Energy Cyprus Midstream Holding LLC (fka NBL Cameroon Holding, LLC)	Delaware
Noble Energy Cyprus Midstream Limited (fka NBL Cameroon Limited)	Cayman Islands
Noble Energy EG Ltd.	Cayman Islands
Noble Energy EMEA Ventures Limited (fka EDC Ireland)	Cayman Islands
Noble Energy Falklands Holding, LLC	Delaware
Noble Energy Falklands Limited	United Kingdom
Noble Energy Gabon Holding Company, LLC (fka Noble Energy EG Holding Company, LLC)	Delaware
Noble Energy Gabon Limited (fka Noble Energy EG II Limited)	Cayman Islands
Noble Energy Global Ventures Ltd. (fka Noble Energy India Ltd.)	Cayman Islands
Noble Energy International Holdings, Inc.	Delaware
Noble Energy International Holdings, LLC	Delaware
Noble Energy International Ltd (fka Samedan International)	Cyprus
Noble Energy Mediterranean Ltd. (fka Samedan Mediterranean Sea)	Cayman Islands
Noble Energy Mexico, S. de R.L. de C.V.	Mexico
Noble Energy New Ventures, LLC (fka Noble Energy New Ventures, Inc.)	Delaware
Noble Energy Services, Inc.	Delaware
Noble Energy Sierra Leone Holdings, LLC	Delaware
Noble Energy SL Limited (fka Noble Energy Sierra Leone UK Limited)	United Kingdom
Noble Energy US Holdings, LLC	Delaware
Noble Energy WyCo, LLC	Delaware
Noble Midstream GP LLC (fka Noble Energy Midstream GP LLC)	Delaware
Noble Midstream Partners LP* (fka Noble Energy Midstream LP)	Delaware
Noble Midstream Services, LLC (fka Noble DJ Midstream Services Company, LLC)	Delaware
Romere Pass Acquisition L.L.C. (fka Romere Pass Acquisition Corp.)	Delaware
Rosetta Resources Holdings, LLC (fka Calpine Natural Gas Holdings, LLC)	Delaware
Rosetta Resources Michigan Limited Partnership (fka Rosetta Resources Gathering LP)	Delaware
Rosetta Resources Offshore, LLC	Delaware
Rosetta Resources Operating GP, LLC (fka Calpine Natural Gas GP, LLC)	Delaware
Rosetta Resources Operating LP (fka Calpine Natural Gas L.P.)	Delaware
Samedan Methanol	Cayman Islands
Samedan of North Africa, LLC (fka Samedan of North Africa, Inc.)	Delaware
Samedan Pipe Line Corporation	Delaware
San Juan River DevCo GP LLC	Delaware
San Juan River DevCo LP	Delaware

Seven Oaks Insurance Limited	Bermuda
Southwest Royalties, Inc.	Delaware
Tamar 10 Inch Pipeline Ltd.*	Tel Aviv
Tamar Mediterranean Gas Ltd.	Tel Aviv
Trinity River DevCo LLC	Delaware

Warrior Gas Co.	Texas
West Coast Energy Properties GP, LLC	Texas
White Star Insurance LLC	Texas
Yam Tethys Ltd*	Tel Aviv

* Indicates ownership is less than 100%

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

The Board of Directors
Noble Energy, Inc.:

We consent to the incorporation by reference in the registration statement (No. 333-209573) on Form S-3, registration statements (No. 033-54084, 333-39299. 333-108162, 333-118976, 333-124964, 333-143203, 333-143204, 333-158922, 333-177825, 333-191878, 333-205728. 333-217605) on Form S-8, and the Post-Effective Amendment No. 1 to the registration statement (No. 333-204592) on Form S-8 of Noble Energy, Inc. of our reports dated February 20, 2018 , with respect to the consolidated balance sheets of Noble Energy, Inc. as of December 31, 2017 and 2016 , and the related consolidated statements of operations, comprehensive income (loss), shareholders’ equity, and cash flows for each of the years in the three-year period ended December 31, 2017 , and all related financial statement schedules, and the effectiveness of internal control over financial reporting as of December 31, 2017 , which reports appear in the December 31, 2017 annual report on Form 10-K of Noble Energy, Inc.

/s/ KPMG LLP

Houston, Texas
February 20, 2018

Exhibit 23.2

Consent of Independent Petroleum Engineers and Geologists

We consent to the incorporation by reference in the registration statement statement (No. 333-209573) on Form S-3, registration statements (No. 033-54084, 333-39299, 333-108162, 333-118976, 333-124964, 333-143203, 333-143204, 333-158922, 333-177825, 333-191878, 333-205728, 333-217605) on Form S-8, and the Post-Effective Amendment No. 1 to the registration statement (No. 333-204592) on Form S-8 of Noble Energy, Inc. (the "Company") of the reference to Netherland, Sewell & Associates, Inc. and the inclusion of our report dated January 24, 2018 in the Annual Report on Form 10-K for the year ended December 31, 2017 , of the Company and its subsidiaries, filed with the Securities and Exchange Commission.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Danny D. Simmons

Danny D. Simmons, P.E.

President and Chief Operating Officer

Houston, Texas

February 20, 2018

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 annual report on Form 10-K 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: February 20, 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 annual report on Form 10-K 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: February 20, 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 Annual Report of Noble Energy, Inc. (the “Company”) on Form 10-K for the period ended December 31, 2017 (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:	February 20, 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 Annual Report of Noble Energy, Inc. (the "Company") on Form 10-K for the period ended December 31, 2017 (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:	February 20, 2018	*/s/ Kenneth M. Fisher*
		Kenneth M. Fisher
		Chief Financial Officer

January 24, 2018

Mr. William T. Van Kleef
Chairman
Noble Energy, Inc. Audit Committee
1001 Noble Energy Way
Houston, Texas 77070

Dear Mr. Van Kleef:

In accordance with your request, we have audited the estimates prepared by Noble Energy, Inc. (Noble), as of December 31, 2017, of the proved reserves to the Noble interest in certain oil and gas properties located in the United States and throughout the world. It is our understanding that the proved reserves estimated herein constitute all of the proved reserves owned by Noble. Economic analysis was performed by Noble only to confirm economic producibility and determine economic limits for the properties. We have examined the estimates with respect to reserves quantities, reserves categorization, future producing rates, and economic producibility using the definitions set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Rule 4-10(a). The estimates of reserves have been prepared in accordance with the definitions and regulations of the SEC and conform to the FASB Accounting Standards Codification Topic 932, *Extractive Activities-Oil and Gas* . We completed our audit on or about the date of this letter. This report has been prepared for Noble's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

The following table sets forth Noble's estimates of the net reserves, as of December 31, 2017, for the audited properties:

	Net Reserves		
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)
Proved Developed Producing	195,723.088	125,769.168	2,532,492.288
Proved Developed Non-Producing	11,218.954	3,989.500	654,366.768
Proved Undeveloped	249,766.624	98,829.936	4,493,593.600
Total Proved	456,708.672	228,588.608	7,680,422.912

Totals may not add because of rounding.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

When compared on a field-by-field basis, some of the estimates of Noble are greater and some are less than the estimates of Netherland, Sewell & Associates, Inc. (NSAI). However, in our opinion the estimates shown herein of Noble's reserves are reasonable when aggregated at the proved level and have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). Additionally, these estimates are within the recommended 10 percent tolerance threshold set forth in the SPE Standards. We are satisfied with the methods and procedures used by Noble in preparing the December 31, 2017, estimates of reserves, and we saw nothing of an unusual nature that would cause us to take exception with the estimates, in the aggregate, as prepared by Noble.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves included herein have not been adjusted for risk. Noble's estimates do not include probable or possible reserves that may exist for these properties.

Oil, NGL, and gas prices were used only to confirm economic producibility and determine economic limits for the properties. Prices used by Noble either are the contract price or are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2017. For oil and NGL volumes, the average West Texas Intermediate spot price of US$51.34 per barrel is used for the United States properties and the average Brent spot price of US$54.42 per barrel is used for the Equatorial Guinea and Israel properties. These prices are adjusted by field for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of US$2.976 per MMBTU is used for the United States properties and is adjusted by field for energy content, transportation fees, and market differentials. The gas price used for the Equatorial Guinea properties is the fixed contract price of $0.25 per MMBTU and is adjusted for energy content. Gas prices for the Israel properties are based on a weighted average of all sales contracts according to their relative volume. These contract prices are derived from various formulae that include indexation to the Consumer Price Index or the Public Utility Authority. All other prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are US$48.13 per barrel of oil, US$23.02 per barrel of NGL, and US$4.537 per MCF of gas.

Costs were used to confirm economic producibility and determine economic limits for the properties. Operating costs used by Noble are based on historical operating expense records. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs. Headquarters general and administrative overhead expenses of Noble are included to the extent that they are covered under joint operating agreements for the operated properties. Capital costs used by Noble are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Abandonment costs used are Noble's estimates of the costs to abandon the wells, platforms, and production facilities, net of any salvage value. Operating, capital, and abandonment costs are not escalated for inflation.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, estimates of Noble and NSAI are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Noble, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts used to confirm economic producibility and determine economic limits for the properties. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing these estimates.

It should be understood that our audit does not constitute a complete reserves study of the audited oil and gas properties. Our audit consisted primarily of substantive testing, wherein we conducted a detailed review of major properties making up 95 percent of the total proved reserves. In the conduct of our audit, we have not independently verified the accuracy and completeness of information and data furnished by Noble with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties and sales of production. However, if in the course of our examination something came to our attention that brought into question the validity or sufficiency of any such information or data, we did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or had independently verified such information or data. Our audit did not include a review of Noble's overall reserves management processes and practices.

We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to establish the conclusions set forth herein. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

Supporting data documenting this audit, along with data provided by Noble, are on file in our office. The technical persons primarily responsible for conducting this audit meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Mr. Richard B. Talley, Jr., a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2004 and has over 5 years of prior industry experience. Mr. Zachary R. Long, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2007 and has over 2 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E. 102425
Senior Vice President

By: /s/ Zachary R. Long
Zachary R. Long, P.G. 11792
Vice President

Date Signed: January 24, 2018

Date Signed: January 24, 2018

RBT:KNE